RBC Capital Markets®

EQUITY | RESEARCH

RBC Dominion Securities Inc.

Mark Friesen (Analyst)
(403) 299-2389
mark.j.friesen@rbccm.com

Sam Roach (Associate)
(403) 299-5045
sam.roach@rbccm.com

December 13, 2010

This report is priced as of market close December 9, 2010 ET.

All values are in Canadian dollars unless otherwise noted.

For Required Non-U.S. Analyst and Conflicts Disclosures, please see page 198.

Emerging Oil Sands Producers

Initiating Coverage: The Oil Sands Manifesto

Investment Summary & Thesis

We initiate coverage of six emerging oil sands focused companies. We are bullish with respect to the oil sands sector and selectively within this peer group of new players. We see decades of growth in the oil sands sector, much of which is in the control of the emerging companies. Our target prices are based on Net Asset Value (NAV), which are based on a long-term flat oil price assumption of US$85.00/bbl WTI. The primary support for our valuations and our recommendations is our view of each management team's ability to execute projects.

We believe that emerging oil sands companies are an attractive investment opportunity in the near, medium and longer term, but investors must selectively choose the companies with the best assets and greatest likelihood of project execution.

Investment Highlights

- **MEG Energy** is our favourite stock, which we have rated as Outperform, Above Average Risk. We have also assigned an Outperform rating to **Ivanhoe Energy** (Speculative Risk).
- We have rated **Athabasca Oil Sands** and **Connacher Oil & Gas** both as Sector Perform, (Above Average Risk). We have also assigned a Sector Perform rating to **SilverBirch Energy** (Speculative Risk).
- We have rated **OPTI Canada** as Underperform, Speculative Risk.
- **Key Industry Themes** – We believe that industry focus has shifted from a resource capture mentality to a project execution mentality. We believe that the oil sands sector is positioning for another boom in the 2012–2015 timeframe (see Exhibit 37). We expect In-Situ projects with a focus on the Athabasca region will continue to dominate the emerging landscape and we expect economics to favour upstream only projects (i.e., no upgrading). We expect ample shipping capacity on export pipelines for the next decade and plenty of downstream demand for Canadian heavy oil. We expect environmental issues to be of keen consideration but not a deterrent to development.
- **Key Challenges/Opportunities** – Near term, we believe the greatest challenge facing most emerging oil sands companies will be to successfully navigate the regulatory, project financing and project execution process in a timely and disciplined manner. In the medium to longer term, we see industry participants developing new technologies to address the most relevant technical, environmental and financial challenges facing the sector. Developing new production methods and unlocking new play types such as the bitumen carbonates could create tremendous investment returns.
- **Key Conclusions** - We expect emerging oil sands companies to continue to demand capital (we estimate ~$20 billion based on projects in the regulatory queue), some companies to become large and well established oil sands producers over the decade and for emerging oil sands companies to likely be the target of corporate acquisition activity based on the resource and production potential they have captured.

Company	Ticker	Exch	Rating	Risk	Mkt Cap ($mm)	Price	Target	Implied Return	Est. Date of First Production
Athabasca Oil Sands	ATH	T	SP	AA	$5,593	$14.06	$16.00	13.8%	2014
Connacher Oil & Gas	CLL	T	SP	AA	$513	$1.16	$1.50	29.3%	Producing
Ivanhoe Energy	IE	T	O	Spec	$868	$2.42	$3.00	24.0%	2015
MEG Energy	MEG	T	O	AA	$7,390	$39.00	$48.00	23.1%	Producing
OPTI Canada	OPC	T	U	Spec	$194	$0.69	$0.60	-13.0%	Producing
SilverBirch Energy	SBE	V	SP	Spec	$360	$7.20	$8.00	11.1%	2020

Source: RBC Capital Markets

Table of Contents

Comparative Valuation Tables

Exhibit 1: Comparative Valuation: Financial

			Ratings and Targets[1.]					Market Data			Capitalization				
Company	Ticker	Exchange	Market Price 9-Dec-10	12 Month Target	Implied Return	Rating	Risk	52 Week High	52 Week Low	100 Day Avg Vol. (mm)	Shares O/S (mm)	Market Cap ($mm)	Net Debt ($mm)	Enterprise Value[2.] ($mm)	Oil Sands EV[2.] ($mm)
Athabasca Oil Sands	ATH	T	$14.06	$16.00	14%	SP	AA	$18.11	$9.89	1.0	$398	$5,593	($1,450)	$4,143	$4,143
Connacher Oil & Gas	CLL	T	$1.16	$1.50	29%	SP	AA	$1.88	$1.10	1.8	$443	$513	$806	$1,319	$1,134
Ivanhoe Energy	IE	T	$2.42	$3.00	24%	O	Spec	$3.94	$1.55	0.4	$359	$868	($46)	$822	$610
MEG Energy	MEG	T	$39.00	$48.00	23%	O	AA	$40.94	$30.30	0.2	$189	$7,390	($397)	$6,992	$6,992
OPTI Canada	OPC	T	$0.69	$0.60	-13%	U	Spec	$2.47	$0.63	2.0	$282	$194	$2,445	$2,639	$2,639
SilverBirch Energy	SBE	V	$7.20	$8.00	11%	SP	Spec	$8.45	$5.55	0.3	$50	$360	($44)	$316	$316
Average					**15%**										

1. RBC CM Ratings: Top Pick (TP); Outperform (O); Sector Perform (SP); Underperform (U); Restricted (R); RBC CM Risk Ratings: Average Risk (Avg); Above Average (AA); Speculative Risk (Spec).
2. EV is based on calendar Q310 net debt and shares outstanding; Oil Sands EV is corporate enterprise value adjusted to exclude the estimated value of non-oil sands related assets.

	Credit (Moody's)		Credit (S&P)		Maturities			CFPS ($/share)			Capex ($/share)			Capex/Cash Flow		
Company[3.]	Rating	Outlook	Rating	Outlook	2010	2011	2012	2010E	2011E	2012E	2010E	2011E	2012E	2010E	2011E	2012E
Athabasca Oil Sands	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	($0.04)	($0.05)	($0.08)	$0.34	$0.35	$0.75	nmf	nmf	nmf
Connacher Oil & Gas	Caa1	Negative	B	Stable	-	-	$90.6	$0.11	$0.30	$0.33	$0.56	$0.24	$0.24	5.1x	0.8x	0.7x
Ivanhoe Energy	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	($0.05)	($0.03)	($0.04)	$0.24	$0.16	$1.63	nmf	nmf	nmf
MEG Energy	B1	Stable	BB-	Watch	$10.7	$10.7	$10.7	$0.64	$1.31	$1.06	$2.93	$4.74	$3.51	4.6x	3.6x	3.3x
OPTI Canada	Caa2	Negative	CCC+	Stable	-	-	$525.0	($1.36)	($0.86)	($0.45)	$0.60	$0.57	$0.19	nmf	nmf	nmf
SilverBirch Energy	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	($0.04)	($0.11)	($0.11)	$0.17	$0.46	$0.79	nmf	nmf	nmf

3. All companies report in Canadian dollars with a Dec 31 fiscal year end with the exception of Ivanhoe (USD - Dec 31 Y/E).

		Net Asset Value[4.]						Unidentified Project Resource[5.]		Non-Evaluated Land[6.]	
		Base NAV			Unrisked NAV						
Company	Ticker	$mm	$/Share	P/NAV	$mm	$/Share	P/NAV	$mm	$/Share	(acres)	($mm)
Athabasca Oil Sands	ATH	$6,354	$15.61	90%	$12,062	$29.64	47%	$1,827	$4.49	185,105	$23.1
Connacher Oil & Gas	CLL	$719	$1.51	77%	$1,264	$2.66	44%	n.a.	n.a.	177,364	$13.3
Ivanhoe Energy	IE	$1,214	$3.23	75%	$1,718	$4.57	53%	n.a.	n.a.	n.a.	n.a.
MEG Energy	MEG	$9,580	$47.15	83%	$13,566	$66.76	58%	$861	$4.23	n.a.	n.a.
OPTI Canada	OPC	$195	$0.68	101%	$791	$2.78	25%	n.a.	n.a.	n.a.	n.a.
SilverBirch Energy	SBE	$424	$8.05	89%	$546	$10.36	69%	n.a.	n.a.	232,320	$16.0
Average				**86%**			**49%**				

4. Corporate items, producing assets and approved projects are included in the Base NAV; announced projects, booked resources and non-evaluated land are all included in the Unrisked NAV.
5. Unidentified project resources are booked contingent resources with no associated project. Value is calculaed using an estimated value per barrel based on transaction history.
6. Non-evaluated land is land with no associated resource. Value is calculated using recent crown land sale results.

Source: Company reports and RBC Capital Markets estimates

Exhibit 2: Comparative Valuation: Operational

Company	Principal Project	Working Interest	Partner	Current Capacity[1.]	Build Out Capacity[1.]	Play Type	Upgrader (Y/N)[2.]	Principal Project Status	Start-Up Date	Identified Projects	Project Status
Athabasca Oil Sands	MacKay	40%	PetroChina	n.a.	150,000	In-Situ	N	Approval 2012E	2014E	Dover	Approval 2012E
Connacher Oil & Gas	G.D./Algar	100%	n.a.	20,000	44,000	In-Situ	Y	Producing	2008	Algar II	Approval 2011E
Ivanhoe Energy	Tamarack	100%	n.a.	n.a.	50,000	In-Situ	Y	Approval 2012E	2014E	n.a.	n.a.
MEG Energy	Christina Lake	100%	n.a.	25,000	210,000	In-Situ	N	Producing	2008	Surmont	Application 2011E
OPTI Canada	Long Lake	35%	Nexen	72,000	360,000	In-Situ	Y	Producing	2007	Kinosis	Approved
SilverBirch Energy	Frontier	50%	Teck Resources	n.a.	240,000	Mining	N	Application 2011E	2020E	Equinox	Application 2011E

1. Productive capacity is stated on a gross bbl/d basis, not adjusted for working interest.
2. Connacher operates a 10,000 bbl/d heavy oil refinery in Great Falls, Montana; Ivanhoe Energy's Tamarack project plans to upgrade the bitumen on-site using their propietary HTL technology; OPTI Canada upgrades produced bitumen on-site using their propietary OrCrude process.

Reserves, Resources and Land

Company	Reserves 1P (P90) (mmboe)	Reserves 2P (P50) (mmboe)	Reserves 3P (P10) (mmboe)	Contingent Resources Low (P90) (mmboe)	Contingent Resources Best (P50) (mmboe)	Contingent Resources High (P10) (mmboe)	Reserves Evaluator[5.]	EV/bbl P50 2P + Best[6].	Reserve Life Index[7.] (years)	Oil Sands Leases (m acres)
Athabasca Oil Sands	n.a.	114	140	n.a.	8,819	n.a.	GLJ, D&M	$0.46	34.8	1,597.6
Connacher Oil & Gas[8.]	182	502	606	216	223	320	GLJ	$1.56	45.1	97.2
Ivanhoe Energy	n.a.	n.a.	n.a.	320	441	558	GLJ	$1.38	24.1	7.5
MEG Energy	549	1,691	n.a.	n.a.	3,724	n.a.	GLJ	$1.29	32.6	537.6
OPTI Canada	194	711	780	n.a.	1,114	n.a.	MDA	$1.45	33.0	90.9
SilverBirch Energy	n.a.	n.a.	n.a.	579	891	1,464	SP	$0.36	49.6	163.9
Weighted Average								**$0.87**		

5. DeGolyer and MacNaughton (D&M), GLJ Petroleum Consultants (GLJ), McDaniel & Associates (MDA), Sproule Associates (SP).
6. EV/Bbl is Oil Sands EV based on Q310 financials and proven and probable reserves plus best estimate contingent resources.
7. RLI uses 2P plus best estimate contingent resource and estimated peak production of announced projects. SBE's RLI represents Frontier resources, and one 80,000 bbl/d phase.
8. Connacher's reserves and contingent resources exclude conventional assets.

Production (net boe/d)

Company	2008	2009	2010E	2011E	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Athabasca Oil Sands	-	-	-	-	-	-	-	2,400	13,600	22,200	28,000	31,200	52,000
Connacher Oil & Gas	10,657	11,435	10,536	17,218	17,133	16,863	21,677	24,509	27,358	32,222	35,100	37,990	37,891
Ivanhoe Energy	1,897	1,434	783	825	800	767	7,729	17,692	20,658	27,625	37,594	40,564	40,536
MEG Energy	1,323	3,467	20,581	25,000	23,743	32,000	47,000	55,000	80,000	105,000	110,000	155,000	195,000
OPTI Canada	3,914	4,355	8,630	12,738	14,238	19,250	21,000	22,750	25,200	25,200	25,200	25,200	25,200
SilverBirch Energy	-	-	-	-	-	-	-	-	-	-	-	-	30,000

Source: Company reports and RBC Capital Markets estimates

Valuation Approach – NAV is our Preferred Method

NAV is our preferred valuation method for oil sands focused companies with well defined projects that have visible timing, scope and capital cost expectations. We apply a risk factor to projects that are still involved in the regulatory process. Our Base NAV reflects value for developed projects, projects in the development and regulatory stage, as well as value for unevaluated lands and corporate adjustments such as cash balances and debt.

- Our Base NAV is our evaluation of what we believe investors should be willing to pay for the stock. We reserve the option of applying a multiple to our NAV to adjust for intangible qualities as necessary; therefore, this Base NAV is the basis of our 12-month target price.
- Our Unrisked NAV reflects a potential upside valuation for the company, including unrisked values for projects in various stages of the development or regulatory process and value for additional resources that do not have development project definition. This methodology could be thought of as a potential upside value as management continues to de-risk projects by moving them through the regulatory and development cycle or a potential value for the company in the event of a change of control event.

In general, we apply the following risk factors to projects in our Base NAV analysis:

- 100% Value – Assigned to projects that are on stream or projects that have received regulatory approvals that we believe are moving forward into development with financing visible.
- 75% Value – Assigned to projects that have been submitted to the regulators and are in the regulatory process. In some cases, we assigned a 75% value to projects that we expect to be submitted to the regulatory process within the next six months.
- 50% Value – Assigned to projects that are expected to be submitted to the regulatory process within the next 12 months.
- 0% Value – Assigned to projects that have questionable development due to company liquidity or financing concerns.

Contingent Resource Value for Clastics – We assign a value of $0.50/bbl to Contingent Resources (Best Estimate) that have not been attributed to a specific development project. During 2010, market transactions varied based on several factors, ranging from a low of $0.14/bbl to a high of $1.84/bbl. We believe that $0.50/bbl fairly reflects value for Best Estimate Contingent Resources that have not yet been given development definition or have not yet entered into the regulatory process. We do not give value to 3P reserves, high case Contingent Resource estimates, or possible and potential resources.

Contingent Resource Value for Carbonates – We assign a value of $0.25/bbl to the carbonate Contingent Resource (Best Estimate). Given the earlier stage of understanding and thus higher degree of risk associated with bitumen carbonate reservoirs, commercial development of these reservoirs will likely take longer and, therefore, should be further discounted.

Undeveloped Land Values – We assign land value to the company's exploration leases. We assign a value of $125/acre to unexplored leases, which is a slight discount to the 2010 average year-to-date of approximately $150/acre and is in line with the 2009–2010 average crown land sale price for leases in the Athabasca region (see Appendix V). For conventional lands, we assign a value of $75/acre.

Technology – We do not assign value to technology *per se*, but we analyze the effect of applying specific technology and base our net asset value on the most economic scenario. For example, we conclude that the use of Heavy-to-Light Upgrading (HTL™) in the current economic environment has a negative economic value. As such, we represent Ivanhoe's NAV on the basis of a non-integrated Steam Assisted Gravity Drainage (SAGD) project without upgrading. For OPTI, we calculate the NAV of Long Lake with the OrCrude upgrader but exclude upgrading from our NAV analysis of future phases.

Conventional & Downstream Assets – We value conventional and downstream assets based on a discounted cash flow approach, as we do with SAGD assets.

Equity Holdings – We value equity holdings at a market value where available.

Risks to Target Prices

All companies are exposed to risk; the question is to what degree are they exposed? While differences exist from one company to the next within this peer group, we suggest that emerging oil sands companies experience a higher degree of risk, in general, than the established senior E&P peer group. As a potential reward for accepting these risks, however, investors could also have the opportunity for substantial growth and financial reward.

The risk matrix details our view of each company's exposure to risk (see Exhibit 3), at least by category. We note that there is a variance of degree of each risk as well. We believe that each of the seven emerging oil sands companies included in this report are exposed to the risks of fluctuations in oil price, the effect of using different discount rate assumptions in our NAV analysis, fluctuations in the U.S. to Canadian dollar foreign exchange rate, project execution risk, reservoir quality risk and environmental risk. In addition, risks that tend to be a bit more unique to each company include regulatory risks, financial risks and technical risks.

Exhibit 3: Risk Matrix

Ticker	Oil Price	Discount Rate	Foreign Exchange	Project Execution	Reservoir	Environmental	Regulatory	Financial	Technical		Risk Rating
ATH	●	●	●	●	●	●	●			=	Above Average
CLL	●	●	●	●	●	●		●		=	Above Average
IE	●	●	●	●	●	●	●	●	●	=	Speculative
MEG	●	●	●	●	●	●	●			=	Above Average
OPC	●	●	●	●	●	●		●	●	=	Speculative
SBE	●	●	●	●	●	●	●	●		=	Speculative

Source: RBC Capital Markets

Allow us to explain the nine key risks to our target price:

1. **Oil Prices –** The asset base of five of the seven emerging oil sands companies on which we initiate in this report is 100% weighted to oil. The two that are not, Connacher and Ivanhoe, are 82% and 83% weighted to oil in terms of NAV valuation, respectively. As demonstrated in our NAV sensitivities, fluctuations in oil price represent the greatest effect on our calculation of NAV for each of these seven companies. We assume a flat oil price of US$85.00/bbl WTI from 2012 onward.
2. **Discount Rates –** We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations for E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk, lower reserve replacement and re-investment (i.e., exploration) risk than E&P companies. On the other hand, however, oil sands companies have greater regulatory, environmental and project execution risk in the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Because of the long-life nature of oil sands projects, small fluctuations in discount rate assumptions change the NAV calculations and thus our target prices, materially.
3. **Foreign Exchange Rates –** Future costs are denominated in Canadian dollars, yet production will be priced in U.S. dollars. Fluctuations in the exchange rate could greatly affect the value of future cash flows and thus our calculation of NAV. We assume a flat US$0.95/C$1.00 exchange rate for the long term.
4. **Project Execution Risk –** Early stage development companies have a high degree of project execution risk. The amount of risk varies from company to company, but projects at emerging companies tend to have a very material effect on production rates, cash flow levels and NAV calculations. Projects not only tend to have a higher degree of materiality, but also emerging companies typically have not established a track record of execution, which, therefore,

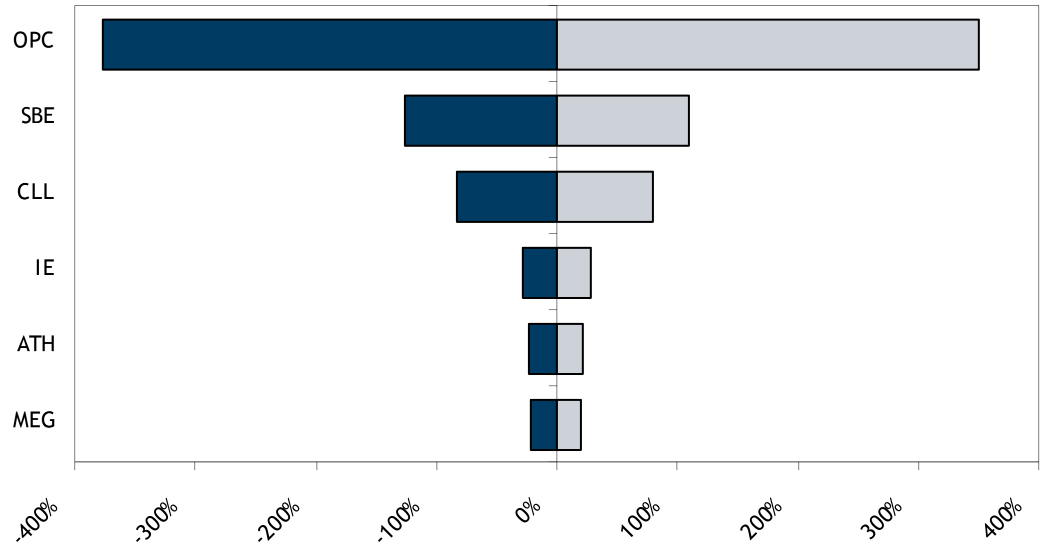
RBC Capital Markets®

introduces a degree of uncertainty. Each individual company has established a different degree of project execution experience. The ability of a company to deliver a project within a set of budget and timing expectations could materially affect our view of NAV.

5. **Reservoir Risks –** Many reservoir characteristics contribute to quality and the overall ability of the reservoir to produce. In addition to reservoir characteristics, such as pressure, bitumen saturation, permeability and porosity (see Exhibit 30), specific risks such as top gas, bottom water, interbedded shales and an appropriate pressure containment cap rock are considerations of reservoir risk.
6. **Environmental Risks –** Oil sands producers have come under increased scrutiny for environmental issues. While longer-term costs or product marketing concerns related to environmental issues are unclear at this time, environmental laws and regulations do not present a risk to the development plans or our perception of valuations at present. We note that the development of In-Situ oil sands typically have less effect on land, air and water than oil sands mining projects. We expect that emissions related to In-Situ production will be comparable to the emissions of the typical oil that is imported into the United States. (see Exhibits 24 & 25).
7. **Regulatory Risks –** Early stage development companies have a high degree of regulatory risk. The amount of regulatory risk varies depending on the stage of the regulatory process. Regulatory approvals typically take 18–24 months from filing to approval. The specific degree of regulatory risk varies by company depending on how many, if any, projects on the companies' development schedule have already entered into the regulatory process or have received approvals. In our valuation methodology, projects that have approval are given more value than those in the regulatory process, which are given more value than those not yet entered into the regulatory queue. Each individual company's growth profile as well as our perception of the company's value would be materially affected should the regulatory approvals be delayed or withheld.
8. **Financing Risks –** Oil sands projects are capital intensive and have a high degree of upfront capital commitments. The ability to realize the full potential value of a project is predicated on the assumption that a company will be able to finance the development of the project. The companies on which we initiate in this report have a wide range of financial capacity. The ability of a company to pursue its objectives with sufficient capital could significantly influence our view of the company. Delays in financing or increases to costs estimates could result in the need for additional financing or a shift in capital spending plans, which could affect our view of the NAV of each company.
9. **Technical –** On occasion, companies attempt to gain a competitive advantage with the use of proprietary technology. While the application of technology could result in improved recovery from the reservoir (e.g., solvents, well configurations, pumps, etc) or reduced costs or marketing advantages (e.g., upgrading, gasification, diluent or transportation solutions), the introduction of new technologies could present a risk with respect to operations or economics.

WTI Oil Price Sensitivity & Upside Potential

Exhibit 4: NAV Sensitivity to a US$10.00/bbl WTI Oil Price Change

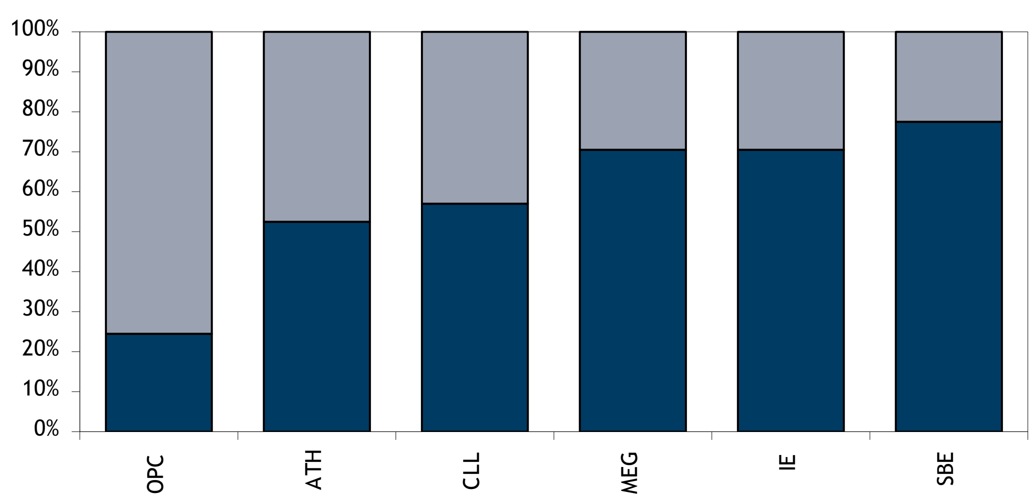


Source: RBC Capital Markets estimates

The variable that generates the greatest sensitivity to our NAV calculations is a change in the long term oil price assumption. The three companies with the highest leverage on the balance sheet, namely OPTI, SilverBirch and Connacher, have the highest beta to a change in the price of oil. The sensitivity of the remaining companies is tightly clustered in the 20-30% range for a US$10.00/bbl WTI change in our long term oil price from our current view of US$85.00/bbl WTI. MEG and Athabasca are the most defensive names given the high degree of financial liquidity they enjoy.

We estimate that OPTI has the highest upside potential beyond its Base NAV, this is a function of early resource capture without the current ability to pursue development of these projects. The question is will a third party be interested in taking on existing liabilities and operational issues to capture the longer term potential? Reflecting of the large resource base and early development stage of the company, we estimate that Athabasca has the potential to double its Base NAV.

Exhibit 5: Base Net Asset Value as a Percentage of Total Net Asset Value



Source: RBC Capital Markets estimates

Oil Sands – Current Activities & Issues

Current Production and Players

Oil sands have been in development in Alberta since the 1960s, but the pace of development has accelerated in the past decade (see Appendix V & VI). The earliest development was undertaken by large and well established companies, and development was primarily focused on mining projects. This early focus can be seen in the current landscape. Currently, companies in Alberta produce approximately 1.3 million barrels per day from the oil sands, with approximately 60% of that production derived from mining projects (see Exhibit 6).

Current oil sands activities are dominated by large companies – Current production is dominated by large and well established companies, because oil sands projects require a long lead time to work through the evaluation, planning, regulatory and project execution stages and a large amount of upfront capital, measured in the hundreds of millions to billions of dollars per project. As Exhibit 6 demonstrates, the only emerging companies to have entered the oil sands with producing projects are MEG (approximately $8 billion enterprise value), OPTI (about $2.8 billion enterprise value) and Connacher (around $1.3 billion enterprise value).

SAGD in the Athabasca region has dominated development – With respect to In-Situ developments, the oldest and largest projects are Cyclic Steam Stimulation (CSS) projects in the Cold Lake region; nevertheless, SAGD development in the Athabasca region has become the technology and region of choice.

Exhibit 6: Producing Oil Sands Projects in Alberta

Company	Project	Region	Technology	Recent Production (bbl/d)	Capacity (bbl/d)	% of Capacity	Start Up
Canadian Natural Resources Ltd.	Horizon Phase I	Athabasca	Mining	99,950	110,000	91%	2009
Shell Canada Energy	Muskeg River Phase 1	Athabasca	Mining	139,000	155,000	90%	2003
Suncor Energy Inc.	Base Plant, Steepbank Mine, Millennium	Athabasca	Mining	235,934	321,000	73%	1967
Syncrude Canada Ltd.	Mildred Lake and Aurora North	Athabasca	Mining	304,000	375,000	81%	1978
Mining Total				**778,884**	**961,000**	**81%**	
Canadian Natural Resources Ltd.	Primrose and Wolf Lake	Cold Lake	CSS	96,000	120,000	80%	1985
Imperial Oil	Cold Lake Phases 1-10	Cold Lake	CSS	140,000	140,000	100%	1985
Shell Canada Energy	Shell Peace River (Pads 42&43)	Peace River	CSS	6,200	12,500	50%	1986
CSS Total				**242,200**	**272,500**	**89%**	
Cenovus Energy Inc.	Christina Lake Ph. 1A, 1B	Athabasca	SAGD	13,054	18,800	69%	2002
Cenovus Energy Inc.	Foster Creek Phases 1A-1E	Athabasca	SAGD	73,308	120,000	61%	2001
Connacher Oil and Gas	Great Divide Pod One & Algar	Athabasca	SAGD	14,000	20,000	31%	2007
ConocoPhillips Canada	Surmont Phase I	Athabasca	SAGD	14,000	28,200	50%	2007
Devon Canada Ltd.	Jackfish I	Athabasca	SAGD	35,000	35,000	100%	2007
Husky Energy	Tucker Thermal Project	Cold Lake	SAGD	3,500	30,000	12%	2006
Japan Canada Oil Sands Ltd.	Hangingstone Pilot	Athabasca	SAGD	7,334	10,000	73%	1999
MEG Energy Corp.	Christina Lake Regional Project Phase 1A & 2	Athabasca	SAGD	26,351	25,000	105%	2008
Nexen Inc. & OPTI Canada	Long Lake Phase I	Athabasca	SAGD	30,100	72,000	42%	2007
Shell Canada Energy	Orion Phase 1	Cold Lake	SAGD	2,716	10,000	27%	2008
Suncor Energy Inc.	Firebag Phases 1 & 2 & Cogeneration and Expansion	Athabasca	SAGD	55,700	93,000	60%	2004
Suncor Energy Inc.	MacKay River Phase 1	Athabasca	SAGD	32,500	33,000	98%	2002
SAGD Total				**299,774**	**495,000**	**61%**	
In-Situ Total				**541,974**	**767,500**	**71%**	
GRAND TOTAL				**1,320,858**	**1,728,500**	**76%**	

Notes:

Excludes the following pilot and reservoir testing projects: ET-Energy's Poplar Creek Pilot (1,000 bbl/d), Southern Pacific's Red Earth Pilot (1,000 bbl/d), Oilsands Quest's Axe Lake Test (600 bbl/d) and Petrobank's Whitesands Pilot (1,800 bbl/d).

Excludes Total's Joslyn project, which ceased operations in March 2009.

Source: Accumap, Company reports and RBC Capital Markets

Proposed Projects & Players

Not all proposed projects will be developed, and certainly not all projects that are developed will be on stream as scheduled; however, we believe that a few very interesting observations can be made by looking at the list of proposed projects.

Our 10 key observations:

- On a production-weighted basis, mining projects comprise approximately one-third of proposed new projects. The proposed mining projects would increase oil sands mining production to 2.9 mmbbl/d from approximately 780,000 bbl/d at present.
- Mining projects are typically larger than In-Situ projects.
- **SilverBirch Energy is the only emerging company with a mining lease and proposed mining project.**
- On a production-weighted basis, 42% of proposed mining projects have received regulatory approval and 25% of proposed mining projects are currently within the regulatory process.
- **Projects in the hands of emerging oil sands companies represent 24% of proposed oil sands production additions and one-third of proposed In-Situ projects.**
- On a production-weighted basis, 32% of In-Situ projects that have been proposed by established producers have already received regulatory approval and 33% of projects are currently within the regulatory process.
- **On a production-weighted basis, only 4% of In-Situ projects that have been proposed by emerging companies have received regulatory approvals, while 44% of projects are currently within the regulatory process.**
- Projects in the Athabasca region comprise 95.2% of all In-Situ proposals.
- Projects in the Cold Lake region comprise 2.6% of all In-Situ proposals.
- Projects in the Peace River region comprise 2.2% of all In-Situ proposals (primarily Shell's Carmon Creek Project).

Our three key conclusions:

- Emerging oil sands companies will likely continue to demand more capital (we estimate about $20 billion based on approved projects and projects awaiting regulatory approvals).
- Emerging oil sands companies will likely become large oil sands producers in the decade.
- Emerging oil sands companies will likely be the target of corporate acquisition activity based on resource and production potential.

Based on our conclusion that emerging oil sands companies have significantly moved projects forward into the regulatory process and beyond, **we believe that emerging oil sands companies are an attractive investment opportunity in the near, medium and longer term, but investors must be extremely cautious to select those companies with the best asset quality and that have the greatest ability to execute projects.**

Exhibit 7: Planned Mining Projects

Company	Project	Region	Technology	Capacity (bbl/d)	Regulatory Status	Start Up
Canadian Natural Resources Limited	Horizon Phase II and III	Athabasca	Mining	122,000	Announced (Not Formalized)	TBD
Canadian Natural Resources Limited	Horizon Phase IV and V	Athabasca	Mining	268,000	Announced (Not Formalized)	TBD
Imperial Oil	Kearl Phase I	Athabasca	Mining	110,000	Under Construction	2012
Imperial Oil	Kearl Phase II	Athabasca	Mining	100,000	ERCB Approved	TBD
Imperial Oil	Kearl Phase III	Athabasca	Mining	100,000	ERCB Approved	TBD
Shell Canada Energy	Jackpine Mine Expansion	Athabasca	Mining	100,000	Regulatory Application Filed	TBD
Shell Canada Energy	Jackpine Mines Phase I Train I	Athabasca	Mining	100,000	Under Construction	2010/2011
Shell Canada Energy	Jackpine Mines Phase I Train II	Athabasca	Mining	100,000	Approved	TBD
Shell Canada Energy	Pierre River Mine Phase 1 & 2	Athabasca	Mining	200,000	Regulatory Application Filed	TBD
SilverBirch Energy/Teck Cominco	Equinox	Athabasca	Mining	50,000	Announced	TBD
SilverBirch Energy/Teck Cominco	Frontier Phase 1 & 2	Athabasca	Mining	160,000	Announced	TBA
Suncor Energy Inc.	Fort Hills	Athabasca	Mining	190,000	ERCB Approved (Delayed)	TBD
Suncor Energy Inc.	Voyageur South Mine	Athabasca	Mining	120,000	Regulatory Application Filed	TBD
Syncrude Canada Ltd.	Aurora South	Athabasca	Mining	200,000	ERCB Approved	2016
Total E&P	Joslyn North Mine	Athabasca	Mining	100,000	Regulatory Application Filed	TBD
Total E&P	Joslyn South Mine	Athabasca	Mining	100,000	Announced	TBD
Total Planned Mining				**2,120,000**		

Source: Company reports and RBC Capital Markets

Exhibit 8: Planned In-Situ Projects (Established Producers)

Company	Project	Region	Technology	Capacity (bbl/d)	Regulatory Status	Start Up
Canadian Natural Resources Limited	Birch Mountain East	Athabasca	In-Situ	60,000	Announced	2016
Canadian Natural Resources Limited	Gregoire Lake Phase 1	Athabasca	In-Situ	60,000	Announced	2018
Canadian Natural Resources Limited	Grouse Phase 1	Athabasca	In-Situ	60,000	Announced	2014
Canadian Natural Resources Limited	Kirby	Athabasca	In-Situ	45,000	Regulatory Application Filed	2012
Canadian Natural Resources Limited	Leismer Phase 1	Athabasca	In-Situ	30,000	Announced	2018
Cenovus Energy Inc.	Borealis Phase 1	Athabasca	In-Situ	35,000	Regulatory Application Filed	2015
Cenovus Energy Inc.	Borealis Phase 2 & 3	Athabasca	In-Situ	65,000	Announced	TBD
Cenovus Energy Inc.	Christina Lake 1C	Athabasca	In-Situ	40,000	Under Construction	2011
Cenovus Energy Inc.	Christina Lake 1D	Athabasca	In-Situ	40,000	ERCB Approved	2013
Cenovus Energy Inc.	Christina Lake 1E-F-G	Athabasca	In-Situ	120,000	Regulatory Application Filed	2014-2017
Cenovus Energy Inc.	Christina Lake 1H	Athabasca	In-Situ	40,000	Announced	2019
Cenovus Energy Inc.	Narrows Lake Phases 1-3	Athabasca	In-Situ	130,000	Public Disclosure Made	2016
Cenovus Energy Inc.	Foster Creek Phases 1F-1H	Athabasca	In-Situ	90,000	Regulatory Application Filed	2014-2017
Chevron Canada Limited	Ells River	Athabasca	In-Situ	100,000	Announced (On Hold)	TBD
ConocoPhillips Canada	Surmont Phase II	Athabasca	In-Situ	83,000	ERCB Approved	2015
Devon Canada Limited	Jackfish 2	Athabasca	In-Situ	35,000	Under Construction	2011
Devon Canada Limited	Jackfish 3	Athabasca	In-Situ	35,000	Regulatory Application Filed	2015
Husky Energy	Caribou Lake Thermal Demonstration Project	Cold Lake	In-Situ	10,000	Approved	TBD
Husky Energy	McMullen	Athabasca	In-Situ	755	Regulatory Application Filed	TBD
Husky Energy	Sunrise Thermal Project Ph. 1-3	Athabasca	In-Situ	200,000	ERCB Approved	2014
Imperial Oil	Cold Lake Phases 14-16:Nabiye, Mahihkan North	Cold Lake	In-Situ	30,000	Approved	TBD
Nexen Inc.	Long Lake Phase II	Athabasca	In-Situ	72,000	ERCB Approved	TBD
Nexen Inc.	Long Lake Phase III Upgrader	Athabasca	In-Situ	72,000	ERCB Approved (Delayed)	TBD
Nexen Inc.	Leismer & Cottonwood	Athabasca	In-Situ	216,000	Announced	TBD
Pengrowth Energy Trust	Lindbergh Pilot	Cold Lake	In-Situ	2,500	Regulatory Application Filed	TBD
Shell Canada Energy	Carmon Creek	Peace River	In-Situ	80,000	Regulatory Application Filed	TBD
Shell Canada Energy	Orion Phase 2	Cold Lake	In-Situ	10,000	ERCB Approved	TBD
Statoil Canada Ltd.	Various	Athabasca	In-Situ	220,000	Regulatory Application Filed	TBD
Statoil Canada Ltd.	Kai Kos Dehseh - Leismer Demo	Athabasca	In-Situ	10,000	Under Construction	2010
Suncor Energy Inc.	Chard	Athabasca	In-Situ	40,000	Announced	TBD
Suncor Energy Inc.	Firebag Phase III & IV	Athabasca	In-Situ	136,000	Under Construction	2011
Suncor Energy Inc.	Firebag Phase V & VI	Athabasca	In-Situ	136,000	Regulatory Application Filed	TBD
Suncor Energy Inc.	Lewis Phase 1	Athabasca	In-Situ	40,000	Regulatory Application Filed	TBD
Suncor Energy Inc.	Lewis Phase 2	Athabasca	In-Situ	40,000	Regulatory Application Filed	TBD
Suncor Energy Inc.	MacKay River Phase 2	Athabasca	In-Situ	40,000	ERCB Approved (Delayed)	TBD
Suncor Energy Inc.	Meadow Creek Phase 1	Athabasca	In-Situ	80,000	Announced	TBD
Suncor Energy Inc.	Meadow Creek Phase 2	Athabasca	In-Situ	40,000	Approved	TBD
Total Planned In-situ (Established Producers)				**2,543,255**		

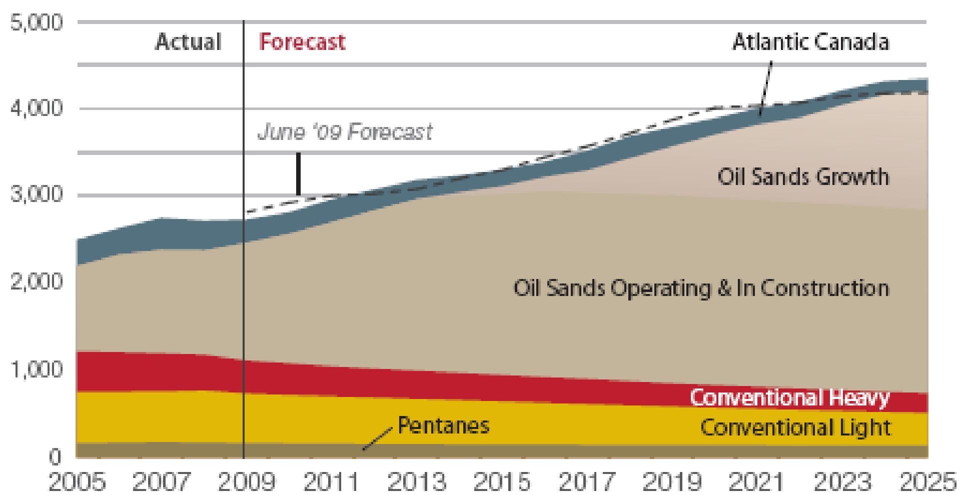
Source: Company reports and RBC Capital Markets

Exhibit 9: Planned In-Situ Projects (Emerging Producers)

Company	Project	Region	Technology	Capacity (bbl/d)	Regulatory Status	Start Up
Alberta Oilsands Inc.	Clearwater - Pilot	Athabasca	In-Situ	4,500	Regulatory Application Filed	2011
Alberta Oilsands Inc.	Clearwater West/East Commercial Project	Athabasca	In-Situ	10,000	Announced	2013
Andora Energy	Sawn Lake	Peace River	In-Situ	700	Approved	TBD
Athabasca Oil Sands Corp.	Dover Central Pilot	Athabasca	In-Situ	2,000	ERCB Approved (Suspended)	TBD
Athabasca Oil Sands Corp.	Dover Commercial Phase	Athabasca	In-Situ	250,000	Public Disclosure Made	2015
Athabasca Oil Sands Corp.	MacKay River Commercial Project	Athabasca	In-Situ	150,000	Regulatory Application Filed	2014
Athabasca Oil Sands Corp.	MacKay River Pilot	Athabasca	In-Situ	2,200	ERCB Approved (Suspended)	TBD
Athabasca Oil Sands Corp.	Hangingstone Experimental Pilot	Athabasca	In-Situ	1,000	Regulatory Application Filed	2011
BlackPearl Resources Inc.	Blackrod - Pilot	Athabasca	In-Situ	600	Regulatory Application Filed	TBD
Connacher Oil and Gas	Great Divide Expansion Project	Athabasca	In-Situ	24,000	Public Disclosure Made	2014
Enerplus Resource Fund	Kirby Phase 1	Athabasca	In-Situ	10,000	Regulatory Application Filed	TBD
Enerplus Resource Fund	Kirby Phase 2	Athabasca	In-Situ	25,000	Announced (Not Formalized)	TBD
E-T Energy	Poplar Creek ET-DSP Project	Athabasca	In-Situ	10,000	Regulatory Application Filed	2011
Grizzly Oil Sands	Algar Lake	Athabasca	In-Situ	10,000	Regulatory Application Filed	-
Ivanhoe Energy	Tamarack	Athabasca	In-Situ	20,000	Regulatory Application Filed	2014
Japan Canada Oil Sands Limited	Hangingstone Phase 1	Athabasca	In-Situ	35,000	Regulatory Application Filed	-
Koch Exploration Canada	Gemini Pilot	Cold Lake	In-Situ	1,200	Regulatory Application Filed	TBD
Koch Exploration Canada	Gemini	Cold Lake	In-Situ	10,000	Regulatory Application Filed	TBD
Korea National Oil Corporation	Black Gold	Athabasca	In-Situ	10,000	Regulatory Application Filed	2012
Korea National Oil Corporation	Black Gold Phase 2	Athabasca	In-Situ	20,000	Announced	TBD
Laricina Energy	Germain Phase 1	Athabasca	In-Situ	10,000	Announced	-
Laricina Energy	Germain Pilot	Athabasca	In-Situ	1,800	Apporved, Ammendment Filed	-
Laricina Energy	Saleski In Situ - Carbonate SAGD Demonstration	Athabasca	In-Situ	1,800	ERCB Approved, Amendmen Approved	-
Laricina Energy	Saleski Phase 1	Athabasca	In-Situ	12,500	Announced	-
MEG Energy Corp.	Christina Lake Regional Project Phase 2B	Athabasca	In-Situ	35,000	Approved	2013
MEG Energy Corp.	Christina Lake Regional Project Phase 3A	Athabasca	In-Situ	75,000	Regulatory Application Filed	2014
MEG Energy Corp.	Christina Lake Regional Project Phase 3B	Athabasca	In-Situ	50,000	Regulatory Application Filed	2018
MEG Energy Corp.	Christina Lake Regional Project Phase 3C	Athabasca	In-Situ	50,000	Regulatory Application Filed	2020
Osum Oil Sands Corp	Taiga	Cold Lake	In-Situ	35,000	Regulatory Application Filed	-
Patch International	Ells River	Athabasca	In-Situ	10,000	Announced	TBD
Petrobank Energy & Resources Ltd.	May River Expansion	Athabasca	In-Situ	90,000	Public Disclosure Made	TBD
Petrobank Energy & Resources Ltd.	May River Phase I	Athabasca	In-Situ	10,000	Regulatory Application Filed	TBD
Petrobank Energy & Resources Ltd.	Whitesands-Expansion	Athabasca	In-Situ	1,800	Approved	TBD
Southern Pacific Resource Corp.	Red Earth Expansion	Peace River	In-Situ	3,000	Announced	TBD
Southern Pacific Resource Corp.	STP MacKay Project	Athabasca	In-Situ	12000	Approved	2012
Sunshine Oil Sands	Harper Pilot	Athabasca	In-Situ	<1000	Approved	-
Sunshine Oil Sands	Legend Lake Phase 1-3	Athabasca	In-Situ	60,000	Announced	-
Sunshine Oil Sands	Thickwood Phases 1-2 Expansion	Athabasca	In-Situ	50,000	Announced	-
Sunshine Oil Sands	West Ells Phases 1-3	Athabasca	In-Situ	90,000	Regulatory Application Filed / Announ	-
Value Creation	Terre de Grace Phases 1&2	Athabasca	In-Situ	80,000	Announced	TBD
Value Creation	Terre de Grace Pilot	Athabasca	In-Situ	10,000	Approved	TBD
Total Planned In-situ (Emerging Producers)				**1,284,100**		

Source: Company reports and RBC Capital Markets

Exhibit 10: Long-Term Canadian Oil Production Forecast



Source: Canadian Association of Petroleum Producers

Oil Sands Recovery Methods – Mining compared to In-Situ

Oil sands can be recovered with either mining or In-Situ techniques. The decision to mine for the resource is one of practicality and economics. Typically, mining for oil sands takes place if the resource has less than 75 metres of overburden that requires removal. If the resource is any deeper than 75 metres, it is generally more economic to drill and produce the bitumen with In-Situ methods of recovery. In-Situ reservoirs can be produced at depths as shallow as 100 metres, but generally In-Situ reservoirs are produced from depths of greater than 300 metres (see Exhibit 30).

Mining – Simple & Effective but Expensive & Environmentally Sensitive

The Energy Resources Conservation Board (ERCB) estimates that approximately 20% of total recoverable bitumen in Alberta is surface mineable; these resources are concentrated in a small area north of Fort McMurray near the Athabasca River. By virtue of technology, mining oil sands for the production of bitumen is a more mature development technique, dating back to 1967 when Suncor opened Alberta's first oil sands mine. Mining projects typically achieve higher recovery factors than In-Situ projects, but they tend to have higher capital costs and are perceived to have a larger environmental footprint, air emissions and water use.

Historically, mining projects have been broken down into three distinct processes:

- **Mining** the oil sands with trucks and shovels in large open-pit mines,
- **Extracting** the bitumen from the oil sands with the use of hot water and
- **Upgrading** the bitumen to synthetic crude oil, which is similar in quality to benchmark crudes such as Edmonton Light or West Texas Intermediate—albeit with unique characteristics that require specific refinery configurations.

Upgrading has long been associated with oil sands mining projects due to historically wide heavy oil differentials and the need to improve the quality of the bitumen for transportation purposes. With the proliferation of upgraded projects in northern Alberta that produce synthetic crude oil, improved diluent supply and a U.S. refining complex that has since adapted to accept greater volumes of heavy oil, the decision to upgrade bitumen in northern Alberta has become more of an economic decision rather than a logistical one.

ERCB Mining Recovery Requirements - The ERCB has defined four criteria used to estimate the volume of bitumen that an operator will be required to recover from its mining and processing operations. Essentially, these criteria prevent a miner from 'cherry picking' the best areas while promoting responsible development. Current oil prices allow oil sands mining companies to push these limits for even greater recovery, in our view.

The four criteria are:

- The minimum bitumen content that would be classified as ore is seven weight percent bitumen.
- The minimum mining thickness has been set at 3 metres.
- The minimum Total Volume to Bitumen In Place (TV:BIP) that would be used to determine the pit crest limits is 12:1.
- Processing plant recovery is 90% for high-quality ore (greater than 11 weight percent bitumen), and determined by a formula for low quality ore (less than 11 weight percent bitumen).

In-Situ Recovery – Stuck in the Steam Age

The ERCB estimates that 80% of Alberta's oil sands resources will require In-Situ recovery techniques. The two primary In-Situ production methods are CSS and SAGD. These methods use heat, which is delivered into the reservoir with the injection of steam, to reduce the viscosity of the bitumen and produce it to surface, preferably with the use of horizontal wells. These two recovery methods are very similar, with one important difference: CSS uses one well that alternates (cycles) between injecting steam and producing bitumen, while SAGD utilizes a pair of horizontal wells with the upper well injecting steam and the lower well producing bitumen. The primary consideration when deciding to use CSS or SAGD is reservoir thickness with CSS being applied to thinner reservoirs.

Steam effectively delivers the necessary heat into the reservoir, but steam also presents problems:

- It is energy inefficient to produce steam to heat bitumen.

- Producing steam requires large amounts of water, which has both environmental and economic considerations.
- Steam that is injected into the reservoir comes back to surface as water that requires separation from the produced bitumen and treatment for re-use or re-injection. Water treatment is a significant source of operational difficulties at CSS and SAGD projects, and a significant component of capital and operating costs.

Given the challenges with steam-based recovery techniques, the industry is attempting to develop new technologies to deliver heat into the reservoir, thereby improving efficiency, recovery factors and reducing costs and environmental effects. Techniques that are being tested include In-Situ combustion techniques such as Toe-to-Heel Air Injection (THAI), conduction and convection heat with the use of electrodes and radio waves and the application of surfactants such as solvents. The common goal of these techniques is to lower the viscosity of bitumen, thereby allowing it to flow into a wellbore to be produced to surface. Solvents are being used to a limited degree; otherwise, none of these techniques have yet to achieve commercialization.

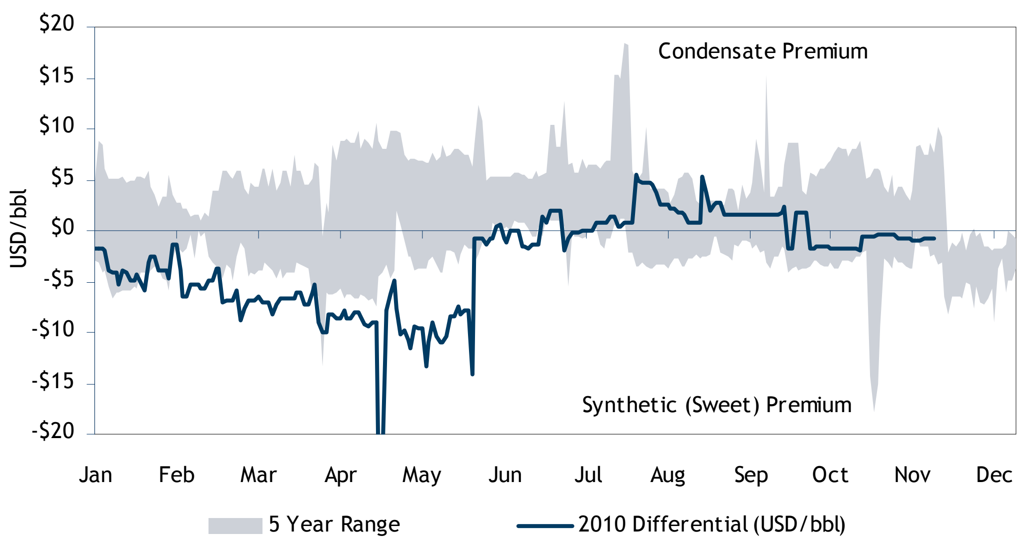
Blending – Economics Favour Dilbit

A unique challenge facing oil sands producers is that bitumen is too viscous to ship via pipeline; therefore, it must be blended with a lighter product in order to achieve a low enough viscosity for transportation to market via truck or pipeline. Bitumen producers have two options for blending: condensate or synthetic crude oil.

Condensate is less viscous than synthetic crude oil; therefore, it requires a lower blend ratio. Dilbit is a blend of diluent (condensate) and bitumen at a ratio of one-half barrel of diluent for each barrel of bitumen. Synbit is a blend of synthetic crude oil and bitumen at a ratio of one to one. Therefore, dilbit is one part diluent and two parts bitumen (33%:67%) and synbit is one part synthetic oil and one part bitumen (50%:50%).

Based on quality and localized demand, condensate has typically traded at a premium to benchmark crude oil prices (see Exhibit 11); however, due to an increased supply of diluent to the western Canadian market as a result of the Southern Lights condensate pipeline, current economics favour blending dilbit. Condensate and synthetic are priced similarly, but the lower blending ratio requirement with condensate reduces the blending and shipping costs. Historically, condensate has traded at a premium to synthetic crude oil but not by enough of a premium to change the preference for condensate among bitumen producers.

Exhibit 11: Dilbit or Synbit?



Source: Bloomberg, RBC Capital Markets

We expect producers to continue to favour blending condensate as compared to synthetic crude oil for the benefits we outlined previously. Unique situations exist in which the availability of synthetic crude oil may be more readily available; therefore, in specific situations, using synthetic crude oil as the blending agent may be favoured.

Upgrading – It's Not What it Used to Be

In the development of the oil sands, the line used to be clear: mining projects included upgraders; In-Situ projects did not. This distinction, however, has become increasingly blurred.

In the past, the reason for this distinction was likely three fold: the economies of scale needed to run an upgrader that more closely matched the size of the mining projects; the remoteness of mining projects required upgrading in order to make the bitumen shippable because local sources of diluent were not available with the required reliability or in the desired volumes; production from mining projects has been more reliable than production levels from In-Situ projects, which is an important consideration when feeding an upgrader that needs a steady supply.

There are five operating upgraders in Alberta – All operating mining projects are integrated with an upgrader while the only integrated In-Situ project is Nexen and OPTI's Long Lake project. Each upgrader produces a slightly different mix of products: Shell produces a refinery feedstock for its Scotford Refinery as well as sweet and heavy synthetic crude; Syncrude, Horizon and Long Lake all produce a light sweet synthetic crude; and Suncor produces diesel, light sweet and heavy sour synthetic crude oil. Most upgraders can achieve volumetric liquid yields of 80–90% using coking as the primary upgrading process; however, some upgraders, such as Shell, can achieve yields north of 100% using hydro-conversion as the primary process.

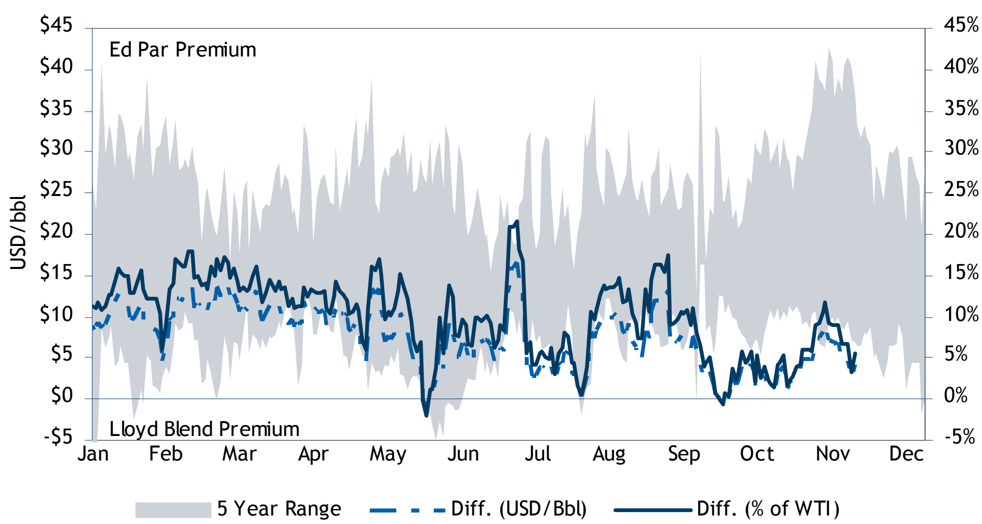
Exhibit 12: Current Upgrading Projects

		Capacity (bbls/d)		Volumetric	
Upgrader	Location	Bitumen	SCO	Yield	Product
AOSP (Shell) Scotford	Fort Saskatchewan	155,000	158,000	102%	Refinery feedstock, sweet, heavy
Suncor Base and Millenium	Fort McMurray	440,000	357,000	81%	Light sweet, medium sour, diesel
Syncrude Mildred Lake	Fort McMurray	407,000	350,000	86%	Light sweet
OPTI/Nexen Long Lake	Fort McMurray	72,000	58,500	81%	Light sweet
CNRL Horizon	Fort McMurray	135,000	114,000	84%	Light sweet
Total		**1,209,000**	**1,037,500**	**86%**	

Source: ERCB and RBC Capital Markets

The economics of upgrading have shifted – Heavy oil differentials have systemically narrowed. Changes to the oil sands royalty calculation have disallowed the deduction of upgrading capital, and operating expenses provide little incentive to move forward with upgrading projects. For upgrading to produce higher netbacks than selling blended bitumen, the heavy oil differential captured must be greater than the additional cost associated with upgrading to synthetic crude oil, including an acceptable return on capital and a return of the original investment.

Exhibit 13: Heavy Oil Differentials: Upgrading Compared to Blending



Source: Bloomberg and RBC Capital Markets

Virtually every proposed upgrading project has been placed on hold – The large upfront capital cost combined with the inability to make profits in the current pricing environment has caused a number of upgrading projects and expansions to be placed on hold. Of the seven projects and three expansions that have been announced, only one is under construction (see Exhibit 14). While the Government of Alberta wishes to encourage upgrading and refining within Alberta (with programs such as BRIK: Bitumen Revenue in Kind), the future of these projects will depend on the long-term demand for Canadian bitumen (compared to synthetic) in U.S. refineries, the long-term outlook for heavy oil differentials, the availability and cost of diluent, pipeline availability and environmental legislation.

We do not expect the emerging oil sands companies to invest in upgrading – With respect to the emerging oil sands companies, two have proposed the use of upgrading technologies. OPTI has regulatory approval to apply its OrCrude™ technology on future expansions, and Ivanhoe has filed a regulatory application to include the use of its HTL™ technology at Tamarack. Based on our view of long-term economics, we do not expect either company to proceed with plans to build an upgrader.

Exhibit 14: Planned Upgrading Projects

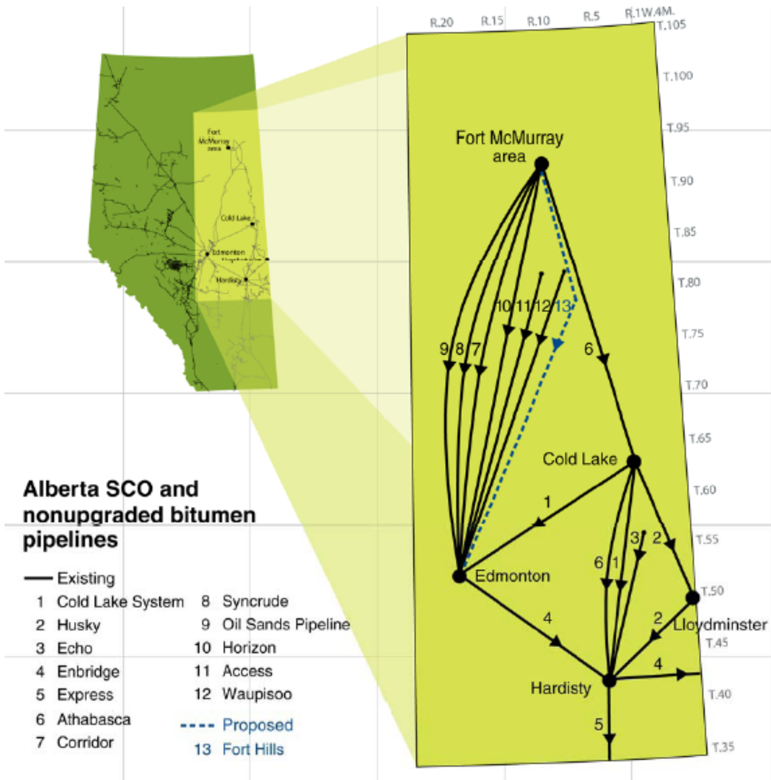
	Scheduled	Capacity (bbls/d)		Volumetric
Upgrader	**Start-up**	**Bitumen**	**SCO**	**Yield**
CNRL Horizon (Expansion)	On Hold	135,000	118,000	87%
Suncor Voyageur	On Hold	234,000	190,000	81%
AOSP (Shell) Scotford	2011	90,000	91,000	101%
North West Upgrading Sturgeon	On Hold	150,000	139,200	93%
Fort Hills Sturgeon	On Hold	340,000	290,000	85%
Nexen Long Lake (Expansion)	On Hold	72,000	58,500	81%
Shell Scotford Upgrader 2	On Hold	400,000	391,000	98%
Total Strathcona	On Hold	295,000	271,000	92%
Value Creation Heartland	On Hold	163,200	138,900	85%
Value Creation Terre de Grace	On Hold	10,000	8,400	84%
Total		**1,889,200**	**1,696,000**	**90%**

Source: ERCB and RBC Capital Markets

In the Pipeline: Awash with Excess Capacity for a Decade

Good news and bad news: A lot of capacity but essentially only one market – The good news is that with 3.3 mmbbl/d of export capacity pipelines are sufficient for all existing projects and capacity exists for several years of development. Current pipeline proposals should also allow for unfettered long-term growth in oil sands projects. Currently, the bad news is that Canadian oil sands producers effectively have only one export market, primarily Padd II in the United States, in which to sell bitumen. Markets are expanding into Padd III, but so far, markets beyond North America are limited to 60,000 bbl/d of heavy oil capacity to the west coast (see Exhibit 17 & 18). Expansions of 900,000 bbl/d of heavy oil capacity are being proposed (see Exhibit 18).

Exhibit 15: Alberta Oil Sands Pipelines



Source: ERCB

Sufficient export capacity visible for the next decade – Gathering systems in Alberta from the Athabasca and Cold Lake regions have ample capacity to move current oil sands production of about 1.3 mmbbl/d. These systems also have the capacity to handle volumes for many years of project expansions. The Canadian Association of Petroleum Producers (CAPP) estimates that existing pipelines that are either on line or going into service have sufficient capacity to handle exports out of Alberta until about 2022.

Exhibit 16: Alberta Oil Sands Pipelines

Pipeline	Destination	Capacity (bbl/d)	Product
Cold Lake	Hardisty, Edmonton	459	Heavy Crude
Husky Oil	Hardisty, Lloydminster	491	Heavy & SCO
Echo	Hardisty	75	Cold Lake Crude
Athabasca	Hardisty	390	Semiprocessed Product & Bitumen Blend
Corridor	Edmonton	300	Diluted Bitumen
Syncrude	Edmonton	389	Syncrude SCO
Oil Sands	Edmonton	145	Suncor Synthetic
Access	Edmonton	150	Diluted Bitumen
Waupisoo	Edmonton	350	Blended Bitumen
Horizon	Edmonton	250	Horizon SCO
Total		**2,998**	

Source: ERCB and RBC Capital Markets

Exhibit 17: Current Export Pipelines

Pipeline	Destinations	Light Capacity (mbbl/d)	Heavy Capacity (mbbl/d)	Total Capacity (mbbl/d)
Enbridge	Eastern Canada, U.S. East Coast & Midwest	1,072	796	1,868
Express	PADD II, PADD IV	98	182	280
Trans Mountain	B.C., U.S. West Coast, Offshore	240	60	300
AB Clipper	PADD II	-	450	450
Keystone	PADD II	109	326	435
Total		**1,519**	**1,814**	**3,333**

Source: Canadian Association of Petroleum Producers, ERCB and RBC Capital Markets

Exhibit 18: Proposed Export Pipelines

Pipeline	Destinations	Capacity (mbbl/d)	Start-Up Date
Northern Gateway	B.C., U.S. West Coast, Offshore	500	2016
Trans Mountain TMX2	B.C., U.S. West Coast, Offshore	80	2012
Trans Mountain TMX3	B.C., U.S. West Coast, Offshore	320	2013
Keystone Cushing Extension	PADD II	155	2011
Keystone XL	U.S. Gulf Coast	700	2012
Altex	U.S. Gulf Coast	~250	2014
Alberta to California	West Coast	400	2016+
Total		**2,405**	

Source: Canadian Association of Petroleum Producers, ERCB and RBC Capital Markets

Exhibit 19: Alberta Oil Sands Pipelines

Source: ERCB

Downstream Refining Complex: How It's Adapted

U.S. refiners are investing in upgraders so Canadian producers may not have to upgrade – A heavy oil upgrader is essentially the front end of a complex heavy oil refinery. Because global and Canadian oil production has become increasingly heavy, U.S. refiners have invested capital to be able to upgrade and refine increasing amounts of heavy oil. These investments continue, with greater than 200,000 bbl/d of heavy oil refining capacity currently being added to the downstream refining complex (see Exhibit 20).

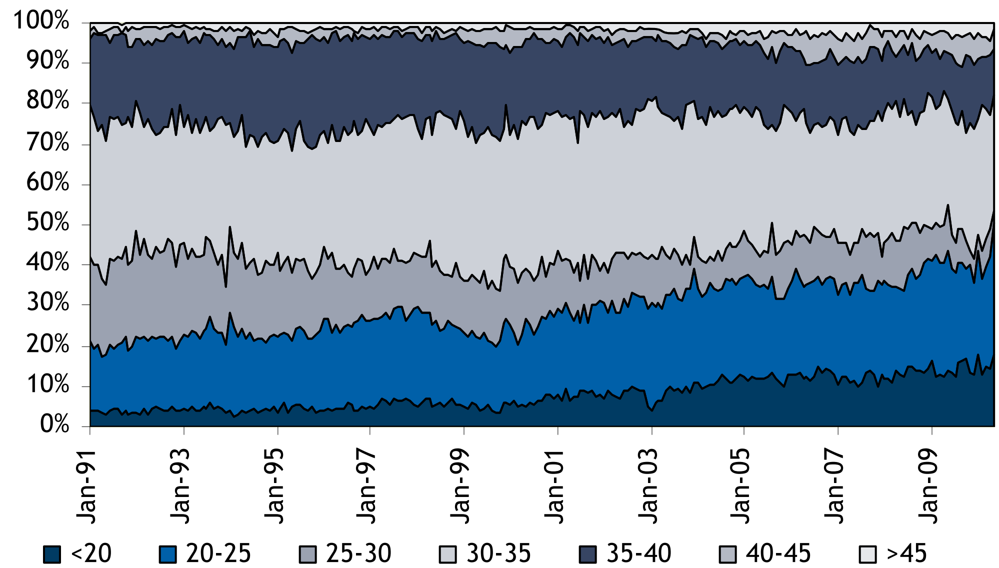
Exhibit 20: U.S. PADD II & III Refinery Upgrades

Operator	Location	PADD	Current Capacity (mbbl/d)	Scheduled In-Service	Description
WRB Refining	Roxana, IL	II	306	2011	Add a 65,000 b/d coker; increase total crude oil refining capacity by 50,000 b/d; increase heavy oil refining capacity to 240,000 b/d
BP	Whiting, IN	II	400	2012	Construction of new coker and a new crude distillation unit
Marathon	Detroit, MI	II	102	Mid 2012	Increase heavy oil processing capacity by 80,000 b/d and increase total crude oil refining capacity to 115,000 b/d
Valero	Memphis, TN	II	195	2012	Cat-cracking unit upgrade
Hunt Refining	Tuscaloosa, AL	III	52	2010	Increase capacity to 65,000 b/d
Valero	St. Charles, LA	III	250	2012	New 45,000 b/d hydrocracker and 10,000 b/d expansions to the crude and coker units
Motiva Enterprises	Port Arthur, TX	III	285	2012	Increase capacity to over 600,000 b/d

Source: Canadian Association of Petroleum Producers and RBC Capital Markets

Heavy oil feeds close to 40% of U.S. refining capacity – Heavy oil now supplies double the percentage of U.S. oil imports than it did just two decades ago (see Exhibit 21). In general, we expect the trend to continue, which supports our view of moderate (i.e., not widening back to historic high levels of greater than 30%) longer-term heavy oil differentials. While U.S. demand for heavy oil has increased, the traditional supplies of heavy oil to the United States (Mexico and Venezuela) have been declining. The gap between supply and demand has largely been filled by Canadian producers. We expect that trend to continue, which is positive for Canadian heavy oil producers.

Exhibit 21: U.S. Crude Oil Imports by API Gravity



Source: EIA and RBC Capital Markets

Fundamentals support moderate heavy oil differentials – A combination of the fact that the investment has already been made downstream by refiners to accept greater amounts of heavy oil and our view of longer-term heavy oil differentials supports our thesis that we do not expect heavy oil upgrading to be a significant part of oil sands projects in Alberta in the foreseeable future.

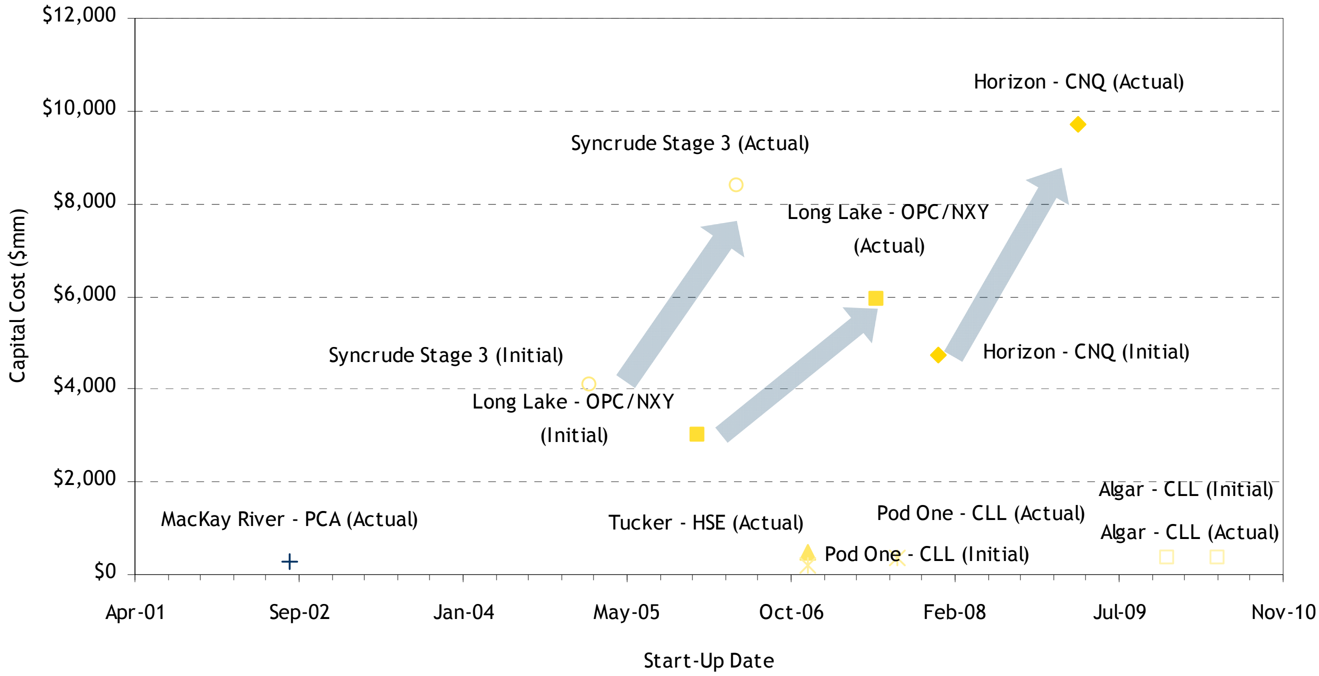
The Oil Sands Stigma: Project Delays and Cost Escalation

Oil Sands projects are often criticized for project delays and for running over budget. Unfortunately, these criticisms have merit; however, we believe that some clarity should be presented in order to assess the risk of delays and overruns on future projects.

In general, we make the following three observations:

- The larger the project, the greater the risk of delays and cost overruns.
- The more complex the project, the greater the risk of delays and cost overruns.
- The more active the industry, the greater the overall risk of delays and cost overruns.

Exhibit 22: Project Delays and Cost Escalation



Note: Husky's Tucker & PetroCanada's (Suncor's) MacKay River projects were completed on schedule and under budget
Source: Company Reports and RBC Capital Markets

For instance, large mining projects or projects with integrated upgrading, especially the projects built in the years of high industry activity in the 2005–2008 timeframe, experienced the highest degree of cost and schedule pressures, such as the Syncrude Stage 3 expansion, Nexen and OPTI's Long Lake and even Canadian Natural Resources' Horizon project.

Smaller scale In-Situ projects, however, have a greater tendency to be on time and on budget. Smaller projects such as Connacher's Pod 1 and Algar projects actually experienced pretty strong project execution, with the delays at Algar resulting from a management decision to stop spending and delay the project due to difficult economic and market conditions at the end of 2008 and early 2009.

It has become well understood that a few specific factors contribute to better initial cost estimates and better project execution:

- **More upfront engineering prior to first construction and fewer changes to design,**
- **Early order of long lead time items,**
- **Executable sized projects or projects broken down into manageable sized units and**
- **Greater degree of company, compared to contractor, control.**

Based on these observations, emerging companies currently enjoy good odds of having good control over costs and schedules given the smaller, non-integrated, In-Situ focus of the projects proposed by the these companies. Current industry activity is also quite moderate, which bodes well for projects in the pipeline for a 2011 start-up having a high probability of being completed on time and on schedule. We expect a higher degree of industry activity, which could put pressure on schedules and budgets, starting in 2012 and continuing until 2015 (see Exhibit 37 and 38).

The Environment: It's the LAW (Land, Air & Water)

Environmental issues and concerns have increased in the Oil Sands sector, to the point—we would argue—that facts have often become distorted and oil sands development has been negatively misrepresented. There is no doubt that oil sands development has an effect on the environment in terms of land and water use, and emissions into the air, but it is important to review some simple facts to put the effect of the oil sands into context.

Land – Reclamation Underway

Only 0.02% of Canada's Boreal Forest has been disturbed by mining – Canada is responsible for the safekeeping of approximately 3.2 million km^2 (20%) of the earth's 16.6 million km^2 of boreal forest. In total, 140,000 km^2 (4.4% of Canada's boreal forest of 0.8% of the total boreal forests) lies within the greater oil sands area. More specifically, only 4,802 km^2 (0.15% of Canada's boreal forest or 0.03% of the total boreal forests) represents areas that are suitable to mining. Furthermore, only 530 km^2 (0.02% of Canada's boreal forest or 0.003% of the total boreal forests) are currently under development. Approximately 12% of all lands disturbed by mining activities have been reclaimed, and the Government of Alberta holds more than $650 million in reclamation security. Land disturbance of In-Situ development is less than mining, with In-Situ development techniques that rely on pad drilling accounting for less than 15% of the surface area of the development area being disturbed.

Exhibit 23: Oil Sands and the Boreal Forest

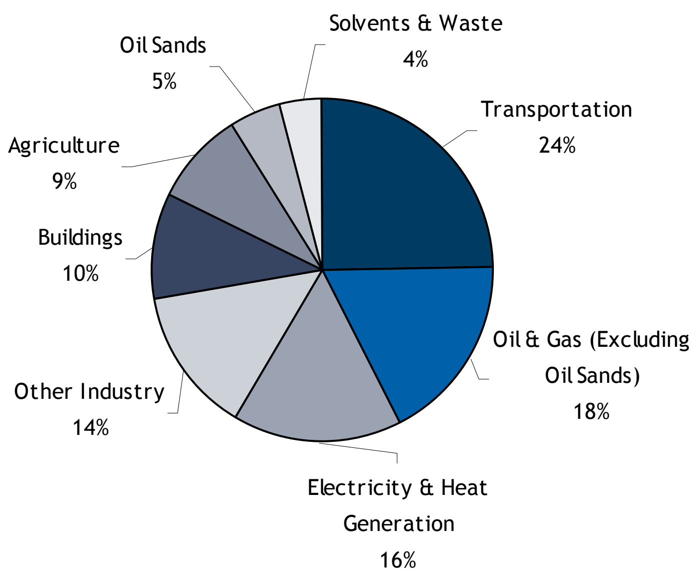
Source: Canadian Association of Petroleum Producers

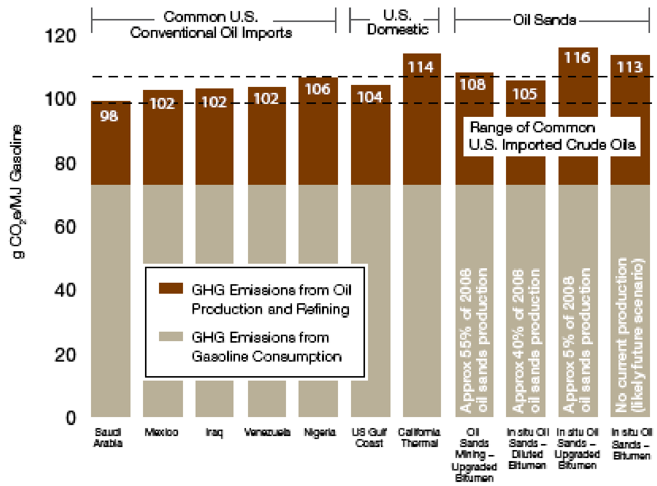
Air – Cleaner Now Than a Decade Ago

Only 0.1% of global greenhouse gas (GHG) emissions are emitted by the oil sands producers – Canada is estimated to emit 2% of global GHG emissions. The Oil Sands sector is estimated to represent 5% of Canada's emissions, or a total of 0.1% of global GHG emissions. Despite the generally small effect that the oil sands have on GHG emissions, the industry is focused on reducing the effect it has on GHG emissions. Emission intensity per barrel produced has been reduced by 30% since 1990 according to Environment Canada. Furthermore, air quality readings in the Fort McMurray region indicate that sulphur dioxide levels have remained flat during the past decade and are lower than levels in Edmonton, Calgary and well below the Alberta objective levels. Similarly, readings of nitrogen dioxide and fine particulate matter, which are also well within the provincial objectives, have dramatically improved in the oil sands region in the past decade.

Carbon tax is $15/tonne – With respect to alternative sources of oil, Canada's oil sands have a comparable level of total emissions per barrel to the oil produced in the United States and with other major sources of oil imported into the United States (see Exhibit 24). With the application of future technology, emissions from oil sands production are expected to become more competitive to the current sources of oil imported into the United States (see Exhibit 25). Since 2007, regulations have started to cause a real reduction in emissions, and the Alberta government has collected more than $120 million (at $15/tonne) into the Climate Change and Emissions Management Fund, which supports research and development of emission reduction technologies.

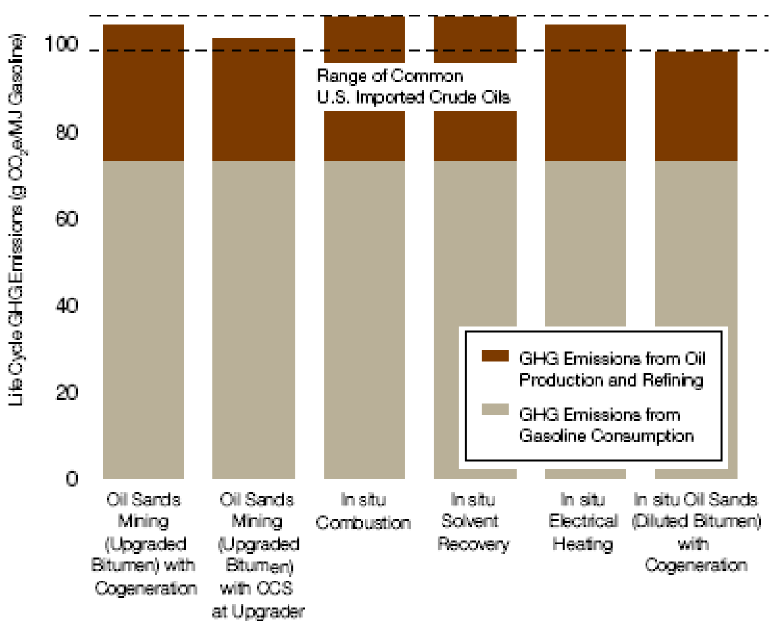
Exhibit 24: Green House Gas Emissions





Source: Environment Canada, Jacobs Consulting and RBC Capital Markets

Exhibit 25: Oil Sands and GHG Emissions



Source: Jacobs Consulting

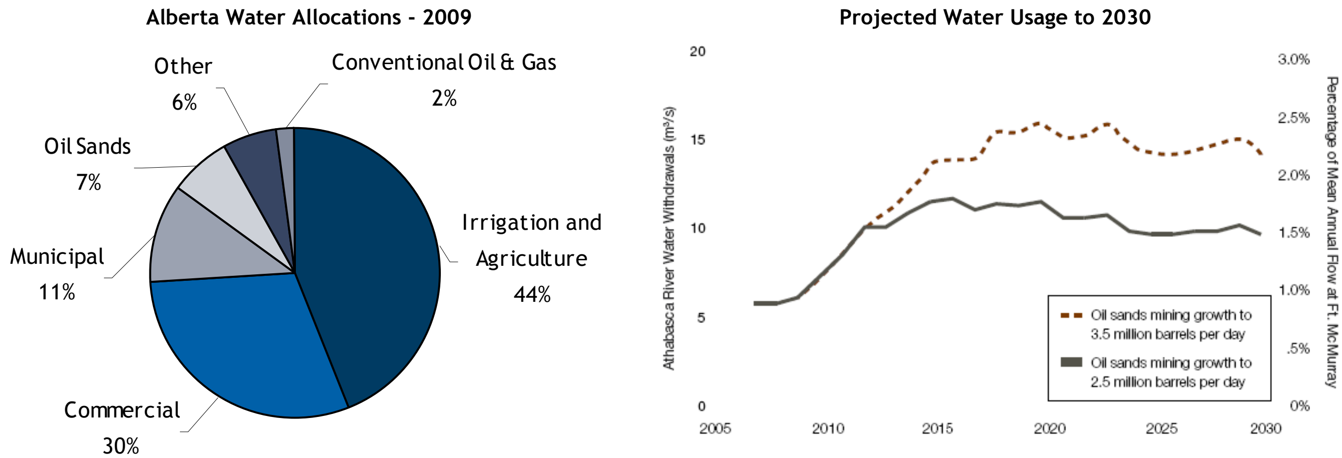
The future of CCS is uncertain – The Government of Alberta has committed $2 billion to Carbon Capture and Storage (CCS) while the federal government has committed $1 billion, with investments also being made by the industry. Despite commitments, the implementation of CCS in the Oil Sands sector remains unclear at this time.

Water – A River Runs Through It

Only about 2% of the mean annual flow of the Athabasca to be used by 2030 – Water supply in Alberta is an issue; however, the issue is not created by the oil sands but rather by climate and population distribution. The drainage basins in the northern part of the province supply 85% of Alberta's water, but the northern region represents only 12% of Alberta's demand for water usage. The challenge for water usage in Alberta is actually in the populated southern part of the province, which demands 88% of Alberta's water allocation while representing only 15% of Alberta's water supply.

Producers in the Oil Sands sector have 7% of the total water use allocations in the province of Alberta. Actual water usage is less. Water usage is different for mining projects and In-Situ projects. In-Situ projects seldom access surface water sources but rather drill for water, which has become predominately supplied by brackish sources. Mining projects north of Fort McMurray are more water intensive and rely on water from the Athabasca River. Currently, the mining industry utilizes approximately 1% of the mean annual flow rate of the river, which represents approximately 5% of the lowest weekly winter flow rates. The Oil Sands Developers Group predicts that the mining industry will demand between 1.5–2.5% of mean annual flow rates by 2030, which would equate to around 7–12% of the lowest weekly winter flow rates. In our opinion, we see the industry taking specific action to reduce the stress on the Athabasca River during the weeks of lowest flow by utilizing on-site water storage ponds to make up for water during the weeks of lowest river flow and by increasing water recycle rates, which often reach 95%.

Exhibit 26: Water Usage by the Oil Sands Sector



Source: Canadian Association of Petroleum Producers, Alberta Environment, OSDG and RBC Capital Markets

Emerging Plays: Bitumen Carbonates

Possibly Canada's next big resource play – The bitumen carbonate deposits hold significant resource potential, representing approximately 26% of Canada's 1,700 billion barrels of Original Bitumen In Place (OBIP). The Grosmont Formation contains 71% of the bitumen carbonate deposits in Canada, with the C & D zones estimated to contain 70% of the bitumen found in the entire Grosmont Formation. The C & D zones also have better reservoir characteristics, demonstrated by having thicker pay, higher porosity and higher bitumen saturation than the lower Grosmont A and B zones (see Exhibit 27). We expect the Grosmont C & D zones to be the logical focus of industry activity.

Exhibit 27: The Grosmont A-D Formations

Grosmont Unit	Initial BVIP (billion bbl)	Initial BVIP	Average Pay Thickness (m)	Average Porosity	Average Bitumen Saturation	Average Water Saturation
Upper Grosmont 3 (Grosmont D)	125.1	39%	16	20%	67% (85-95%)*	33%
Upper Grosmont 2 (Grosmont C)	96.8	31%	10	16%	75% (85-95%)*	25%
Upper Grosmont 1 (Grosmont B)	33.8	11%	5	15%	69%	31%
Lower Grosmont (Grosmont A)	61.9	20%	10	14%	60%	40%
Total	**317.6**	**100%**				

*Published by Osum in CIPC Paper 2009-067
Source: Canadian International Petroleum Conference, Petroleum Technology Alliance Canada and RBC Capital Markets

Unlocking the bitumen carbonates could make Canada number one in the world – A 35% recovery factor from the Grosmont C and D zones would imply an increase of 78 billion barrels to Canada's total current oil reserves of 179 billion barrels (174 billion barrels of oil sands and 5 billion bbls conventional). Unlocking the commercial potential of the bitumen carbonates in the Grosmont C and D zones would catapult Canada into first place as the country with the most recoverable oil reserves in the world.

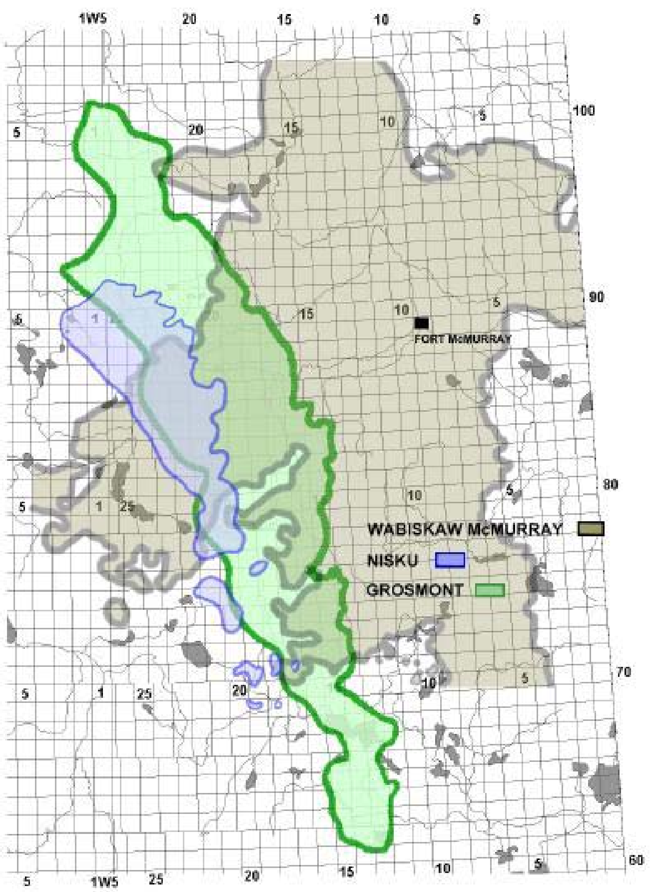
The unique challenges of the bitumen carbonates – The challenge is that the Grosmont contains the heaviest and most viscous oil deposits to be found in a carbonate reservoir anywhere in the world with an average oil quality of 5–9 degrees API and an average viscosity of 1.6 million centipoises. For contrast, the heavy oil found in the other carbonate discoveries around the world contain oil ranging from 10–20 degree API with viscosity ranging from 100–4,600 centipoises. These amounts make the Grosmont reservoir unique, without an analogous reservoir to be found. The other unique challenge is that the Grosmont Formation is an oil wet reservoir with areas of mixed wettability, not water wet like the Wabiskaw-McMurray formation in the Athabasca region. Water wet reservoirs produce more easily because they are physically easier to break the water bond holding the oil to the reservoir than it is to free the oil bonded directly on the reservoir.

Initial pilots were encouraging – We found one pilot test dating back to the 1970s (Chipewyan River) and four pilot tests in the Grosmont dating back to the 1980s (Orchid, Algar, Buffalo Creek and McLean) (see Exhibit 28). These pilots were undertaken by Alberta Oil Sands Technology and Research Authority (AOSTRA), Unocal and Chevron.

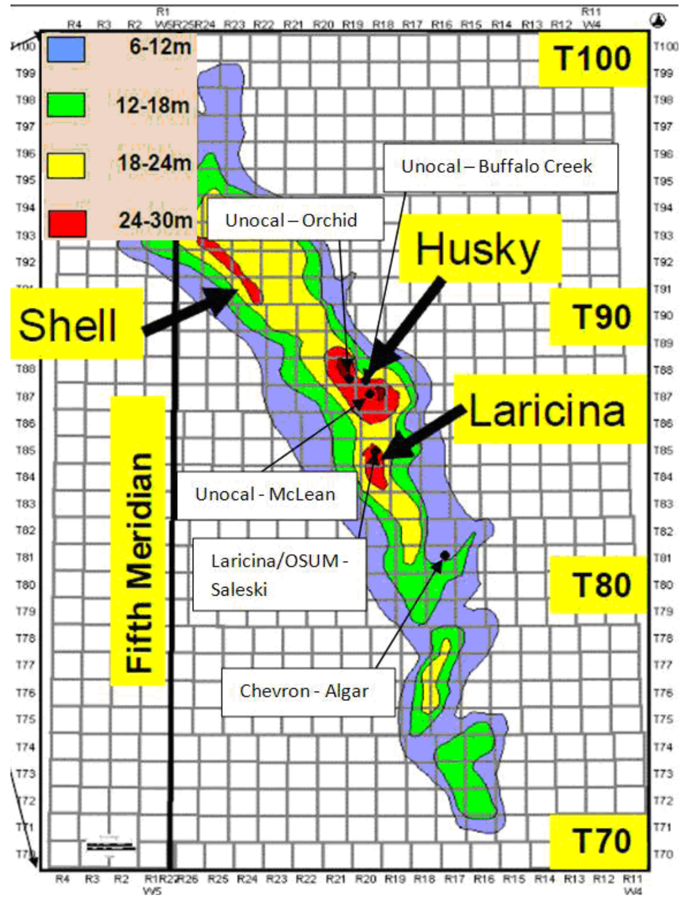
Between December 1974 and April 1975, the Chipewyan River Pilot ran one steam cycle from two vertical wells that quickly resulted in vertical steam loss. Unocal's Buffalo Creek, which ran between 1980–1986, was the most successful pilot test in the carbonates. The test consisted of one vertical CSS well. The pilot produced 100,000 barrels of bitumen from 10 steam cycles before losing steam circulation. The Cumulative Steam: Oil Ratio (CSOR) of the Buffalo Creek pilot was 6.4x.

Exhibit 28: Grosmont Carbonates

The Grosmont vs the Wabiskaw/McMurray



Grosmont Net Pay Isopach



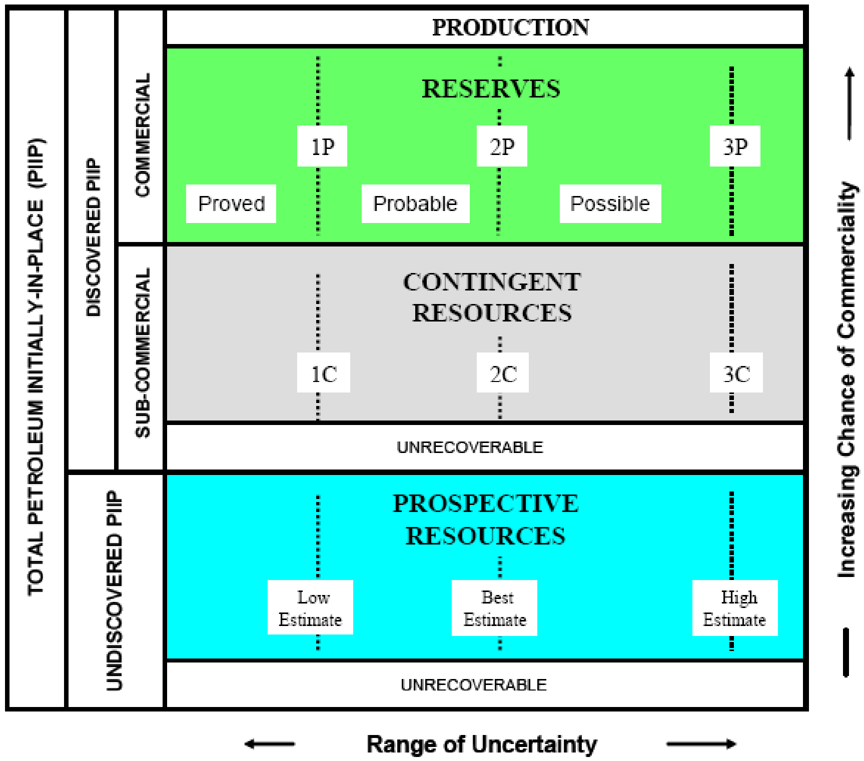
Source: Alberta Energy Utilities Board (AEUB), Laricina Energy Ltd. and RBC Capital Markets

The pilot tests from the 1980s had encouraging, but mixed, results. The pilot tests proved the ability to mobilize oil and, therefore, the ability of the reservoir to produce. The pilot tests, however, ultimately lost steam circulation due to the high vertical permeability and heterogeneity of the reservoir. Technological improvements in drilling and completion techniques during the past three decades (better mud control, horizontal drilling, quick setting cement, etc.) could be expected to help with completions in the carbonates. Horizontal drilling may help because production is a function of gravity drainage rather than pressure mobilizing the bitumen. The use of lower pressure steam and solvents are techniques that could also improve the economic potential of the Grosmont.

Reserves and Resources: Lock, Stock and Barrel

A lot of mistakes and misunderstandings surround the usage of reserve and resource definitions with respect to the oil sands, which are the context of this short discussion (see Exhibit 29). It is critical to understand the differences among each category in order to appreciate the stage of commerciality and level of confidence in the estimate.

Exhibit 29: Reserves and Resources



Source: Society of Petroleum Engineers

Total PIIP (Petroleum Initially in Place) refers to an estimate of all the bitumen contained under the lease. This estimate is often also referred to as OBIP (Original Bitumen in Place), BOIP (Bitumen Originally in Place) or even OOIP (Oil Originally in Place). This number is often referred to as captured resource potential and is sometimes cited as an indication of long-term upside potential, which could be somewhat misleading because OBIP (which is our preferred terminology) is usually a volumetric calculation based on geologic models often made before extensive delineation drilling. Also, this estimate does not factor in quality differences in reservoirs that could affect recovery factors.

Total PIIP is subdivided into **Discovered PIIP** and **Undiscovered PIIP**. Resource estimates fall into the Discovered PIIP category when a well is drilled into the reservoir. Undiscovered PIIP is based on geologic modelling, perhaps supported by seismic data, but without well control. What separates PIIP from reserves and resources is the application of a recovery factor.

Referring to Exhibit 29, **Prospective Resources** are the estimated quantities of resource to be potentially recoverable from an undiscovered reservoir. The calculation of Prospective Resources involves two variables: a chance of discovery and a chance of development, which is decided by the reserves evaluator. As a rule, we do not attribute value in our Base NAV to PIIP or Prospective Resources.

Once drilled, Prospective Resources become **Contingent Resources**. Contingent Resources are discovered volumes that are not yet considered commercially recoverable due to contingencies. Contingencies can be regulatory, legal, technical, logistical or timing issues. Once all contingencies have been removed the volume is considered commercial, and Contingent Resources become **Reserves**.

Confidence and uncertainty levels are applied to the above three categories of reserves and resources. In each category, there are three levels:

- Low, 1C or proved (1P or P90) is considered the most conservative measure.
- Best, 2C or probable (2P or P50) is considered the best estimate.
- High, 3C or possible (3P or P10) is considered the most optimistic estimate.

The number in parentheses above represents a probability distribution; for example, P90 means there should be a 90% probability that actual recovered volumes will meet or exceed the estimate. A P50 estimate means that there is an equal chance that actual recovery will be more or less than the estimate, and a P10 estimate implies that there is only a 10% chance that recovery will be above the estimate and a 90% chance that the actual recovery will be less than estimated.

We use 2P or P50 Reserves plus 2C Contingent Resources – Barrels move vertically through the system not horizontally. For instance, the level of confidence is roughly the same from 2P or P50 Reserves to 2C Contingent to Best Estimate Prospective; however, the level of information or information barriers has changed. It is common to see barrels move from the 2C Contingent Resource category into the 2P or P50 Reserve category. For this reason, we are most comfortable attributing value to 2P or P50 Reserves plus 2C Contingent Resources. Please refer to the Valuation Approach section in this report to see our valuation approach for reserve and resource estimates.

Contingent Resource estimates become reserve estimates when all levels of contingency have been removed. Most conservatively, a company would transfer Contingent Resource estimates to reserve estimates following regulatory approval, project financing and project execution. Most companies make the transfer from Contingent Resource to reserves following the receipt of regulatory approval; however, it is becoming increasingly common for evaluators to move barrels from Contingent Resource to reserves upon filing of the regulatory application.

Exploitable PIIP excludes any bitumen that cannot be exploited. For example, a reservoir that has interbedded shale could prevent the development of a steam chamber through the entire reservoir; therefore, the part that cannot receive steam could be considered un-exploitable.

Economic Contingent Resources are resources that are currently economic to produce. These resources will largely depend on the assumptions applied by the reserves evaluator. Some key assumptions that we believe could apply are product pricing, capital efficiency, steam-oil ratio and presence of infrastructure.

Reservoir Basics – Spotting the Good from the Bad

Many factors contribute to the performance of an oil sands reservoir, but the combination of reservoir thickness, bitumen saturation, permeability, porosity and pressure seem to be the most relevant factors in contributing to the successful development of a SAGD reservoir.

Thickness – A rule of thumb is that the reservoir should be a minimum of 18–20 metres for SAGD development to be possible. Thinner reservoirs may be suitable for CSS development. Thicker reservoirs are expected to have longer average well lives and lower longer-term capital costs per barrel.

Bitumen Saturation – Simply stated, this is a measure of how much bitumen is contained in the reservoir. Higher bitumen saturation levels are better.

Vertical Permeability – Not a frequently quoted number, but vertical permeability is an indication of how well the steam chamber will grow vertically in the reservoir during formation. High vertical permeability promotes steam chamber development. Higher permeability translates into the easier flow of bitumen to the well bore.

Porosity – Higher porosity means that more bitumen can be contained in the reservoir.

Reservoir Pressure – Pressure generally increases with depth. Higher pressure generally translates into higher production rates; however, higher pressure also requires greater amounts of steam to sustain reservoir pressure, which can negatively influence steam-to-oil ratio (SOR) over time. Many producers are attempting to produce at lower pressure conditions with the use of low pressure steam injection, non-condensable gas injection and the conversion of wells to electrical submersible pump (ESP) from gas lift.

Exhibit 30: Comparative Reservoir Characteristics

Project	Company	Reservoir Depth (m)	Average Net Pay Thickness (m)	Avg Permeability (Darcies)	Avg Bitumen Saturation	Avg Porosity	Native Reservoir Pressure (kPa)	Developed Reservoir Pressure (kPa)	Target Formation
MacKay	Athabasca Oil Sands	180	18	2 - 9	77%	33%	600 - 1,100	1,800 - 2,200	McMurray
Dover	Athabasca Oil Sands	160 - 500	21	2 - 9	76%	35%	700 - 1,000	3,000 - 5,000	McMurray
Great Divide	Connacher Oil & Gas	475	20	3 - 9	85%	33%	1,480	4,300	McMurray
Tamarack	Ivanhoe Energy	75 - 132	24-38	6	80%	33%	~500	1,250-1,450	McMurray
Christina Lake	MEG Energy	390	28	>5	71%	34%	2,000	2,700 - 3,500	McMurray
Hangingstone	Japan Canada Oil Sands	300	11 - 26	n.a.	85%	30%	n.a.	4,500	McMurray
Long Lake	OPTI Canada	200	30	6.3	75%	30%	1,200	2,750	McMurray
McKay	Southern Pacific Resource	180	19	0.5 - 11	65% - 75%	32%	650	2,450	McMurray
Taiga	Osum Oilsands	365 - 440	7 - 26	1.1 - 3.4	45% - 76%	33% - 35%	3,000	3,000+	Clearwater
West Ells	Sunshinie Oilsands	>250	13.5 - 18	0.4 - 8	78%	32%	~925	2,000 - 4,000	Wabiskaw
Saleski	Laricina Energy	400	24+	10+	83%	25 - 40+%	1,000 - 1,300	1,000 - 1,500	Grosmont
Germain	Laricina Energy	225	<23	2 - 5	65% - 75%	35%	1,200	1,200	Grand Rapids
Christina Lake	Cenovus	385	28	3 - 10	80%	30%	2,000	2,300-3,000	McMurray
Foster Creek	Cenovus	500	30	6	85%	34%	2,700	2,400-2,700	McMurray
Firebag	Suncor	320	36	6-10	79%	35%	800	3,150	McMurray
McKay	Suncor	135	15-35	1-5	76%	34%	300-500	1,500-2,000	McMurray
Surmont	ConocoPhillips	435	39	n.a.	80%	35%	1,700	3,000-4,500	McMurray
Jackfish	Devon	415	15-40	2-10	80%	33%	2,700	2,700-2,900	McMurray

Source: Company reports and RBC Capital Markets

Reservoir Hazards – Be Careful Out There

Many different hazards can negatively affect the economics of an In-Situ development; however, the most common reservoir related causes of poor performance are depleted top gas zones, bottom water, interbedded shales and cap rock integrity issues.

Depleted Top Gas – In some cases, natural gas reservoirs are located on top of bitumen reservoirs and are in direct pressure communication. Early production of the natural gas reduces pressure of the overbearing reservoir, which then must be re-pressurized before the formation of a steam chamber will occur in the bitumen bearing zone. In some cases, the depleted natural gas cap can be repressurized before SAGD is applied. If left unaddressed, the depleted top gas zone serves as a thief zone for steam injection thereby resulting in low productivity and very high SOR. In many situations, regulators have ordered natural gas wells producing from zones in direct pressure communication to be shut-in.

Bottom Water – In some cases, water bearing zones lie directly underneath the bitumen bearing reservoir, which could present productivity and SOR problems if the lower producing well is located too close to the water bearing zone. The typical method of dealing with the presence of bottom water is to locate the lower producing well several metres higher off the bottom of the reservoir than normal. If the reservoir is thick, say 25 metres or more, locating the well higher off the bottom of the reservoir should not present any issues; nevertheless, the presence of bottom water combined with a thin reservoir of less than 20 metres will likely not result in a good development scenario.

Interbedded Shales – Gross reservoir thickness may sound very attractive, but that does not mean the entire reservoir thickness can be developed. Shale beds may interrupt the bitumen bearing reservoir. In some cases, if thin enough, the shale zones may not present much impairment between bitumen zones; however, if the interbedded shale zones are thick, the shale may interrupt, divert or stop the migration of steam and the growth of the steam chamber. Interbedded shale zones can negatively affect economics by impairing production rates, SOR and recovery factors.

Cap Rock – Vertical steam migration stops on reaching a barrier, which is usually the cap rock, at which time the steam chamber that drives production begins to form out and sweep the reservoir horizontally. The absence of a suitable cap rock that is capable of pressure containment results in breakthrough and the loss of steam. Insufficient cap rock may not only result in disadvantaged economics, it may result in a reservoir that cannot be produced at all. The cap rock that overlies the McMurray formation is generally the Clearwater shale, which can range from several metres in thickness to tens of metres of thickness.

Quartile Performance – Not All SAGD Projects are the Same

Looking at the first 24 months of performance of a normalized type well for the producing projects in our coverage universe, we are able to make the following statements in the context of industry wide performance (see Exhibits 31 and 32):

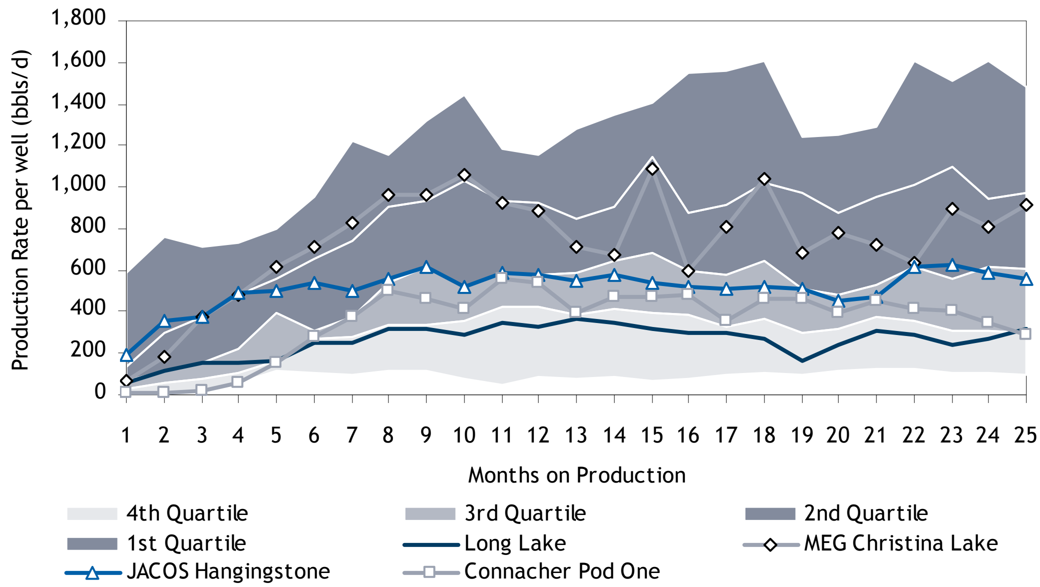
- MEG’s Christina Lake can be called a top-quartile project. The project has set the new gold standard with respect to CSOR performance. Production ramp up for the first year was top quartile as well. Production rate for the second year looks noisy, but those rates are based on only three producing well pairs that have been on production between 12–24 months,- so any interruptions to install an ESP or the like cause large fluctuations in the rate. It is reasonable to see that when wells are producing, they are top-quartile performers.

- Hangingstone (JACOS) started out as an average project in terms of production rate per well and CSOR with a rate of 500–600 bbl/d per well pair and an SOR of approximately 3.2x. In its maturing years, the average rate per well has dropped to about 400 bbl/d with a CSOR of greater than 4.0x.

- Pod 1 at Great Divide (Connacher) has been a third-quartile project in terms of both production rate per well and SOR performance.

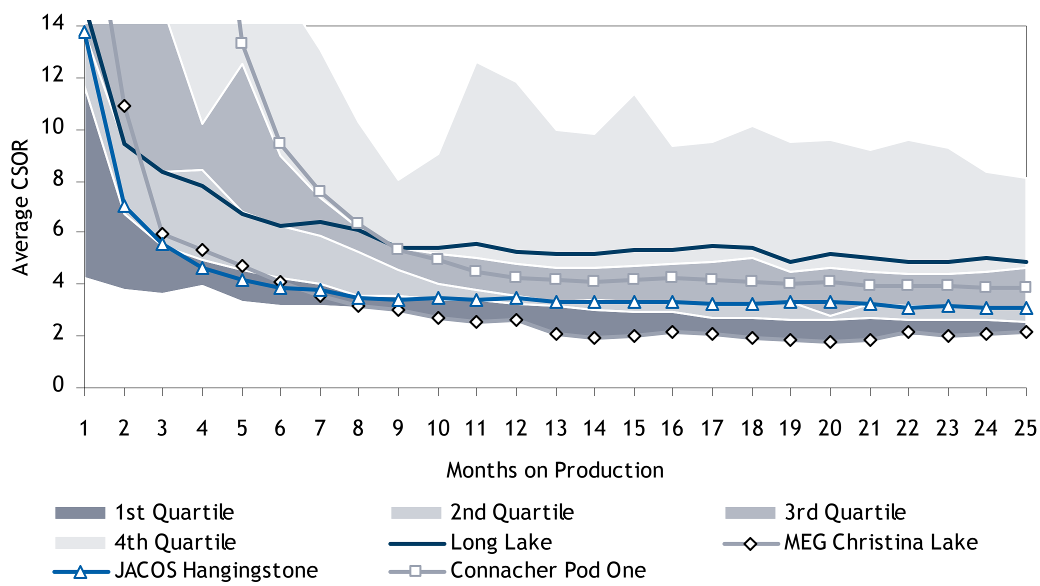
- Long Lake (OPTI and Nexen) has been a fourth-quartile project in terms of both production rate per well and SOR.

Exhibit 31: Production Rate Per Well



Source: Accumap and RBC Capital Markets

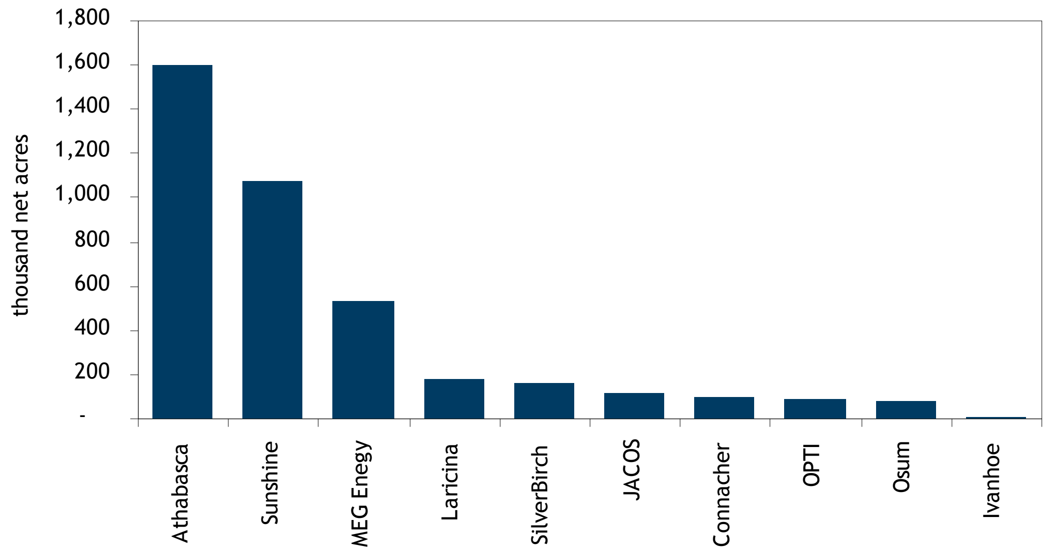
Exhibit 32: SOR Performance



Source: Accumap and RBC Capital Markets

Fundamental Comparative Analysis

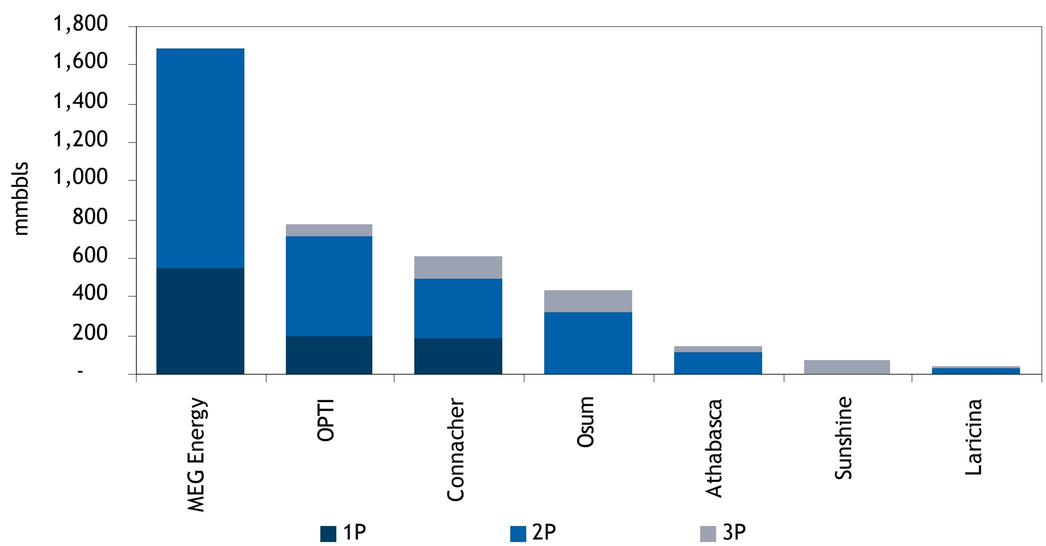
Exhibit 33: Oil Sands Lease Holdings



Source: Company reports and RBC Capital Markets

- The largest benefactors of the 2006–2008 oil sands land rush have emerged and are now moving projects through the regulatory process.

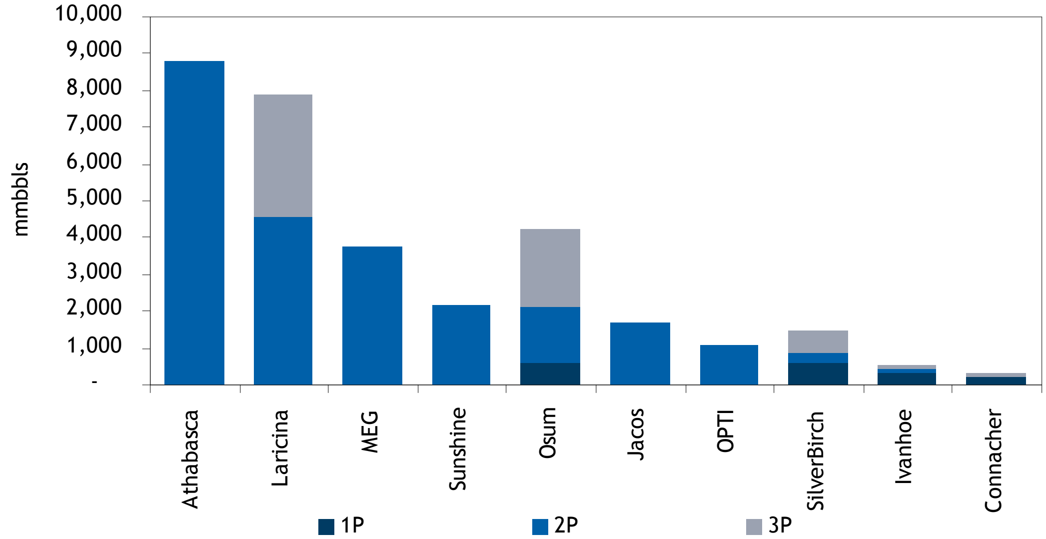
Exhibit 34: Bitumen Reserves



Source: Company reports and RBC Capital Markets

- Emerging oil sands companies are moving projects forward and have begun to book reserves.

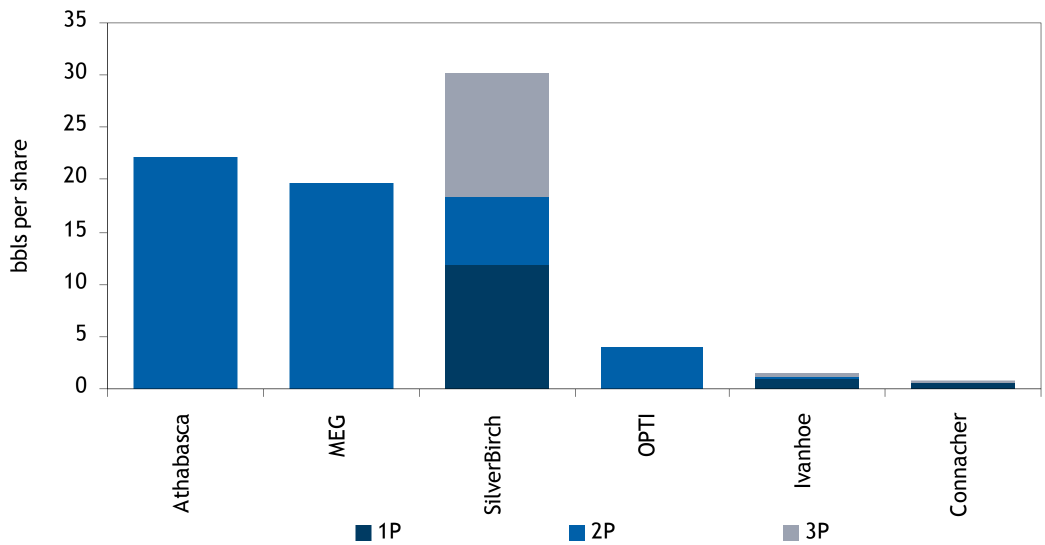
Exhibit 35: Contingent Resource



Note: Laricina's resource reflects Contingent and Prospective Resources
Source: Company reports and RBC Capital Markets

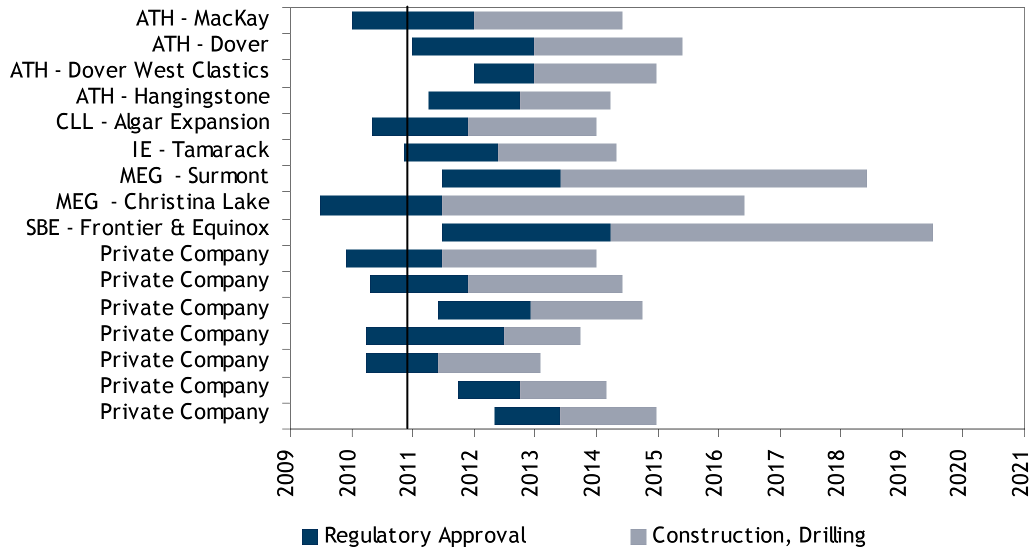
- Emerging oil sands companies have captured huge resource opportunities. Development of these resources is the challenge that now faces these companies.

Exhibit 36: Contingent Resource per Share



Source: Company reports and RBC Capital Markets

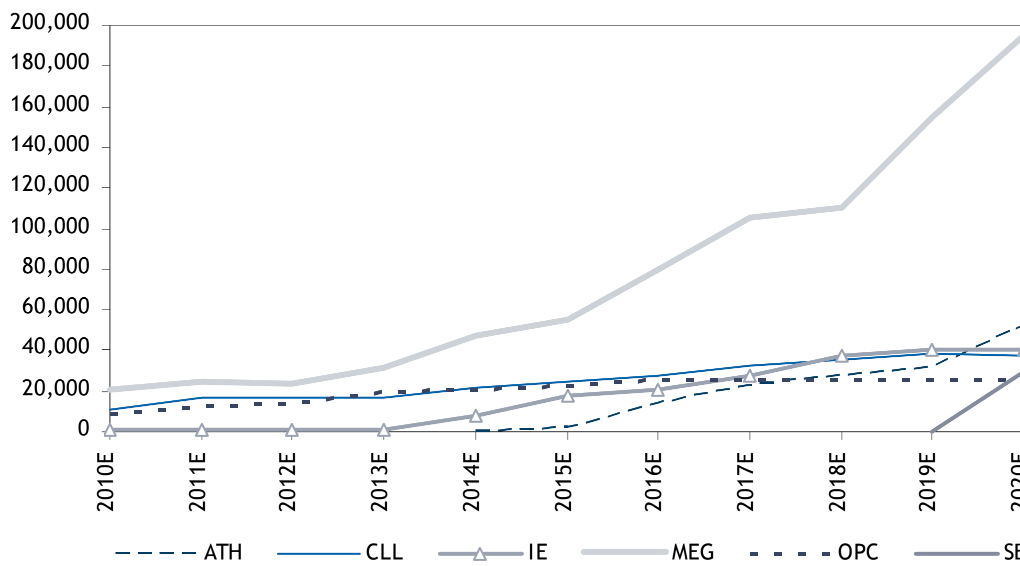
Exhibit 37: Regulatory Schedule



Source: Company reports and RBC Capital Markets

- We expect that the companies that are ready to build in 2011 will have a good chance of controlling costs and schedules before the next oil sands boom time of activity begins in the 2012–2015 timeframe, when we believe that costs and schedules will be more difficult to manage.

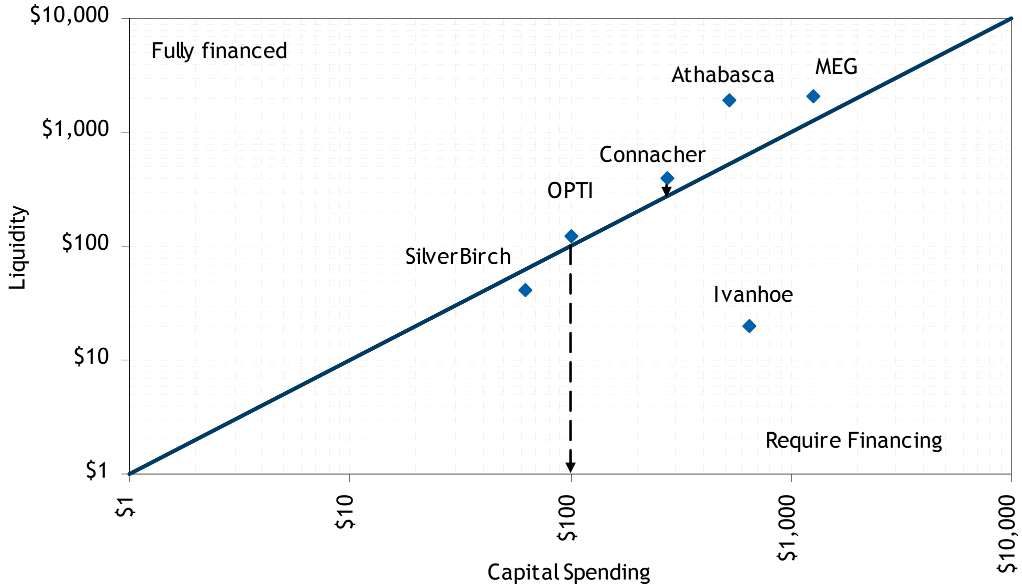
Exhibit 38: Production Growth Schedule by Company



Source: Company reports and RBC Capital Markets

- While not perfectly correlated, it should not come as a surprise that the top-five companies with Contingent Resources expect to exit this decade as the top-five producers among this emerging oil sands peer group.

Exhibit 39: Financial Liquidity Outlook (Remainder of Forecast Period)



Source: Company reports and RBC Capital Markets

- Several companies have achieved financial liquidity in the next 24 months; however, several companies still have to find financing solutions.

Company Profiles

Athabasca Oil Sands Corp. (TSX: ATH; $14.06)

Prepare for Launch

Market Statistics			Net Asset Value			
Rating		Sector Perform			Base	Unrisked
Risk		Above Average	Net Asset Value	($mm)	$6,354	$12,062
Target Price		$16.00	NAV/Sh	($/share)	$15.61	$29.64
Market Price		$14.06	P/NAV	(%)	90%	47%
Implied Return		13.8%	Target Price/NAV	(%)	102%	54%

Capitalization			Resources		
Diluted Shares O/S	(mm)	397.8	Oil Sands EV[(a)]	($mm)	$4,143
Market Capitalization	($mm)	$5,593	2P Reserves	(mmbbl)	114
Net Debt	($mm)	($1,450)	Contingent Resources[(b)]	(mmbbl)	8,819
Enterprise Value	($mm)	$4,143	EV/Bbl[(c)]	($/bbl)	$0.46

Operating & Financial		2007A	2008A	2009A	2010E	2011E	2012E
Total Production	(boe/d)	n.a.	0	0	0	0	0
Operating Cash Flow	($mm)	n.a.	($22.2)	($165.2)	($15.4)	($20.8)	($30.3)
Diluted CFPS	($/share)	n.a.	($0.12)	($0.83)	($0.04)	($0.05)	($0.08)

Sensitivity to WTI	(US$/bbl)	$60	$70	$80	$90	$100	$110
NAV/Share	($/share)	$6.39	$10.20	$13.85	$17.35	$20.67	$23.78
P/NAV	(%)	220.1%	137.8%	101.5%	81.0%	68.0%	59.1%

(a) Adjusted to exclude the estimated value of non- oil sands assets
(b) Best Estimate
(c) Based on 2P reserves + Best Estimate Contingent Resource
Source: Company reports and RBC Capital Markets estimates

Investment Highlights

- **One of the most attractive long-term growth portfolios in the industry –** Currently with no production, management estimates that its current asset base is capable of supporting 500,000–800,000 bbl/d of production. The company has seven primary focus areas: MacKay and Dover Joint Ventures (JV), Dover West Clastics, Hangingstone, Birch, and the Dover West Leduc and Grosmont bitumen carbonates in the Athabasca oil sands region of northern Alberta.
- **Committed JV partner in PetroChina –** PetroChina paid Athabasca $1.9 billion in cash and provided preferred terms for an incremental $1.1 billion of debt financing that effectively cover MacKay Phase 1 development for a 60% non-operated working interest (W.I.).
- **Ample financial liquidity –** Athabasca has a current cash equivalent balance of ~$1.7 billion and current borrowing capacity of $646 million under the PetroChina loan facilities. This is sufficient financial liquidity to fund the company's capital spending plans of $2.4 billion through to the end of 2014 and into first production from MacKay.
- **Catalyst rich –** We are watching for the company to file its regulatory application for Dover and we are waiting on the ERCB's final decision regarding the shut-in natural gas wells in the Dover West Clastics area before year-end 2010. We are also watching for the company to initiate this winter's drilling program, to drill and steam the Leduc carbonate test wells and drill the Thermal Assisted Gravity Drainage (TAGD) horizontal wells this winter.
- **Valuation support –** We see asset value support for Athabasca, which is currently trading at a P/NAV (Base) ratio of 90% and a P/NAV (Unrisked) ratio of 47%. We calculate a Base NAV of $15.61/share on the assumption that the JV partners proceed with MacKay and Dover and do not exercise the Put/Call option. We calculate an Unrisked NAV of $29.64/share.
- **Recommendation –** Sector Perform, Above Average Risk, 12-month target price of $16.00/share. Our target price is based on a 1.0x multiple of our Base NAV, which is in line with the peer group average.

Summary & Investment Thesis

We initiate coverage of Athabasca Oil Sands Corp. (TSX: ATH) with a Sector Perform (SP) investment rating, an Above Average Risk Rating and a 12-month target price of $16.00/share, based on a 1.0x multiple of our Base NAV analysis, which is in line with the peer group average.

In our opinion, Athabasca has captured one of the more attractive land holdings and growth portfolios in Canada's oil sands sector. We see Athabasca as a catalyst-rich, opportunity-rich, well-financed company with a long-term asset portfolio. Management estimates long-term production potential of its current assets to be in the range of 500,000–800,000 bbl/d, which is dependent on regulatory approvals, project execution, financing solutions and a degree of technical risk.

The company has seven In-Situ focus areas in the Athabasca region of northern Alberta: MacKay and Dover JVs, Dover West Clastics, Hangingstone, Birch, Dover West Leduc bitumen carbonates and the Grosmont bitumen carbonates. For the most part, the company will implement proven SAGD technology.

A financially committed JV partner – Athabasca entered into a JV agreement with PetroChina in February of 2010, just prior to the company's IPO. The JV provides PetroChina with a non-operated 60% working interest in the MacKay and Dover leases. To earn this working interest, PetroChina paid Athabasca $1.9 billion in cash and provided preferred terms, based on the strength of PetroChina's balance sheet, for an incremental $1.1 billion of debt financing. The preferred borrowing terms substantially reduce the company's cost of debt financing from an interest rate of 13% to LIBOR + 4.5%. Interest cost savings total approximately $35 million per year at existing borrowing levels and approximately $90 million per year should these facilities be fully utilized.

Floor value of $2 billion for remaining 40% W.I. – The partners entered into a unique Put/Call option for Athabasca's remaining 40% working interest in the JV leases, intending to provide certainty as to the commitment of the partners and the perceived value of the assets. The Put/Call option values Athabasca's remaining 40% W.I. at $2 billion, which would be paid to Athabasca in cash if either party exercised the option.

JV assets worth more developed than if Put/Call option is exercised – We have valued both MacKay and Dover on a DCF basis, on the assumption that neither JV partner exercises the Put/Call option. Also, we calculate twice as much value for the MacKay and Dover projects on a discounted cash flow basis than if the Put/Call option is exercised for $2 billion of cash.

Athabasca enjoys significant financial liquidity to be able to fund its capital spending plans through first development and to the end of 2014. Athabasca Oil Sands enjoys operatorship on all of its leases and 100% working interest stakes on most, aside from the company's 40% working interest at MacKay and Dover because of its JV with PetroChina and a 50% working interest on its Grosmont lease.

We see continued support to asset value as management continues to move projects through the regulatory and development stages. Pending regulatory approvals, the company has development plans in place for several projects over the next four to five years. Development of the JV assets could add 28,000 bbl/d of net production from MacKay Phase 1 and Dover Phase 1 by 2015. First phases of development on the JV leases are scheduled to be followed up by the company's first 100% W.I. production possibly as early as 2014.

Exhibit 40: Athabasca - Pros & Cons

Pros	Cons
Joint Venture – Cash payment, access to lower-cost debt financing, Put/Call option values remaining interests at $2 billion	**Pre Regulatory Stage** – Approvals expected in 2011 (MacKay) and 2012 (Dover) with first production ~2014
Production Potential – Staged production potential estimated to reach 500,000 bbl/d (gross), first production estimated by 2014	**Materiality** – PetroChina is the largest public energy company in the world with a market value of ~C$350 billion…the investment into AOSC represents ~0.5% of PetroChina's market capitalization
Large Resource Base – 8.819 billion barrels of Contingent Resource (Best Estimate) and 114 million barrels of reserves (2P) makes AOSC the holder of one of the largest undeveloped resource portfolios	**Uncertainty Regarding All Resource Potential** – Carbonates appear to hold significant resource potential but commercial production is unproven from bitumen carbonate reservoirs. AOSC expects that Dover West Leduc Carbonates may be suitable for existing SAGD or CSS schemes, but needs testing (pilot in 2013)
Initial Development in the McMurray Sands – Well established McMurray sands reduces perceived risk of initial development phases at MacKay	**Top Gas** – Roughly 22% of the resources associated with the Dover development area and up to 45% of the Dover West area may be affected by top gas issues…these areas may need some degree of repressuring which could affect productivity and which would negatively affect SORs
In-Situ Development – In-Situ can be easier to sell to investors especially from an environmental perspective	**Tax Pools** – Effectively wiped out as a result of the PetroChina payment. Exercise of the Put/Call option could result in AOSC paying significant cash taxes
Clearwater Shale Cap Rock – Thick and consistent 12-20 m thick shale overlying Dover development area	
Operatorship – Controlled by a JV but initially operated by AOSC	
Pure Play – Easy to understand and value	
Future Potential – Large unexplored lease holdings, many at 100% W.I.	
Capitalization – Sufficient capitalization to fund Stage I development	

Source: Company reports and RBC Capital Markets

Potential Catalysts

In the immediate term, we are watching for the following catalysts:

- The Energy Resources Conservation Board's (ERCB) final decision regarding the shut-in natural gas wells in the Dover West Clastics area before year-end 2010.
- Filing the regulatory application for Dover by year-end 2010.
- Initiating this winter's evaluation drilling program.
- Drilling and steaming the Leduc carbonate test wells this winter.
- Drilling and initiating the test of the TAGD horizontal wells this winter.

In 2011, we are watching for the following catalysts:

- Results from the company's evaluation drilling programs at Dover, Dover West (Clastics), Birch and Hangingstone.
- Filing of the regulatory application for the Leduc Carbonate pilot project by mid-2011.
- We anticipate the company receiving regulatory approval for the MacKay JV project before year-end 2011.
- Following approval of the MacKay project, the Put/Call option comes into effect for a window of 31 days before it expires. At this time, we do not anticipate the Put or Call option to be exercised by either party.

In 2012, we are watching for the following catalysts:

- We anticipate construction to begin on the MacKay Phase 1 project in the first quarter of 2012.
- Filing of the regulatory application for the Dover West Clastics project.
- We expect regulatory approval for the Dover Project before year-end 2012.
- Following approval of the Dover project, the Put/Call option comes into effect for a period of 31 days before it expires. At this time, we do not anticipate either party to exercise its Put or Call option at Dover.

Longer term, we expect the company to begin pilot testing the Leduc carbonate and to receive regulatory approval for the Dover West Clastics project by year end 2013. More significantly, we expect the company to realize first commercial production at MacKay and Hangingstone by the end of 2014, followed by project start-up at Dover and the Dover West Clastics in 2015. The Hangingstone Phase 2 expansion is scheduled for 2016. The MacKay Phase 2 expansion is scheduled for 2017. The company's Hangingstone Phase 3 expansion and the company's 100%-owned Dover West Clastics project are expected in 2018. The MacKay Phase 3, Dover West Clastic Phase 3 and MacKay Phase 4 are scheduled for 2019, 2020 and 2021 respectively.

Exhibit 41: Athabasca - Potential Catalysts

2011E	2012E	2013E+
Q1 - Winter core hole drilling (initiated in Q4 2010)	Q1 - Construction of MacKay Phase 1 begins	2013 - Expected regulatory approval for Dover West Clastics Project (100% WI)
Q1 - Drilling and steaming of Leduc Carbonate Test	Q1 - Expected application for 12,000 bbl/d pilot project targeting Dover West Leduc Carbonates	2013 - Expected start up of Leduc Carbonate Pilot Project (100% WI)
Q1 - Drilling and initiating TAGD horizontal test	Q3 - Results of winter drilling program	2014 - First production at MacKay JV Phase 1 (40% W.I.)
Q2 - Expected filing of regulatory application for 12,000 bbl/d demonstration facility at Hangingstone	Q3 - Expected filing of regulatory application for 25,000 bbl/d Phase 2 at Hangingstone	2014 - First production at Hangingstone Phase 1 (100% W.I.)
Q3 - Results of winter drilling program	Q3 - Expected regulatory approval for Hangingstone Phase 1	2014 - Expected regulatory approval for Hangingstone Phase 2 (100% W.I.)
Q4 - Expected filing of regulatory application for 12,000 bbl/d demonstration facility at Dover West	Q4 - Expected regulatory approval for Dover West Leduc Carbonates Pilot	2015 - Expected filing of regulatory application for 25,000-40,000 bbl/d Phase 3 at Hangingstone (100% W.I.)
Q4 - Expected regulatory approval for 150,000 bbl/d (gross) MacKay project	Q4 - Expected regulatory approval for 200,000 - 270,000 bbl/d (gross) Dover project	2015 - First production at Dover JV Phase 1 (40% W.I.)
Q4 - Potential exercise of put/call options on MacKay joint venture project (30 days after MacKay regulatory approval)	Q4 - Potential exercise of put/call options on Dover joint venture project (30 days after MacKay regulatory approval)	2015 - First production at Dover West Clastics Phase 1 (100% W.I.)
Q4 - Continued winter core hole drilling		2015 - Expected filing of regulatory application for 25,000 bbl/d Phase 2 at Dover West Clastics (100% W.I.)
		2015 - Expected filing of regulatory application for commercial development at Dover West Leduc Carbonates (100% W.I.)
		2016 - First production at Hangingstone Phase 2 (100% W.I.)
		2016 - Expected regulatory approval for Hangingstone Phase 3 (100% W.I.)
		2017 - First production at MacKay Phase 2 JV Project (40% W.I.)
		2017 - Expected regulatory approval for Dover West Clastics Phase 2 (100% W.I.)
		2017 - Expected filing of regulatory application for 35,000 bbl/d Phase 3 at Dover West Clastics (100% W.I.)
		2018 - First production at Hangingstone Phase 3 (100% W.I.)
		2018 - First production at Dover West Clastics Phase 2 (100% W.I.)
		2019 - Expected regulatory approval for Dover West Clastics Phase 3 (100% W.I.)
		2019 - First Production at MacKay Phase 3 JV
		2020 - First Production at Dover West Clastics Phase 3 (100% W.I.)
		2021 - First Production at MacKay Phase 4 JV

Source: Company reports and RBC Capital Markets estimates

Company Overview

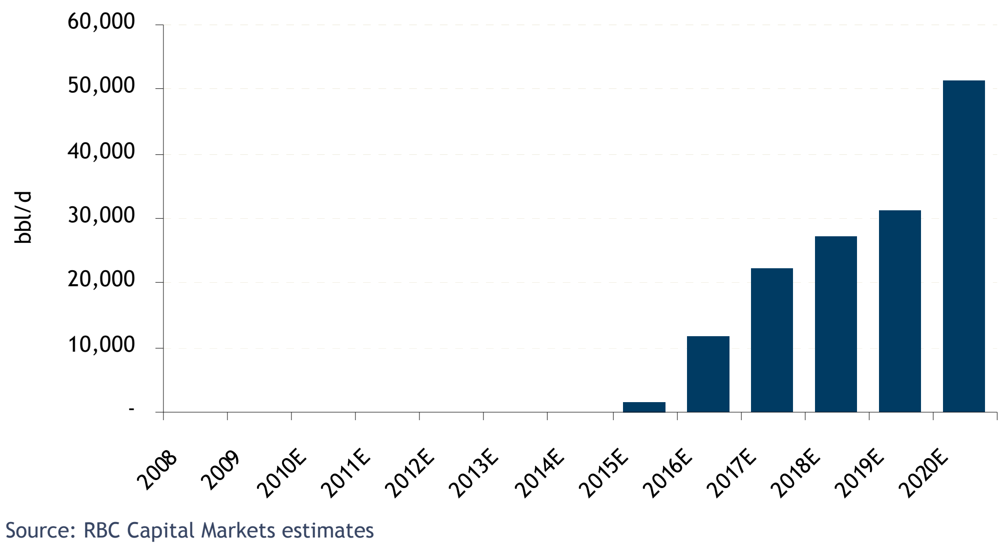
IPO, Asset & Project Summary – Long on Prospects, Short on Approvals

IPO raised $1.350 billion but the stock remains ~20% below issue price – Athabasca Oil Sands raised its first funds as a private company by way of a private placement in September 2006. The company raised $100 million, and spent $88 million to acquire its first oil sands leases. Following several more rounds of private placement financings which raised a total of ~$800 million, lease acquisitions and four more delineation drilling seasons, the company completed its initial public offering on the Toronto Stock Exchange on April 6, 2010. The company issued 75 million shares at $18.00/share for total proceeds of $1.350 billion ($1.269 billion net of issuance costs).

The company has seven project focus areas but no regulatory approvals in hand – Athabasca Oil Sands is a pure-play, pre-production stage oil sands company focused on the development of In-Situ assets in the Athabasca region of Northern Alberta. The company entered into a JV with PetroChina in February 2010 to develop the MacKay and Dover leases, whereby Athabasca Oil Sands holds a 40% operated working interest and PetroChina holds a 60% non-operated working interest. In addition, the company retained a 100% working interest in its Dover West, Birch and Hangingstone leases and a 50% operating working interest in the Grosmont lease (ZAM Ventures Alberta Inc. 50% (W.I.). In total, Athabasca holds 635,700 net acres of oil sands leases with 8.933 billion barrels of reserves (2P) and Contingent Resources (Best Estimate), approximately 3.121 billion barrels (35%) of which is estimated to be bitumen carbonate resource (2.725 billion barrels in the Leduc carbonate and 0.396 billion barrels in the Grosmont carbonate). Reserve and resource estimates have been prepared by GLJ and D&M. First production is scheduled for 2014 and the company has a Reserve to Total Reserve Plus Resource ratio of 1.3%, indicating the early development stage of the company's assets.

The JV development will begin with Phase 1 of 35,000 bbl/d gross (14,000 bbl/d net to ATH) of the MacKay project, which is seeking regulatory approval for multiple phases with total development potential of 150,000 bbl/d gross (60,000 bbl/d net to ATH). The regulatory application was filed on December 10, 2009 and we expect regulatory approval to be received around year-end 2011.

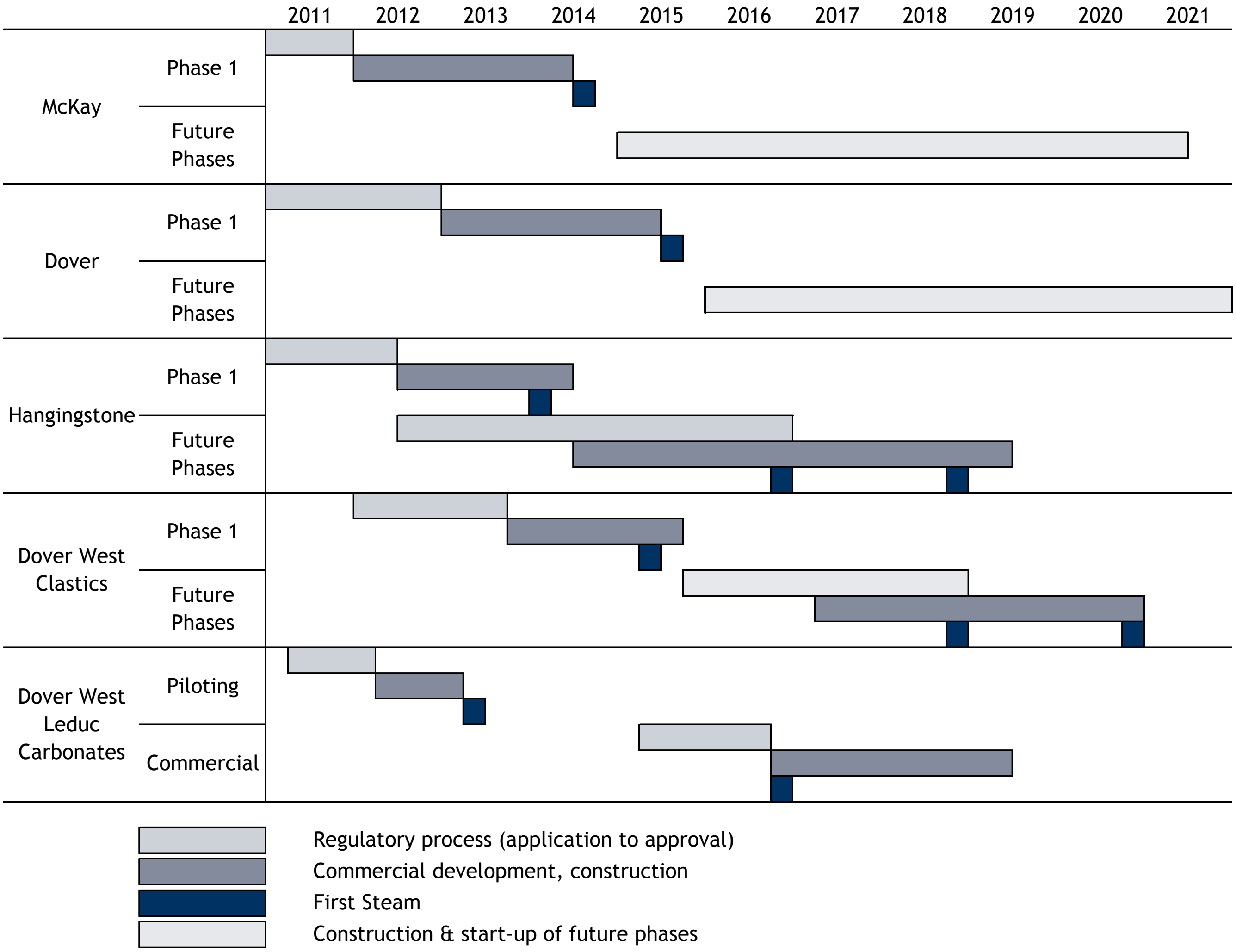
Exhibit 42: Athabasca Production Forecast



Source: RBC Capital Markets estimates

We expect the regulatory application to be filed for Dover by year-end 2010 followed by the filing for the pilot of the Dover West Carbonates by mid year 2011, the Hangingstone demonstration facility by mid year 2011 and for the Dover West Clastics by year-end 2011.

Exhibit 43: Athabasca Development Schedule



Source: Company reports and RBC Capital Markets estimates

PetroChina JV - Good for Athabasca

JV Terms - $3 Billion of Cash & Credit + $2 Billion Put Value to Athabasca

$1.9 billion of cash + $1.1 billion of low interest rate debt facilities – Athabasca entered into a JV agreement with PetroChina in February of 2010, just prior to the company's IPO. The JV provides PetroChina with a non-operated 60% working interest in the MacKay and Dover leases. To earn this working interest, PetroChina paid Athabasca $1.9 billion in cash and provided preferred terms, based on the strength of PetroChina's balance sheet, for an incremental $1.1 billion of debt financing. The preferred borrowing terms substantially reduce the company's cost of debt financing from an interest rate of 13% to LIBOR + 4.5%.

Floor value of $2 billion for remaining 40% W.I. – The partners also entered into a unique two-part Put/Call option for Athabasca's remaining 40% working interest in these two leases, intending to provide certainty as to the commitment of the partners and the perceived value of the assets. The Put/Call option values Athabasca's remaining 40% W.I. at $2 billion, which would be paid to Athabasca in cash if either party exercised the option. The structure and details of the PetroChina debt financing terms and the Put/Call option are discussed in the "Key Issues" section later in this report. The partners established Dover Operating Corporation, which has predominately been staffed by secondees from Athabasca Oil Sands Corp.

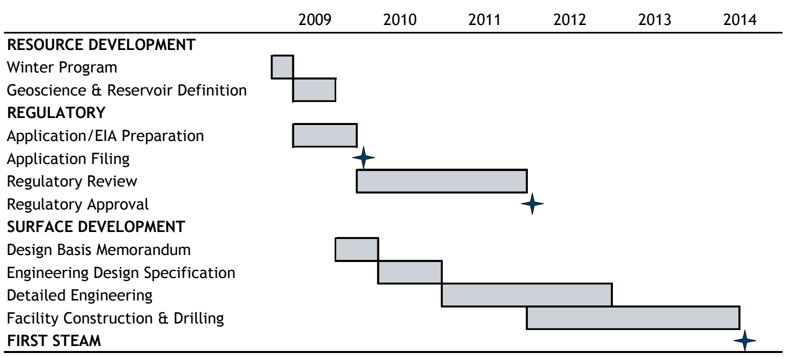
MacKay – First Out of the Gate but You Still Have to Wait

Athabasca Oil Sands built its lease holdings of 187,875 acres (gross) through crown land sales between 2006 and 2009. The two townships on trend with Athabasca's MacKay deposit located at T91-R14W4 and R15W4 (see Exhibit 45) are held by Southern Pacific Resource Corp. (TSX: STP) and are being developed as the STP-McKay project.

Four-year wait to first production diluted by 40% W.I. – In preparation for filing the regulatory application at MacKay, the company drilled 132 delineation wells on its lease. The regulatory application is seeking ultimate development potential of 150,000 bbl/d gross (60,000 bbl/d net). Regulatory approval is expected in late 2011 or early 2012 with first production from Phase 1 expected in late 2014. Phase 1 is planned at 35,000 bbl/d gross (14,000 bbl/d net) to be followed by three subsequent phases each of 35,000–40,000 bbl/d gross (14,000–16,000 bbl/d net) with planned start-up for Phase 2 in 2017, Phase 3 in 2019 and Phase 4 in 2021; therefore, targeting full development of the MacKay lease by 2021. GLJ has assigned 114 million barrels of probable (2P) reserves and 573 million barrels of Contingent Resource (Best Estimate) to Athabasca's 40% W.I. in MacKay.

Exhibit 44: MacKay Development Schedule

Phase One



Subsequent Phases

MacKay River Project	Design Capacity (bbl/d)	Construction	First Steam
Phase 1	35,000	2012-2014	Jun-14
Phase 2	40,000	2015-2017	Jun-17
Phase 3	40,000	2017-2019	Jun-19
Phase 4	35,000	2019-2021	Jun-21
Total	**150,000**		

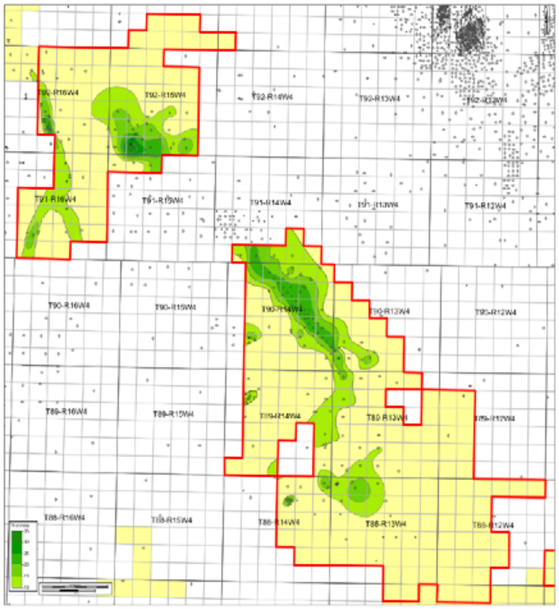
Source: Company reports and RBC Capital Markets estimates

Spending to ramp up in 2012 following approval, sanction and expiry of Put/Call option – We do not expect capital spending to ramp up materially until 2012, namely after regulatory approval has been received in late 2011 or early 2012. Management has estimated capital intensity for Phase 1 at ~$35,000 bbl/d for a total capital cost of ~$1.25 billion.

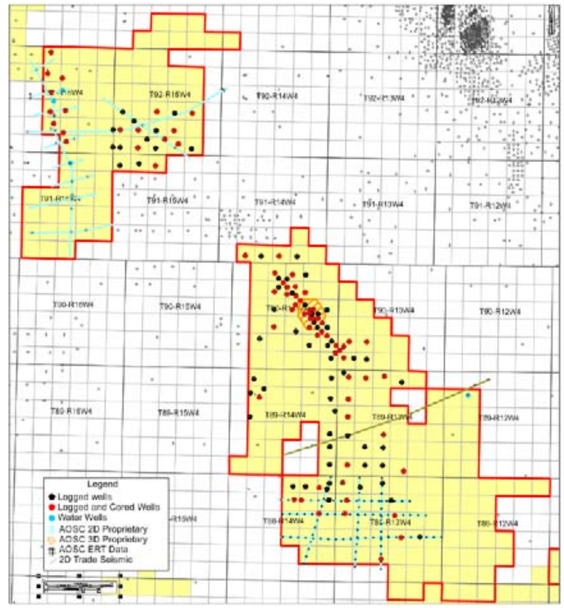
Suitable reservoir conditions for SAGD development – Phase 1 development will focus on the northern part of the southern lease. This deposit is located in the McMurray formation at depths between 130 and 200 metres with an average depth of ~180 metres. Reservoir thickness on the Athabasca leases ranges between 8 and 30 metres with an average thickness of 18 metres. The MacKay area has significant overbearing Clearwater shale deposits (~30 m) that should act as an excellent seal. The reservoir itself does not have any material amounts of top gas or bottom water, which we expect to result in excellent reservoir conditions to support development.

Exhibit 45: MacKay Lease Area

Net Pay ≥10m



Delineation



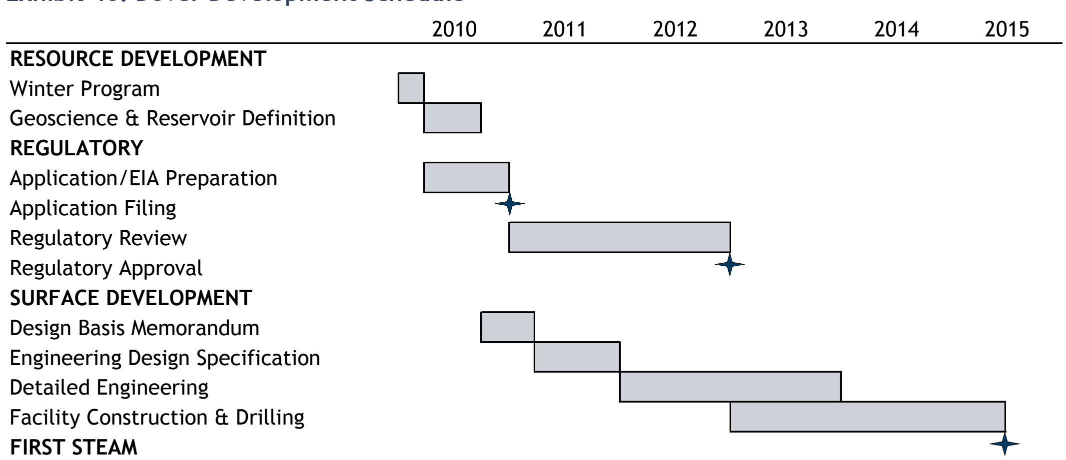
Source: Company reports

Dover - Full Development Potentially Affected by Depleted Top Gas

To date, the company has drilled 176 delineation wells and acquired 18 km^2 of 3D seismic. Additional core hole drilling will be completed this winter season. A total of 3.395 billion barrels gross (1.358 billion barrels net) of Contingent Resources (Best Estimate) have been assigned to the Dover lease area by GLJ. Athabasca assembled 148,365 acres from crown land sales between 2006 and 2009.

First production five years out and diluted by 40% W.I. – The partners expect to file the regulatory application for Dover by year-end 2010 or early 2011, and therefore anticipating regulatory approval by mid-to-late 2012. The Dover application will seek approval for ultimate development potential of 200,000–270,000 bbl/d gross (80,000–108,000 bbl/d net) with Phase 1 at Dover focussing on the northern part of the lease and scoping out at 35,000–50,000 bbl/d gross (14,000–20,000 bbl/d net). First production at Dover is planned for 2015. Additional delineation drilling would be required to advance subsequent stages of development at Dover.

Exhibit 46: Dover Development Schedule

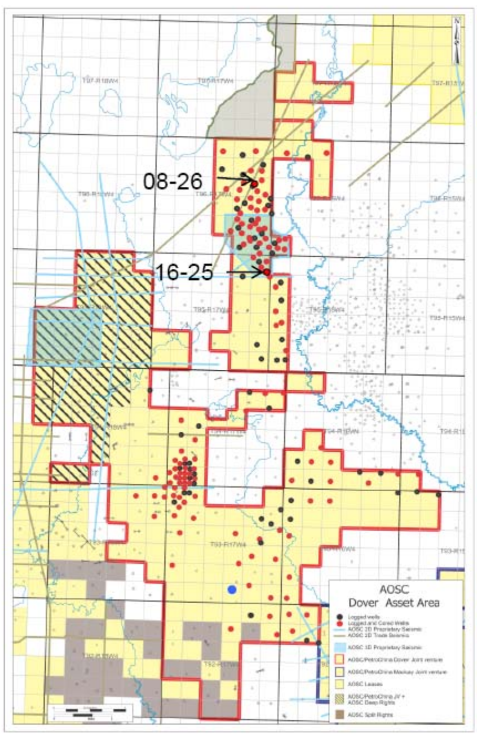


Source: Company reports and RBC Capital Markets estimates

RBC Capital Markets®

Depleted top gas may impair the development of 22% of Contingent Resource – The Dover lease has exposure to the McMurray formation, although at greater depth than found at MacKay. At Dover, the McMurray formation can be found at depths ranging from 160–500 metres, with an average depth of 240 metres. Reservoir depth of the initial development area is approximately 400 metres. Reservoir thickness of the McMurray ranges from 8-30 metres with an average thickness of 20 metres. Overlying the McMurray formation is the Clearwater shale with a consistent thickness of 12–20 metres, which should serve as a good containment rock for SAGD development. Bottom water does not appear to be an issue for the Dover lease area; however, there are areas affected by pressure depleted top gas pools. The region located immediately southeast of the ATH/PetroChina Split Rights lease area is affected by depleted top gas pressure. Depleted top gas pressure zones could act as thief zones for steam injection, which may impair production rates or result in higher steam oil ratios and thus the productivity and economic performance of this area may be negatively affected. Management estimates that ~22% of the Contingent Resource allocated to the Dover lease area (i.e., 729.3 million barrels gross, 291.7 million barrels net) may potentially be affected by this depleted top gas zone. The JV partners are looking at methods of repressurizing this area, which has been done successfully by other operators. Other parts of the Dover lease area have exposure to top gas but these gas pools appear to be thin, contain bitumen saturation and remain at virgin reservoir pressures so as not to affect the ability to produce from the greater Dover lease area negatively.

Exhibit 47: Dover Delineation



Source: Company reports

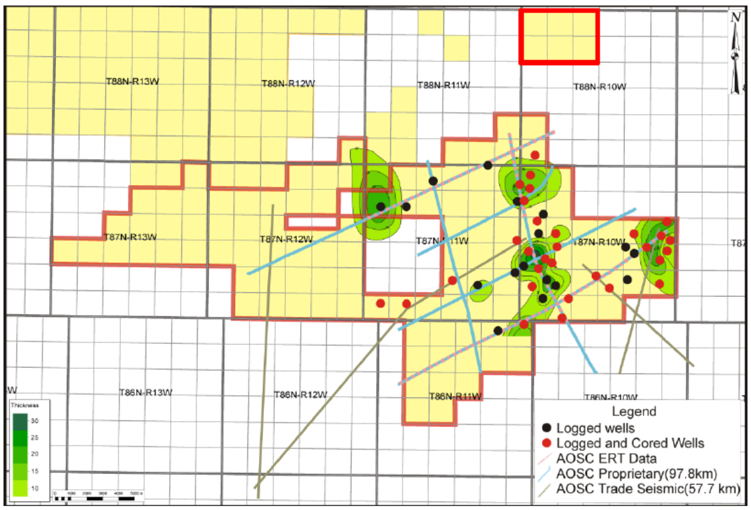
Hangingstone – Moving Forward as a Core Area with First Production Scheduled in 2014

Unlike the JV leases, Athabasca Oil Sands enjoys a 100% W.I. over the Hangingstone leases and, as such, the development of this lease would have a material effect on the company. Following the acquisition of Excelsior Energy and the consolidation of land interests from Bounty Developments, the estimate of Contingent Resource (Best Estimate) at Hangingstone is 640 million barrels, which is based on the DeGolyer (D&M) report of 421 million barrels originally held by Athabasca plus the ~230 million barrels recently acquired. Management estimates that the Hangingstone lease area now has the capability to be developed to 70,000 bbl/d of production.

Athabasca Oil Sands acquired 85,398 acres of land at crown land sales between 2006 and 2009 and has recently added ~25,000 acres by way of acquiring the Excelsior and Bounty interests in the area for total leaseholdings in the Hangingstone area of ~110,000 acres. The company holds a 100% W.I. on all of its Hangingstone leases. The company has previously drilled 47 delineation wells on its Hangingstone leases while a total of 55 core holes have been drilled and logged on the Excelsior Hangingstone lease. This winter season the company has planned a two-rig program targeting 40 delineation wells. Athabasca acquired 98 km of 2D seismic and 43 km of electrical resistivity tomography and purchased an additional 58 km of 2D seismic.

The average depth of the McMurray formation at Hangingstone is 140 metres with an average continuous thickness of 8–25 metres. The average thickness of the overlying Clearwater shale is 17–21 metres, making Hangingstone a good candidate for In-Situ SAGD development. Management estimates that more than 70% of its Hangingstone lease is unexplored acreage.

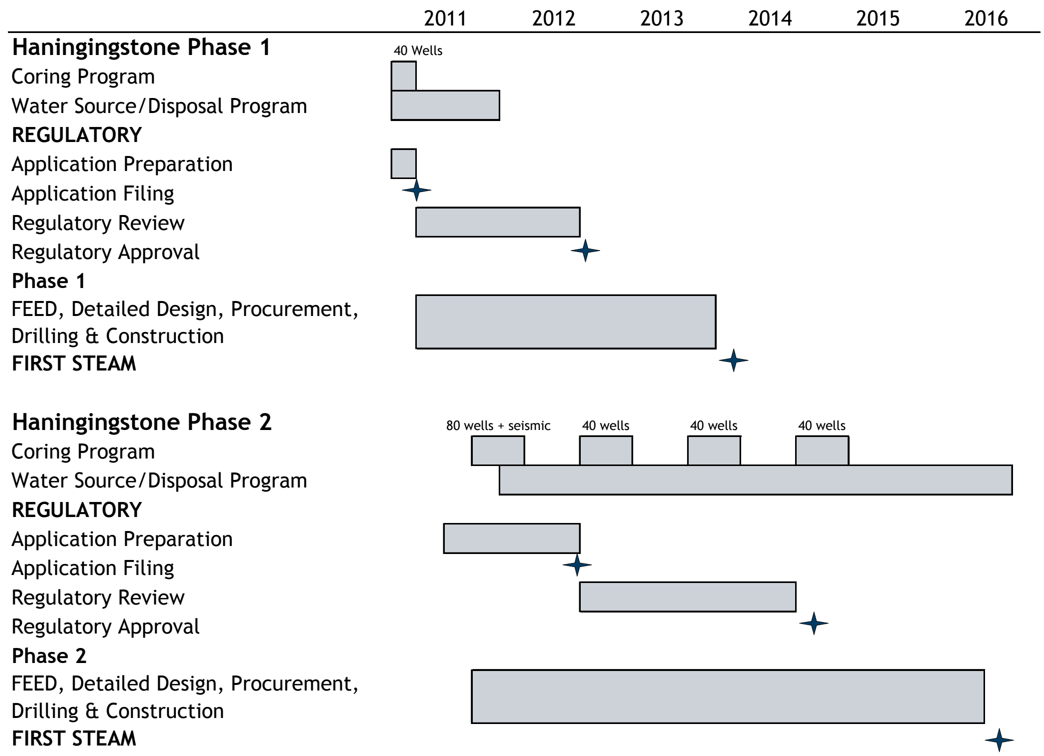
Exhibit 48: Hangingstone Net Pay ≥ 10m



Source: Company reports

Management is now pushing the Hangingstone development forward so that it may be the company's first 100% W.I. production. Since a 12,000 bbl/d demonstration facility does not require an environmental impact assessment, the process is expected to be relatively quick. Management is expecting that first steam at Hangingstone could be as early as year-end 2013 with first production by mid-2014. Management is estimating that the second stage of development would be 25,000 bbl/d and could possibly start up as early as 2016 (see Exhibit 49).

Exhibit 49: Hangingstone Development Schedule

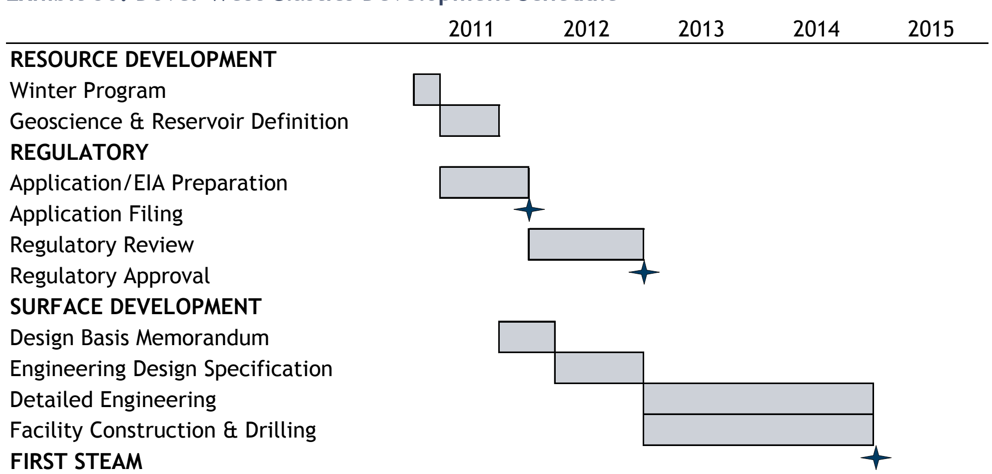


Source: Company reports and RBC Capital Markets estimates

Dover West Clastics - Project Accelerated to 2015

First 100% W.I. production scheduled in the 2015 timeframe – Athabasca Oil Sands enjoys a 100% W.I. over the Dover West lease. Management assembled the Dover West lease of 202,424 acres at crown land sales between 2006 and 2009. A total of 2.013 billion barrels of Contingent Resource (Best Estimate) has been assigned to the Dover West Clastics by GLJ, which management estimates could support development of 165,000 bbl/d of production from the Wabiskaw and McMurray formations. The first three phases of development represent 72,000 bbl/d of production. Management anticipates filing its regulatory application for Phase 1 in the second half of 2011 with first steam on the first 12,000 bbl/d demonstration facility by as early as year end 2014.

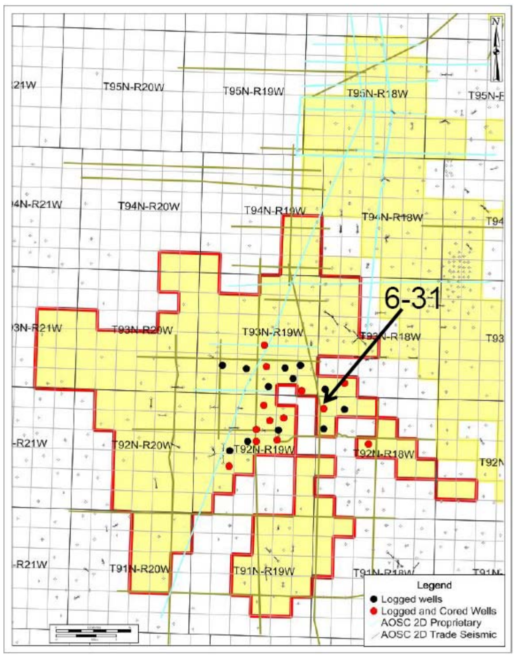
Exhibit 50: Dover West Clastics Development Schedule



Source: Company reports and RBC Capital Markets estimates

Presence of Wabiskaw and McMurray have a combined average thickness of 26 metres – At Dover West, the Upper Wabiskaw is found at a depth of 200–300 metres, with an average depth of 220 metres; at the Dover West lease the continuous thickness of the reservoir ranges from 8–17 metres, with an average thickness of 13 metres. The thickest portions of the Wabiskaw formation are found in the central parts of the lease area. The top of the McMurray formation is found at a depth of 220–350 metres, with an average depth of 240 metres. Initial development of the Dover West lease will likely be focused on the central part of the lease, where the McMurray is at a depth of ~230 metres. The McMurray ranges in thickness from 8–20 metres, with an average thickness of 13 metres. This is somewhat thinner than most SAGD reservoirs, which tend to have a minimum 20 metres of thickness; however, the combination of both reservoirs, and any heat migration between the McMurray and the upper Wabiskaw may make this a more attractive project. The Wabiskaw and McMurray formations have 25–55 metres of Clearwater shale cap rock and no indications of bottom water, making this reservoir a good candidate for SAGD development.

Exhibit 51: Dover West Clastics Delineation



Source: Company reports

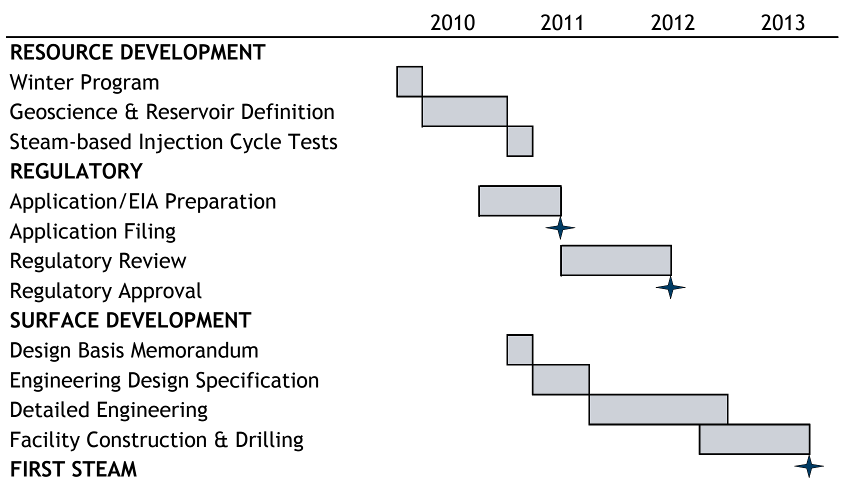
Pressure depleted top gas pools could impair up to 45% of lease potential – Top gas pressure depletion presents a risk at Dover West. In October 2009, the ERCB ordered the shut-in of 158 natural gas wells in this region in order to stop the depletion of gas pressures over this bitumen-bearing reservoir. Management expects a final decision relating to the shut-in of these natural gas wells before year-end 2010. We expect the ERCB to hold up the natural gas well shut-in decision. Management estimates that up to 45% (905.4 million barrels) of the resource potential in the Wabiskaw/McMurray clastic formations may be impaired from production due to the depressurized top gas zones; therefore, repressurizing these zones may be required. As such, management has selected an area with no top gas depletion issues for a potential Phase 1 development of 12,000 bbl/d, which the company will drill to a density of 6–8 evaluation wells per section by the end of this winter season. Management is planning Phase 2 at 25,000 bbl/d and Phase 3 at 35,000 bbl/d.

More evaluation drilling required to understand full potential – Athabasca has drilled 46 evaluation wells at Dover West, 22 were drilled to the base of the McMurray (i.e., clastic formations) while 24 were drilled to the base of the Leduc (i.e., Carbonate formation) but also penetrated the upper McMurray. In addition to these evaluation wells, there are a minimum of 430 wells that penetrate the McMurray formation on or around the Dover West lease. The drilling density for evaluation wells is at least one well per section in the main part of the lease but more drilling is required to understand this reservoir. The company is planning a two rig program to drill ~40 core holes targeting the Dover West Clastics this winter season.

Leduc Carbonates - New Resource Play Concept to Be Pilot Tested

New resource play concept in experimental stage – While carbonate reefs present excellent reservoir characteristics for natural gas and light oil, there are no commercially producing bitumen carbonate reservoirs at this time to draw upon for analogies. As such, the commerciality of the Leduc carbonates is experimental at this stage. Athabasca is planning to drill two test wells this winter, one horizontal well into the reef shelf and one deviated well into the main reef structure. The company is seeking approval to perform short-term steam injection and production tests on these two wells this winter season and next to gain a sense for the production response of the reservoir to steam injection. In addition, the company is also seeking approval to test an experimental recovery method called TAGD (Thermally Assisted Gravity Drainage), which uses electrical conduction heating in two horizontal wells instead of steam. The plan is to drill the wells and initiate the conduction heat this winter with a production test next winter. Athabasca is planning to submit an application for a Dover West Leduc Carbonate pilot project by mid 2011 for a pilot to start up by 2013. We expect that commercial development, if possible, is likely close to a decade away on this play.

Exhibit 52: Dover West Leduc Development Schedule



Source: Company reports and RBC Capital Markets estimates

Large resource potential – GLJ has assigned 2.725 billion barrels of Contingent Resource (Best Estimate) to the Dover West Leduc Carbonates, or roughly 31% of the company's total estimated net resource. Management estimates that the resource base it has captured in the Leduc carbonates could be capable of supporting production of 250,000 bbl/d of production. In addition to the 24 evaluation wells that the company has drilled into the Leduc carbonates, the company has also acquired 28 km^2 of 3D seismic and 76 km of 2D seismic over the play.

Long-Term Growth Potential - Birch and Grosmont

Birch - Winter Drilling Program to Confirm Resource Potential

The company has a three-rig program targeting ~40 evaluation wells this winter season to confirm the DeGolyer (D&M) report estimate of Contingent Resource (Best Estimate) at Birch at 1.141 billion barrels.

Athabasca has access to data from 168 wells that have penetrated the Wabiskaw and McMurray formations on or near the lease area. The company has acquired 73 km of 2D seismic and has purchased 876 km of additional 2D seismic data. The company is conducting a three rig program at Birch this winter to drill up to 40 wells.

The company has assembled a large land base of 448,054 acres (100% W.I.) through crown land sales between 2006 and 2009. These leases hold both Wabiskaw and McMurray resource potential at an average reservoir depth of ~450 metres with a Clearwater shale cap rock with consistent thickness of 45-65 metres, making Birch a good candidate for In-Situ development.

Grosmont Carbonates – Taking a Passive Approach

Athabasca Oil Sands plans to run a two rig program to drill 12 core holes into the Grosmont Carbonates this winter. The company will observe developments made by industry participants focused on the Grosmont Carbonates.

The company assembled 778,817 gross acres (389,408 net acres) at crown land sales between 2007 and 2009. Athabasca Oil Sands holds an operated 50% W.I. in the leases with the other 50% owned by ZAM Ventures Alberta Inc., a family investment company advised by Ziff Brothers Investments LLC. The company has only drilled four wells into the Grosmont C & D formations and five wells into the Nisku. The company has also purchased more than 2,000 km of 2D seismic.

The GLJ report estimates Contingent Resource (Best Estimate) net to the company's working interest at 369 million barrels based on the limited work done on this lease to date.

Key Issues

Put/Call Option – Protection for Both Partners

At this stage, we do not expect either partner to exercise the option. The partners structured a unique Put/Call option on Athabasca's remaining 40% W.I. in both the MacKay and Dover JV leases. The intent of this structure was to ensure mutual commitment to the project by not allowing either party to cause project delay against the will of the other partner at the time of project sanction.

Athabasca's put option, open for 31 days following regulatory approval, guarantees a minimum value of $2 billion for its remaining 40% working interest in MacKay and Dover. PetroChina gave Athabasca Oil Sands two put options, one on the MacKay project and one on the Dover project. The put options allow Athabasca to sell its remaining 40% working interest in the MacKay and/or Dover projects to PetroChina on a schedule of pre-determined prices starting at $2 billion. These options are only exercisable for a period of 31 days following the receipt of the regulatory approval of each project. Presumably, Athabasca would only exercise either put option if management believed PetroChina was less than fully committed to the project and was likely to delay the project, thus impairing the project's value or compromising the company's ability to manage its capital commitments to its other projects due to overall uncertainty.

PetroChina's call option has some unique features, but in its basic form allows the company to call Athabasca's remaining 40% W.I. for $2 billion. The call options given to PetroChina by Athabasca Oil Sands have much the same intent. PetroChina has two call options, one call option would allow PetroChina to buy Athabasca's remaining 40% W.I. in MacKay and one call option would allow PetroChina to buy Athabasca's remaining 40% W.I. in Dover, both on a schedule of pre-determined prices starting at $2 billion. The call options have some unique terms not found in the put options held by Athabasca, but otherwise are much the same in structure. The similarity of the call option is that the options are exercisable for a period of 31 days following the receipt of the regulatory approval for each project. Presumably PetroChina would only exercise either call option if management believed that Athabasca Oil Sands was less than fully committed to the project and would therefore be likely to delay the projects. Since Athabasca effectively holds operatorship of the project, we believe that PetroChina has no intent of exercising its call options on either project as it values Athabasca's operational experience in SAGD and familiarity with the Alberta regulatory process.

The MacKay and Dover Put/Call options are effectively tied as one option. A unique characteristic of the Put/Call agreement is that should the MacKay Put/Call option expire without being exercised, the Dover Put/Call option automatically expires simultaneously. However, should the MacKay Put/Call option be exercised by either party, the Dover option remains outstanding. Pragmatically, the outcome of the MacKay Put/Call option will dictate the outcome of the JV for both projects.

Exhibit 53: Put/Call Option Terms

MacKay Option		2010	2011	2012	2013	2014	2015
Put Value	($mm)	$680	$680	$680	$646	$612	0.9x Fair Market Value
Attributed Resources	(mmbbl 2P + Best Est)	687	687	687	687	687	
Implied Value	($/bbl)	$0.99	$0.99	$0.99	$0.94	$0.89	

Dover Option		2010	2011	2012	2013	2014	2015
Put Value	($mm)	$1,320	$1,320	$1,320	$1,254	$1,188	0.9x Fair Market Value
Attributed Resources	(mmbbl 2P + Best Est)	1,358	1,358	1,358	1,358	1,358	
Implied Value	($/bbl)	$0.97	$0.97	$0.97	$0.92	$0.87	

Source: Company reports and RBC Capital Markets

PetroChina's call option has the following unique terms:

- **Insolvency clause –** This clause does not expire with the rest of the Put/Call option but remains open to PetroChina for the full life of the JV. PetroChina holds a call option on each project for a period of 61 days following an insolvency event or change-of-control event at Athabasca Oil Sands. In either of these cases, the exercise price of the call options would be at the highest agreed upon value, namely $680 million for MacKay and $1.32 billion for Dover.

Exhibit 54: Put/Call Insolvency or Change-of-Control Clause

		Insolvency or Change of Control Clause	
		MacKay	Dover
Put Value	($mm)	$680	$1,320
Attributed Resources	(mmbbl 2P + Best Est)	687	1,358
Implied Value	($/bbl)	$0.99	$0.97

Source: Company reports and RBC Capital Markets

- **Regulatory clause –** The intent of this clause is to encourage the timely filing of the Dover application, which we expect to be filed by year-end 2010 thereby nullifying this clause. PetroChina holds a call option on each project for a period of five business days following March 31, 2011 in the event that the Dover Operating Company has not yet filed the regulatory application for the Dover project with the ERCB and Alberta Environment. The exercise price of this call option has been set at $578 million for MacKay ($0.84/bbl) and $1.112 billion for Dover ($0.85/bbl).

Exhibit 55: Put/Call Dover Regulatory Filing Clause

		Dover Regulatory Filing Clause	
		MacKay	Dover
Put Value	($mm)	$578	$1,122
Attributed Resources	(mmbbl 2P + Best Est)	687	1,358
Implied Value	($/bbl)	$0.84	$0.83

Source: Company reports and RBC Capital Markets

- **December 31 clause –** This clause is only in effect in the event that the main Put/Call event has not yet occurred, which implies that this clause only comes into effect in the event of an unexpected delay in regulatory approvals. PetroChina holds a call option on each project for a period of five business days following December 31 in any calendar year beginning in 2012 to purchase Athabasca Oil Sands' working interests in MacKay and/or Dover at predetermined prices.

Exhibit 56: Put/Call December 31 Clause

		December 31 Clause			
MacKay		**2013**	**2014**	**2015**	**2016+**
Put Value	($mm)	$680	$612	$544	0.8x Fair Market Value
Attributed Resources	(mmbbl 2P + Best Est)	687	687	687	
Implied Value	($/bbl)	$0.99	$0.89	$0.79	
Dover		**2013**	**2014**	**2015**	**2016+**
Put Value	($mm)	$1,320	$1,189	$1,056	0.8x Fair Market Value
Attributed Resources	(mmbbl 2P + Best Est)	1,358	1,358	1,358	
Implied Value	($/bbl)	$0.97	$0.88	$0.78	

Source: Company reports and RBC Capital Markets

ROFR – Sale of Interests Not Permitted Prior to Expiry of Put/Call Option

Each partner also holds the right to sell interests, generally in 20% increments (with the exception that sales to affiliates must be the entire working interest), in either JV project. The remaining partner holds a right of first refusal (ROFR) for a period of 45 days. Neither party is permitted by the JV agreement to divest any interests prior to the expiry of the Put/Call options.

Loans from PetroChina – Financial Liquidity at Advantageous Rates

Athabasca Secured Three Loan Agreements from PetroChina:

- **The first loan agreement was for $430 million.** Proceeds were used to repay outstanding debt. Athabasca makes interest payments to PetroChina semi-annually at a rate of LIBOR + 450 bps. The loan is repayable in full at the earliest of June 30, 2022, a change-of-control event for Athabasca or the exercising of the Put/Call option by either party.
- **The second loan agreement is for $100 million** to fund investment in the MacKay and Dover JV developments. The terms are similar to the first loan agreement except that the loan is repayable in full at the earliest of June 30, 2024, a change-of-control event for Athabasca or if either party exercises the Put/Call option.
- **The third loan agreement is for $560 million** to fund the development of MacKay and Dover. The terms of this loan agreement are effectively the same as the second loan agreement.

In total, PetroChina has agreed to lend ~$1.1 billion to the company at LIBOR more than 4.5%. Athabasca has already drawn $443.6 million. The remaining $646 million of liquidity provided by the PetroChina loans is sufficient capital to fund the company's commitments at MacKay and Dover well into 2013. Prior to these preferential loan agreements with PetroChina, Athabasca Oil Sands was paying an interest rate of 13%; therefore, these loan agreements provide significant financing cost savings to Athabasca. Interest cost savings total approximately $35 million per year at existing borrowing levels and approximately $90 million per year should these facilities be fully utilized.

Capital Commitments versus Financial Liquidity – Cash & Opportunity Rich

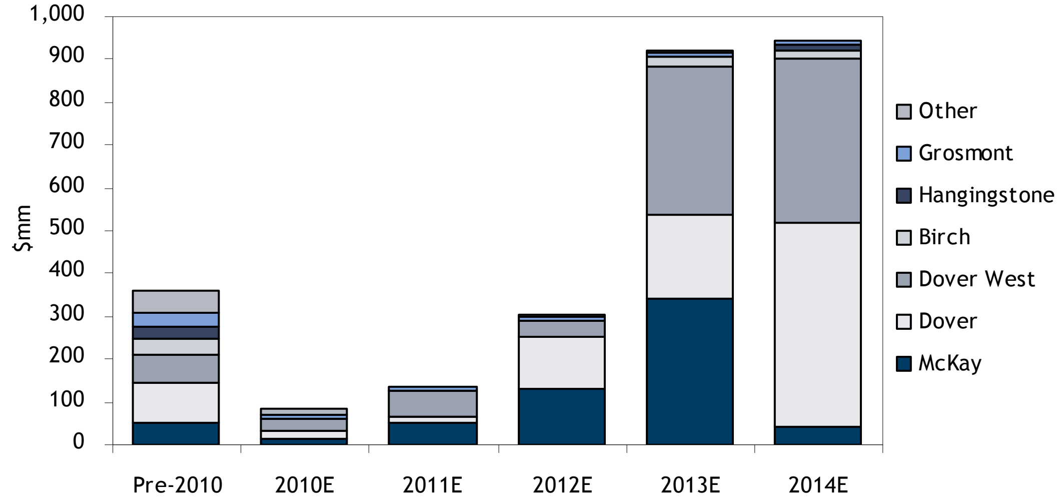
$2.4 billion of capital commitments to the end of 2014 – Athabasca Oil Sands has assembled a significant inventory of seven project areas, many of which have several phases of development. With this bounty of opportunity comes a significant capital expenditure commitment of $2.4 billion between 2011 and 2014.

Exhibit 57: Capital Spending (Management Estimates)

	Pre-2010	2010E	2011E	2012E	2013E	2014E	Total
McKay	$49.6	$14.4	$50.6	$130.2	$343.4	$42.4	$630.6
Dover	$94.1	$16.6	$14.3	$120.2	$193.2	$477.5	$915.9
Dover West	$68.6	$28.2	$60.6	$38.9	$348.5	$381.3	$926.1
Birch	$35.5	$0.9			$21.7	$19.4	$77.5
Hangingstone	$29.0	$0.3				$11.9	$41.2
Grosmont	$33.9	$11.6	$10.2	$10.4	$10.6	$10.8	$87.5
Other	$49.1	$14.2	$2.0	$2.0	$2.1	$2.2	$71.6
Total	**$359.8**	**$86.2**	**$137.7**	**$301.7**	**$919.5**	**$945.5**	**$2,750.4**

Source: Company reports and RBC Capital Markets

Exhibit 58: Capital Spending (Management Estimates)



Source: Company reports and RBC Capital Markets

$2.4 billion of current financial liquidity – Athabasca is also uniquely well positioned with significant current financial liquidity. Although the company paid out a one-time special dividend of $1.332 billion to shareholders following the cash payment from PetroChina and prior to the company's IPO, Athabasca enjoys a current cash equivalent balance of ~$1.7 billion and current borrowing capacity of $646 million under the PetroChina loan facilities. This is sufficient financial liquidity to fund the company's capital spending plans through to the end of 2014 and into first production (and cash flow) from MacKay. The PetroChina loan agreements provide sufficient funding to fully finance Athabasca's capital commitment at MacKay Phase 1 or to fund half of the total capital commitment of Phase 1 MacKay and Phase 1 of Dover, funding both projects into mid-2013.

Valuation

Approach & Methodology – NAV-Based Approach

Our preferred method of valuation for oil sands companies with projects that have enough definition surrounding scope, timing and capital cost expectations is NAV. We apply a risk factor to projects that are involved in the regulatory process, or we expect will be during our 12-month target price window. We also include value for resources not assigned to specific development projects, unevaluated lands and corporate adjustments such as cash and debt. Our Base NAV is our evaluation of what we believe investors should be willing to pay for the stock. We reserve the option of applying a multiple to our NAV to adjust for intangible qualities as necessary and therefore this is the basis of our 12-month target price. Our Unrisked NAV includes potential upside based on our Unrisked valuation of all projects regardless of their stage of development or regulatory process and includes value for additional resources that do not have development project definition. The Unrisked NAV can be thought of as a potential take-out value for the company in the event of a change-of-control event.

Relative Valuation – Supportive for Athabasca

Because of the company's large prospect inventory and current cash balance following the IPO, we see strong asset value support for Athabasca Oil Sands, which is currently trading at an 90% P/NAV ratio (Base) and a 47% P/NAV ratio (Unrisked), compared to peer group average valuations of 86% and 49%, respectively.

JV assets worth more developed than if Put/Call option is exercised. Our Base NAV reflects full discounted value for the MacKay project as we expect the company to receive the regulatory approval for MacKay within the window of our 12-month target price. We have also included a risked value for Dover because we believe the regulatory application will be filed with the Alberta government in late 2010 or early 2011. We have valued both MacKay and Dover on a DCF basis, on the assumption that neither JV partner exercises the Put/Call option, as detailed earlier in this report. Also, we calculate twice as much value for the MacKay and Dover projects on a DCF basis than if Athabasca exercises the Put/Call option for $2 billion of cash. We have included a risked value for the Dover West Clastics and Hangingstone as we expect these projects to be progressing toward greater definition and closer to regulatory filings.

The company's large net cash balance is worth $4.65/share. We have calculated a value of $4.74/share for the company's 40% W.I. at MacKay, $5.31/share for our risked valuation for the company's 40% W.I. at Dover (compared to a value of ~$5/share for MacKay and Dover if the Put/Call option was exercised) and $0.94/share for our risked valuation for the company's 100% W.I. in its Dover West Clastics (Phase 1) project and $1.00/share for Hangingstone. We have assigned a 1.0x multiple of our Base NAV calculation of $15.61/share based on peer group average valuations to determine our 12-month target price of $16.00/share.

Exhibit 59: Athabasca NAV Summary

Project	Reserve / Resource Est. mmbbl	Project PV $mm	Implied PV/Bbl $/bbl	W.I. %	Base NAV: Risk Factor %	Base NAV: $mm	Base NAV: $/share	Base NAV: % NAV	Unrisked NAV: $mm	Unrisked NAV: $/share	Unrisked NAV: % NAV
MacKay											
Phase 1 (Pre Approval)	285	$1,359	$4.77	40%	100%	$544	$1.34	9%	$544	$1.34	5%
Phase 2 (Pre Approval)	478	$1,375	$2.88	40%	100%	$550	$1.35	9%	$550	$1.35	5%
Phase 3 (Pre Approval)	478	$1,176	$2.46	40%	100%	$470	$1.16	7%	$470	$1.16	4%
Phase 4 (Pre Approval)	478	$913	$1.91	40%	100%	$365	$0.90	6%	$365	$0.90	3%
Total	**1,718**	**$4,823**	**$2.81**			**$1,929**	**$4.74**	**30%**	**$1,929**	**$4.74**	**16%**
Dover											
Phase 1 (Pre-Application)	679	$2,050	$3.02	40%	75%	$615	$1.51	10%	$820	$2.01	7%
Phase 2 (Pre-Application)	679	$1,607	$2.37	40%	75%	$482	$1.18	8%	$643	$1.58	5%
Phase 3 (Pre-Application)	679	$1,372	$2.02	40%	75%	$412	$1.01	6%	$549	$1.35	5%
Phase 4 (Pre-Application)	679	$1,163	$1.71	40%	75%	$349	$0.86	5%	$465	$1.14	4%
Phase 5 (Pre-Application)	679	$1,015	$1.49	40%	75%	$304	$0.75	5%	$406	$1.00	3%
Total	**3,395**	**$7,207**	**$2.12**			**$2,162**	**$5.31**	**34%**	**$2,883**	**$7.08**	**24%**
Dover West Clastics											
Phase 1 (Pre Application)	183	$511	$2.80	100%	75%	$383	$0.94	6%	$511	$1.25	4%
Phase 2 (Pre Application)	365	$736	$2.02	100%	0%	$0	$0.00	0%	$736	$1.81	6%
Phase 3 (Pre Application)	500	$825	$1.65	100%	0%	$0	$0.00	0%	$825	$2.03	7%
Total	**1,048**	**$2,072**	**$1.98**			**$383**	**$0.94**	**6%**	**$2,072**	**$5.09**	**17%**
Hangingstone											
Phase 1 (Pre-Application)	229	$542	$2.37	100%	75%	$407	$1.00	6%	$542	$1.33	4%
Phase 2 (Pre-Application)	206	$701	$3.40	100%	0%	$0	$0.00	0%	$701	$1.72	6%
Phase 3 (Pre-Application)	206	$634	$3.08	100%	0%	$0	$0.00	0%	$634	$1.56	5%
Total	**641**	**$1,877**	**$2.93**			**$407**	**$1.00**	**6%**	**$1,877**	**$4.61**	**16%**
Total Projects	**6,801**	**$15,980**	**$2.35**			**$4,881**	**$11.99**	**77%**	**$8,762**	**$21.53**	**73%**
Resource	**Reserve / Resource Est. mmbbl**	**Project PV $mm**	**Attributed Value $/bbl**	**W.I. %**					**$mm**	**$/share**	**% NAV**
Dover West Leduc	2,725	$681	$0.25	100%					$681	$1.67	6%
Grosmont	738	$185	$0.25	50%					$92	$0.23	1%
Birch	1,141	$571	$0.50	100%					$571	$1.40	5%
Dover West Clastics	966	$483	$0.50	100%					$483	$1.19	4%
Total Resource	**5,570**	**$1,919**	**$0.34**						**$1,827**	**$4.49**	**15%**
Land	**Position Acres**	**Project PV $mm**	**Value $/Acre**	**W.I. %**	**Factor %**	**$mm**	**$/share**	**% NAV**	**$mm**	**$/share**	**% NAV**
Other Land	185,105	$23	$125.00	100%	100%	$23	$0.06	0%	$23	$0.06	0%
Total Land	**185,105**	**$23**	**$125.00**			**$23**	**$0.06**	**0%**	**$23**	**$0.06**	**0%**
Corporate Adjustments											
Net Working Capital						$1,893	$4.65		$1,893	$4.65	
Long Term Debt						($444)	($1.09)		($444)	($1.09)	
Total Corporate						**$1,450**	**$3.56**	**23%**	**$1,450**	**$3.56**	**12%**
Net Asset Value						**$6,354**	**$15.61**	**100%**	**$12,062**	**$29.64**	**100%**

Risk Factors

100% of DCF value given to producing projects and projects that have received regulatory approval

75% of DCF value given to projects expected to be in the regulatory application process within the next 12 months

0% of DCF value given to projects expected to be in the regulatory application process within the next 12-24 months

Assumptions:

WTI crude oil assumptions: US$78.02, US$83.00, US$85.00 for 2010E, 2011E and 2012E forward respectively

Henry Hub natural gas assumptions: US$4.54, US$5.00, US$5.50 for 2010E, 2011E and 2012E forward respectively

US/CAD foreign exchange assumptions: $0.96, $0.95, $0.95 for 2010E, 2011E and 2012E forward respectively

After tax discount rate assumption: 8.5%

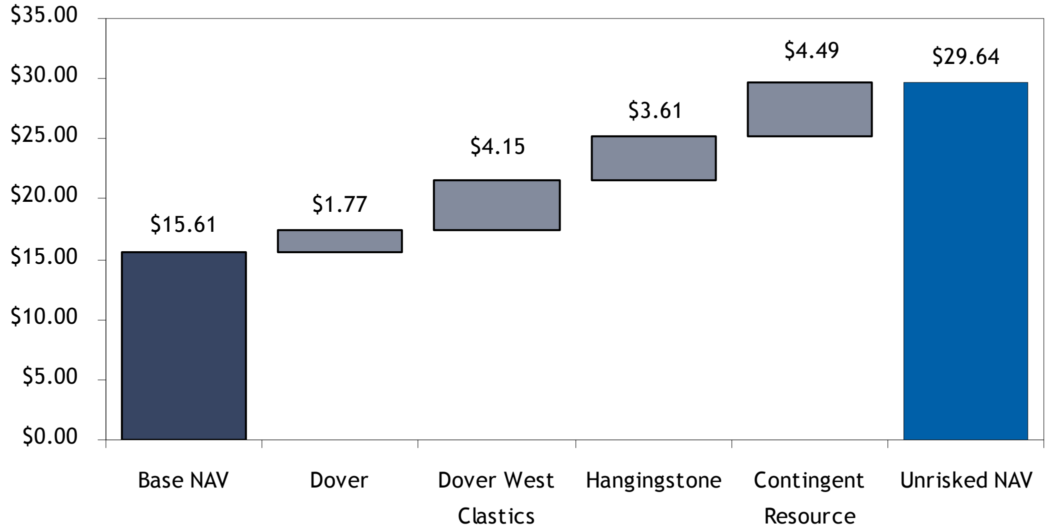
Long term operating cost assumption: $13.00/bbl

Source: Company reports and RBC Capital Markets estimates

Unrisked NAV – Visible Value Upside Potential

Significant value upside potential visible with regulatory approval and project execution – Unrisking Dover, the Dover West Clastics and Hangingstone and adding value for the company's Contingent Resources increases our estimate of Athabasca's NAV to $29.64/share (Unrisked), which we believe is a good indication of the value of the company as management continues to advance its projects through the regulatory and development stages.

Exhibit 60: Athabasca Upside Potential – Base and Unrisked NAV



Source: Company reports and RBC Capital Markets estimates

Contingent Resource Value – Valued at $4.49/share Unrisked

We have assigned a value of $0.50/bbl to Contingent Resources (Best Estimate – Clastics) that have not been attributed to the MacKay, Dover or Dover West Clastics projects, which we value with a DCF approach. Year to date, transactions have ranged from a low valuation of $0.14/bbl to a high of $1.84/bbl. We believe that a valuation of $0.50/bbl fairly reflects value for Best Estimate Contingent Resources that have not yet been given development definition or have not yet entered into the regulatory process.

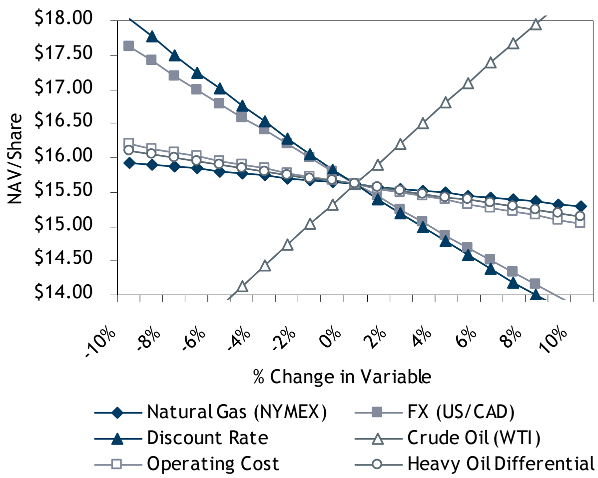
We have assigned a value of $0.25/bbl to the Dover West Leduc and Grosmont Carbonate Contingent Resource (Best Estimate). Given the earlier stage of understanding and thus higher degree of risk associated with bitumen carbonate reservoirs, commercial development of bitumen carbonate reservoirs will ultimately take longer and should therefore be further discounted.

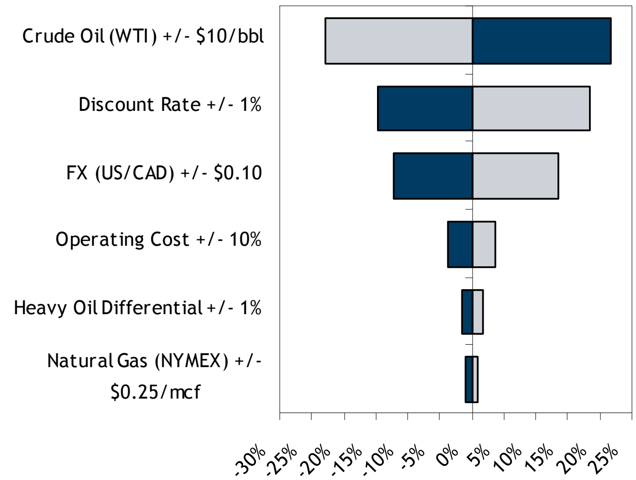
We do not assign value to the High Case Contingent Resource estimate and we do not attribute value to possible or potential resources.

Sensitivities

Athabasca's NAV is positively correlated to, and is most sensitive to, changes in the long-term oil price. Our calculation of NAV is negatively correlated to changes in the discount rate, the Canadian/U.S. dollar exchange rate, operating costs, heavy oil differentials and natural gas prices. Next to oil price, the company's NAV is most sensitive to the discount rate and the exchange rate.

Exhibit 61: Athabasca NAV Sensitivity





Source: Company reports and RBC Capital Markets estimates

Risks to Target Price

We assign Athabasca Oil Sands Corp. an Above Average Risk rating. In general, Athabasca is exposed to above-average risk with respect to regulatory approvals and project execution due to the early pre-development stage of the company.

We identify eight key risks to our target price:

1. **Oil Prices –** Athabasca's asset base, and therefore the NAV calculation, is 100% weighted to oil. As demonstrated in the NAV sensitivity chart (see Exhibit 61), fluctuations in oil price represent the greatest effect on our calculation of NAV of the company. We assume a flat oil price of US$85.00/bbl from 2012 onward.

2. **Discount Rates –** We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations of E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk and lower reserve replacement and re-investment (i.e., exploration) risk than E&P companies. However, oil sands companies have greater regulatory, environmental and project execution risk over the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our target price, materially.

3. **Regulatory Risks –** Athabasca, as an early-stage development company, is exposed to a high degree of regulatory risk. To date, the company has not received regulatory approval for any of its projects. Athabasca has filed its application for MacKay and we expect the company to file the application for the Dover project to be filed before year-end 2010 or in early 2011. We expect approval for the MacKay JV to be received from the Alberta government by the end of 2011. The company's growth profile as well as our perception of the company's value would be materially affected should the regulatory approvals be delayed or withheld.

4. **Project Execution Risk –** We anticipate regulatory approval for the company's first project, MacKay Phase 1, to be received by year-end 2011. The implication of this is that the company does not have any operating projects and Athabasca, as a company, has not demonstrated

project execution. This risk is somewhat mitigated by the fact that the management and employees of Athabasca individually have tremendous experience across the industry. Also, given the anticipated timing of the company's first regulatory approval, spending for MacKay Phase 1 will significantly ramp up in 2012. At this time it is uncertain what the environment will be like in 2012 and 2013 with respect to access to labour and services or the overall inflationary conditions.

5. **Reservoir Risks –** As we detailed in the company overview section of this report, Athabasca has a couple of unique reservoir-related issues that could impede the development of some of its assets. Of the company's 8.933 billion barrels of total estimated reserves (2P) and Contingent Resources (Best Estimate), 3.094 billion barrels (35%) are bitumen carbonates which have not yet been commercially produced and are in the pre-piloting stage for Athabasca and for the industry. The company also has depleted top gas pools in direct pressure communication with its oil sands reservoirs that could impede the development of 1.197 billion barrels (13%). In total, half of the company's total resource estimate of 8.933 billion barrel could be impaired from development due to technical reservoir related issues. We have risked the Dover and Dover West Clastics projects and have excluded value for the Dover West Leduc and Grosmont bitumen carbonates in our estimate of Base NAV. We have given value for both in our estimate of Unrisked NAV.
6. **Foreign Exchange Rates –** The company's future costs are denominated in Canadian dollars yet production will be priced in U.S. dollars. Fluctuations in the exchange rate can greatly effect the value of future cash flows and thus our calculation of NAV. We assume a flat US$0.95/C$1.00 exchange rate long term.
7. **Financing Risks –** Athabasca Oil Sands has sufficient liquid capital, both cash on hand and available credit facilities by way of the PetroChina loan agreements, to fund the planned capital program to the end of 2014. First cash flow is anticipated midway through 2013. Delays in MacKay Phase 1 or increases to costs estimates could result in the need for additional financing or a shift in capital spending plans, which could affect our view of NAV of the company.
8. **Environmental Risks –** Oil sands producers in general have come under increased scrutiny for environmental issues. While longer-term costs or product marketing concerns related to environmental issues are unclear at this time, it does not present a risk to the company's development plans or our perception of the valuation of the company. We note that Athabasca is strictly engaged in the development of In-Situ oil sands, which typically have less effect on land, air and water than oil sands mining projects. We expect that emissions related to Athabasca's future production will be comparable to the emissions of the typical oil that is imported into the U.S. (see Exhibit 24).

Exhibit 62: Athabasca - Operational and Financial Summary

C$ millions, unless noted	2007	2008	2009	2010E	2011E	2012E
Production						
Bitumen (bbl/d)	n.a.	0	0	0	0	0
Diluent Purchases (bbl/d)	n.a.	0	0	0	0	0
Blend Sales (bbl/d)	**n.a.**	**0**	**0**	**0**	**0**	**0**
Blend Ratio	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
YOY Production Growth (%)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Bitumen (%)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Commodity Prices						
WTI Crude Oil (US$/bbl)	$72.25	$99.50	$61.81	$78.02	$83.00	$85.00
Ed. Par (C$/bbl)	76.05	102.75	66.48	77.69	86.05	88.16
Bow River Heavy (C$/bbl)	50.50	83.00	59.25	68.23	73.30	72.29
Exchange Rate (US$/C$)	0.93	0.94	0.88	0.96	0.95	0.95
Henry Hub - NYMEX (US$/mcf)	6.95	8.85	3.92	4.54	5.00	5.50
AECO (C$/Mcf)	6.60	8.15	3.94	4.05	4.37	4.90
Realized Pricing and Costs						
Blend Sales ($/bbl)	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**
Bitumen Sales ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Transportation & Selling ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Royalties ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Operating Costs ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Netback ($/bbl)	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**
Consolidated Financials						
Blend Sales (net of royalties)	n.a.	$0.0	$0.0	$0.0	$0.0	$0.0
Other Income	n.a.	5.5	2.6	12.7	14.5	14.0
Cost of Diluent	n.a.	0.0	0.0	0.0	0.0	0.0
Operating and G&A	n.a.	7.4	13.9	16.6	22.5	24.5
Interest	n.a.	19.8	75.0	24.1	24.0	34.3
DD&A	n.a.	3.5	0.4	0.7	0.8	0.8
Pre-Tax Income	n.a.	(32.5)	(92.7)	(39.8)	(42.8)	(55.6)
Current Tax	n.a.	0.0	91.1	(20.0)	(11.2)	(14.5)
Deferred Tax	n.a.	(7.8)	(108.2)	160.2	3.5	4.5
Net Income	**n.a.**	**(24.6)**	**(75.7)**	**(179.9)**	**(35.1)**	**(45.6)**
Cash Flow From Operations	**n.a.**	**(22.2)**	**(165.2)**	**(15.4)**	**(20.8)**	**(30.3)**
Capital Expenditures	**n.a.**	**179.9**	**112.0**	**134.6**	**140.0**	**300.0**
Per Share Data						
Diluted CFPS ($/Share)	**n.a.**	**($0.12)**	**($0.83)**	**($0.04)**	**($0.05)**	**($0.08)**
YOY Diluted CFPS Growth (%)	n.a.	n.a.	576%	-95%	20%	45%
Diluted EPS ($/Share)	**n.a.**	**($0.14)**	**($0.38)**	**$4.16**	**($0.09)**	**($0.11)**
YOY Diluted EPS Growth (%)	n.a.	n.a.	180%	-1196%	-102%	30%
Weighted Avg Diluted Shares O/S (mm)	n.a.	312.2	313.9	397.8	397.8	397.8
Financial Leverage						
Net Debt	n.a.	99.92	137.12	(1,258.52)	(1,087.72)	(747.47)
Long Term Debt	n.a.	378.91	399.00	443.60	510.00	770.00

1. Capital spending excludes acquisitions, divestitures, changes in short-term investments and changes in working capital
Source: Company reports and RBC Capital Markets estimates

Exhibit 63: Athabasca - Company Profile

Business Description

The Company is focused on the exploration for, and the sustainable development and production of, bitumen from oil sands in the Athabasca region of northeastern Alberta, Canada. Athabasca is advancing only in-situ oil sands exploration and development projects using methods such as SAGD and CSS technologies. The Company's principal oil sands assets include MacKay, Dover, Dover West (Clastics and Leduc Carbonates), Birch, Hangingstone and Grosmont.

Land Position

Key Areas	W.I.	Net Acres	Delineation	Partners
MacKay	40%	75,152	132 core holes	PetroChina
Dover	40%	59,347	176 core holes	PetroChina
Dover West	100%	202,429	46 core holes	n.a.
Birch	100%	448,064	949 km 2D seismic	n.a.
Hangingstone	64.3% - 100%	112,000	102 core holes	Bounty Developments
Grosmont	50%	389,416	8 core holes	ZAM Ventures
Other	100%	311,160	2 core holes	n.a.
Total		**1,597,568**		

Reserve & Resource Estimates (GLJ, D&M)

	Reserves (mmbbl)		Contingent Recoverable Resources (mmbbl)		
	2P	3P	Low	Best	High
MacKay	114	140	345	573	983
Dover			772	1,358	1,775
Dover West (Clastics)			1,318	2,013	2,736
Dover West (Leduc)				2,725	4,650
Birch			130	1,141	1,826
Hangingstone				640	
Grosmont				369	1,843
Total	**114**	**140**		**8,819**	

Potential Catalysts

Q4 2010	Expected Filing of Regulatory Application for Dover Project
Q4 2011	Expected Regulatory Approval for MacKay Project
Q4 2012	Potential Exercise of JV Put/Call Options - 30 Day Option Follows Approval
Q1 2012	Construction Begins at MacKay Project (upon approval)
Q1 2012	Expected Regulatory Application for Dover West Clastics Project
Q4 2012	Expected Regulatory Approval for Dover Project

Management Team

Name	Position	Past Experience
Sveinung Svarte	President & CEO	VP Oil Sands Total E&P Canada
Rob Harding	VP Finance & CFO	Controller Total E&P Canada
Ian Atkinson	VP Geoscience, Tech. & Reservoir	VP Eng & Ops with Morpheus Energy
Anne Schenkenberger	General Counsel and Corp. Secretary	Legal Counsel with ConocoPhillips
Allan Hart	VP Development & Operations	Director Oil Sands, Shell Canada
Bryan Gould	VP New Ventures and Business Dev.	VP New Business for Shell Canada
Heather Douglas	VP Communication & Eternal Affairs	CEO Calgary Chamber of Commerce
Don Verdonck	VP Development & Operations (Op. Co.)	Murphy Oil Company Ltd. (Heavy Oil)
Bob Bruce	VP Corporate Development (Op. Co.)	Sr Commercial Advisor ConocoPhillips
Laura Sullivan	VP Geosciences & Reservoir (Op. Co.)	Team Lead Oil Sands, Enerplus

Board of Directors

Name	Experience
William Gallacher (Chairman)	Partner and Managing Director of Avenir Capital Corporation
Thomas Buchanan	President, CEO & Director of Provident Energy Trust
Gary Dundas	VP Finance, CFO & Director of Avenir Diversified Income Trust
Jeff Lawson	Principal with Peters & Co
Marshall McRae	CFO of CCS Corporation
Sveinung Svarte	President & CEO

Leduc Carbonates Exposure & TAGD Technology

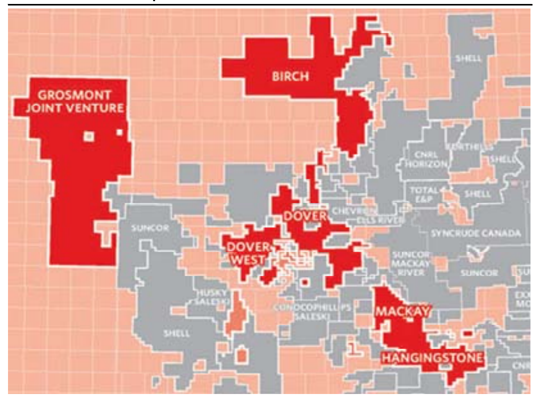
Athabasca's large land position at their Dover West lease gives the company exposure to three different reservoirs: The McMurray, Wabiskaw, and Leduc. The Leduc Carbonate reservoir is the most technically challenging but is estimated to hold the greatest potential upside. Athabasca is the single largest holder of Leduc rights, with rights to almost the entire reservoir. The company has submitted two regulatory applications for experimental tests this winter. One is a traditional steam injection test, and the other is a process which Athabasca calls TAGD (Thermally Assisted Gravity Drainage) which uses electrical resistance heaters to heat the reservoir using conduction. The tests are expected to provide information on how the Leduc reservoir responds to the two heating methods.

ATHABASCA OIL SANDS CORP.

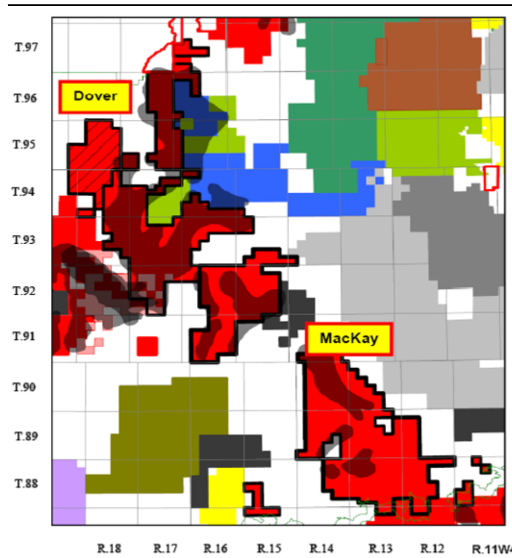
Recent News

Nov-10	Accelerates Development at Hangingstone & Dover West
Nov-10	Closes Acquisition of Excelsior Energy
Jun-10	Reports Increase to Contingent Resource Estimates
Apr-10	Announces Closing of IPO
Feb-10	Files Preliminary Prospectus
Feb-10	Joint Venture Transaction Closes

Athabasca Lease Map



PetroChina Joint Venture Assets



Source: Company reports and RBC Capital Markets estimates

Exhibit 64: Athabasca - Financial Profile

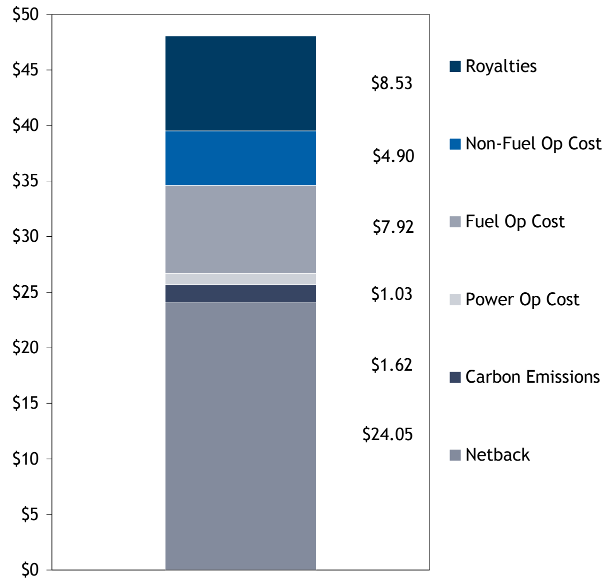
Insider Ownership

Management	Shares (M)	Options (M)	Total (M)	%of FD
Sveinung Svarte	13,625	-	13,625	3.4%
Ian Atkinson	3,002	25	3,027	0.8%
Don Verdonck	516	49	565	0.1%
Bob Bruce	398	21	419	0.1%
Rob Harding	311	50	360	0.1%
Laura Sullivan	275	80	356	0.1%
Anne Schenkenberger	177	102	279	0.1%
Bryan Gould	70	203	274	0.1%
William Hart	60	180	240	0.1%
Heather Douglas	59	176	234	0.1%
Total Management	**18,492**	**885**	**19,378**	**4.9%**

Directors	Shares (M)	Options (M)	Total (M)	%of FD
William Gallacher	25,185	-	25,185	6.4%
Gary Dundas	1,875	-	1,875	0.5%
Thomas Buchanan	420	-	420	0.1%
Jeff Lawson	330	-	330	0.1%
Marshall McRae	15	50	65	0.0%
Total Directors	**27,824**	**50**	**27,874**	**7.0%**
Total	**46,317**	**935**	**47,252**	**11.9%**

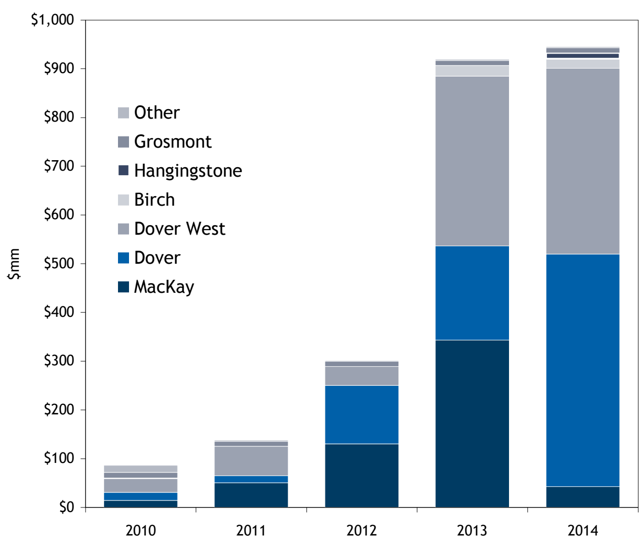
At Sep 30 2010, 2,588,300 options were outstanding, weighted average exercise price of $10.27

Estimated MacKay Netback



Assumptions: US$70 WTI, 10:1 oil:gas pricing, US$0.90/CAD, 20% heavy oil differential

Capital Spending (Management Estimates)



Resource Valuation Summary (mmbbl)

	Best + 2P
Clastics	6,008
Carbonates	2,925
Total	8,933

EV/bbl @ Current Share Price ($/bbl)

	Best + 2P
Clastics	$0.68
Clastics + Half Carbonates	$0.55
Total	$0.46

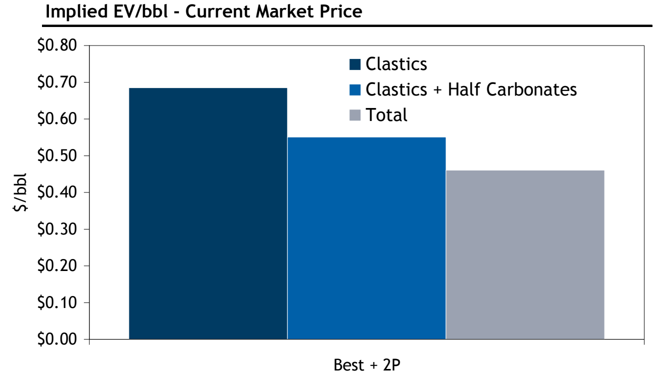
EV/bbl @ $18 IPO Share Price ($/bbl)

	Best + 2P
Clastics	$0.95
Clastics + Half Carbonates	$0.76
Total	$0.64

Selected Financing History

Type	Date	# Shares (mm)	Issue Price	Amount ($mm)
Common Shares (IPO)	Apr-10	75.0	$18.00	$1,350.0
Senior Secured Notes	Jul-08	n.a.	n.a.	$400.0
FT Common Shares	Dec-07	2.7	$10.00	$27.3
FT Common Shares	Aug-07	5.1	$8.50	$42.9
Common Shares	Aug-07	29.6	$7.00	$207.1
FT Common Shares	Dec-06	4.4	$3.00	$13.3
Common Shares	Dec-06	4.0	$2.50	$10.0
Common Shares	Sep-06	100.0	$1.00	$100.0
Common Shares	Aug-06	10.0	$0.10	$1.0

Implied EV/bbl - Current Market Price



Source: Company reports, SEDI and RBC Capital Markets estimates

Connacher Oil & Gas Ltd. (TSX: CLL; $1.16)

Teetering on Success

Market Statistics	
Rating	Sector Perform
Risk	Above Average
Target Price	$1.50
Market Price	$1.16
Implied Return	29.3%

Net Asset Value		Base	Unrisked
Net Asset Value	($mm)	$719.3	$1,264.5
NAV/Sh	($/share)	$1.51	$2.66
P/NAV	(%)	77%	44%
Target Price/NAV	(%)	99%	56%

Capitalization		
Diluted Shares O/S	(mm)	443.5
Market Capitalization	($mm)	$514.5
Net Debt	($mm)	$788.6
Enterprise Value	($mm)	$1,303.0

Resources		
Oil Sands EV[a]	($mm)	$1,134.7
2P Reserves	(mmbbl)	502
Contingent Resources[b]	(mmbbl)	223
EV/Bbl[c]	($/bbl)	$1.57

Operating & Financial		2007A	2008A	2009A	2010E	2011E	2012E
Total Production	(boe/d)	2,321	3,124	9,216	10,536	17,218	17,133
Operating Cash Flow	($mm)	$45.0	$54.8	$12.5	$47.7	$139.3	$151.6
Diluted CFPS	($/share)	$0.21	$0.26	$0.04	$0.11	$0.30	$0.33

Sensitivity to WTI	(US$/bbl)	$60	$70	$80	$90	$100	$110
NAV/Share	($/share)	($1.68)	($0.38)	$0.89	$2.12	$3.31	$4.47
P/NAV	(%)	nmf	nmf	77%	183%	285%	385%

(a) Adjusted to exclude the estimated value of non- oil sands assets
(b) Best estimate
(c) Based on 2P reserves + best estimate Contingent Resources
Source: Company reports and RBC Capital Markets estimates

Investment Highlights

- **Success hinges on a little good fortune –** Connacher is a company that is teetering on the verge of working itself out of an uncomfortably over-leveraged balance sheet. Strong operational performance at Algar or an increase in oil prices could be the boost that Connacher needs to get its balance sheet leverage under better control.
- **We expect exit rates to miss guidance and we are cautious on 2011 –** Management is targeting a 2010 exit rate for Pod One of 8,500–9,000 bbl/d, compared to our expectation of 7,000–7,500 bbl/d. Management provided 2011 production guidance of 14,500–16,500 bbl/d for Pod One and Algar combined; we forecast 2011 oil sands production of 14,950 bbl/d.
- **First half of 2011 is key for Algar –** Algar is on track to reach targeted 2010 exit rates of 7,000–7,500 bbl/d. In our view, the true test will come in the first half of 2011, when we should see if Algar continues to track the top-tier performance established by MEG Energy or if production falls short of design capacity as it did at Pod One.
- **Both expansions could be on by 2015, but more likely 2016/2017 –** The Algar 2a expansion could be steaming and producing by early 2013. We expect the Algar 2b expansion to be on stream around 2016/17.
- **Valuation –** Our NAV for Connacher is supported by Pod One and Algar and to a much lesser degree the company's conventional and downstream assets. We calculate a Base NAV of $1.51/share and an unrisked NAV of $2.66/share for a price to base NAV ratio of 77% and a price to unrisked NAV of 44% compared to peer group average ratios of 86% and 49%, respectively.
- **The stock is discounting Pod One and Algar at 10% –** A 10% discount rate, which reflects the company's current weighted average cost of debt, reduces our base NAV to $1.16/share and our unrisked NAV to $2.00/share.
- **Recommendation –** Sector Perform, Above Average Risk with a 12-month price target of $1.50/share. Our price target is based on a 1.0x multiple of our base NAV calculation, which is in line with the peer group average.

Summary & Investment Thesis

We assume coverage of Connacher Oil & Gas Ltd. (TSX: CLL) with a Sector Perform, Above Average Risk rating and a 12-month price target of $1.50/share, which is based on a peer group average 1.0x multiple of our risked NAV analysis.

In our opinion, Connacher is a company that is teetering on the verge of working itself out of an uncomfortably over-leveraged balance sheet. Strong operational performance at Algar or an increase in oil prices could be enough of a boost to help Connacher get its balance sheet leverage under better control. We would like to see the company address its main challenges head-on by proactively addressing the operational issues at Pod One that could improve performance there in the context of limited steam-generation capacity. We believe it would also be best for management to proactively address the pending financing issues surrounding the next Algar expansion in 2012, which is coincident with the maturity of the company's $100 million debenture. We could become more optimistic on Connacher with evidence of stronger operational results and increased clarity on expansion financing.

We expect Pod One to fall short of exit rate guidance – Management is targeting a 2010 exit rate for Pod One of 8,500–9,000 bbl/d, which implies a SOR of 3.0–3.2x based on full and reliable steam generation. Based on a steam generation rate of ~25,000 bbl/d average and an SOR of 3.3x-3.7x, we expect exit rates of 7,000–7,500 bbl/d at Pod One.

Algar looking good, but performance in the first half of 2011 is key – Management incorporated lessons learned at Pod One into the design of Algar. Two important design modifications are longer horizontal well pairs (100 m longer) and the integration of a 13 MW cogeneration facility to improve on stream reliability factors that have been negatively affected by unreliable electricity supply from the Alberta power grid. Production from the 17 Steam Assisted Gravity Drainage (SAGD) well pairs has increased to over 5,000 bbl/d, tracking the ramp-up performance of Pod One and MEG's Christina Lake. Ramp-up performance is measured as a percentage of design capacity. Algar is on track to reach targeted 2010 exit rates of 7,000–7,500 bbl/d. For us, the true test will come in the first and second quarters of 2011, when we should see if Algar continues to track the top-tier performance established by MEG or if production becomes limited by steam capacity as it was at Pod One.

Both expansions could be on by 2015, but more likely 2017 – If management delivers the Algar expansions with the same speed of project execution demonstrated at Pod One and Algar, the next expansion could be steaming by early 2013. While it may be physically possible to have both expansions producing by 2015, we expect a two- to three-year window between expansions for organizational and financial reasons; therefore, we expect the second expansion to likely come on stream around 2016/2017.

Debt on a pro forma basis remains high – Following the divestiture of the conventional assets, net debt to total capitalization is estimated at 44% and net debt to 2011E cash flow is estimated at 4.6x. We anticipate approximately $40 million of free cash flow above spending plans for 2011. On a pro forma basis, we expect that Connacher will be paying ~$10/bbl in interest expense in 2011.

Potential upside value apparent as expansion financing becomes clear – While we usually allocate partial value for projects that have entered into the regulatory process, on the assumption that the projects will be approved and subsequently built, we have not included value for the Algar expansions in our base NAV due to the financial challenges presented by the company's higher than desirable debt balance. We have included a value of $0.66/share for Algar Phase 2a and a value of $0.49/share for Algar Phase 2b in our unrisked NAV on the recognition that the continual derisking of these projects through the regulatory, financing, and execution stages has the potential to add material value to Connacher over the coming years.

The market is currently valuing Pod One and Algar at a 10% discount rate – Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our price target, materially. We assume an 8.5% discount rate in our NAV calculations, but at a 10% discount rate, which reflects the company's current weighted average cost of debt, our base NAV would drop to $1.16/share and our unrisked NAV would drop to $2.00/share.

Exhibit 65: Connacher - Pros and Cons

Pros	Cons
Producing Projects – Pod One and Algar are both on stream and producing.	**Pod One Production Performance** – Pod One is producing at ~70% (+/-10%) of design capacity and we believe it will miss 2010 target exit rates.
Production Potential – Pod One, Algar and the Algar expansions have a combined stated production capacity of 44,000 bbl/d at a 100% W.I. with Algar expansions already in the regulatory process.	**Facility Design** – We are concerned that facilities have been undersized for steam generation, thereby restricting production potential.
In-Situ Development – In-Situ can be easier to sell to investors, especially from an environmental perspective.	**Downstream** – We believe the downstream investment has been a negative return on capital.
Divestiture of Conventional Assets – Sale of the bulk of conventional assets focuses operations and reduces net debt.	**High Debt Leverage** – Current debt level and cost of debt are high.
Medium-Term Debt Maturities – The company's two larger debt issues mature following the next expected expansion onstream date, which should help with refinancing.	**Maturity Date of Debentures** – Debentures mature (and most likely will not be converted given $5.00/share conversion price) mid-way through expected project spend at Algar expansion, which introduces an unwelcomed financing risk.
Current Financial Liquidity – Sufficiently capitalized for ongoing operations through 2011.	
Oil Price Hedges – Provide downside protection to cash flow, which is welcomed given high financial leverage.	
Co-Gen – Increased reliability of power supply.	
Evaluation Drilling – Understanding assets to look for the next stage of growth opportunity.	
Catalyst Rich – The company has several potential material catalysts over the course of 2011 and 2012.	

Source: Company reports and RBC Capital Markets

Potential Catalysts

In the immediate term, we are watching for the following potential catalysts:

- Monthly operational updates on Algar and Pod One performance
- Possible announcement of conventional asset sales

In 2011, we will be watching for the following catalysts:

- Details and closing of conventional asset sale effective January 1
- Update on 2010 production exit rates at Pod One and Algar, which we expect to fall short of expectations
- Continued results detailing ramp-up at Algar
- Completion of the winter core hole program; results and resource estimate likely to be reported in Q3
- A new electrical sub-station near Pod One, which is expected to improve utilization rates
- Possible regulatory approval of Algar expansion

In 2012, we will be watching for the following catalysts:

- Possible financing for Algar phase 2a expansion, which we estimate at $300–400 million
- Maturity of $100 million convertible debentures
- Possible construction beginning at Algar Phase 2a

Exhibit 66:Connacher - Potential Catalysts

2011E	2012E	2013E+
Q1 – Effective date of asset sale	Q1 – Possible financing to fund Algar Phase 2a expansion	Q1 2013 – Possible first steam/production at Algar expansion Phase 2a
Q1 – We expect 2010 exit rates to fall short of expectations	Q2 – Maturity of $100 mm debentures	Q3 2014 – Maturity of US$200 mm notes
Q1 – Winter core hole drilling at Great Divide Lands (initiated in Q4 2010)	Q2 – Possible construction beginning at Algar Phase 2a expansion	Q4 2015 – Maturity of US$587 mm notes
Q1/Q2 – Watch for ramp-up results at Algar		2016/2017 – Possible first steam/production at Algar expansion Phase 2b
Q2 – New substation at Algar; may reduce irregular power supply problem		
Q3 – Results of winter drilling program		
Q4 – Anticipated approval of 24,000 bbl/d Algar expansion		

Source: Company reports and RBC Capital Markets estimates

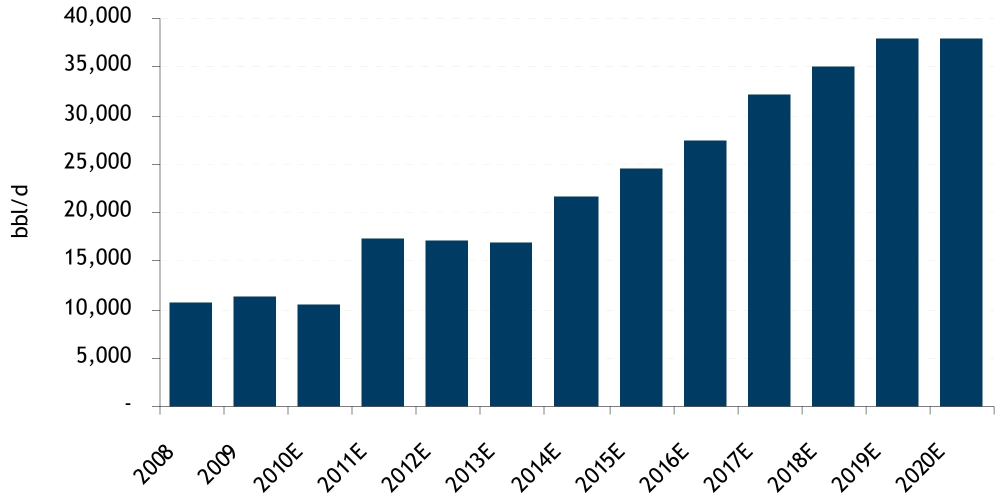
Company Overview

Connacher Oil & Gas Ltd. is a small integrated oil sands company. The company is primarily focused on the development of In-Situ oil sands projects in the Athabasca oil sands region of Northern Alberta. The company's Great Divide lease is located ~80 km south of Fort McMurray. Due to the relative size of the projects, diluent is trucked to site and dilbit is trucked to market. Connacher is also engaged in conventional light oil and natural gas production in Alberta and Saskatchewan; however, the company has recently initiated a process to divest approximately 90% of its conventional production by year-end 2010. While the company will retain conventional oil and natural gas assets, conventional operations will drop from ~10% to ~1–2% of estimated Q1/11 production. The company also owns a 9,500 bbl/d heavy oil refinery in Montana.

Great Divide - Potential Growth to 44,000 bbl/d by 2015?

Connacher owns 152 net sections (97,248 acres) of land in the Great Divide lease area. The company acquired the land in January 2004 and subsequently drilled 131 core holes and shot 128 km of 3D seismic. Pod One and Algar have been developed at a combined name plate design capacity of 20,000 bbl/d. The company has filed its application with the Alberta regulatory bodies for the Algar expansion of an incremental 24,000 bbl/d. The application was filed in mid-May 2010. The application can reasonably be expected to be approved by late 2011 or early 2012. We expect the expansion to be executed in two phases of 12,000 bbl/d each.

Exhibit 67: Connacher Production Forecast

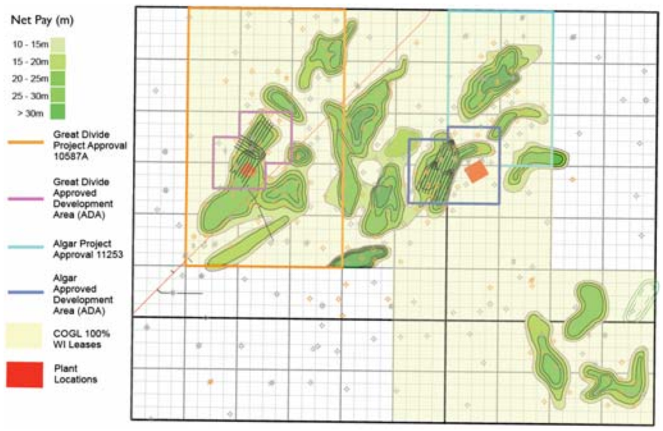


Source: RBC Capital Markets estimates

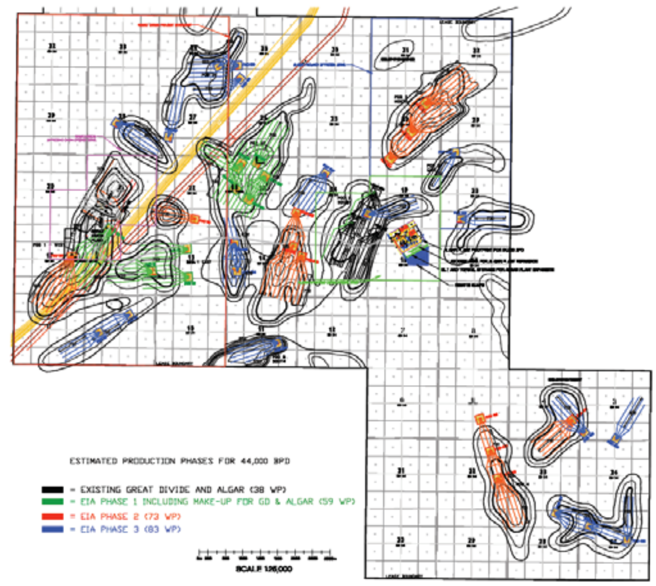
If management delivers the Algar expansions with the same speed of project execution demonstrated at Pod One and Algar, the next expansion could be steaming by early 2013. While it may be physically possible to have both expansions producing by 2015, we expect a two- to three-year window between expansions for organizational and financial reasons; therefore, we expect the second expansion to likely come on stream around 2016 or 2017.

Exhibit 68: Great Divide Lease Area

Net Pay Isopach



Future Drilling Locations



Source: Company reports

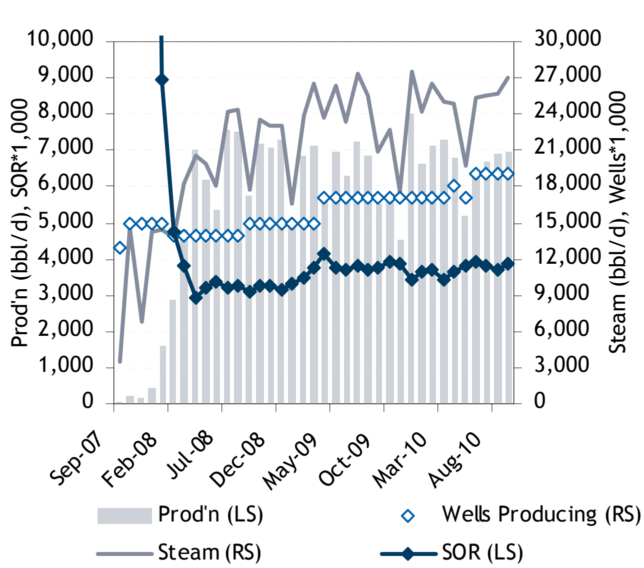
Pod One - Producing Below Design Capacity

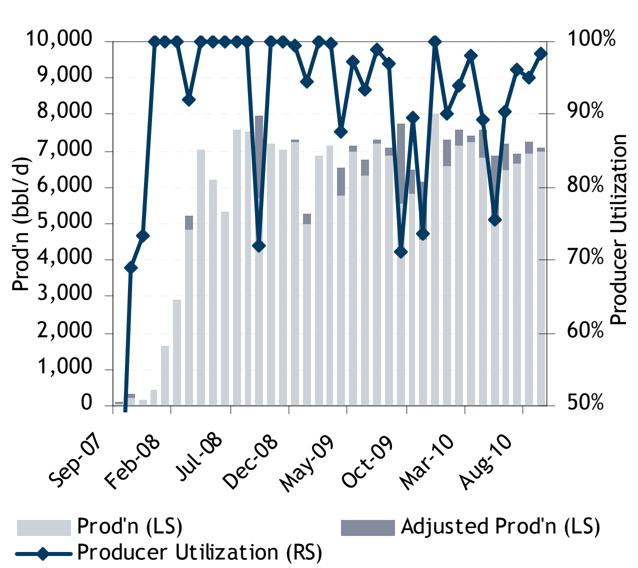
Designed for 10,000 bbl/d at an SOR of 2.7x – Connacher built the Pod One project in fewer than 300 days at a capital cost of $272 million ($297 million including sunk costs). The project was completed in August 2007, commissioning and first steam occurred in September 2007, and first sales occurred in October 2007. Production ramped up quickly and commerciality was declared in March 2008. Connacher designed Great Divide Pod One to produce 10,000 bbl/d of bitumen from 15 SAGD well pairs at an SOR of 2.7x.

Producing ~7,000 bbl/d at an SOR of ~3.7x – While production rates may have approached capacity on a day rate from time to time, sustained (one-month) production rates reached a peak of ~ 7,600 bbl/d in July 2008. With deteriorating bitumen markets, management curtailed production at Pod One in December 2008 to 5,000 bbl/d. A combination of challenging economics and operational difficulties (see Exhibit 69) kept production rates in the 4,500–7,000 bbl/d range from January to November 2009. December 2009 marked the highest averaged production rate at Pod One to date at 8,005 bbl/d; however, that rate has not been sustained and production has averaged ~6,700 bbl/d from January to September 2010, even with the tie-in of two new well pairs early in the year. The operating SOR during this period has been ~3.7x (see Exhibit 69).

We expect exit rates to fall short of guidance– Management is targeting a 2010 exit rate for Pod One of 8,500–9,000 bbl/d, which implies an SOR of 3.0x-3.2x based on full and reliable steam generation. Based on a steam generation rate of ~25,000 bbl/d average and an SOR of 3.3–3.7x, we expect exit rates of 7,000–7,500 bbl/d at Pod One.

Exhibit 69: Pod One Operational Performance





Source: Accumap and RBC Capital Markets

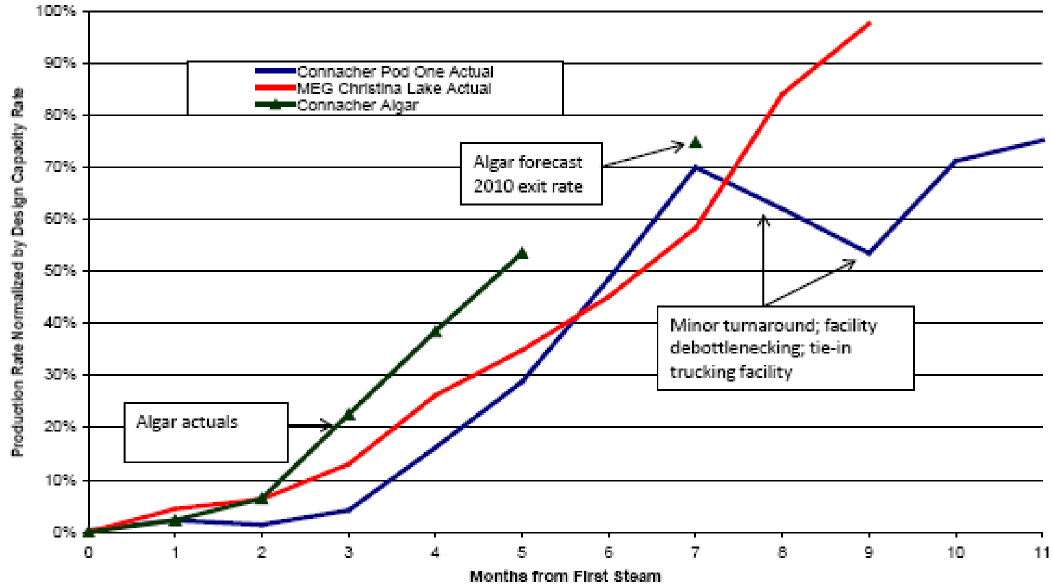
Algar (Pod 2) - So Far, So Good

Running well after a false start – Connacher received regulatory approval for Algar in November 2008, but shortly after sanctioning the project, in an effort to protect financial liquidity, management suspended construction. Construction of the project was restarted in July 2009 and it was completed in April 2010. Commissioning and first steam occurred during May with first production in August. Commerciality at Algar was declared on October 1, 2010.

Design modifications may make the difference – Management incorporated lessons learned at Pod One into the design of Algar. Two important design modifications are longer horizontal well pairs (100 m longer) and the integration of a 13 MW cogeneration facility to improve on-stream reliability factors that have been negatively affected by unreliable electricity supply from the Alberta power grid.

First half 2011 will be the true test – Production from the 17 SAGD well pairs has increased to over 5,000 bbl/d, tracking the ramp-up performance of Pod One and MEG's Christina Lake (see Exhibit 70). Ramp-up performance is measured as a percentage of design capacity. Algar is on track to reach targeted 2010 exit rates of 7,000–7,500 bbl/d. In our view, the true test will come in the first and second quarters of 2011, when we should see if Algar continues to track the top-tier performance of MEG's Christina Lake reservoir or if production becomes limited by steam generation as it was at Pod One.

Exhibit 70: Algar Ramp-up Comparison



Source: Company reports

Conventional – Non-Core Goes Out the Door

Assets were on decline due to lack of investment in the past 24 months – The company has ~2,350 boe/d of conventional oil and natural gas production, which is down from about 3,300 boe/d in early 2009. Connacher owns these conventional assets by way of acquiring Luke Energy in March 2006 for $204 million ($91.5 million cash plus 30 million shares of Connacher). Luke Energy was producing 2,750 boe/d (90% natural gas) and had 2P reserves of 35.3 bcfe, for an implied purchase price of $5.78/mcfe. The conventional assets have not been drawing investment from Connacher and have been on decline since early 2009. Currently, the production is made up of approximately one-third light oil and two-thirds natural gas. The assets are located in Marten Creek and Latornell in Northern Alberta, Gilby/Three Hills in central Alberta, and Battrum in southwestern Saskatchewan.

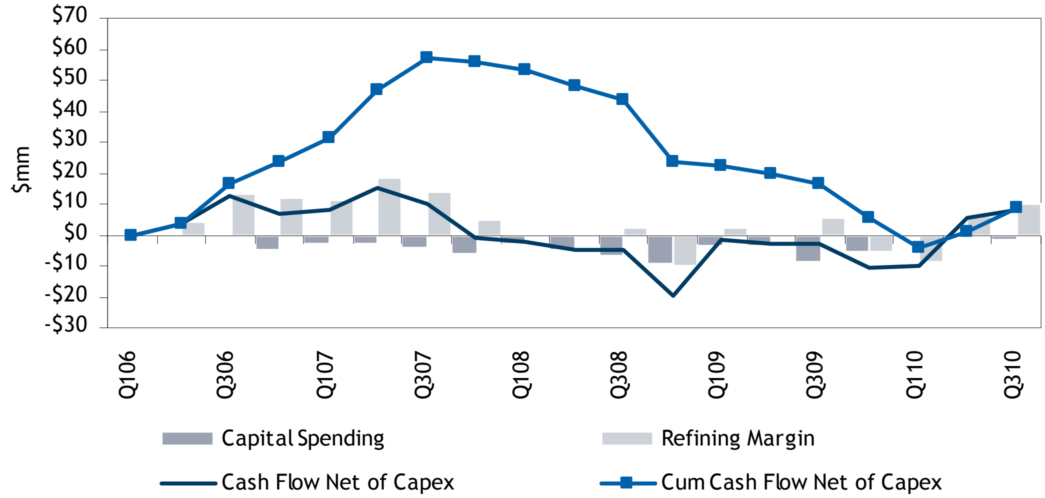
Conventional production to comprise ~2% of 2011E production – On November 10, 2010, management announced that the company has initiated a divestiture process for its Marten Creek and Battrum area assets. The combined production from these assets is ~1,950 boe/d, leaving the company with ~350 boe/d of production following the asset sale, approximately 2% of estimated 2011 production.

We expect proceeds of ~$90 million around year-end 2010 – Data rooms are currently open, bids are due on December 9, 2010, and the transaction is expected to be effective January 1, 2011. We expect to adjust our estimates once the details of the sale have been announced. We expect the assets to generate ~$90 million of proceeds, which would be a welcomed reduction to net debt.

Downstream Refining – A High-Cost Diluent Supply

The company purchased the Montana Refining Company in the first quarter of 2006 for ~US$55 million (in cash and shares). Since the acquisition, the company has generated cash flow of ~$80 million from its downstream operation and re-invested ~$85 million for maintenance and to convert the refinery to produce ULSD (Ultra Low Sulpher Diesel) in order to be compliant with U.S. environmental policy. While the Refinery operates in a somewhat insulated niche market, which behaves differently than Mid-West, East Coast or Gulf Coast markets, the two years immediately following the acquisition of the refinery (2006–2007) were two of the strongest years for downstream margins in decades. Over the foreseeable future, we expect margins to again be narrow.

Exhibit 71: Downstream Cash Flow versus Investment



Source: Company reports and RBC Capital Markets

Key Issues

Operational Performance - Steam Capacity Limiting Production

Reservoir characteristics look compelling – The reservoir qualities in the location of Pod One compare favourably to most other producing SAGD reservoirs (see Exhibit 30). The reservoir is located at a depth of ~475 metres, has good pressure characteristics, an average thickness of ~20 metres, high bitumen saturation and average porosity and permeability characteristics. No bottom water is found at Pod One and only thin amounts of top gas are found in the location of the south pad, which is currently operating at an SOR of ~ 3.1x.

You get what you pay for – The Pod One project was built for a very competitive $27,000 bbl/d (capital intensity as determined by design rate capacity), which appears to be considerably lower-cost than other SAGD projects that are built for $30,000–35,000 bbl/d. However, if capital intensity is adjusted for actual performance, a considerable normalization of costs can be seen across projects (see Exhibit 72). One area where the company saved money was with respect to the designed steam generation capacity, which was built to generate 27,000 bbl/d of steam for a designed SOR of 2.7x. The problem is that the wells drilled to date do not operate at an average SOR of 2.7x, but rather the project has recently been operating at an average SOR of ~3.5x, which limits production of Pod One to +/- 7,700 bbl/d. Adjusting the stated capital cost of $27,000 bbl/d for ~77% utilization (7,700 bbl/d from a facility designed to process 10,000 bbl/d) implies an adjusted capital intensity of $35,000 bbl/d (capital intensity as determined by calendar day rate).

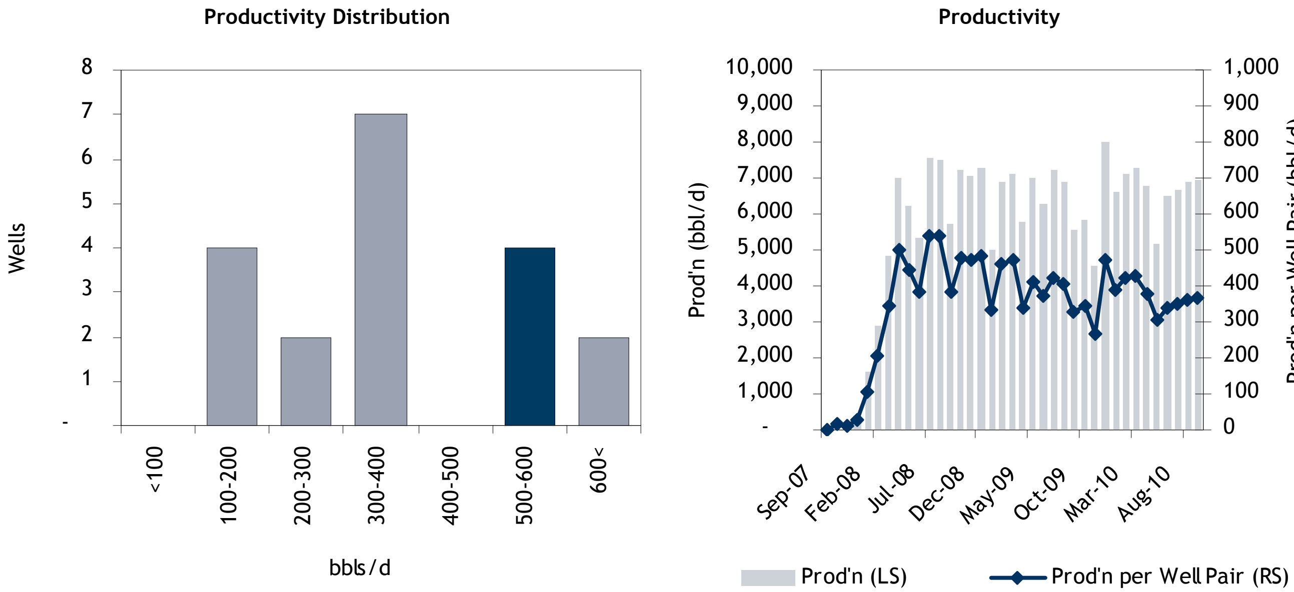
Exhibit 72: Name Plate versus Adjusted Capital Intensity

Capital Intensity @ Name Plate Capacity	$25,000	$30,000	$35,000	$40,000
Production Rate as a % of Name Plate Capacity	75%	85%	100%	110%
Adjusted Capital Intensity @ Production Rate	$33,333	$35,294	$35,000	$36,364

Source: RBC Capital Markets

High concentration of production at Pod One – The average well is not the typical well. Pod One has 19 producing well pairs. Based on 19 well pairs, average rate per well should be 526 bbl/d to fill the 10,000 bbl/d facility. The issue is that 15 of Connacher's 19 well pairs are producing less than 500 bbl/d (~300 bbl/d average for these 15 well pairs), and the remaining four well pairs are producing more than one-third of total Pod One production. It is encouraging to see strong wells, but it is concerning to think what would happen to overall production rates if one of these star wells were to go off production or begin to decline.

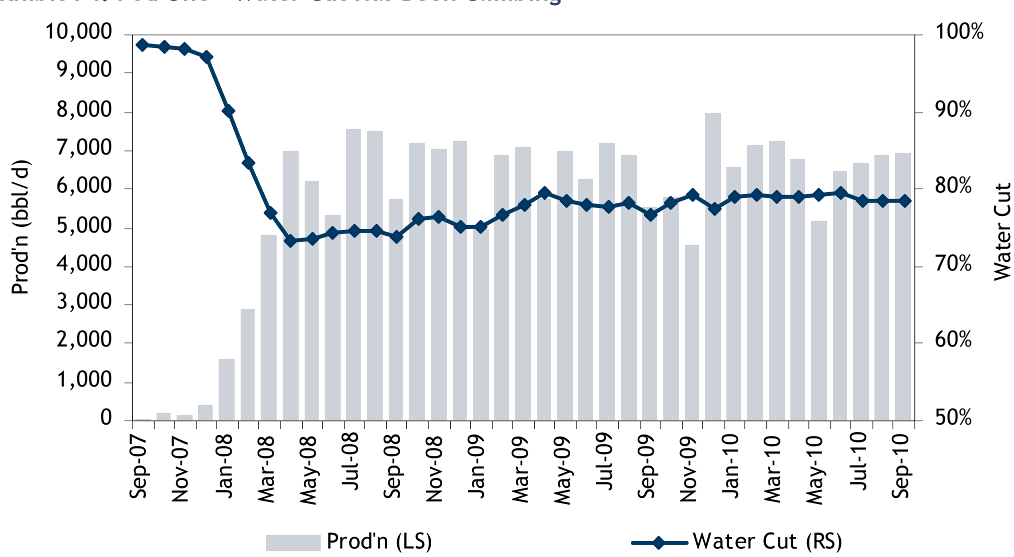
Exhibit 73: Pod One - Distribution of Well Productivity and Average Rate Per Well



Note: To reach nameplate capacity each well would need to produce 526 bbls/d
Source: Accumap and RBC Capital Markets

Increased water cut may cause upward pressure on costs – The average well at Pod One just celebrated its third birthday, and as seen in Exhibit 73, the average rate per well has slowly declined from ~540 bbl/d in mid-2008 (there were 15 wells on production at that time) to 350–400 bbl/d currently (with 19 wells on production). In addition to the average rate per well declining, which has been offset by drilling additional well pairs to sustain total production in the 7,000 bbl/d range, average water cut at the project has also increased from ~73% in April 2008 to 79% currently. Higher water cut in general means more water handling causing upward cost pressures. Fluctuating production volumes can cause distortion in per barrel operating costs due to the high fixed nature of costs, but higher water cut can also play a role. We observe that non-energy related operating costs averaged ~$14/bbl in both 2008 and 2009, even with fluctuations in rate, and non-energy related operating costs have averaged ~$15/bbl during the first three quarters of 2010. The company also incurred a cost of $3–4 million to add an additional free water knock out unit at its Pod One facility.

Exhibit 74: Pod One - Water Cut Has Been Climbing



Source: Accumap and RBC Capital Markets

RBC Capital Markets®

Algar to the rescue – The start-up of the Algar project is going to blur project-by-project results. Rate per well at Algar is on a growth curve and SORs are improving. Management has indicated that they will begin reporting results on a combined basis. We will continue to track operational performance on a project-by-project basis, which we believe provides better operational insight and predictability to results.

Long-Term Debt and Financial Liquidity - The Situation Is Improving

Over-leveraged balance sheet correcting slowly with free cash flow and asset sales – The company has $100 million of Canadian dollar denominated convertible debentures that mature in mid-2012, US$200 million of notes that mature in mid-2014, and US$587 million of notes that mature at year-end 2015. We calculate a weighted average cost of debt at 9.97%, which is likely to increase upon the refinancing of the debentures that mature in June 2012.

Exhibit 75: Long-Term Debt

Instrument	Rate, Maturity	Currency		Amount
Convertible Debentures	@ 4.75% due June 30, 2012	C$	100	mm
First Lien Notes	@ 11.75% due July 15, 2014	US$	200	mm
Second Lien Notes	@ 10.25% due Dec 15, 2015	US$	587	mm
Total		**$**	**887**	**mm**

Source: Company reports and RBC Capital Markets

Before adjusting for the pending asset sale – we calculate a net debt to total capitalization ratio of 47% and a net debt to 2011E cash flow ratio of 4.7x. While the leverage is high, the company is fortunate to have recently completed its last expansion at Algar, which is beginning to generate higher amounts of cash flow. We anticipate approximately $40 million of free cash flow above spending plans for 2011. We also anticipate ~$90 million of cash to be realized from the sale of the company’s conventional assets at year-end.

On a pro forma basis – we calculate a net debt to total capitalization ratio of 44% and a net debt to 2011E cash flow ratio of 4.6x. We anticipate approximately $40 million of free cash flow above spending plans for 2011. On a pro forma basis, we expect that Connacher will be paying ~$10/bbl in interest expense.

Next financing tied to Algar Expansion – The company is taking a bit of a break on spending activity as it ramps up operations at Algar and as it awaits regulatory approval for its expansions, which is expected late 2011 or early 2012. The company will enjoy free cash flow and no refinancing obligations over the next 12 months. We estimate the cost of the next expansion at $300–400 million, and therefore we do expect the company to seek additional financing in association with a sanctioning decision. Pending the timing of regulatory approval and market conditions, Connacher could be seeking its next round of financing in late 2011 or early 2012 as it contemplates the next expansion.

Valuation

Base versus Unrisked NAV – Algar Expansions Build Long-Term Value

Debt erodes all of Pod One, conventional and downstream value at current oil prices – Our base NAV for Connacher is supported by the developed Pod One and Algar SAGD projects and to a much lesser degree the company's conventional and downstream assets.

We calculate the value of Pod One at $1.50/share, Algar at $1.31/share, conventional upstream assets at $0.26/share, the downstream refinery at $0.09/share, Petrolifera equity holding at $0.04/share (based on current market capitalization), and undeveloped land at $0.03/share. The value of the company's positive net debt is worth ($1.68/share). We calculate a base NAV at $1.51/share given our production and cost outlook.

No value given to Algar Expansions in Base NAV – While we usually allocate partial value for projects that have entered into the regulatory process, on the assumption that the projects will be approved and subsequently built, we have not included value for the Algar expansions in our Base NAV due to the financial challenges presented by the company's higher than desirable debt balance. We have included a value of $0.66/share for Algar Phase 2a and a value of $0.49/share for Algar Phase 2b in our Unrisked NAV on the recognition that the continual derisking of these projects through the regulatory, financing and execution stages has the potential to add material value to Connacher over the coming years.

Exhibit 76: Connacher NAV Summary

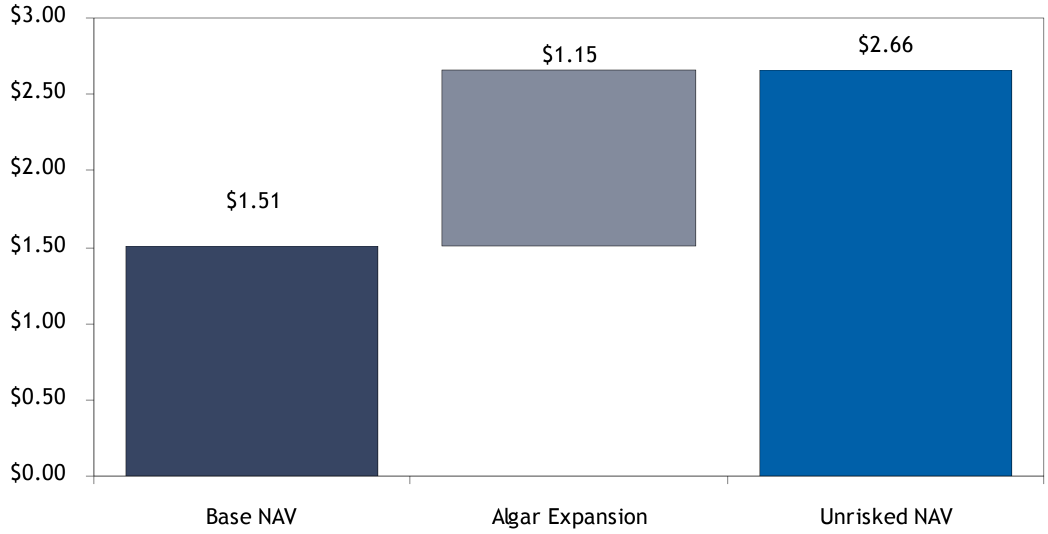
Project	Reserve / Resource Est. mmbbl	Project PV $mm	Implied PV/Bbl $/bbl	W.I. %	Risk Factor	Base NAV $mm	Base NAV $/share	Base NAV % NAV %	Unrisked NAV $mm	Unrisked NAV $/share	Unrisked NAV % NAV
Pod One											
Pod One (Producing)	251	$715.4	$2.85	100%	100%	$715.4	$1.50	100%	$715.4	$1.50	57%
	251	**$715.4**	**$2.85**			**$715.4**	**$1.50**	**100%**	**$715.4**	**$1.50**	**57%**
Algar											
Algar (Producing)	251	$622.1	$2.48	100%	100%	$622.1	$1.31	87%	$622.1	$1.31	49%
Algar Phase 2a (Application)	112	$312.8	$2.80	100%	0%	$0.0	$0.00	0%	$312.8	$0.66	25%
Algar Phase 2b (Application)	112	$232.4	$2.08	100%	0%	$0.0	$0.00	0%	$232.4	$0.49	18%
	474	**$1,167.3**	**$2.46**			**$622.1**	**$1.31**	**87%**	**$1,167.3**	**$2.45**	**92%**
Total Great Divide	**725**	**$1,882.8**	**$2.60**			**$1,337.5**	**$2.81**	**186%**	**$1,882.8**	**$3.96**	**149%**
Conventional & Downstream											
Conventional					100%	$124.9	$0.26	17%	$124.9	$0.26	10%
Downstream					100%	$43.5	$0.09	6%	$43.5	$0.09	3%
Total Conventional						**$168.3**	**$0.35**	**23%**	**$168.3**	**$0.35**	**13%**
Land	**Position Acres (Net)**		**Attributed Value $/Acre**								
Total Undeveloped Land	177,364		$75		100%	$13.3	$0.03	2%	$13.3	$0.03	1%
Corporate Adjustments		**Market Value**		**Ownership**							
Petrolifera Petroleum Ltd.		$90.2		18.5%		$16.7	$0.04	2%	$16.7	$0.04	1%
Net Working Capital						$58.6	$0.12	8%	$58.6	$0.12	5%
Long Term Debt						($876.0)	($1.84)	-122%	($876.0)	($1.84)	-69%
Total Corporate						**($800.7)**	**($1.68)**	**-111%**	**($800.7)**	**($1.68)**	**-63%**
Net Asset Value						**$718.5**	**$1.51**	**100%**	**$1,263.7**	**$2.66**	**100%**

Risk Factors
- 100% of DCF value given to producing projects and projects that have received regulatory approval
- 0% of DCF value given to projects in the regulatory application process due to corporate liquidity risk

Assumptions:
- WTI crude oil assumptions: US$78.02, US$83.00, US$85.00 for 2010E, 2011E and 2012E forward respectively
- Henry Hub natural gas assumptions: US$4.54, US$5.00, US$5.50 for 2010E, 2011E and 2012E forward respectively
- US/CAD foreign exchange assumptions: $0.96, $0.95, $0.95 for 2010E, 2011E and 2012E forward respectively
- After tax discount rate assumption: 8.5%
- Long term operating cost assumption: $12.00/bbl

Source: Company reports and RBC Capital Markets estimates

Exhibit 77: Connacher Upside Potential – Base and Unrisked NAV



Source: Company reports and RBC Capital Markets estimates

Relative Valuation – Lower Debt Needed to Improve Valuation

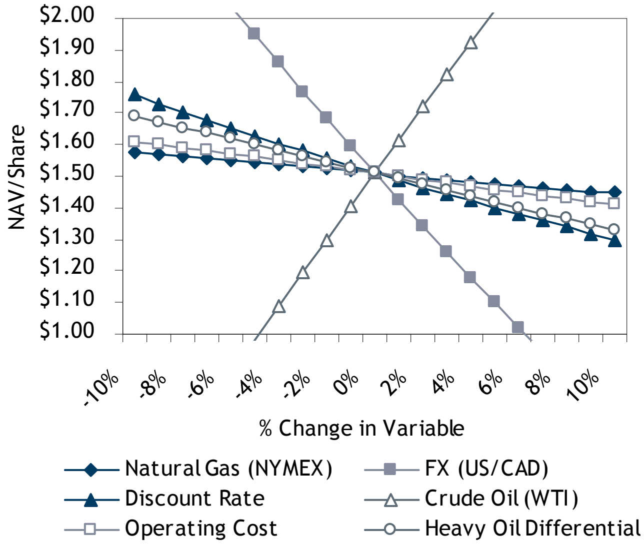
Connacher is trading at a 77% P/NAV ratio (Base) and a 44% P/NAV ratio (Unrisked). Peer group average valuations are 86% P/NAV (Base) and 49% P/NAV (Unrisked).

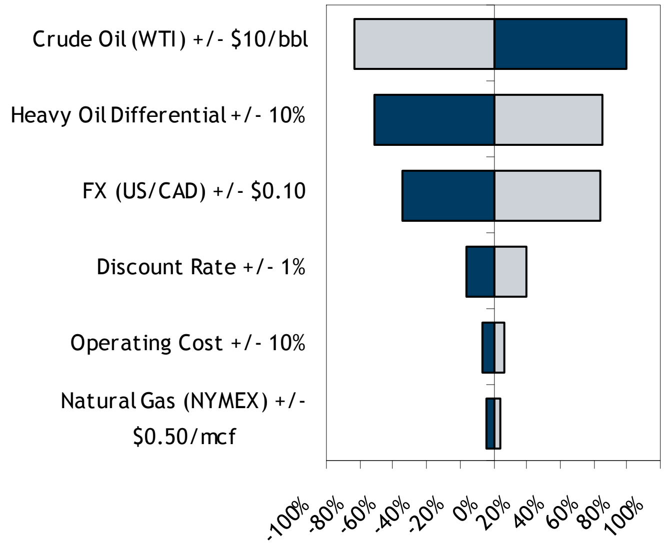
We see upside potential to Connacher's share price with strong results from the asset divestiture program and strong operational results over the course of 2011, both of which serve to reduce net debt. A reduction in net debt during the lead-up to an expansion at Algar would reduce the financing risk surrounding the project and allow us to begin representing partial value of the expansion in our Base NAV.

Sensitivities

Connacher's NAV is positively correlated, and most sensitive, to changes in the long-term oil price. Our calculation of NAV is negatively correlated to changes in the discount rate, the Canadian/U.S. dollar exchange rate, operating costs, heavy oil differentials, and natural gas prices. Next to oil price, the company's NAV is most sensitive to the discount rate and the exchange rate and less sensitive to changes in operating costs, heavy oil differentials or natural gas prices.

Exhibit 78: Connacher - NAV Sensitivity





Source: Company reports and RBC Capital Markets estimates

Risks to Target Price

We consider Connacher to be an early stage oil sands development company. While two online projects reduce overall project execution risks, high leverage presents higher overall financial risk.

We identify six key impediments to our price target:

1. **Oil Prices –** Following the divestiture of non-core assets, Connacher's production will be ~95% weighted to oil. As demonstrated in Exhibit 78, fluctuations in oil price represent the greatest effect on the NAV of the company. To protect cash flow, management has entered into oil price hedges, hedging approximately 40% of expected first half 2011 oil production and approximately 25% of expected second quarter 2011 production. We do not expect a material gain or loss on these hedges, which are very near current market prices. We assume a flat oil price of US$85.00/bbl from 2012 onward.

2. **Discount Rates –** We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations of E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk and lower reserve replacement and re-investment (i.e., exploration) risk than E&P companies. However, on the other hand, oil sands companies have greater regulatory, environmental and project execution risk over the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our price target, materially. At a 10% discount rate, which reflects the company's current weighted average cost of debt, our base NAV would drop to $1.16/share and our Unrisked NAV would drop to $2.00/share.

3. **Foreign Exchange Rates –** Connacher's capital and operating costs are incurred in Canadian dollars while its production is priced in U.S. dollars. Fluctuations in the U.S./Canadian dollar exchange rate can greatly affect the value of future cash flows. Somewhat offsetting fluctuations in the exchange rate is ~90% of the company's long-term debt, which is denominated in U.S. dollars. A $0.01 increase in the Canadian dollar in relation to the U.S. dollar decreases our estimate of NAV by approximately $0.04/share (approximately $20 million), offset by a decrease in the value of the U.S. denominated debt by approximately $0.02/share (approximately $8 million). We assume a flat US$0.95/C$1.00 exchange rate long-term.

4. **Regulatory Risks –** With Pod One and Algar already developed, Connacher has significantly reduced its regulatory risk. However, with the application for the Algar expansion on the desk of the regulators, future stages of development require additional regulatory approvals. The company's growth potential as well as our perception of its potential upside value would be materially affected should the regulatory process be delayed or not forthcoming for the Algar expansion.

5. **Financing Risks –** The company has recently started producing from its second project, which means that the balance sheet has been stretched to finance the production that has just recently started to contribute cash flow. We expect the company to bank some free cash flow in 2011 and to use proceeds from asset sales to reduce net debt before beginning the next round of expansion. Aside from a higher than ideal debt balance, the company does not face any immediate financing risk during 2011. The company has $100 million of debt maturing in June 2012, likely in the midst of the Algar project expansion spending. The company has US$200 million of debt maturing in July 2014 and US$587 million of debt maturing in December 2015, following the expected completion of the first Algar expansion and before the expected timing of the second Algar expansion spending.

6. **Environmental Risks –** Oil sands producers in general have come under significant scrutiny for environmental issues. While longer-term costs or product marketing concerns related to environmental issues are unclear at this time, they do present a risk to the company's operations and our perception of its valuation. That said, we note that Connacher is engaged in the development of In-Situ oil sands projects, which typically have less effect on land, air and water than oil sands mining projects. In addition, Connacher recently fired up its cogeneration facility, which generates clean electricity from natural gas instead of drawing electricity off the Alberta electricity grid, which is largely generated by coal. We expect that Connacher's In-Situ production should be roughly average in terms of emissions per barrel of production compared to most oil imported into the U.S. (see Exhibit 24).

Exhibit 79: Connacher - Operational and Financial Summary

C$ millions, unless noted	2007	2008	2009	2010E	2011E	2012E
Production						
Bitumen (bbl/d)	**n.a.**	**5,456**	**6,274**	**8,113**	**14,951**	**15,000**
Diluent Purchases (bbl/d)	n.a.	2,077	2,219	2,760	5,393	5,548
Blend Sales (bbl/d)	n.a.	7,533	8,493	10,873	20,344	20,548
Blend Ratio	n.a.	28%	26%	29%	27%	27%
Crude Oil & NGLs(boe/d)	792	1,029	1,041	818	850	800
Natural Gas (mmcf/d)	9.2	12.6	11.4	9.3	8.5	8.0
Conventional Production (boe/d)	**2,321**	**3,124**	**2,942**	**2,423**	**2,266**	**2,133**
YOY Production Growth (%)	n.a.	35%	7%	14%	63%	0%
Bitumen (%)	n.a.	64%	68%	77%	87%	88%
Commodity Prices						
WTI Crude Oil (US$/bbl)	$72.25	$99.50	$61.81	$78.02	$83.00	$85.00
Ed. Par (C$/bbl)	76.05	102.75	66.48	77.69	86.05	88.16
Bow River Heavy (C$/bbl)	50.50	83.00	59.25	68.23	73.30	72.29
Exchange Rate (US$/C$)	0.93	0.94	0.88	0.96	0.95	0.95
Henry Hub - NYMEX (US$/mcf)	6.95	8.85	3.92	4.54	5.00	5.50
AECO (C$/Mcf)	6.60	8.15	3.94	4.05	4.37	4.90
Realized Pricing and Costs						
Bitumen ($/bbl)	**n.a.**	**$45.74**	**$39.39**	**$48.11**	**$56.62**	**$59.73**
Crude Oil & NGLs ($/bbl)	52.80	82.01	54.61	66.26	74.05	76.16
Natural Gas ($/mcf)	6.38	7.90	3.90	3.95	4.27	4.80
Total ($/boe)	**43.22**	**50.49**	**37.81**	**46.04**	**54.93**	**58.08**
Royalties ($/boe)	(6.93)	(5.00)	(2.37)	2.73	2.25	2.21
Operating Costs ($/boe)	(11.06)	(20.38)	(16.88)	18.22	17.23	17.46
Netback ($/boe)	**25.23**	**25.11**	**18.56**	**66.99**	**74.40**	**77.75**
Consolidated Financials						
Revenue (net of royaltclls)	$30.7	$249.7	$166.8	$279.4	$576.6	$603.8
Other Income	313.8	379.7	254.9	318.7	302.1	307.2
Diluent Purchases	n.a.	92.3	53.3	78.5	183.4	196.2
Operating and G&A	17.9	75.8	71.5	89.1	128.3	130.5
Interest	6.9	34.7	44.4	61.0	87.1	84.8
DD&A	31.1	56.4	66.6	87.0	140.0	144.0
Pre-Tax Income	45.1	(43.0)	26.3	(35.7)	(7.5)	(0.6)
Current Tax	13.0	(12.9)	(1.6)	(0.7)	0.0	0.0
Deferred Tax	0.0	7.6	(5.7)	(11.3)	(2.0)	(0.2)
Net Income	**32.1**	**(37.7)**	**33.6**	**(23.6)**	**(5.5)**	**(0.5)**
Cash Flow From Operations	**45.0**	**54.8**	**12.5**	**47.7**	**139.3**	**151.6**
Capital Expenditures	**323.0**	**351.7**	**322.1**	**249.9**	**98.2**	**98.4**
Per Share Data						
Diluted CFPS ($/Share)	**$0.21**	**$0.26**	**$0.04**	**$0.11**	**$0.30**	**$0.33**
YOY Diluted CFPS Growth (%)	n.a.	21%	-84%	173%	176%	9%
Diluted EPS ($/Share)	**$0.20**	**($0.13)**	**$0.08**	**($0.07)**	**($0.01)**	**($0.00)**
YOY Diluted EPS Growth (%)	n.a.	nmf	nmf	nmf	nmf	-92%
Weighted Avg Diluted Shares O/S (mm)	212.75	214.6	327.1	436.6	462.3	462.3
Financial Leverage						
Net Debt	274.7	580.8	631.1	817.4	800.3	774.4
Long Term Debt	664.5	778.7	876.2	876.0	876.0	776.0

Source: Company reports and RBC Capital Markets estimates

Exhibit 80: Connacher - Company Profile

Business Description

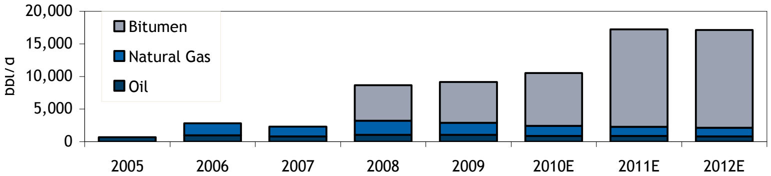
Connacher Oil and Gas Ltd. is an integrated oil and gas company primarily engaged in the production, refining and marketing of bitumen. The company's principal asset is its 100% working interest in ~98,000 acres of oil sands leases in the Athabasca region of Alberta. Connacher produces bitumen from two 10,000 bbl/d SAGD projects in the Great Divide Region (Pod One and Algar), and has submitted an application to expand production in the area to 44,000 bbls/d. While two-thirds of the company's production is bitumen, Connacher also has conventional production. Natural gas production offsets some of the gas consumption at Pod One and Algar. Connacher also operates a 10,000 bbl/d heavy oil refinery in Great Falls, Montana. Connacher markets gasoline, ashphalt and diesel in the niche markets surrounding its refinery in both the U.S. and Canada.

Connacher OIL AND GAS LIMITED

Recent News

Oct-10	Combined Bitumen Production of >13,200 bbls/d
Oct-10	Announces $22 mm Flow-Through Financing
Sep-10	Algar Co-gen Completed On Time & On Budget
Aug-10	Full SAGD Bitumen Production Underway at Algar
Jul-10	2P Reserves Surpass Half a Billion Barrels
Jun-10	First Oil Sold from Algar SAGD Plant

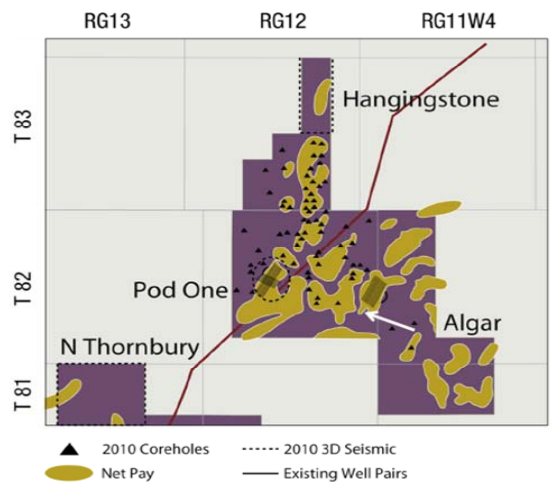
Connacher Production Profile



Reserve & Resource Estimates (GLJ)

	Reserves (mmboe)			Contingent Resource (mmbbl)		
	1P	2P	3P	Low	Best	High
Bitumen	182	502	606	216	223	320
Light/Med Crude	2	3	3	-	-	-
Natural Gas	135	193	193	-	-	-
Total	**320**	**698**	**802**	**216**	**223**	**320**

Connacher Great Divide Region Projects



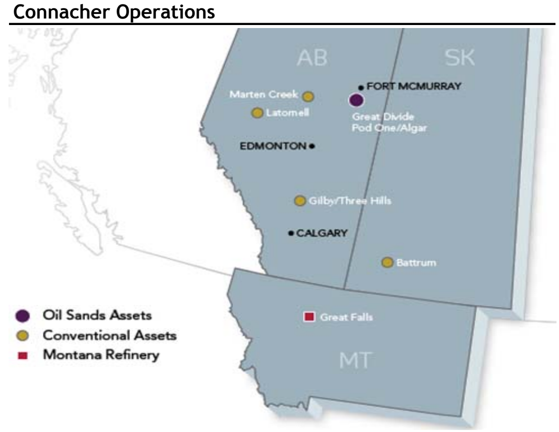
Potential Catalysts

Q1 2011	Effective date of asset sale
Q2 2011	New substation at Algar; may reduce irregular power supply problem
Q4 2011	Potential use of solvents at Algar to improve productivity and SORs
Q4 2011	Expected approval of Great Divide expansion project to 44,000 bbls/d
H2 2012	Potential infill well program at Pod One

Management Team

Name	Position	Past Experience
Richard A. Gusella	Chairman & CEO	Executive Chairman of Petrolifera
Peter D. Sametz	President & COO	COO & Director of Surge Petroleum Inc.
Richard R. Kines	VP Finance & CFO	Financial Consultant for Connacher
Cameron Todd	Sr VP Ops, Marketing	VP Marketing of Pioneer Natural Resources
Merle Johnson	VP Engineering	Development Engineer for Encana Corporation
Steve Marston	VP Exploration	Chief Geophysicist of Real Resources Inc.
Grant Ukrainetz	VP Corp. Development	Supervisor, Treasury for Talisman Energy Inc.
Brenda G. Hughes	Asst. Corp. Secretary	CFO & Controller for Insignia Energy Ltd.

Connacher Operations



Board of Directors

Name	Experience
Stewart D. McGregor (Lead Director)	President of Camun Consulting Corporation
Richard A. Gusella (Chairman)	Executive Chairman of Petrolifera
Peter D. Sametz	COO & Director of Surge Petroleum Inc.
Kelly J. Ogle	President and CEO of Trafina Energy Ltd.
D. Hugh Bessell	Deputy Chairman and COO of KPMG LLP
Colin M. Evans	Senior VP of Milestone Exploration Inc
Jennifer K. Kennedy	Partner of Macleod Dixon LLP since 2000
W.C. (Mike) Seth	Chairman of McDaniel & Associates

Source: Company reports and RBC Capital Markets estimates

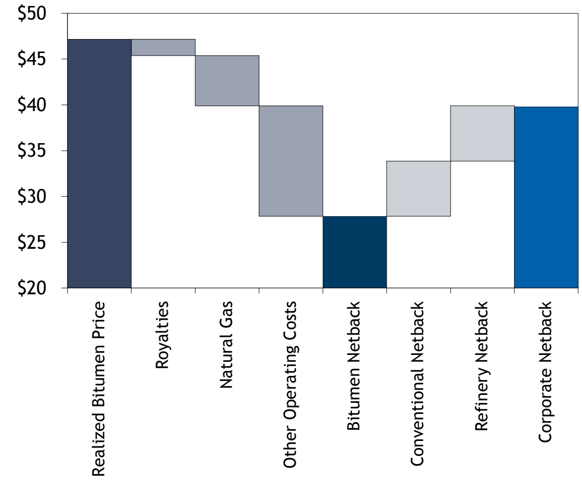
Exhibit 81: Connacher - Financial Profile

Insider Ownership

Management	Shares (M)	Options (M)	Total (M)	%of FD
Richard A. Gusella	797	2,449	3,246	0.7%
Peter D. Sametz	322	1,563	1,885	0.4%
Richard R. Kines	244	799	1,043	0.2%
Cameron Todd	89	933	1,022	0.2%
Grant Ukrainetz	87	670	757	0.2%
Steve Marston	110	814	924	0.2%
Merle Johnson	32	464	496	0.1%
Brenda G. Hughes	-	120	120	0.0%
Total Management	**1,680**	**7,812**	**9,492**	**2.1%**
Directors	**Shares (M)**	**Options (M)**	**Total (M)**	**%of FD**
Stewart D. McGregor	838	150	988	0.2%
W.C. (Mike) Seth	323	201	524	0.1%
Jennifer K. Kennedy	334	96	430	0.1%
D. Hugh Bessell	222	201	423	0.1%
Colin M. Evans	271	150	421	0.1%
Kelly J. Ogle	155	-	155	0.0%
Total Directors	**2,143**	**798**	**2,942**	**0.6%**
Total	**3,824**	**8,610**	**12,433**	**2.7%**

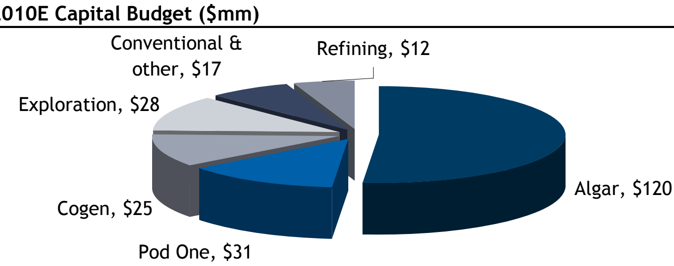
At Sep 30 2010, 27.1 million options were outstanding, weighted average exercise price of $1.63

Integrated Operations Netback (Management Estimates)



Assumptions: US$77.23, 1.04 CAD/US$, 15% heavy oil differential
$4.02 realized natural gas price, accounts for hedging program

2010E Capital Budget ($mm)



Commodity Hedges (bbls/d; US$)

Volume	Term	Price
2,500	FY 2010	$78.00
1,000	Q1 2011	$86.10
1,000	Q1 2012	$88.10
2,000	Q1 2013	$100.25
2,000	Q1 2014	$80.00
2,500	Remainder of 2010	$95.00
2,500	Remainder of 2010	$75.00

Selected Quarterly Operating & Financial Data

Production		Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Q1 10	Q2 10	Q3 10
Oil & Liquids	(bbl/d)	1,181	1,180	1,114	993	881	937	906	819
Natural Gas	(mmcf/d)	12.4	12.8	12.1	10.4	10.3	9.7	9.3	9.2
Total Conventional	**(boe/d)**	**3,244**	**3,318**	**3,138**	**2,723**	**2,600**	**2,547**	**2,452**	**2,345**
% Natural Gas	(%)	63.6%	64.4%	64.5%	63.5%	66.1%	63.2%	63.1%	65.1%
Oil Sands	(bbl/d)	7,085	6,170	6,284	6,551	6,089	6,936	6,211	6,758
Total Production	**(boe/d)**	**10,329**	**9,488**	**9,422**	**9,274**	**8,689**	**9,483**	**8,663**	**9,103**
% Oil Sands	(%)	68.6%	65.0%	66.7%	70.6%	70.1%	73.1%	71.7%	74.2%
Financials									
Operating Cash Flow	($mm)	$0.0	($4.7)	$9.6	$10.4	($2.8)	$3.9	$8.7	$15.2
Diluted CFPS	($/share)	($0.02)	($0.02)	$0.03	$0.03	($0.06)	$0.01	$0.02	$0.04
Net Income	($mm)	$0.0	($47.1)	$39.1	$53.2	($11.5)	$6.1	($28.9)	$8.4
Diluted EPS	($/share)	($0.22)	($0.22)	$0.14	$0.11	($0.03)	$0.01	($0.08)	$0.02
Capital Spending	($mm)	$0.0	$73.1	$39.6	$107.6	$105.6	$115.6	$51.6	$48.4
Capex/CF	(x)	nmf	-15.6 x	4.1 x	10.3 x	nmf	nmf	6.0 x	3.2 x
Net Debt	($mm)	$0.0	$683.9	$505.6	$542.0	$631.1	$724.9	$788.6	$806.1
Net Debt/CF	(x)	nmf	nmf	52.8 x	52.1 x	nmf	nmf	91.0 x	53.1 x

Source: Company reports, SEDI and RBC Capital Markets

Ivanhoe Energy Inc. (TSX: IE; $2.42)

Putting the "ands" in Oil Sands

Market Statistics			Net Asset Value			
					Base	Unrisked
Rating		Outperform				
Risk		Speculative	Net Asset Value	($mm)	$1,214	$1,718
Target Price		$3.00	NAV/Sh	($/share)	$3.23	$4.57
Market Price		$2.42	P/NAV	(%)	75%	53%
Implied Return		24.0%	Target Price/NAV	(%)	93%	66%
Capitalization			**Resources**			
F.D. Shares Outstanding	(mm)	358.9	Oil Sands EV[(a)]	($mm)		$609.8
Market Capitalization	($mm)	868.5	2P Reserves	(mmbbl)		n.a.
Net Debt	($mm)	($46.3)	Contingent Resources[(b)]	(mmbbl)		441
Enterprise Value	($mm)	$822.1	EV/Bbl[(c)]	($/bbl)		$1.38

Operating & Financial		2007A	2008A	2009A	2010E	2011E	2012E
Total Production	(boe/d)	1,870	1,897	1,434	783	825	800
Operating Cash Flow	(US$mm)	$6.0	$10.9	($11.8)	($17.5)	($12.3)	($14.2)
Diluted CFPS	(US$/sh)	$0.02	$0.04	($0.04)	($0.05)	($0.03)	($0.04)
Sensitivity to WTI	**(US$/bbl)**	**$60**	**$70**	**$80**	**$90**	**$100**	**$110**
NAV/Share	($/share)	$0.83	$1.83	$2.78	$3.69	$4.53	$5.37
P/NAV	(%)	290%	133%	87%	66%	53%	45%

(a) Adjusted to exclude the estimated value of non- oil sands assets
(b) Best estimate
(c) Based on 2P reserves + best estimate Contingent Resources

Source: Company reports and RBC Capital Markets estimates

Investment Highlights

- **Oil sands present the greatest opportunity for Ivanhoe** – Phase 1 production of 20,000 bbl/d at Tamarack can reasonably be expected by mid 2014. We assume that Ivanhoe will proceed without the use of HTL. Given our estimate of capital costs of ~$600 million, we would not be surprised to see the company consider a joint-venture agreement at Tamarack as a means of reducing capital requirements.
- **Expect a financing before year-end 2011** – The company has ~$90 million of cash at the end of the third quarter. We see it exhausting its current liquidity by the end of 2011. Success at Zitong or in Ecuador could accelerate the need for capital.
- **Catalysts may include surprises** – In addition to expected catalysts, management has hinted at possible events such as asset spinouts, new country entries and joint-venture partnerships that cannot be predicted with certainty or timing, but that could significantly affect the Ivanhoe story and valuation.
- **Speculative risk** – The company is exposed to a higher degree of risk due to the early stage of the regulatory process, international exploration exposure, future project financing requirements, future project execution requirements, and the technical and economic risks surrounding the planned implementation of its HTL technology.
- **Valuation requires imagination** – Tamarack, which we have risked at 75%, is the primary valuation support for our Base NAV. We calculate a Base NAV of $3.23/share and an Unrisked NAV of $4.57/share for a price to Base NAV ratio of 75% and a price to Unrisked NAV ratio of 53% compared to peer group average ratios of 86% and 49%, respectively.
- **Recommendation** – Outperform, Speculative Risk, 12-month target price of $3.00 /share. Our target price is based on a 0.9x multiple of our base NAV analysis, which is slightly below the peer group average of 1.0x Base NAV due to the speculative nature of the company's exploration program.

Summary & Investment Thesis

We initiate coverage of Ivanhoe Energy Inc. (TSX: IE; NASDAQ: IVAN) with a rating of Outperform, Speculative Risk and a 12-month target price of $3.00/share, which is based on a 0.9x multiple of our base NAV analysis, which is slightly below the peer group average of 1.0x Base NAV due to the speculative nature of the company's exploration program.

In our opinion, Ivanhoe Energy presents a unique, albeit somewhat unfocused, investment opportunity. We see Ivanhoe as a catalyst-rich company with a portfolio of emerging opportunities that emphasize exploration in China, Mongolia and Ecuador while it awaits regulatory approval on Tamarack. While the company enjoys financial liquidity for 2011, success in any of these regions would create a significant demand for capital. We see significant medium term production potential, especially at Tamarack (40,000 bbl/d); current production is non-strategic and current cash flow is not material. Given our current outlook, we do not believe HTL makes economic sense at Tamarack, but the technology may be instrumental in unlocking heavy oil assets in countries like Ecuador with limited infrastructure.

The company has a very diverse asset portfolio – Too diverse, in our view. Ivanhoe's asset portfolio spans oil sands in Canada, heavy oil exploration in Ecuador, light oil production in China, natural gas exploration in China, light oil exploration in Mongolia and the development of a proprietary upgrading technology. For a company with an enterprise value of $700 million, we believe that its resources are being spread too thin and that the range of assets inside the portfolio causes valuation of the stock to become increasingly difficult. We would prefer to see greater focus of the company's strategy and assets. We believe the simplest way of achieving greater focus would be to spin out the Sunwing division, which holds the company's Asian assets.

Tamarack is the company's primary project in terms of Contingent Resources, production potential and likely capital requirements – The regulatory application for Tamarack was filed in early November 2010, meaning that the approval could be expected in mid-to-late 2012. First production of 20,000 bbl/d from Phase 1 can reasonably be expected by mid 2014. Given our view of heavy oil differentials, natural gas prices and capital costs, we have assumed that Ivanhoe will proceed at Tamarack without the use of HTL. We estimate the capital cost of Tamarack at ~$600 million. Ivanhoe has a 100% working interest in the project, which provides significant production growth but also a daunting capital requirement nearly equal to the enterprise value of the company at present. We would not be surprised to see the company consider a joint-venture agreement at Tamarack.

HTL technology needs sustainably wide differentials to be economic – The use of HTL technology would allow the company to capture a portion of the heavy oil differential and reduce the input costs for natural gas and diluent. However, we estimate that at current differentials and natural gas prices, the costs outweigh the benefits, especially in the context of considering invested capital. We estimate the capital intensity of building an HTL facility at $25,000 bbl/d to $30,000 bbl/d. Assuming a cost of capital of 10%, the requirement to recover the invested capital and the cost of operating the facility (including the product yield loss), we estimate a loss of ~$3.50/bbl produced. Holding all else constant, we expect that light/heavy differentials need to be sustainably above 24% to make HTL economically viable. As such, we do not expect Ivanhoe to use HTL at Tamarack, although it may still have application in unlocking stranded heavy oil assets in places such as Ecuador.

Financing required before the end of 2011 – The company has ~$90 million of cash at the end of the third quarter. Based on current spending plans of $10 million to $20 million per quarter, we see the company exhausting its current liquidity by the end of 2011. Any acceleration of spending plans at Zitong or in Ecuador could accelerate the need for capital. We expect the company to begin seeking financing opportunities by mid-2011.

We have not assigned any value in our NAV for Mongolia or Ecuador – Our base NAV for Ivanhoe is supported predominantly by a risked value (75%) for the full development of Tamarack, which supports 88% of our target price. We have also given a risked value for exploration potential at Zitong (mid-point of resource estimate of 600 bcf to 1,000 bcf risked at 75%). We calculate a Base NAV of $3.23/share.

Exhibit 82: Ivanhoe - Pros & Cons

Pros	Cons
Tamarack – Regulatory application has been filed, thereby giving us increased confidence in the project	**Strategically Unfocused Asset Base** – Ivanhoe's assets, which include oil sands in Canada, heavy oil exploration in Ecuador, natural gas exploration in China, light oil exploration in Mongolia and HTL upgrading technology do not share a common strategic objective, thereby making the company more difficult to understand and value
Production Potential – Tamarack application for 40,000 bbl/d at a 100% W.I	**Lack of Material Current Production** – While the company owns current production in China, it is neither meaningful nor strategic
Clearwater Shale Cap Rock - Thick and consistent 30m+-thick shale overlying development area	**Four Year Wait for Tamarack Production** – First production not expected until mid 2014
In-Situ Development – In-Situ can be easier to sell to investors, especially from an environmental perspective	**Pre Regulatory Stage** – Approvals expected in mid-to-late 2012 for Tamarack with first production ~2015
No Debt – The company has zero debt and US$90 million of cash on hand	**Top Gas** – Appears to limit the development of the two western-most sections of the lease
Catalyst Rich – The company has frequent and potentially material news flow	**Bottom Water** – Presence of bottom water presents a technical risk for Phase 1 development
Capitalization – Sufficient to fund operations for 2011	**Early Stages in Ecuador** – Appraisal-stage exploration with commercial production not likely before 2015
HTL Technology – Demonstrated at the commercial and test facilities. Economics permitting, HTL may serve to unlock stranded heavy oil assets	**HTL Economics** – Economics do not support the use of HTL at Tamarack at this time
	Capital Drain – Sunwing, which does not have a strategic fit with Ivanhoe's heavy oil development strategy, could become a major user of capital in the event of Zitong development

Source: Company reports and RBC Capital Markets

Potential Catalysts

In the immediate term, we are watching for the following catalysts:

- Release of Class III (+25%/-20%) capital cost estimate for Tamarack
- Continued testing, and the commencement of seismic, at Pungarayacu, Ecuador
- Commence testing at Zitong-1
- Commence testing at Yixin-2
- Dagang operating at restricted volumes again in the fourth quarter due to production quotas

In 2011, we are watching for the following catalysts:

- Update of reserve and resource estimates at Tamarack, concurrent with 2010 results
- Initiation of a five well exploration program in Mongolia
- Possible appraisal wells to Zitong-1 and Yixin-2
- Possible submission of 23 well development program at Zitong
- Drilling at Pungarayacu, Ecuador
- Financing before year-end 2011

In 2012, we are watching for the following catalysts:

- Continued drilling at Zitong, China
- Continued activities in Mongolia
- Continued exploration and evaluation at Pungarayacu, Ecuador
- Expected regulatory approval of Tamarack before year end

Actuality and timing are highly uncertain, but watch for the following speculative catalysts:

- Possible spinout of Sunwing Energy
- Possible entry into the Middle East under Ivanhoe Energy MENA Inc.
- Possible entry into another South American country under Ivanhoe Energy Latin America Inc.
- Possible announcement of a midstream implementation of HTL, most likely in South America
- Possible announcement that Tamarack will not utilize HTL due to current economics

Exhibit 83: Ivanhoe - Potential Catalysts

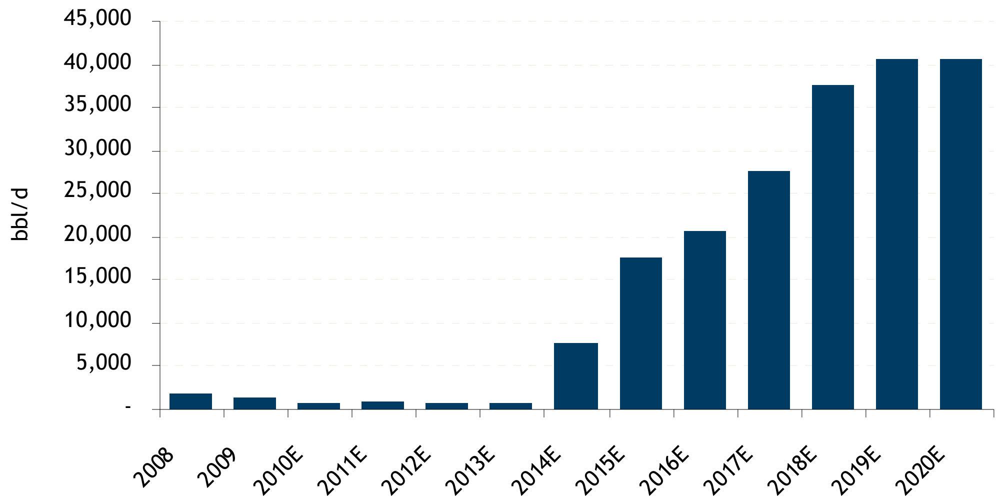
2011E	2012E	2013E+
Q1 – Reserve and resource update concurrent with 2010 results	2012 – Continued drilling at Zitong, China.	2014E – First bitumen at Tamarack
2011 – Initiation of five-well program in Mongolia	2012 – Continued activity in Mongolia	Long term – Exploitation program at Zitong (pending successful exploration efforts)
2011 – Possible appraisal wells to Zitong-1 and Yixin-2	2012 – Appraisal drilling in Pungarayacu, Ecuador	Long term – Development phase at Nyalga, Mongolia (pending successful exploration efforts)
2011 – Possible submission of 23 well development program at Zitong, China.	2012 – Expected regulatory approval for Tamarack Project	Long term – Piloting, exploitation at Pungarayacu, Ecuador (pending successful appraisal efforts)
2011 – Appraisal drilling in Pungarayacu, Ecuador	2012 – Construction begins at Tamarack (upon approval and sanctioning)	
2011 – Financing to fund Tamarack project and other capital spending		

Source: Company reports and RBC Capital Markets estimates

Company Overview

Ivanhoe Energy has three wholly owned subsidiaries: Ivanhoe Energy MENA (Middle East and North America), Ivanhoe Energy Latin America and Sunwing Energy, which is the operating company for Ivanhoe's Asian operations. The company holds a portfolio of oil and natural gas assets in Canada, Ecuador, China and Mongolia. The company is also developing a proprietary upgrading technology called HTL Upgrading. The company's strategy is to utilize its HTL technology to unlock previously economically stranded heavy oil assets.

Exhibit 84: Ivanhoe - Production Forecast



Source: RBC Capital Markets estimates

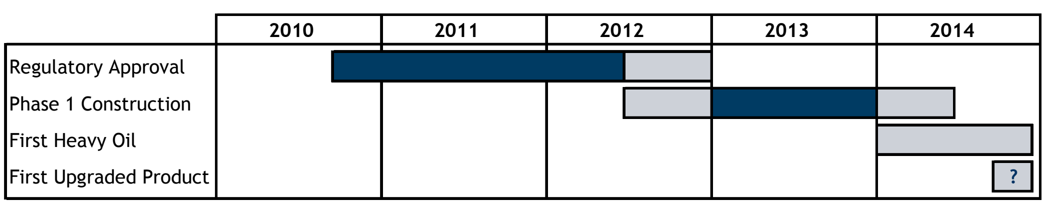
Tamarack – Joining the Oil Sands Racetrack

The company owns a 100% W.I. in the Tamarack oil sands lease located ~25 km north of Ft. McMurray, Alberta. Ivanhoe purchased the lease from Talisman Energy in July 2008 for $90 million. Talisman retains a right to back in at a 20% W.I. ownership of the lease for an estimated $40 million. This right expires on July 11, 2011 and we expect Talisman to allow it to expire unexercised.

Following an extensive delineation program over the lease, GLJ Petroleum Consultants (GLJ) has assigned 441 million barrels of Contingent Resource (best estimate) to Tamarack based on an SAGD recovery scheme. The company is proposing a two-phase development to reach 40,000 bbl/d, with each phase 20,000 bbl/d in size.

We anticipate first bitumen production in early to mid 2014. Management filed the regulatory application for Tamarack with the Alberta Government on November 4, 2010. The application does not include co-generation facilities, but makes reference to the fact that the company may make a separate application for two 30 MW cogeneration plants. The application does include an HTL upgrading facility. We expect the regulatory process to take 18 to 24 months, at which point the company can consider project sanction in mid-to-late 2012. We anticipate a construction window of 12 to 18 months to be followed by three to six months of steaming and commissioning (see Exhibit 85). We anticipate first bitumen production from Phase 1 in early to mid 2014.

Exhibit 85: Tamarack – Estimated Schedule

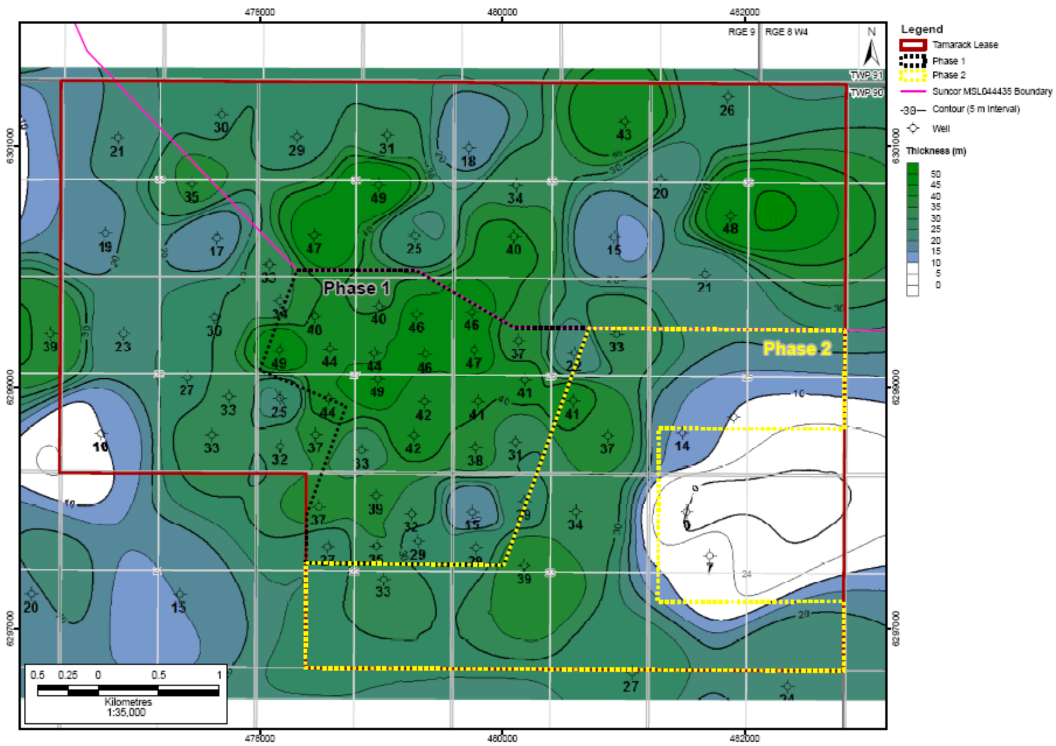


Source: Company reports and RBC Capital Markets estimates

Suitable for SAGD with notable risks – The Tamarack lease covers 11 contiguous sections (6,880 acres); however, we estimate that only about half of the lease is suitable for development due to reservoir thickness, bottom water, top gas and Suncor's Mineral Surface Lease constrictions.

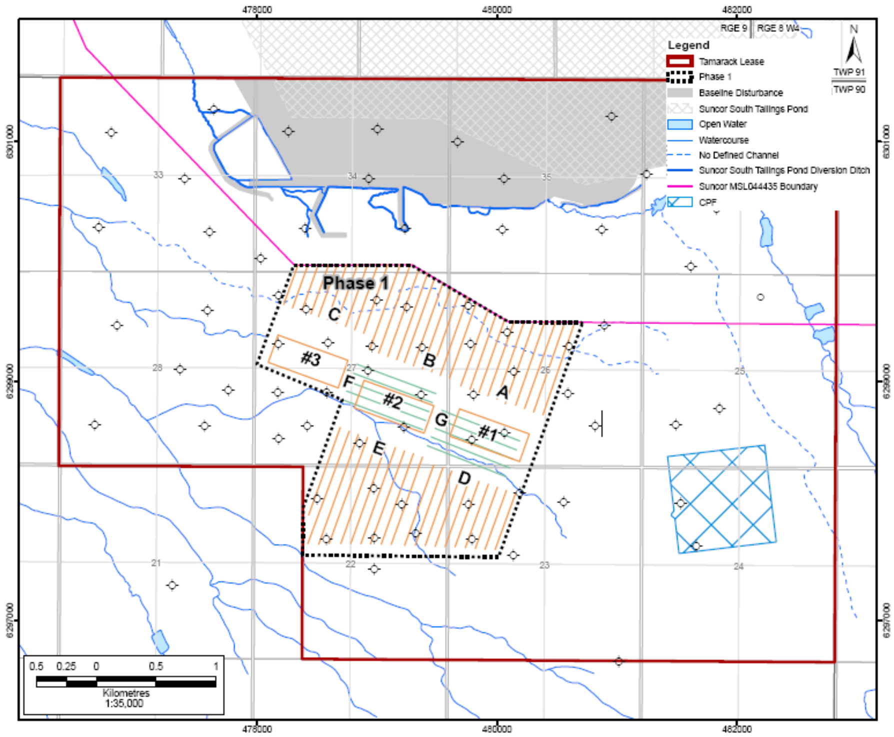
The reservoir on the Tamarack lease enjoys many compelling characteristics that make it suitably attractive for SAGD development – The Tamarack reservoir has high bitumen saturation (80%), good porosity (33%), permeability (6 darcies) and reservoir thickness. The reservoir is thickest in the Phase 1 development area, reaching up to 49 metres with an average thickness of 38 metres. The average thickness in the Phase 2 development area is 24 metres (see Exhibit 30). The entire lease is also covered by sufficient containment shales (the Upper McMurray shale of five to 16 metres, the Wabiskaw B shale of five metres and the Clearwater shale of more than 30 metres) that serve as a suitable cap rock.

Exhibit 86: Tamarack - McMurray Reservoir Thickness



Source: Company reports

Exhibit 87: Tamarack – Phase 1 Development Patterns

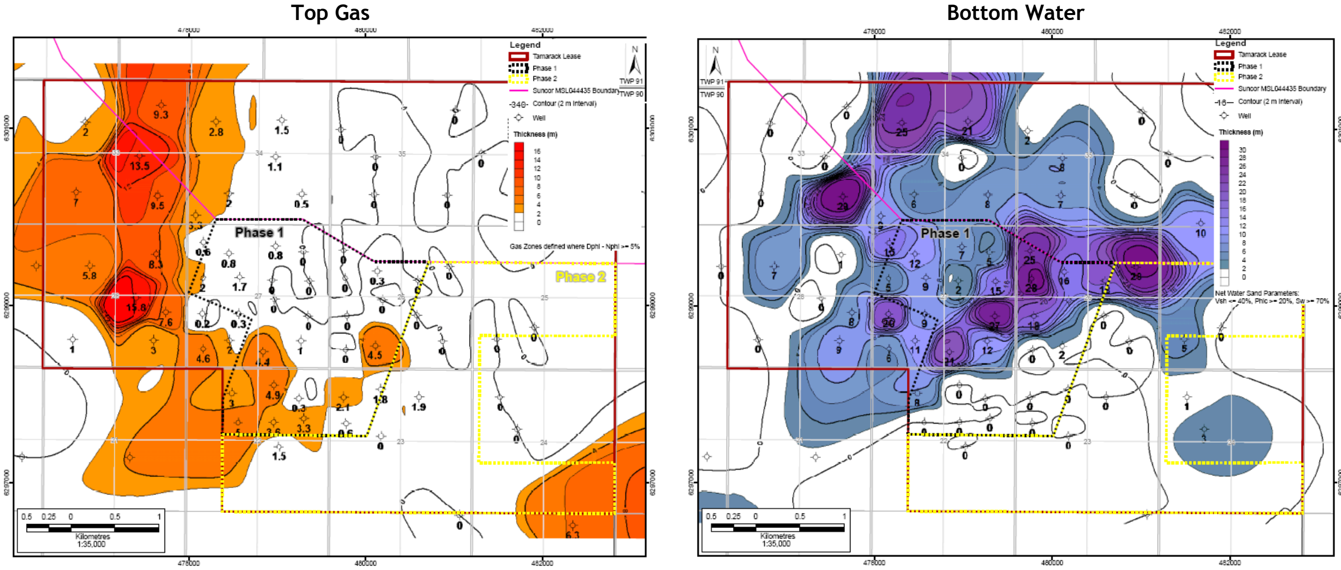


Source: Company reports

Tamarack Reservoir Risks – Be Aware, but be Fair

- **The shallowest and lowest pressure SAGD reservoir in Alberta** – Tamarack is the shallowest In-Situ reservoir to be developed to date at reservoir depth of 75 to 132 metres. So shallow, in fact, that at surface, drilling begins at a 45 degree slant to allow the well bores to reach horizontal at reservoir depth. Shallow reservoir depth translates into lower reservoir pressure, which may introduce production challenges. The native reservoir pressure at Tamarack is ~500 kPa with planned production pressure of 1,450 kPa, similar to native reservoir pressure at Suncor's MacKay, which produces at 1,500kPa to 2,000 kPa. Management wants to drop operating pressures to 1,250 kPa after a couple of years of production, likely in conjunction with converting wells to PCP (Progressive Cavity Pumps) lift. At these pressures, this would be the lowest operating pressure SAGD reservoir in Alberta.
- **Top gas present over the lease area** – The presence of top gas largely sterilizes the two western sections of the lease and encroaches somewhat into the Phase 1 development area (see Exhibit 88). More specifically, top gas can be found over the D and E development patterns of Phase 1. Where top gas is present, it is in thin beds of one to two metres with high bitumen concentrations of ~50%. No natural gas has been produced on the lease. At any rate, we anticipate the Phase D and E development patterns will not be drilled until 2020. As such, we do not anticipate top gas presenting a production risk in the immediate future of development. The Phase 2 development area is not affected by top gas.
- **Bottom water present at Tamarack** – The presence of bottom water is most pronounced in the areas denoted for the A, B, C, F and G development patterns. The A and B development patterns will be drilled in 2013, followed by the C pattern in 2016. As such, we believe that bottom water presents a technical risk with respect to Phase 1 development. In some areas, the water-bearing sands are separated from the producing McMurray formation by a mudstone bed. Where the mudstone bed is not present, the bottom-producing well can be located five to 10 metres off the base of the reservoir. We believe that the presence of the lower mudstone bed and the ability to locate the wells higher in the thick reservoir will largely mitigate the risk, but bottom water does present a technical risk at Tamarack.

Exhibit 88: Tamarack - Top Gas and Bottom Water Isopachs



Source: Company reports

Capital intensity ranges widely dependent on scope – We expect the capital intensity on the SAGD-only component to be comparable to other industry project at roughly $30,000 bbl/d for a total Phase 1 SAGD cost of $600 million. We expect the cogeneration facilities to cost approximately $60 million to $75 million per 30 MW phase, representing an incremental capital intensity of $3,000 bbl/d to the project should they be built. We expect the capital intensity of the HTL facility to be approximately $25,000 bbl/d to $30,000 bbl/d, for a total cost of $500 million to $600 million for each phase. We estimate that capital costs could range from $600 million for a SAGD-only project to $1.25 billion for a fully integrated project. Management plans to release its Class III cost estimate (+25%/-20%) by year-end 2010 or in early 2011.

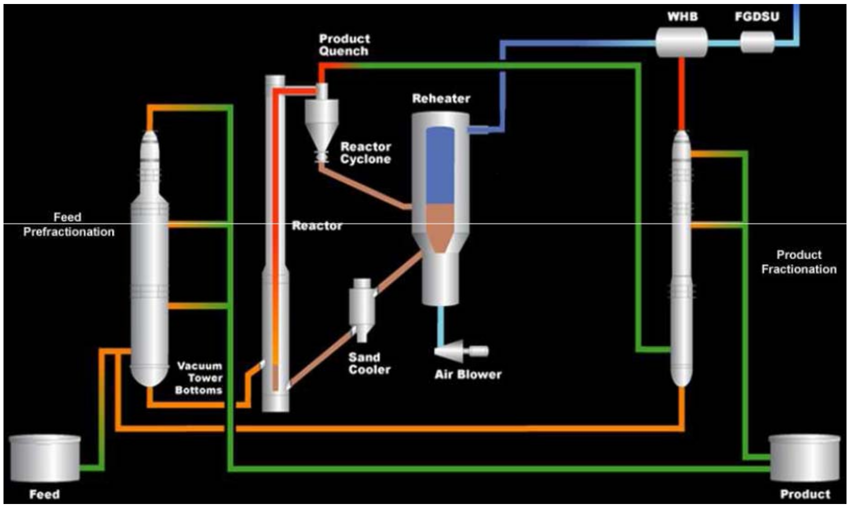
HTL Upgrading - A Key to Unlocking Stranded Assets

Actually, more like HTM – The company has been developing its proprietary HTL technology for application in upgrading heavy oil. The HTL technology is an adaptation of its parent technology, which converted biomass to energy. While the name suggests the bitumen or heavy oil feedstock is upgraded to light oil, this is somewhat of a misnomer. Outcome is variable depending on the initial quality of the oil, but the objective is to refine to an end product that meets pipeline specifications, which is likely in the range of 20 to 22 degree API. While the feedstock is only partially upgraded to get it to pipeline specifications, capital intensity is commensurately less than a higher-complexity facility that increases product quality to the 34 to 39 degree API range.

Full commercial-scale implementation dependent on opportunities – The ability to avoid sourcing, shipping and blending diluent and shipping higher volumes of dilbit all at a significant cost may be enough to unlock stranded heavy oil assets in Canada or internationally. The implementation of this technology on a full commercial scale could be carried out on one of the company's own heavy oil leases (Tamarack or Pungarayacu) or as a mid-stream solution third-party supplier. Implementation of HTL will likely be determined by economics (see Key Issues section of this report below).

The technology itself is fairly simple – The upgrader takes only the heaviest ends of the bitumen into the HTL process. The lightest ends of the bitumen are separated in a standard vacuum tower and bypass the entire process to be mixed at the end. The heaviest ends get circulated to extinction through the patented HTL process in the centre of the process flow diagram (see Exhibit 89). Simply, the heavy bottoms of the bitumen are sprayed onto rapidly moving sand particles where the coking takes place inside the reactor at incredibly quick residence times (measured in seconds, not minutes). The coke is flashed off the bitumen-coated sand particles; the heat is used to generate steam or electricity. The lighter ends become vapourized, are collected, returned to a liquid and are mixed back with the lighter ends that were originally separated off to become the end product.

Exhibit 89: HTL Process Flow Diagram



Source: Company reports

Robust process yields shippable crude – There are no added catalysts, hydrogen or blend stocks. The sand is normal (i.e., inexpensive) beach sand (size controlled) and is recycled repeatedly through the process. The process upgrades the oil from 8-12 degree bitumen out of the reservoir to 18–22 degree medium heavy oil. The process also results in viscosity, sulphur and metal contents that are suitable for pipeline specifications. This process avoids the need to add diluents to make the product shippable and the heat created from the reaction process can be used to generate steam or electricity, likely capable of making the process largely self sufficient. The liquid yield loss is approximately 9%.

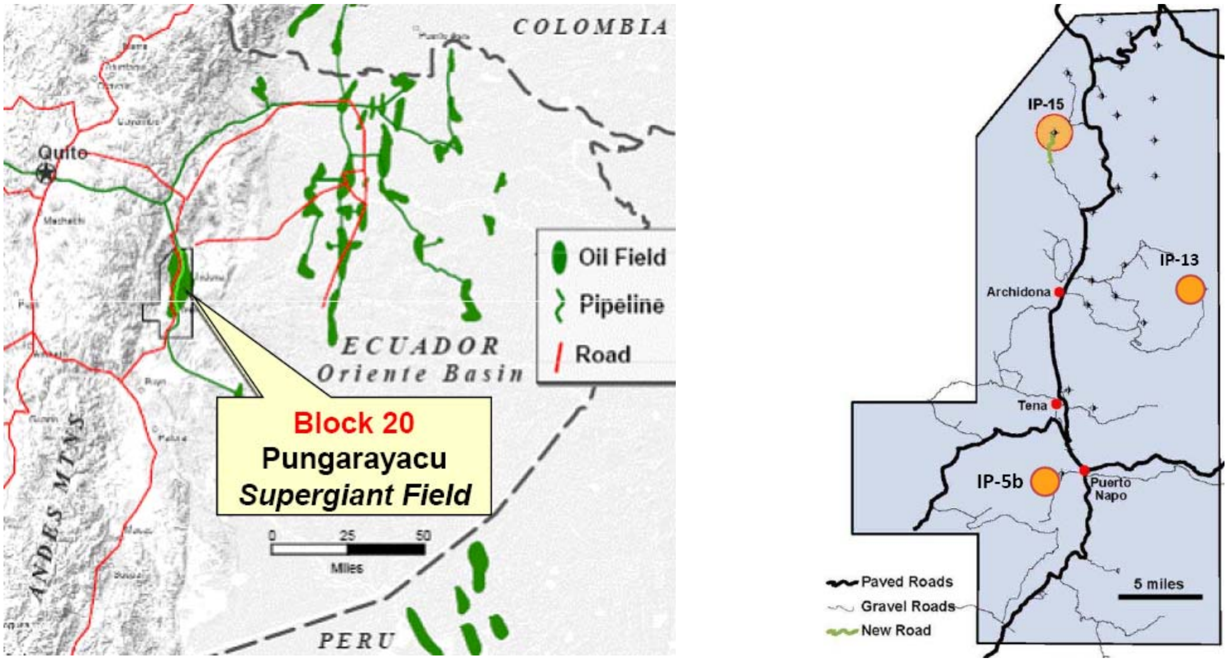
Commercially demonstrated and tested – Ivanhoe ran a 1,000 bbl/d commercial demonstration facility in California from 2005 to 2009, proving up the robust nature and scalability of the technology. Following the application of the demonstration facility, Ivanhoe constructed a test facility at the Southwest Research Institute in San Antonio, Texas. The purpose of this feedstock test facility is to allow for incremental refinements in the process, instrumentation and design at the same time as allowing the facility to test various different types of heavy crude at small batch sizes.

Ecuador - Potential Application for HTL

Service contract may limit economics – In October 2008, Ivanhoe Energy entered into a 30-year contract with Petroecuador and Petroproduccion that gives it exclusive rights to explore for, develop and produce heavy oil on Block 20 and to apply the company's HTL technology. The company also has the right to explore for and produce light oil for the sole purpose of using it as a diluent for any heavy oil production. The company initiated a three-year appraisal in May 2009 following the receipt of all required regulatory and environmental approvals. The contract provides for a payment of US$37.00/bbl (to be inflation adjusted), which Ivanhoe Energy may elect to take in kind.

Ivanhoe successfully produced heavy oil – Oil has never been produced from Block 20. In the company's three-well appraisal program, the first well drilled was the IP-15 well (see Exhibit 90), which was lost due to poor casing completion. The well, however, found lower API and higher-viscosity oil than was expected. The IP-5b well was completed, steamed for almost three weeks and flow tested. Production from this well will be tested at the company's HTL feedstock test facility in San Antonio before year end.

Exhibit 90: The Pungarayacu Project



Source: Company reports

Aquifers present a technical risk – A potential risk with production from this field could be water breakthrough from high-pressure aquifers. However, during the steam and production test Ivanhoe did not notice any effect from the nearby aquifer on production. The presence and effect of aquifers will be an important factor to monitor in future production tests.

Ivanhoe pursuing a partner for this long lead time project – Ivanhoe is considering its plans, but management has not yet outlined a specific 2011 program. We expect the company to shoot and acquire more seismic by which to select additional drilling locations and to resume drilling in the second half of 2011. At this pace, we would not expect commercial development until 2015 at the earliest. Ivanhoe is actively pursuing partners for Block 20.

Sunwing – Exploration in Asia Does Not Fit Heavy Oil Strategy

China – Zitong Success Could be the Catalyst for Spinout of Sunwing

Exploration success at Zitong would be very encouraging, but it does not translate into immediate cash flow or development opportunity. However, success at Zitong would create a large, long term development program and significant demand for financing, which could be the basis for a stand-alone company.

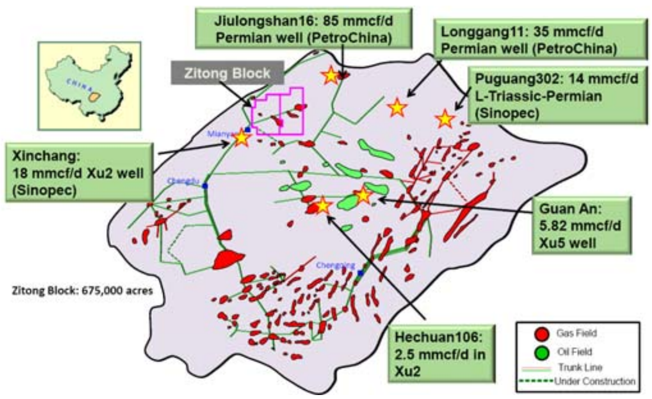
In addition to a small oil interest of 600 bbl/d to 800 bbl/d (net) in Dagang (southeast of Beijing) and a small overriding royalty at Daqing (northeast of Beijing), Sunwing's primary area of focus is at Zitong, a natural gas exploration block located in the Sichuan basin (southwest of Xi'an). The company is actively drilling on these leases.

Tcf potential – Sunwing entered this region in 2000 with five blocks, three of which have been relinquished. The company has ~900,000 acres on the Zitong block but may potentially need to relinquish ~300,000 more acres. The company has been developing a tight sands exploration play concept that could extend the exploration terms over the lease and potentially avoid another relinquishment near term; however, should a relinquishment take place the company would retain the structures already identified (see Exhibit 91). Sunwing is estimating that its lease could hold up to 1 tcf of natural gas potential.

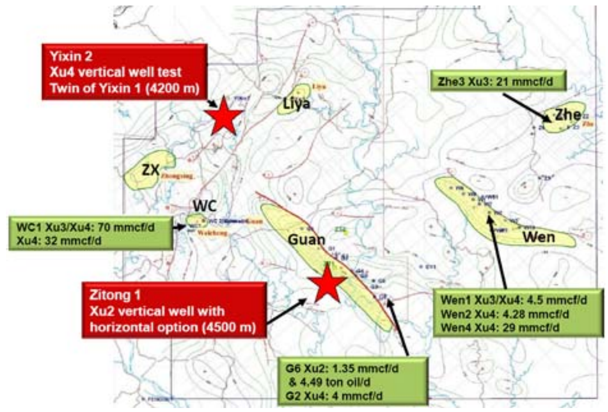
Long lead time & expensive program – Pending a successful test indicated by a flow rate of 0.7 mmcf/d as measured over eight hours, Sunwing would earn exploration access to all identified, but undrilled, structures on the block (see Exhibit 91). The company has identified follow up drilling locations. The company has discussed filing a 23-well development plan exploiting all structures. This development program would take ~18 months to receive approval and could cost upwards of $200 million.

Exhibit 91: Sunwing – Natural Gas Exploration in the Sichuan Basin

Sichuan Basin



Zitong Block



Source: Company reports

Yixin 2 a twin of Yixin 1 – The Yixin 2 well has reach targeted depth of ~4,165 metres. The Yixin 2 well twined the Yixin 1 well, which was drilled by Sunwing in 2007. The Yixin 1 well flowed natural gas but the well was lost to surface equipment failures. The Yixin 2 well should be logged, cored and tested before year end. This well has an estimated cost of ~$8 million.

Zitong 1 testing the large 0.6 Tcf potential Guan structure – The largest identified structure on the block, Guan, had never been penetrated prior to this well. The upper Xu-5 and Xu-4 formations have already been drilled and logged with positive indications. The target reservoir is the Xu-2 at ~4,500 metres. The well has reached its targeted depth and will be followed up with testing. This well has an estimated cost of ~$12 million. The company may elect to kick off a horizontal test well up hole to test the Xu-5 or Xu-4 formations.

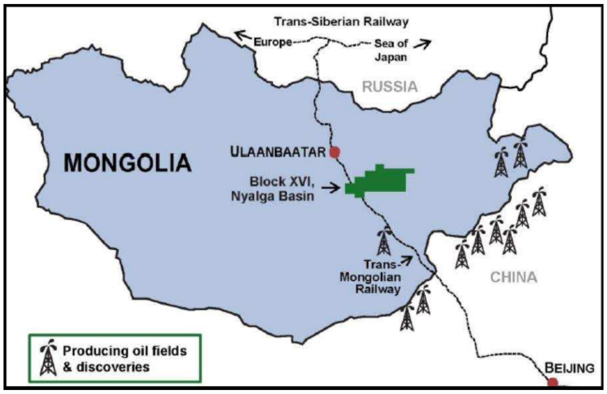
Mongolia – Wildcat Exploration

In 1999, Sunwing merged with PanAsian Petroleum, whose sole asset of interest was Block 16 in Mongolia. Ivanhoe has a 100% W.I. on the large 12,500 km^2 block (following relinquishments). The company has approximately 1,000 km of 2D seismic and is starting another seismic program. The lease has seepages of bitumen at surface, but the target is light oil. Bitumen at surface could indicate reservoir filled to spill point or the absence of trap. Light oil becomes heavy oil at surface following degradation of the light ends of the oil.

The lease is located approximately 100 km southeast of the capital, Ulaanbaatar. The Trans-Mongolian Railway, linking railway networks and markets in Russia to the north, and China to the south, runs through the western edge of Block 16, closely following Mongolia's main north-south highway. All services must be imported from either China or Russia and given the company’s operating base in China that is the natural source for rigs and personnel.

Plans are to bring in rigs and drilling crews from China and to initiate a five-well program in the spring of 2011. Wells cost ~$1.5 million each, and this is wildcat exploration.

Exhibit 92: Mongolia Nyalga Basin Block 16



Source: Company reports

Key Issues

HTL Economics - No Go for Tamarack at Current Economics

Very attractive economic benefits – The development of HTL technology is appealing, providing an upgrading solution for smaller in-field projects of 10,000 bbl/d to 40,000 bbl/d. The benefits of utilizing HTL sound promising, namely capturing the differential between bitumen and heavy oil, avoiding the cost and disadvantage of using diluent and avoiding the cost of natural gas. In the right context, these benefits can be significant, but based on realistic current assumptions, we estimate the benefits associated with running an HTL facility at approximately $16/bbl (see Exhibit 93).

Very real economic costs – In the current environment, and for the foreseeable future, we do not anticipate the benefits of HTL outweighing the associated costs, at least in Canada. In addition to the actual cost associated with running the facility, the investment needs to carry itself in terms of covering the cost of financing and returning the initial investment over the life of the asset. In addition, because of the process, the liquid yield loss also has a real cost associated with lower volume sales. Based on realistic current assumptions, we estimate the costs associated with running an HTL facility at close to $20/bbl (see Exhibit 93).

We expect that the HTL facility would lose ~$3.66/bbl in the current environment; as such, we do not expect Ivanhoe Energy to proceed with the HTL upgrader at Tamarack.

Exhibit 93: Benefits and Costs of HTL

HTL Benefit

Benefits		
Diff Capture	$/bbl	$6.27
Dilluent Avoidance	$/bbl	$5.89
Natural Gas Avoidance	$/bbl	$4.00
HTL Benefit	$/bbl	$16.16
Costs		
HTL Operating Expense *	$/bbl	$5.00
Return on Capital (10%)	$/bbl	$6.85
Return of Capital	$/bbl	$2.27
Liquid Yield Loss	$/bbl	$5.71
HTL Cost	$/bbl	$19.83
HTL Benefit (net)	**$/bbl**	**-$3.66**

* Est. from Company
** RBC CM Estimate

Benefits

Diluent		
Cost of Diluent		
WTI **	$/bbl	$85.00
Diluent Premium **	%	3%
Diluent Price	$/bbl	$87.55
Diluent/bbl of Dilbit **	%	33%
Cost of Diluent/bbl of Dilbit	$/bbl	$28.89
Revenue from Diluent		
WTI	$/bbl	$85.00
Light/Heavy Differential **	%	18%
Heavy	$/bbl	$69.70
Bit Diff (50% of L/H Diff) **	%	9%
Bitumen	$/bbl	$63.43
Revenue from Diluent/bbl of Dilbit	$/bbl	$23.00
Net Cost of Diluent/bbl of bitumen	$/bbl	$5.89
Natural Gas		
SOR **		3.0
Natural Gas	mcf/bbl	1.0
Cost of Natural Gas **	$/mcf	$4.00
Cost of Natural Gas/bbl	$/bbl	$4.00

Costs

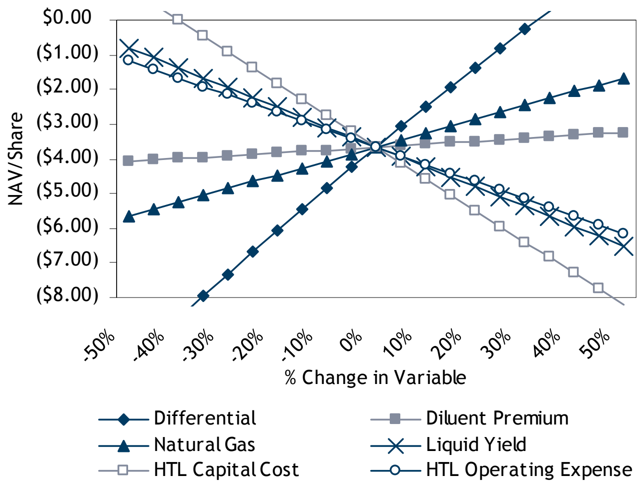
Return on Capital		
HTL Capital Cost *	$mm	$500
Rate **	%	10%
ROC/Year	$mm	$50
Production Capacity	bbl/d	20,000
Production/Year	mmbbl	7.3
Return on Capital	$/bbl	$6.85
Return of Capital		
HTL Capital Cost	$mm	$500
Production Capacity	bbl/d	20,000
Production/Year	mmbbl	7.3
Resources	mmbbl	220.5
RLI	years	30.2
Return of Capital	$/bbl	$2.27
Liquid Yield Loss		
Liquid Yield *	%	91%
Liquid Yield Loss	%	9%
Bitumen	$/bbl	$63.43
Liquid Yield Loss/bbl	$/bbl	$5.71

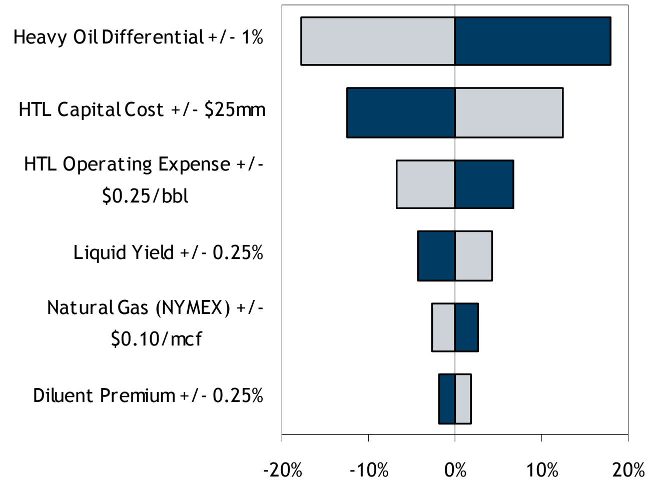
Source: Company reports and RBC Capital Markets estimates

Multiple variables effect value – There are many dynamic variables that can influence the economic viability of HTL. As expected, the most significant variable to influence economics is the heavy oil differential, followed by changes in the capital cost and the operating cost of running the facility. Not included in our sensitivity analysis, but of significant importance would be the financing rate on the project.

All else constant, we believe differentials need to be more than 24% to justify economics – Holding all of our assumptions constant (i.e., the diluent premium, the blend ratio, the price of natural gas, the capital and operating costs, and liquid yield), we estimate that the HTL facility teeters on breakeven with a long-term light/heavy oil price differential of 24%. We believe long-term differentials will be lower than this.

Exhibit 94: Economic Sensitivities of HTL Upgrading





Source: Company reports and RBC Capital Markets estimates

Strategic Focus - Oil Sands or International Exploration?

Ivanhoe Energy does not fit the mould of the typical company appealing to investors as an oil sands developer. The company has a wide variety of assets and projects around the world that do not appear to share a common strategic focus. This mix of assets and strategies makes it difficult to value and may make it more difficult to attract shareholders.

The primary benefit of the HTL technology is that it could possibly be used to unlock economically stranded heavy oil assets. HTL may have application in Canada, subject to economics, but it may be the key to unlocking heavy oil assets elsewhere in the world. The application of HTL may be the key to ultimately developing the company's lease in Ecuador, for instance. Therefore, we can understand the strategic fit of these assets under the larger umbrella of being a heavy oil developer.

Since the assets inside Sunwing do not seem to fit with Ivanhoe's oil sands and heavy oil strategy, looking for alternatives for it may be the best strategic option for Ivanhoe longer term, in our view. Management is aware of the possible benefits of spinning Sunwing out as a stand-alone company. Of course, predicting the timing or certainty of such an event is impossible.

Financial Liquidity & Possible Sources of Funds - Think Creatively

Need financing before year-end 2011 – The company has ~$90 million of cash at the end of the third quarter. Based on current spending plans of $10 million to $20 million per quarter, we see it exhausting its current liquidity by the end of 2011. Any acceleration of spending plans at Zitong or in Ecuador could accelerate the need for capital. We expect the company to begin seeking financing opportunities by mid-2011 or earlier.

China spinout? – Success in China could result in demand for up to $250 million, which would not necessarily all need to be raised at once. However, success in China may also be the right catalyst to cause Ivanhoe to spin Sunwing out as an independent company, thereby also resolving a significant part of its strategic focus.

Tamarack joint venture? – Development of Tamarack could result in demand for up to $1.25 billion in capital. That assumes a fully integrated development at 100% W.I. Capital requirements for an SAGD-only project would be closer to $500 million to $700 million. While we do not anticipate it near term, the company could sell part of its working interest at Tamarack, thereby raising funds and reducing its net financial commitment significantly. For instance, the sale of 40% of Tamarack at $1/bbl of Contingent Resource would raise ~$180 million and reduce the SAGD only capital commitment from ~$600 million to ~$360 million. Netting off the proceeds from the sale would reduce Ivanhoe's financing commitment by 70% from ~$600 million to ~$180 million by only reducing its working interest by 40% from 100% to 60%.

Valuation

Relative Valuation

Largely because Tamarack has entered into the regulatory process, we see strong asset value support for Ivanhoe Energy, which is currently trading at a ~75% P/NAV ratio (Base) and a ~53% P/NAV ratio (Unrisked), compared to peer group average valuations of 86% and 49%, respectively. Risked exploration success at Zitong, China, also comprises a significant amount of our Base and Unrisked NAV.

Tamarack worth more without HTL – Our Base NAV reflects value for Tamarack, without HTL, risked at 75% as the project just entered into the regulatory process that is expected to take 18 to 24 months. We have also included a risked value for Zitong because we believe early indications have been encouraging based on the Yixin 1 well, uphole natural gas shows at Zitong 1 in the Xu-5 and Xu-4 zones, and the overall geological and geophysical setting of the wells.

As demonstrated on a per barrel basis above, the use of HTL in the current economic environment has a negative value per barrel. This same result was evidenced through the NAV calculation, which increased by about 13% as a result of removing HTL. As such, we represent NAV on the basis of a non-integrated SAGD project without upgrading.

We calculate a value of $1.59/share for the company's 100% W.I. at Tamarack Phase 1, $1.05/share for its 100% W.I. at Tamarack Phase 2 (compared to a value of $1.39/share for Phase 1 and $0.70/share for Phase 2 including HTL) and $0.57/share for its operations in China (mainly comprised of a 50% risked value for exploration upside potential at Zitong). Our 12-month target price of $3.00/share is based on a 0.9x multiple of our base NAV analysis, which is slightly below the peer group average of 1.0x Base NAV due to the speculative nature of the company's exploration program.

Exhibit 95: Ivanhoe - NAV Summary

					Base NAV				Unrisked NAV		
Project	Reserve / Resource Est. mmbboe	Project PV $mm	Implied PV/Bbl $/bbl	W.I. %	Risk Factor %	$mm	$/share	% NAV	$mm	$/share	% NAV
Tamarack Excl. HTL											
Phase 1 (Application)	221	$796	$3.61	100%	75%	$597	$1.59	49%	$796	$2.12	46%
Phase 2 (Application)	221	$528	$2.40	100%	75%	$396	$1.05	33%	$528	$1.41	31%
Total Oil Sands	**441**	**$2,143**	**$4.86**			**$993**	**$2.64**	**82%**	**$1,324**	**$3.52**	**77%**
Conventional											
Dagang (Producing)	1.4	$39	$28.66		100%	$39	$0.10	3%	$39	$0.10	2%
Zitong (Exploration)	133.3	$346	$2.60		50%	$173	$0.46	14%	$346	$0.92	20%
Total Conventional	**134.7**	**$385**	**$2.86**			**$212**	**$0.57**	**17%**	**$385**	**$1.03**	**22%**
Corporate Adjustments											
Net Working Capital						$49	$0.13	4%	$49	$0.13	3%
Long Term Debt						($40)	($0.11)	-3%	($40)	($0.11)	-2%
Total Corporate						**$8**	**$0.02**	**1%**	**$8**	**$0.02**	**0%**
Net Asset Value						**$1,214**	**$3.23**	**100%**	**$1,718**	**$4.57**	**100%**

Risk Factors:

100% of DCF value given to producing projects and projects that have received regulatory approval
75% of DCF value given to projects in the regulatory application process
50% of DCF value given to projects in the exploration phase

Assumptions:

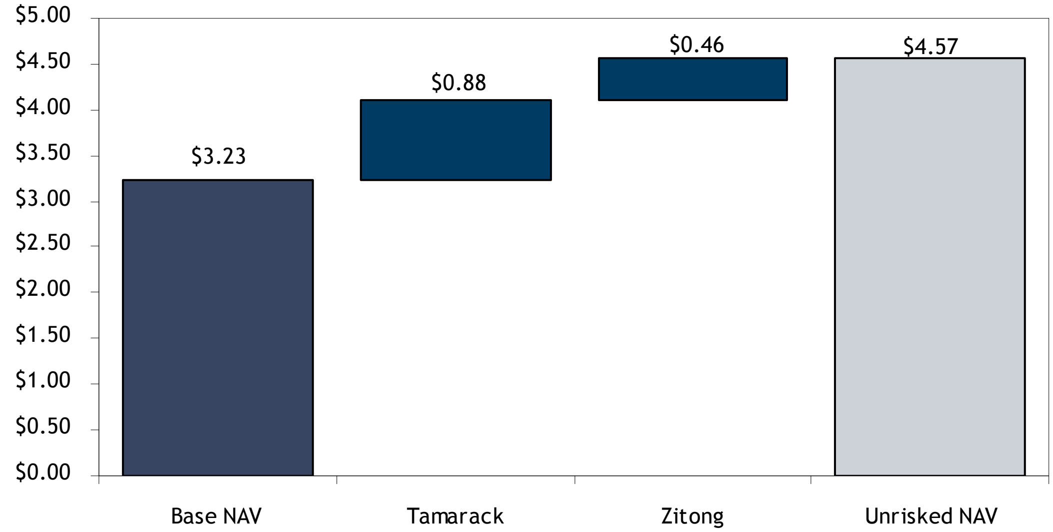
WTI crude oil assumptions: US$78.02, US$83.00, US$85.00 for 2010E, 2011E and 2012E forward, respectively
Henry Hub natural gas assumptions: US$4.54, US$5.00, US$5.50 for 2010E, 2011E and 2012E forward, respectively
US/CAD foreign exchange assumptions: $0.96, $0.95, $0.95 for 2010E, 2011E and 2012E forward, respectively
After tax discount rate assumption: 8.5%
Long term operating cost assumptions: $18.00/bbl and $13.00/bbl for conventional and oil sands, respectively

Source: Company reports and RBC Capital Markets estimates

Base vs. Unrisked NAV – Upside Potential Beyond Base NAV by Derisking Projects

We have not assigned any value in our NAV for potential exploration success in Mongolia or Ecuador – Our base NAV for Ivanhoe is predominantly supported by a risked value (75%) for the full development of Tamarack, which supports 88% of our target price. We have also given a risked value for exploration potential at Zitong (mid point of resource estimate of 600–1,000 bcf risked at 50%). We calculate a Base NAV of $3.23/share. **Our $3.00 target price is based on a 0.9x multiple of our Base NAV analysis, which is slightly below the peer group average of 1.0x Base NAV due to the speculative nature of the company's exploration program.**

Exhibit 96: Ivanhoe Upside Potential – Base and Unrisked NAV

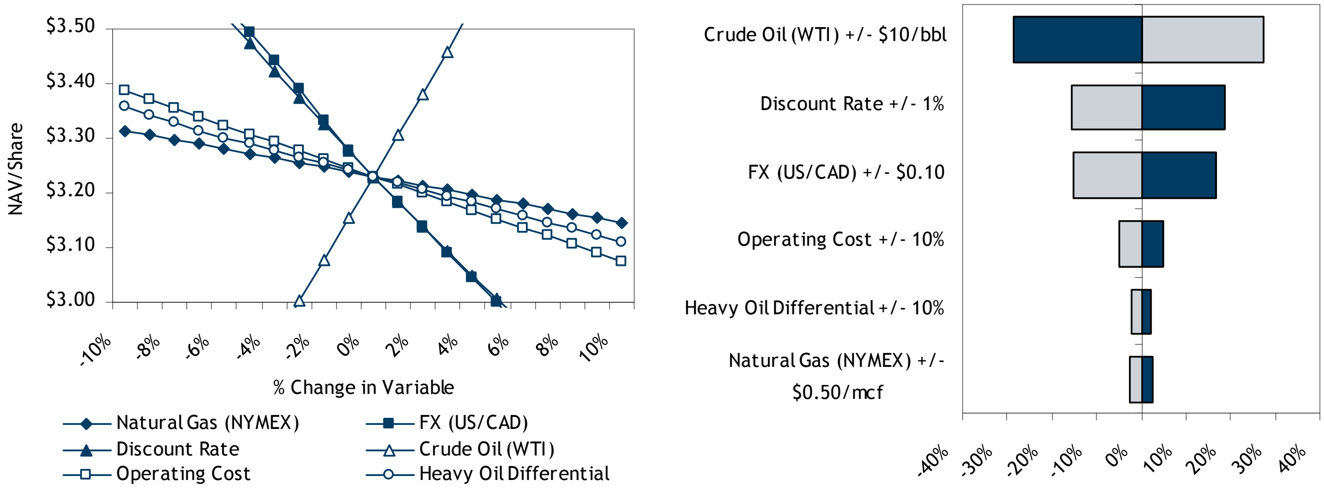


Source: Company reports and RBC Capital Markets estimates

Sensitivities

Ivanhoe's NAV is positively correlated and most sensitive to changes in oil prices – All other variables have a negative correlation to NAV, starting with the discount rate and the foreign exchange rate between the Canadian and US dollars. The price of natural gas, fluctuations in operating costs and even heavy oil differentials do not affect asset value by as much as might be expected, but are still important inputs to performance and value.

Exhibit 97: Ivanhoe - NAV Sensitivity



Source: Company reports and RBC Capital Markets estimates

Risks to Target Price

We assign Ivanhoe Energy a Speculative risk rating. In general, the company is exposed to a higher degree of risk due to the early stage of the regulatory process, international exploration exposure, future project financing requirements, future project execution requirements, and the technical and economic risks surrounding the planned implementation of its HTL technology.

We identify eight key risks to our target price:

1. **Oil Prices** – The vast majority of the company's value is weighted to oil and thus fluctuations in oil prices represent the greatest effect on NAV (see Exhibit 97). We assume a flat oil price of US$85.00/bbl from 2012 onward.
2. **Discount Rates** – We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations of E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk and lower reserve replacement and re-investment (i.e., exploration) risk than E&P companies. However, on the other hand, oil sands companies have greater regulatory, environmental and project-execution risk over the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our target price, materially.
3. **Foreign Exchange Rates** – Capital and operating costs will be incurred in Canadian dollars, yet the company's current and future production is priced in U.S. dollars. Fluctuations of the U.S./Canadian dollar exchange rate can greatly affect the value of future cash flows. We assume a flat US$0.95/C$1.00 exchange rate long term.
4. **Regulatory Risks** – Ivanhoe Energy recently filed its regulatory application for Tamarack, a 40,000 bbl/d In-Situ oil sands project made up of two stages of 20,000 bbl/d. Since Tamarack requires regulatory approval, we have risked the value of the project by 25% in our Base NAV. We have included a value of $1.59/share for Tamarack Phase 1 and a value of $1.05/share for Tamarack Phase 2 in our Base NAV and a value of $2.12/share and $1.41/share in the Unrisked NAV, respectively. The company's growth potential as well as our perception of its value would be affected materially should the regulatory process be delayed or not forthcoming.
5. **Financing Risks** – Capital costs for Tamarack Phase 1 are estimated at $1.2 billion, for an implied capital intensity of $60,000 bbl/d. The company effectively has to secure all of its financing, presenting significant financing risk. The company's growth potential as well as our perception of its value would be affected materially should financing be delayed or not

forthcoming. In addition, success inside Sunwing could also create a demand for proceeds in the order of $250 million.

6. **Heavy Oil Differential Risk** – Differentials between light and heavy oil represent the input variable with the greatest sensitivity to value for the HTL facility. As we have not included the HTL facility in our assumption of the Tamarack project, sensitivity to differentials is quite small; however, should HTL be implemented in the future the sensitivity to light/heavy differentials could become a significant risk factor in the valuation of Ivanhoe Energy.
7. **International Exploration Risk –** We have risked estimated resource potential at Zitong by 50%, the approximate exploration success rate in the Sichuan basin. Our risked value for Zitong comprises ~18% of our Base NAV and as such the lack of exploration success there would have a material effect on our valuation of the stock.
8. **Environmental Risks –** Oil sands producers have come under increased scrutiny for environmental issues. While longer-term costs or product-marketing concerns related to environmental issues is unclear at this time, we do not think it presents a risk to the company's development plans or our perception of the valuation of the company. In Canada, we note that Ivanhoe is strictly engaged in the development of In-Situ oil sands, which typically have less effect on land, air and water than oil sands mining projects. We expect that emissions related to Ivanhoe's future production will be comparable to the emissions of the typical oil that is imported into the United States. (see Exhibit 24).

Exhibit 98: Ivanhoe - Operational & Financial Summary

US$ millions, unless noted	2007	2008	2009	2010E	2011E	2012E
Production						
Asia (Dagang and Daqing) (boe/d)	1,325	1,339	1,276	783	825	800
U.S.A. (boe/d)	545	558	158	0	0	0
Equivalent (boe/d)	**1,870**	**1,897**	**1,434**	**783**	**825**	**800**
YOY Production Growth (%)	n.a.	1%	-24%	-45%	5%	-3%
Commodity Prices						
WTI Crude Oil (US$/bbl)	$72.25	$99.50	$61.81	$78.02	$83.00	$85.00
Ed. Par (C$/bbl)	76.05	102.75	66.48	77.69	86.05	88.16
Bow River Heavy (C$/bbl)	50.50	83.00	59.25	68.23	73.30	72.29
Exchange Rate (US$/C$)	0.93	0.94	0.88	0.96	0.95	0.95
Henry Hub - NYMEX (US$/mcf)	6.95	8.85	3.92	4.54	5.00	5.50
AECO (C$/Mcf)	6.60	8.15	3.94	4.05	4.37	4.90
Realized Pricing and Costs						
Revenue ($/bbl)	**$63.94**	**$95.77**	**$52.75**	**$76.77**	**$83.37**	**$85.48**
Operating, Engineering & Support ($/bbl)	(19.57)	(23.09)	(17.77)	(19.83)	(18.00)	(18.00)
Windfall Levy & Production Tax ($/bbl)	(5.81)	(15.30)	(3.31)	(11.24)	(12.09)	(12.39)
Net Operating Revenue ($/bbl)	**38.56**	**57.38**	**31.67**	**45.70**	**53.28**	**55.08**
Consolidated Financials						
Revenue (net of royalties)	$33.0	$68.5	$23.6	$21.7	$25.1	$25.0
Other Income	0.5	0.7	0.0	0.1	0.0	0.0
Business & Technology Development	9.6	6.5	9.5	10.5	10.0	10.0
Operating and G&A	29.4	44.8	31.9	31.1	29.4	31.3
Interest	1.1	1.8	0.9	0.0	0.0	0.0
DD&A	26.5	31.9	19.9	9.2	10.0	10.0
Pre-Tax Income	(39.2)	(33.5)	(45.6)	(26.7)	(24.3)	(26.2)
Current Tax	0.0	0.7	1.8	0.1	0.0	0.0
Deferred Tax	0.0	0.0	(9.6)	(0.0)	0.0	0.0
Net Income	**(39.2)**	**(34.2)**	**(37.7)**	**(26.8)**	**(24.3)**	**(26.2)**
Cash Flow From Operations	**6.0**	**10.9**	**(11.8)**	**(17.5)**	**(12.3)**	**(14.2)**
Capital Expenditures	**31.6**	**25.6**	**26.4**	**86.0**	**58.5**	**584.0**
Per Share Data						
Diluted CFPS ($/Share)	**$0.02**	**$0.04**	**($0.04)**	**($0.05)**	**($0.03)**	**($0.04)**
YOY Diluted CFPS Growth (%)	n.a.	71%	nmf	nmf	nmf	nmf
Diluted EPS ($/Share)	**($0.16)**	**($0.13)**	**($0.22)**	**($0.08)**	**($0.07)**	**($0.07)**
YOY Diluted EPS Growth (%)	n.a.	nmf	nmf	nmf	nmf	nmf
Weighted Avg Diluted Shares O/S (mm)	242.36	258.8	279.7	339.6	358.9	358.9
Financial Leverage						
Net Debt	13.35	6.26	18.62	(16.96)	55.85	656.10
Long Term Debt	9.8	37.9	36.9	38.3	38.3	38.3

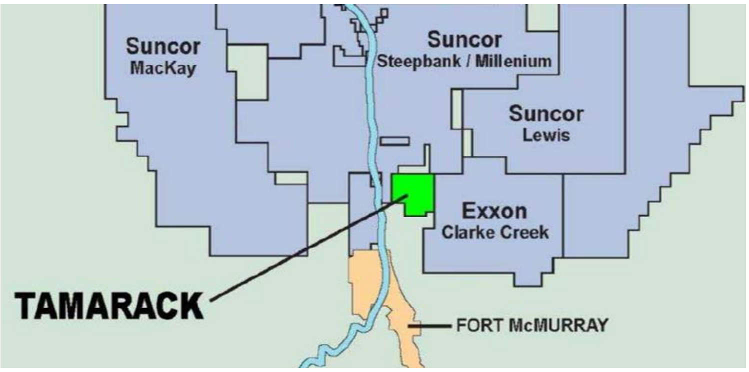
Source: Company reports and RBC Capital Markets estimates

Exhibit 99: Ivanhoe - Company Profile

Business Description

Ivanhoe Energy is an international company focused on heavy oil development and production. The company plans to utilize its proprietary HTL™ technology to access otherwise stranded heavy oil resources. The company's assets are in China, Mongolia, Canada and Ecuador. Ivanhoe Energy has three wholly owned subsidiaries: Ivanhoe Energy Latin America, Ivanhoe Energy MENA (Middle East & North America), and Sunwing Holding Corp. Ivanhoe has a 100% interest in eleven sections of land 16 km northeast of Fort McMurray. The lease has been fully delineated for commercial application, GLJ has assigned 441 mmbbl of best estimate contingent resource to Ivanhoe at Tamarack.

Ivanhoe Energy Tamarack Lease Map



Recent News

Nov-10	Submits regulatory application for Tamarack
Nov-10	Positive log evaluation results at Zitong
Oct-10	Produces oil from 2nd appraisal well in Ecuador
Aug-10	Commences drilling at Yixin-2 in China
Aug-10	Reaches total depth at second Ecuador well

HTL Technology

Ivanhoe Energy's proprietary, patented heavy oil upgrading technology upgrades the quality of heavy oil and bitumen by producing lighter, more valuable crude oil, along with by-product energy which can be used to generate steam or electricity. The HTL™ Technology has the potential to substantially improve the economics and transportation of heavy oil.

Management Team

Name	Position
Robert Friedland	Executive Co-Chairman & CEO
David Dyck	President & Chief Operating Officer
Gerald Schiefelbein	Chief Financial Officer
Ian Barnett	Executive Vice President, Corporate Development
Grag Phaneuf	Senior Vice President, Corporate Development
Michael Silverman	Executive Vice President & Chief Technology Officer
Ed Veith	Executive Vice President, Upstream
Patrick Chua	Executive Vice President
Gerald Moench	Executive Vice President
David Martin	Chairman, President & CEO, I.E. Latin America Inc.

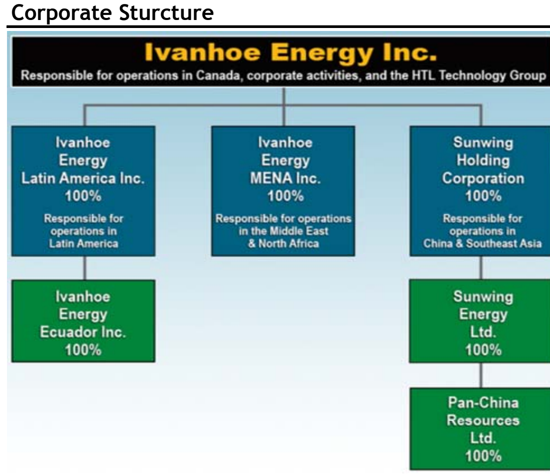
Heavy Oil Implementation Strategy

1. **Execute** on the two initial HTL projects (Tamarack and Pungarayacu)
2. Capture **additional projects.**
3. **Advance the technology** through the first commercial application.
4. **Finance initial projects** with a combination of partnerships and financing.
5. **Build internal capabilities** and execution teams in order to execute projects.

Board of Directors

Name	Experience
Robert M. Friedland (Co-Chairman)	International Financier associated with resource and technology
A. Robert Abboud (Co-Chairman)	President and COO of Occidental Petroleum Corporation
Howard Balloch	Canada's ambassador to China, Mongolia and North Korea
Carlos A. Cabrera	Chairman, President and CEO of UOP, a Honeywell company
Brian Downey	President and CEO of Credit Union Central of Canada
Robert Graham	Chairman of Ensyn Corporation
Peter Meredith	CFO, Ivanhoe Capital Corp.
Alex Molyneux	Head of Metals and Mining Investment Banking for Citigroup
Robert Pirraglia	Chief Operating Officer and Director of Ensyn Corporation

Corporate Sturcture



Source: Company reports and RBC Capital Markets

Exhibit 100: Ivanhoe - Financial Profile

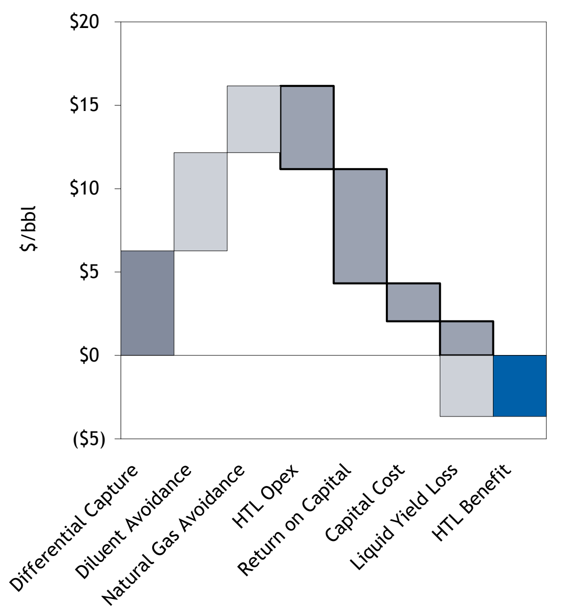
Insider Ownership

Management	Shares (m)	Options (m)	Total (m)	%of FD
Robert M. Friedland	49,212	5,700	54,912	14.6%
David Martin	2,461	380	2,841	0.8%
David Dyck	360	790	1,150	0.3%
Ian Barnett	190	650	840	0.2%
Michael Silverman	13	780	793	0.2%
Ed Veith	50	651	700	0.2%
Gerald Moench	112	430	542	0.1%
Patrick Chua	94	310	404	0.1%
Gerald Schiefelbein	-	330	330	0.1%
Total Management	**52,492**	**10,021**	**62,513**	**16.6%**

Directors	Shares (m)	Options (m)	Total (m)	%of FD
Robert Graham	4,497	400	4,897	1.3%
A. Robert Abboud	650	580	1,230	0.3%
Robert Pirraglia	309	250	559	0.1%
Peter Meredith	38	411	448	0.1%
Brian Downey	100	220	320	0.1%
Howard Balloch	50	250	300	0.1%
Carlos A. Cabrera	-	300	300	0.1%
Alex Molyneux	-	180	180	0.0%
Total Directors	**5,643**	**2,591**	**8,234**	**2.2%**
Total	**58,135**	**12,612**	**70,747**	**18.8%**

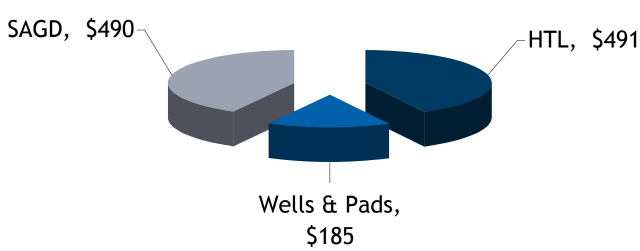
At Sep 30 2010, 14.8 million options were outstanding at a weighted average exercise price of $2.28

Theoretical HTL Benefit



Assumptions: US$85 WTI, US$4 NYMEX natural gas, 18% heavy oil differential $500 mm HTL capital cost, diluent premium 103% of WTI, 9% liquid yield loss

Tamarack Phase 1 Capital Speding Estimate ($mm)



Selected Financing History

Type	Date	# Shares (mm)	Share Price	Amount ($mm)
Common	Apr-06	11.4	$2.23	$25.4
Loan*	Apr-08	2.3	$2.24	$5.13
Common	Jan-10	$41.7	$3.00	$125.0
Associated Warrants				
Warrants	Apr-06	11.4	$2.63	$30.0
Warrants	Jul-08	$29.3	$3.00	$88.0
Warrants	Jan-10	$10.4	$3.16	$32.9
Warrants	Feb-10	$8.3	$3.00	$25.0

*Convertibe loan, excercised in August 2008 at $2.24 per share

Operating & Financial Data

Production		Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Q1 10	Q2 10	Q3 10
Oil & Liquids	(bbl/d)	1,895	2,095	1,405	1,403	845	804	869	610
Realized Pricing	(US$/bbl)	$75.62	$40.83	$46.99	$61.34	$76.88	$76.63	$76.46	$74.41

Financials		Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Q1 10	Q2 10	Q3 10
Operating Cash Flow	(US$mm)	$3.0	($4.0)	$1.1	($1.3)	($7.6)	($4.0)	($3.5)	($6.1)
Diluted CFPS	(US$/share)	$0.01	($0.01)	$0.00	($0.00)	($0.03)	($0.01)	($0.01)	($0.02)
Net Income	(US$mm)	($14.0)	($12.3)	($11.4)	($2.8)	($11.2)	($2.6)	($10.2)	($7.2)
Diluted EPS	(US$/share)	($0.05)	($0.04)	($0.04)	($0.09)	($0.05)	($0.01)	($0.03)	($0.02)
Capital Spending	(US$mm)	$8.6	$5.5	$7.1	($27.9)	$9.0	$25.7	$15.7	$20.9
Capex/CF	(x)	2.9 x	nmf	6.4 x	nmf	nmf	nmf	nmf	nmf
Net Debt	(US$mm)	$6.3	$16.0	$1.8	$2.7	$18.6	($94.3)	($71.7)	($46.3)
Net Debt/CF	(x)	2.1 x	nmf	1.7 x	nmf	nmf	nmf	nmf	nmf

Source: Company reports, SEDI and RBC Capital Markets estimates

MEG Energy Corp. (TSX: MEG; $39.00)

First-Round Draft Pick

Market Statistics		
Rating		Outperform
Risk		Above Average
Target Price	($)	$48.00
Market Price	($)	$39.00
Implied Return	(%)	23%
Capitalization		
Diluted Shares O/S	(mm)	189.5
Market Capitalization	($mm)	$7,389.6
Net Debt	($mm)	($397.3)
Enterprise Value	($mm)	$6,992.3

Net Asset Value		Base	Unrisked
Net Asset Value	($mm)	$9,580	$13,566
NAV/Sh	($/share)	$47.15	$66.76
P/NAV	(%)	83%	58%
Target Price/NAV	(%)	102%	72%
Resources			
Oil Sands EV[(a)]	($mm)		$6,992.3
2P Reserves	(mmbbl)		1,691
Contingent Resources[(b)]	(mmbbl)		3,724
EV/Bbl[(c)]	($/bbl)		$1.29

Operating & Financial		2007A	2008A	2009A	2010E	2011E	2012E
Total Production	(boe/d)	n.a.	1,323	3,467	20,581	25,000	23,743
Operating Cash Flow	($mm)	$3.0	($12.5)	($62.2)	$114.9	$248.1	$201.2
Diluted CFPS	($/share)	$0.03	($0.10)	($0.45)	$0.64	$1.31	$1.06
Sensitivity to WTI	**(US$/bbl)**	**$60**	**$70**	**$80**	**$90**	**$100**	**$110**
NAV/Share	($/share)	$21.36	$32.03	$42.22	$52.01	$61.04	$69.75
P/NAV	(%)	183%	122%	92%	75%	64%	56%

(a) Adjusted to exclude the estimated value of non- oil sands assets
(b) Best estimate
(c) Based on 2P reserves + best estimate Contingent Resources

Source: Company reports and RBC Capital Markets estimates

Investment Highlights

- **100% exposure to top quality growth** – MEG has embarked on a remarkable growth trajectory that could see the company increase production to more than 300,000 bbl/d by the end of this decade. The company operates and holds a 100% working interest (W.I.) in all of its leases, which we believe are top quartile in terms of reservoir quality across the industry.
- **Excellent operational performance** – Current production of 26,000–27,000 bbl/d exceeds design capacity of 25,000 bbl/d, which we believe reflects the superior quality of the reservoir and the robust design of the facilities. MEG has recently realized average project SORs of 2.3x, which is well below design capacity of 2.8x and an industry average of 3.8x for similar vintage projects. Results indicate that MEG's Christina Lake is one of the stronger performing projects in the industry.
- **Long-term cost advantage of approximately $10/bbl** – MEG enjoys a cost advantage due to lower energy costs (i.e., better SOR), Access pipeline (less expensive diluent and transportation) and co-gen power sales. In our opinion, the advantage will become evident as operating costs and price realizations improve.
- **Catalyst rich** – Before year-end 2010, we expect MEG to receive regulatory approval at Christina Lake Phase 3 (150,000 bbl/d). We expect construction of Christina Lake Phase 2B (35,000 bbl/d) to begin in early 2011, May River core hole drilling results by Q3/11 and for the company to make its regulatory filing for Surmont (100,000 bbl/d) before year-end 2011.
- **Fully financed growth** – MEG has more than $2 billion of liquidity to finance the 35,000 bbl/d Phase 2B expansion with a total estimated capital cost of about $1.4 billion.
- **Strong valuation support** – We see strong NAV support for MEG, which is currently trading at P/NAV (Base) ratio of 83% and a P/NAV (Unrisked) ratio of 58%. We calculate a Base NAV of $47.15/share and an Unrisked NAV of $66.76/share.
- **Recommendation** – Outperform, Above Average Risk, 12-month Target Price of $48.00/share, which we based on 1.0x our Base NAV, which is in line with the peer group average.

RBC Capital Markets®

Summary & Investment Thesis

We initiate coverage of MEG Energy Corp. (MEG – TSX) with an Outperform, Above Average risk rating and a 12-month target price of $48.00/share, which we base on 1.0x our risked NAV analysis, which is in line with the peer group average.

In our opinion, MEG has positioned itself with top-quartile assets, demonstrated project execution and top-quartile operational performance to become a leading oil sands success story. We are excited by the company's captured production-growth prospects that have the potential to increase the corporate production more than tenfold during the next decade. We believe that investors should be attracted by strong production results and a long-term competitive cost advantage of approximately $10/bbl. The cost advantage, in our opinion, should become increasingly evident in financial results as the company begins to realize improved price realizations with higher marketed volumes of Access blend and with lower operating costs as a function of greater economies of scale.

MEG has a focused strategy that we believe should appeal to investors. Management has directed investment in the Athabasca oil sands region, and the company is using proven steam assisted gravity drainage (SAGD) technology in the highest-quality reservoirs. The company is not applying any unique extraction technologies and will not include any upgrading to its current or future projects.

MEG's Christina Lake is a top-quartile project as measured across the entire In-Situ industry (see Exhibit 31 & 32). Performance of Phase 2A indicates that the project is producing from a top-quality reservoir and through a robust facility. We also see continued value creation growth as management continues to advance projects through the regulatory and development stages. In the near term, we see modest year-over-year production growth into 2011 because production should sustain full-design rates during the entire calendar year compared to 2010, which was a ramp year that included a facility turnaround in September. Production, however, is expected to be fairly flat with current rates during the next two and a half years until the start up of Phase 2B. We expect the next stage of production growth beginning in mid 2013.

MEG has built a competitive advantage worth about $10/bbl. We estimate that the Access pipeline provides a competitive advantage of approximately $5/bbl due to reduced diluent costs and lower transportation costs. We estimate the benefit of power sales from the co-generation facility at approximately $3/bbl and the benefit of the company's low SOR to be around $2/bbl.

Longer term, we expect MEG to be capable of achieving significant production growth from current levels of 25,000 bbl/d. The 35,000 bbl/d Phase 2B has been de-risked with regulatory approval and by management securing financing. Growth beyond 60,000 bbl/d to the stated capacity of more than 310,000 bbl/d is dependent on regulatory approvals, additional financing and project execution.

The company has established itself in the capital markets with a strong IPO in August 2010. After initial weakness, the stock has regained strength to now trade above its issue price of $35.00/share. We believe the market liquidity of the shares potentially to double following the expiry of the lock-up agreement around February 7, 2011. We expect Warburg Pincus and CNOOC to remain substantial shareholders at 23% and 15% holdings, respectively, and thereby somewhat impairing trading liquidity for the longer term.

We see strong asset value support for the current trading price of MEG and significant upside potential to our Base NAV if we un-risk the components of our valuation. MEG enjoys the best performance on existing operations, the largest market capitalization and the highest debt rating in this oil sands peer group. While the stock still experiences limited stock market trading liquidity on a consistent basis, we expect that to also improve early in 2011.

Exhibit 101: MEG - Pros & Cons

Pros	Cons
Growth Potential - 35,000 bbl/d expansion underway will more than double current production	**Lack of Stock Market Liquidity** - Share lock up post IPO has resulted in low market liquidity in near term
Top Quartile Project - at Christina Lake demonstrated by performance	**Top Gas** - at Christina Lake, Surmont, May River & Thornbury
Largest Market Capitalization - in this peer group should make MEG of interest to broader investor base	**Hedging Policy** - Possible revenue volatility due to power sales and no hedge policy
Access Pipeline System & Sturgeon Terminal - secures diluent import, dill-bit export and maximized price realizations	**Closely Held** - Concentrated shareholder base may result in low market liquidity longer term
Expansion Plans Underway - Significant expansion upside (150,000 bbls/d) already in regulatory process	**Full Capacity** - Production fairly flat from now until Phase 2B start up mid-2013
Existing Production - Meaningful existing production and cash flow	
Cash Flow - Strong positive CFPS growth into 2011E	
Debt Rating - Strongest debt rating in the group	
Valuation Support - Strong NAV support with significant upside potential	
Ownership - 100% WI in all projects	
Fully Financed - Fully financed for next expansion	
Co-Gen - secures power supply; generates excess revenue, GHG credits	

Source: Company reports and RBC Capital Markets

Potential Catalysts

We highlight the important near-term catalyst events to watch for during the coming quarters:

- Construction of the 35,000 bbl/d expansion of Christina Lake Phase 2B to begin in early 2011 with first steam expected in early to mid 2013.
- Christina Lake Phase 3 regulatory approval for the full 150,000 bbl/d expansion by mid 2011.
- May River winter core hole drilling results by the third quarter of 2011.
- We expect MEG to make its regulatory filing for the 100,000 bbl/d Surmont project by year end 2011.

On more of an operational note, we expect the company to complete its 900,000 barrel Stonefell tank farm, near the company's Sturgeon terminal. We expect that the company will require an additional winter drilling season in order to prepare its May River project regulatory application.

Mid to longer-term, the company should continue to have several catalysts every year as it continues to develop its multi-staged projects until the end of this decade and beyond. The effect of moving these projects ahead directly affects our valuation of the company because projects become increasingly de-risked, and the company continues to move projects through the regulatory and development phases closer to first production and cash flow.

Exhibit 102: MEG - Upcoming Catalysts

2011E	2012E	2013E+
Q1 - Winter core hole drilling at Greater May River Area (initiated in Q4 2010)	Q1 - Winter core hole drilling at Greater May River Area (initiated in Q4 2011)	2013 - Commissioning, first steam at Christina Lake Phase 2B
Q1 - Construction of Christina Lake Phase 2B begins	Q2 - Preliminary costs estimate for Christina Lake Phase 3A	2016 - Commissioning, first steam at Christina Lake Phase 3A
Q1 - Completion of 900,000 bbl Stonefell tank farm (50% WI) near Sturgeon Terminal	Q3 - Results of winter drilling program	2018 - Commissioning, first steam at Christina Lake Phase 3B
Q3 - Results of winter drilling program	Q3 - Plant and cogen turnaround at Christina Lake (duration three weeks; cost $5 million)	2018 - Commissioning, first steam at Surmont Phase 1
Q3 - Expected regulatory approval for Christina Lake Phase 3 (150,000 bbl/d)	Q4 - Expected regulatory application for commercial project in the Greater May River Area	2020 - Commissioning, first steam at Christina Lake Phase 3C
Q3 - Expected filing of regulatory application for 100,000 bbl/d Surmont Project (First Phase 50,000 bbl/d)		Long Term - Potential expansion of Access pipeline
Q4 - Final winter core hole drilling at Greater May River Area		Long Term - Infill drilling at Christina Lake (piloting could start as early as 2012)

Source: Company reports and RBC Capital Markets estimates

Company Overview

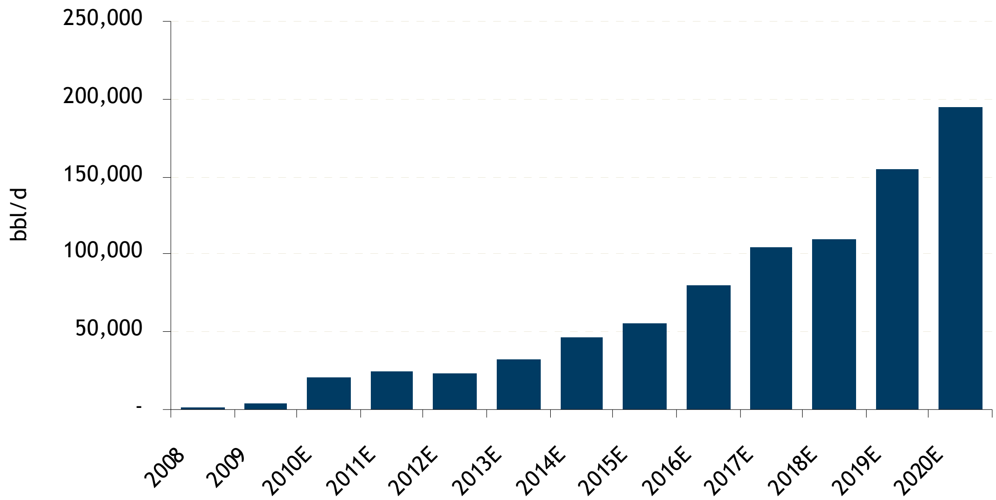
IPO, Asset & Project Summary

Shares of MEG began trading on the Toronto Stock Exchange on August 6, 2010 following the company's initial public offering. The company issued 20 million shares at $35.00/share for gross proceeds of $700 million ($666 million net of issuance costs).

MEG is pure-play, upstream, oil sands company focused on In-Situ development of bitumen from the Athabasca region of northern Alberta. The company holds a 100% W.I. in its 537,600 acres of oil sands leases, which have not yet been fully delineated, but currently have 5.414 billion barrels of proved reserves (2P) reserves and Best Estimate Contingent Resources assigned to them by GLJ (see Exhibit 116).

The company has developed Phase 1 and Phase 2A of its Christina Lake lease with designed production capacity of 25,000 bbl/d. In early 2011, the company is scheduled to begin construction of Christina Lake Phase 2B, which is designed to add an incremental 35,000 bbl/d of production capacity with first production scheduled for mid 2013. In addition to its 100% W.I. in multiple stages of future growth at Christina Lake with full build out capacity of 210,000 bbl/d, MEG holds a 100% W.I. in its Surmont project, which is estimated to have full build out capacity of 100,000 bbl/d. MEG also holds a 100% W.I. in exploration leases that have yet to be fully delineated. In addition, MEG holds a 50% W.I. in the Access Pipeline system, which ships diluent to the lease and transports the company's dilbit to market.

Exhibit 103: MEG Production Forecast



Source: RBC Capital Markets estimates

Christina Lake – A Top-Quartile Project

The company has developed Phase 1 (3,000 bbl/d) with three initial well pairs that started producing in 2008. Three additional well pairs were drilled at Phase 1 Pad A at the same time that the company drilled the wells at Phase 2A. Phase 2A (22,000 bbl/d) started producing with 29 well pairs on its 100% owned Christina Lake lease in late 2009. Well pairs generally achieved communication with steam injectivity within two months of first steam and were generally on production within three months of first steam. Most well pairs were converted to ESP from gas lift within a few months of production start up, which allowed for reduced operating pressures and lower SORs. Currently, 24 of 29 well pairs have been converted to produce with an ESP.

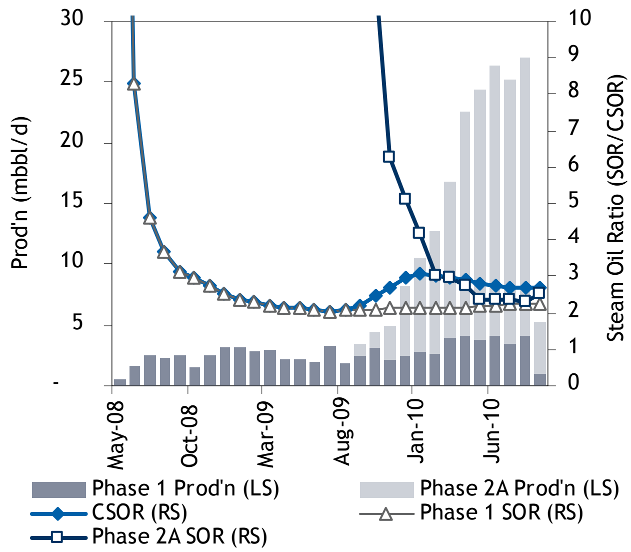
Phase 1 & 2A Demonstrating Excellent Performance & Cost Advantage

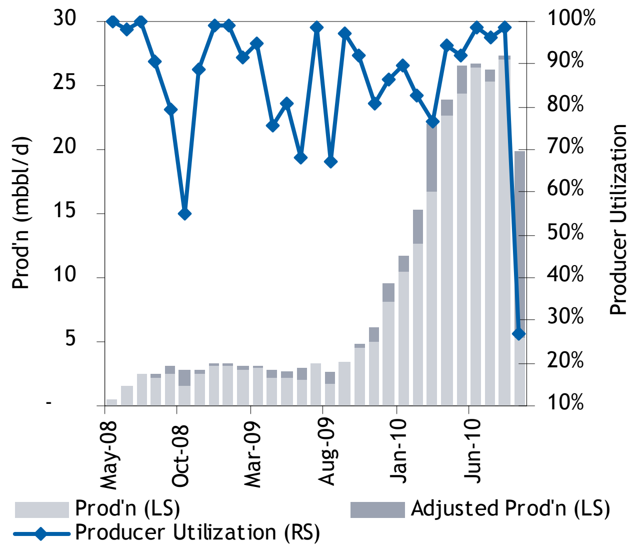
We see evidence of a top-quality reservoir and robust facility design in strong operational performance – MEG has sustained production rates in the 26,000–27,000 bbl/d range with an average project SOR of 2.3x compared to the design capacity of these first two phases of 25,000 bbl/d and a facility design SOR capacity of 2.8x. We recognize that MEG's Christina Lake is one of the stronger projects in the industry, as measured by the rapid-production response and low SOR. MEG completed its first-planned SAGD facility turnaround in September. We expect turnarounds to occur every two years with the next turn around in the third quarter of 2012. The typical turnaround should take three to four weeks at a cost of approximately $5 million.

$2/bbl cost advantage due to low SOR – The average industry SOR for a project at 12–24 months of production history is approximately 3.8x. The significance of having an SOR of 2.3x as opposed to 3.8x represents a lower natural gas cost (about 0.5 mcf/bbl advantage), improved capital efficiency (discussed below) and a lower environmental footprint in terms of water usage and emissions (see Exhibit 24).

$3/bbl cost advantage due to co-gen power sales – Uninterrupted power supply from the company's co-gen facility has also contributed to strong utilization rates that have averaged in the greater than 90% range for most of the past 12 to 18 months. Power sales, which MEG nets off of operating costs, provides a cost advantage of approximately $3/bbl.

Exhibit 104: Christina Lake - Efficiency & Utilization





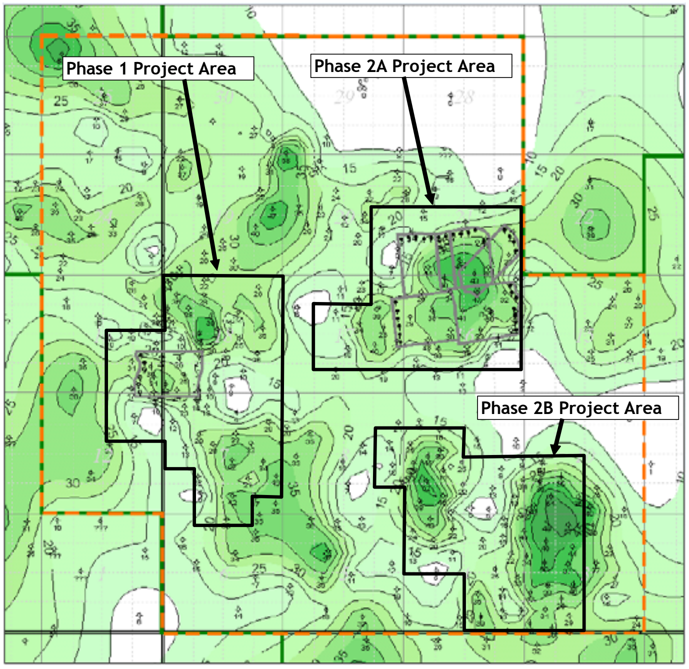
Source: Accumap and RBC Capital Markets

Phase 2B Expansion - Double Production by 2013

The Phase 2B expansion has received all regulatory approvals and is set to add 35,000 bbl/d of production in mid 2013, thereby more than doubling existing design capacity and providing NAV support (see Exhibit 112)**.**

At MEG's Christina Lake, the McMurray formation is found at an average depth of 360 metres with an average reservoir thickness of 20 metres (10–56 metre range). Limited bottom water zones exist; however, they are manageable with good production techniques. On occasion, pressure-depleted top-gas pools in contact with the McMurray are also present, yet these zones are not present in the Phase 2A or Phase 2B development areas. The Energy Resources Conservation Board (ERCB) ordered natural gas production from these pools shut-in in 2004. Some of these depleted natural gas pools will require repressurization. Given the performance of Phase 1 and Phase 2A, management's approach to facility design along with the company's extensive evaluation of the remainder of its Christina Lake lease with 527 vertical well penetrations of the reservoir including 454 core holes, **we expect Phase 2B to perform in line with Phase 2A results.**

Exhibit 105: Christina Lake Net Pay ≥10m



Source: Company reports and RBC Capital Markets

Capital Intensity – Comparable When Normalized

We find that MEG's capital cost intensity adjusted to a per flowing barrel basis is comparable to average industry costs. Construction of this $1.4 billion project is set to begin in early 2011 at an implied capital cost intensity of $40,000 bbl/d, which is higher than other SAGD projects across the sector, which are priced in the $25,000–35,000 bbl/d range. While MEG has incurred higher capital cost intensity on stated name plate capacity than other projects across industry the benefits of the incremental investment is clearly demonstrated by stronger operational performance. We recognize that the reason for the higher capital cost is that the facility has essentially been overbuilt with respect to expected long-term steam generation requirements and includes incremental infrastructure such as a co-generation facility. The co-generation facility could increase the capital intensity by $6,000–10,000 bbl/d. Adjusting capital intensity based on performance normalizes capital cost intensity.

Exhibit 106: Name Plate vs. Adjusted Capital Intensity

Capital Intensity @ Name Plate Capacity	$25,000	$30,000	$35,000	$40,000
Production Rate as a % of Name Plate Capacity	75%	85%	100%	110%
Adjusted Capital Intensity @ Production Rate	$33,333	$35,294	$35,000	$36,364

Source: RBC Capital Markets

We believe that management's decisions regarding facility design has been a contributing factor to its strong overall operational performance. We expect management to apply the same design philosophy of excess steam generation capacity to Phase 2B as was successfully used in Phase 1 and Phase 2A. Excess steam capacity is often required to initiate production, because both producer and injector wells initially receive steam injection to stimulate the reservoir. If steam generation capacity is limited at the stimulation phase, overall production rate builds at a slower pace, and, depending on reservoir response, under-built steam generation capacity is often to blame for production rates that grow slowly or sometimes never reach name plate design capacity. While capital intensity is higher to build excess steam capacity, the extra steam not only aids with a quick production ramp up but also, following ramp up, spare steam can be directed to additional well pairs to increase the total overall rate. Oil processing facilities can be fairly easily debottlenecked above name plate capacity to handle increased bitumen production. Alternatively, total steam generation could be dialled back to the point that the facility has redundancy in its steam capacity thereby ultimately resulting in higher overall facility utilization.

Phase 3 – Potential to Increase Production to 210,000 bbl/d by 2020

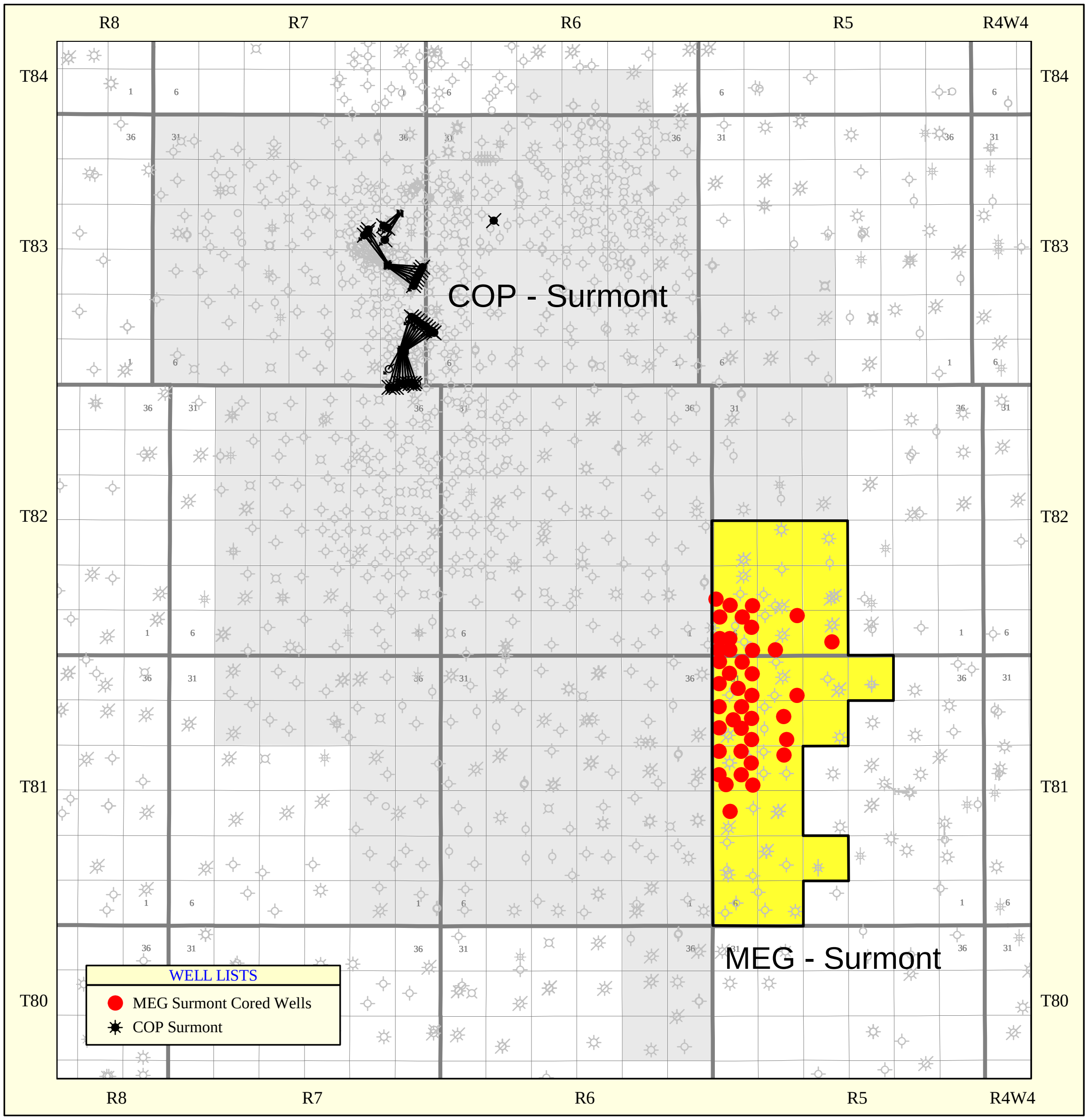
Beginning in 2016, Phase 3 of MEG's Christina Lake is expected to add an additional 150,000 bbl/d of production in three phases of 50,000 bbl/d. Phase 3A is scheduled for first steam in 2016, Phase 3B is scheduled for first steam in 2018 and Phase 3C is scheduled for first steam in 2020. The regulatory application for all three stages of Phase 3 was filed in mid 2008, which we expect to receive regulatory approval in late 2010 or early 2011. MEG has 1.691 billion barrels of 2P and 1.355 billion barrels of Contingent Resources (Best Estimate) booked at Christina Lake, which we calculate would be enough resource to support full-scale production at Christina Lake of 210,000 bbl/d for 40 years.

Surmont – Growth to 310,000 bbl/d from 210,000 bbl/d

MEG is currently completing its regulatory application to develop 100,000 bbl/d of production at Surmont, which it intends to file before year end 2011. The company intends to develop Surmont with two phases of 50,000 bbl/d. The lease area has been assigned 647 million barrels of Contingent Resources (Best Estimate) by GLJ, which could be enough to support Phase 1 development for 30–35 years and full-scale (Phase 1 and 2) development for 15-17 years. It is reasonable to expect first production at MEG's Surmont in 2018 with Phase 2 to follow two to three years later.

MEG's Surmont lease is located approximately 50 km north of its Christina Lake lease. The McMurray formation at Surmont has an average reservoir depth of about 230 metres with an average thickness of 27 metres. Significant overbearing Clearwater shale cap rock should provide sufficient seal for SAGD development. Some areas of the lease have bottom water; however, management considers any presence of bottom water to be manageable with existing production practices. Of greater relevance, in our view, is the presence of pressure-depleted top-gas pools that are in direct communication with the McMurray formation. Some of these pools at Surmont were ordered shut in by the ERCB in 1999. Where MEG finds depleted gas pools in direct communication with McMurray, repressurization of these pools will be required before production takes place.

Exhibit 107: MEG Surmont Lease & Delineation



Source: Accumap and RBC Capital Markets

Growth Properties – Long-Term Growth Beyond 2020

Thinner average reservoir and a greater presence of depleted top-gas pools indicate that these project areas are likely not the company's best assets – MEG has close to half a million acres of oil sands leases located west of its Christina Lake lease. To date, approximately 40% of these lands have been evaluated by GLJ, which has assigned 1.721 billion barrels of Contingent Resources (Best Estimate) to these leases. These assets still need roughly two more winter seasons of evaluation work to be done in order to proceed to the regulatory application stage. We expect a regulatory application for the company's May River leases to be filed no sooner than year-end 2012. We would expect projects from the May River area to provide the third stage of growth beyond Christina Lake and Surmont. In addition to May River, the growth properties include the West Jackfish and Thornbury project areas.

May River partially affected by top gas – At May River, average reservoir depth is 480 metres with an average reservoir thickness of 23 metres (10–40 metre range), with a thick and consistent overbearing Clearwater shale cap rock for pressure containment. Limited bottom water is present but is expected to be manageable. Depressurized top-gas pools in contact with the McMurray formation are present; however, an ERCB ruling resulted in these wells being shut-in from production in 2003. Repressurizing of these partially depleted gas pools would be required in order to pursue production of regions of the May River area.

West Jackfish has thinner average reservoir – At West Jackfish, the McMurray formation is found at an average depth of 430 metres with an average reservoir thickness of 18 metres (10–33 metre range), and a thick and consistent overbearing Clearwater shale cap rock. Limited bottom water exists at West Jackfish, although this is expected to be manageable with proper operating processes. Top gas is not present at West Jackfish.

Thornbury has thinner average reservoir & top gas – At Thornbury, the average depth of the McMurray formation is found at 470 metres with an average reservoir thickness of 16 metres (10–35 metre range) with a consistent overbearing Clearwater shale cap rock present over the lease. Bottom water is present, but appears to be manageable. Depressurized top-gas pools in contact with the McMurray formation are occasionally present at Thornbury, and some of these gas pools are still in production. Repressurization of these depleted gas pools would likely be required to pursue development.

Access Pipeline – A Strategic & Economic Advantage

MEG owns a 50% W.I. (Devon Energy Corp. DVN-N 50% W.I.) in the dedicated Access Pipeline. The Access Pipeline brings diluent to Devon's Jackfish lease and MEG's Christina Lake lease in a 16 inch diluent line from Edmonton. The Access Pipeline also carries the companies' production back to Edmonton in a 24 inch blend line to the company's 50%-owned Sturgeon Terminal located just outside of Edmonton.

The strategic advantages are three fold:

- The company is able to use diluent instead of synthetic oil as blend stock.
- The company is able to source diluent from the Edmonton region and transport it to site.
- The company is also guaranteed export capacity for its production to market.

The economic advantage is three fold:

- Diluent cost advantage that currently approaches $3/bbl of bitumen.
- Transportation cost advantage that currently approaches $2/bbl of bitumen.
- The ability to market the company's dilbit product from the Edmonton region (which has multiple-export options) at the strongest possible price realization. To date, we have not seen this advantage develop, the opposite in fact, but this advantage should continue to mature as Access Blend gains greater market acceptance, which will in part be related to increased production rates from both MEG and Devon Energy.

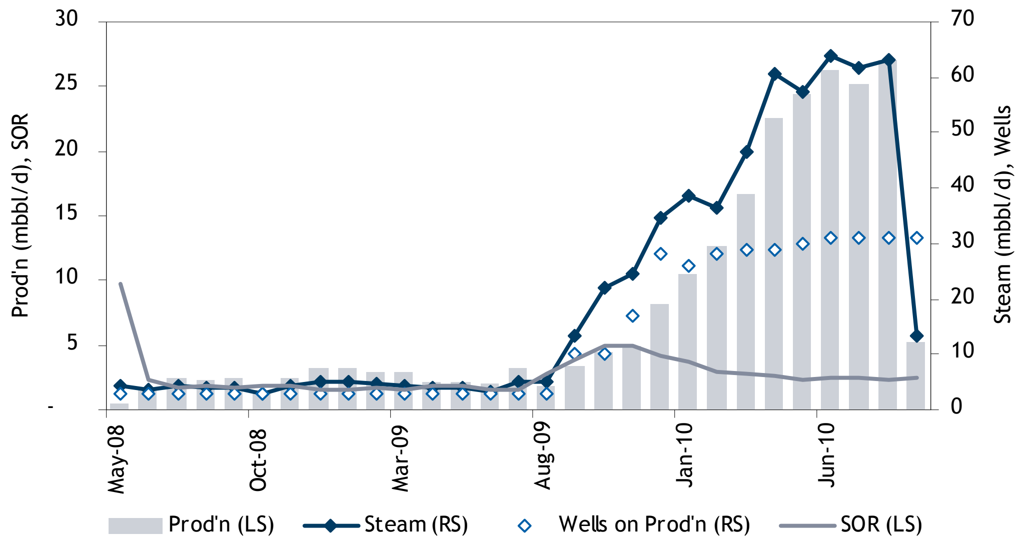
The Access Pipeline has current transportation capacity of 156,000 bbl/d (78,000 bbl/d net to MEG) of dilbit and 70,000 bbl/d of diluent (35,000 bbl/d net to MEG). In other words, current capacity of the Access Pipeline accommodates the Christina Lake Phase 2B expansion. The capacity of the pipeline can be expanded to 394,000 bbl/d (197,000 bbl/d net to MEG) of dilbit and 206,000 bbl/d (103,000 bbl/d net to MEG) of diluent with the addition of pumping stations. MEG expects that the expansion capacity of the Access Pipeline will be sufficient enough to transport planned volumes up to and including Phase 3A. The addition of looping and an additional pipeline along the same right of way should be sufficient to accommodate production from Phases 3B and 3C, from Surmont and possibly even from any future project proposals in the May River area in the company Growth Property leases.

Key Issues

Operational Performance - Best in Class

To date, we believe that MEG's Christina Lake Phases 1 and 2A have been among the better performing SAGD projects in the industry. Operational utilization has been high, and production has ramped up quickly, thereby reaching full-design capacity within nine months of first production with the original design well pair count. In addition, production has ramped up with SOR dropping to 2.3x, which is below the original-design expectations of 2.8x and well below the average SAGD project in the province of Alberta of the same vintage of approximately 3.8x. These metrics easily rank MEG's Christina Lake as a top-quartile project (see Exhibit 31 & 32).

Exhibit 108: Christina Lake – Operational Summary

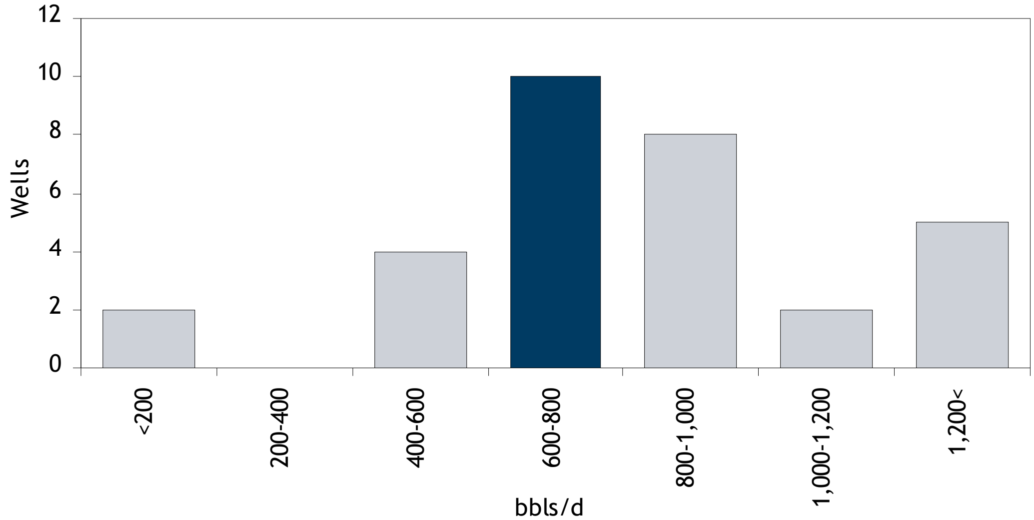


Source: Accumap and RBC Capital Markets

Well Distribution of Performance - The Average Well is a Good Well

Most wells at MEG's Christina Lake project have well exceeded targeted production averages – The distribution of well pair performance is also a strong indicator of the overall robustness of the project. Phases 1 and 2B have 35 well pairs with a combined name plate design capacity of 25,000 bbl/d for an implied average rate per well pair of around 700 bbl/d. With that average requirement in mind, individual well performance at MEG's Christina Lake is also very strong, meaning that essentially all wells are carrying their share of the overall production. The wells indicated as producing at low rates below 200 bbl/d each (see Appendix III) are all new wells that are either still on steam circulation or have just been converted to producers within the past one to two months. Looking at the type curve, wells at MEG's Christina Lake typically take three months to have production rates increase to greater than 200 bbl/d and take six months to reach rates of more than 700 bbl/d, at which point the SOR is below 3.0x (see Exhibit 110). **While production of the type well reaches 1,000 bbl/d nine months after first production, a full 20% of producing wells are currently producing more than 1,000 bbl/d with several in the range of 1,500 bbl/d.**

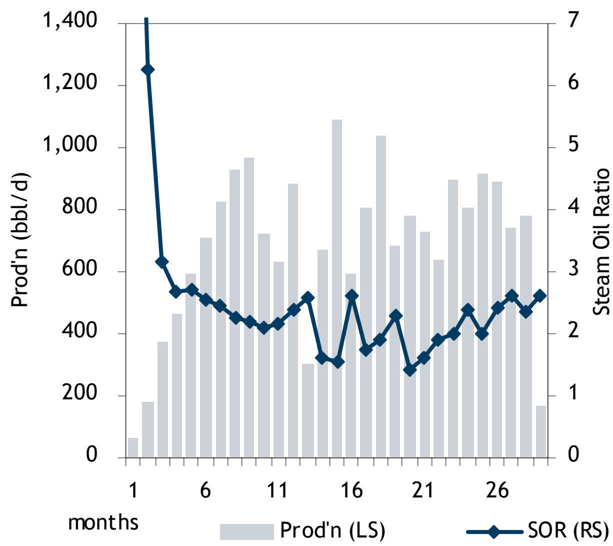
Exhibit 109: Christina Lake – Well Pair Performance Distribution

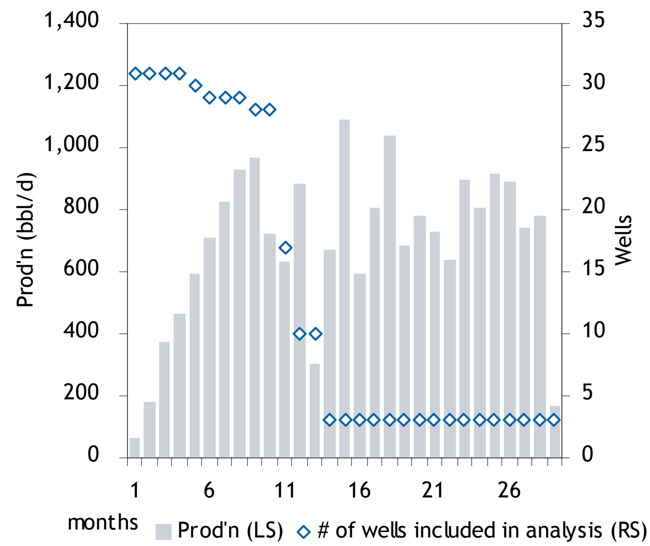


Note: To produce at nameplate capacity each well has to produce 694 bbls/d

Source: Accumap and RBC Capital Markets

Exhibit 110: Christina Lake – Type Well



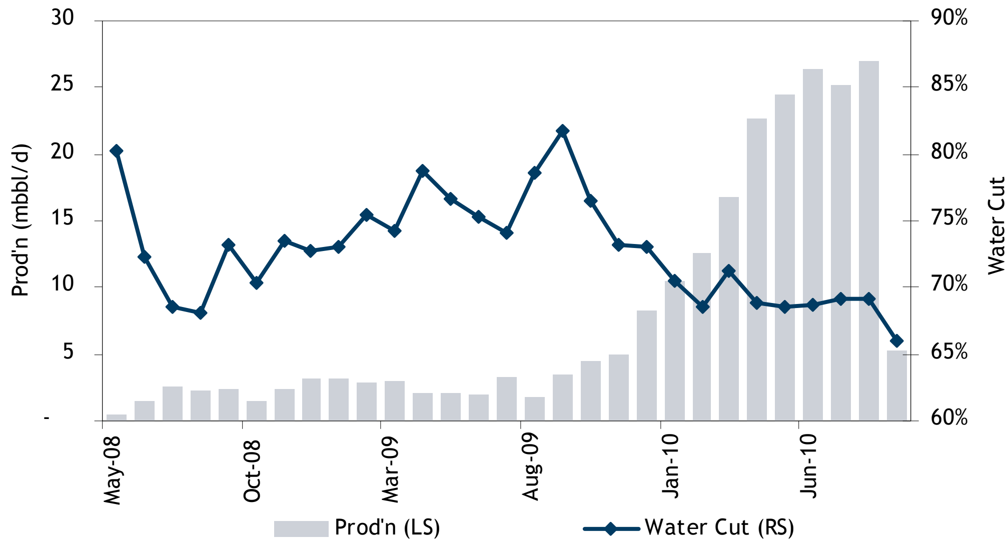


Source: Accumap and RBC Capital Markets

Water Cut Stabilized at 70% Indicates Reservoir is Early in Life Cycle

Another strong indicator that the Christina Lake reservoir is a good-quality producer is the water cut once production reaches sustained rates. At the beginning of the production phase, water cuts are high and are variable because injected steam produces back quickly. Once production reaches stabilized rates, however, sustained water cuts provide an indication of the future life expectancy of the reservoir. A reservoir with a current water cut of 70% should be expected to have a longer remaining life than a reservoir producing with a water cut of 85%, which is presumably closer to its economic limit. Now that production appears to be producing at a sustained rate at, or above design capacity (excluding the effect of the scheduled September turnaround), MEG's Christina Lake Phase 1 and 2A have settled in to an average water cut of approximately 70% (see Exhibit 111).

Exhibit 111: Christina Lake – Water Cut



Source: Accumap and RBC Capital Markets

Liquidity and Project Finance – Phase 2B is Fully Funded

We estimate that the company has more than $2 billion of liquidity to finance the approximately $1.4 billion Phase 2B expansion. MEG, having recently completed its $700 million IPO, has about $1.4 billion of cash and short-term investments on its balance sheet. In addition, MEG has undrawn credit facilities of $185 million, and we expect the company to generate cash flow close to $600 million from existing operations before first production from Phase 2B.

Stock Market Liquidity – Should Improve Following Expiry of Lock-Up

We believe the market liquidity of the shares could potentially double following the expiry of the lock-up agreement in early February, however to remain somewhat impaired longer term. Although MEG has 189 million basic shares outstanding and the largest market capitalization within our oil sands initiation peer group at around $7 billion, investors may be somewhat frustrated by the general lack of stock market liquidity. At the time of the IPO, shareholders representing 65% of the total shareholder base agreed to a lock-up agreement for 180 days following the IPO. Since the company began trading at the beginning of August, the stock has traded an average of only about 100,000 shares per session. Following the expiry of the lock-up agreement, the public float of the stock should increase to approximately 118 million shares from around 67 million shares currently. We expect Warburg Pincus and CNOOC to remain substantial shareholders at 23% and 15% holdings, respectively, and thereby somewhat impairing trading liquidity even longer term.

Valuation

Approach & Methodology – NAV Based Approach

Net Asset Value is our preferred valuation method for oil sands focused companies with well defined projects that have visible timing, scope and capital cost expectations. We apply a risk factor to projects that are still involved in the regulatory process. Our Base NAV reflects value for developed projects, projects in the development and regulatory stage, as well as value for unevaluated lands and corporate adjustments such as cash balances and debt. Our Base NAV is our evaluation of what we believe investors should be willing to pay for the stock. We reserve the option of applying a multiple to our NAV to adjust for intangible qualities as necessary; therefore, this is the basis of our 12-month target price. Our Unrisked NAV reflects a potential upside valuation for the company, including Unrisked values for projects in various stages of the development or regulatory process and value for additional resources that do not have development project definition. This methodology could be thought of as a potential take-out value for the company in the event of a corporate transaction.

Relative Valuation – Compelling for MEG

We see strong asset value support for MEG, which is currently trading at P/NAV (Base) ratio of 83% and a P/NAV (Unrisked) ratio of 58% compared to a peer group average valuations of 86% and 49%, respectively. The company’s producing projects, projects currently in development and positive net debt represent $27.74/share of value. Adding risked value for the company’s Stage 3 at Christina Lake, which is expected to receive regulatory approval within the next 12 months, increases our calculation of NAV to $47.15/share. We base our $48.00/share target price on 1.0x our Base NAV calculation, which is in line with the peer group average.

Exhibit 112: MEG - NAV Summary

Project	Reserve / Resource Est. Mmbbl	Project PV $Mm	Implied PV/Bbl $/Bbl	W.I. %	Base NAV Risk Factor	Base NAV $Mm	Base NAV $/Share	Base NAV % NAV	Unrisked NAV $mm	Unrisked NAV $/Share	Unrisked NAV % NAV
Christina Lake											
Phase 1 & 2 (Producing)	363	$3,270	$9.02	100%	100%	$3,270	$16.09	34%	$3,270	$16.09	24%
Phase 2b (Sanctioned)	508	$1,969	$3.88	100%	100%	$1,969	$9.69	21%	$1,969	$9.69	15%
Phase 3a (Pre Reg Approval)	725	$2,213	$3.05	100%	75%	$1,660	$8.17	17%	$2,213	$10.89	16%
Phase 3b (Pre Reg Approval)	725	$1,710	$2.36	100%	75%	$1,283	$6.31	13%	$1,710	$8.42	13%
Phase 3c (Pre Reg Approval)	725	$1,335	$1.84	100%	75%	$1,001	$4.93	10%	$1,335	$6.57	10%
Total	**3,046**	**$10,497**	**$3.45**			**$9,182**	**$45.19**	**96%**	**$10,497**	**$51.66**	**77%**
Surmont											
Phase 1 (Pre-Reg Application)	324	$990	$3.06	100%	0%	$0	$0.00	0%	$990	$4.87	7%
Phase 2 (Pre-Reg Application)	324	$820	$2.54	100%	0%	$0	$0.00	0%	$820	$4.04	6%
Total	**647**	**$1,811**	**$2.80**			**$0**	**$0.00**	**0%**	**$1,811**	**$8.91**	**13%**
Total Projects	**3,693**	**$12,308**	**$3.33**			**$9,182**	**$45.19**	**96%**	**$12,308**	**$60.57**	**91%**
Resource	**Reserve / Resource Est.**	**Project PV**	**Attributed Value**	**W.I.**	**Risk Factor**	**$Mm**	**$/Share**	**% NAV**	**$Mm**	**$/Share**	**% NAV**
Total Resource	1,721	$861	$0.50	100%	0%	$0	$0.00	0%	$861	$4.23	6%
Corporate Adjustments											
Net Working Capital						$1,404	$6.91	15%	$1,404	$6.91	10%
Long Term Debt						($1,007)	($4.95)	-11%	($1,007)	($4.95)	-7%
Total Corporate						**$397**	**$1.96**	**4%**	**$397**	**$1.96**	**3%**
Net Asset Value						**$9,580**	**$47.15**	**100%**	**$13,566**	**$66.76**	**100%**

Risk Factors:
- 100% of DCF value given to producing projects and projects that have received regulatory approval
- 75% of DCF value given to projects in the regulatory application process
- 0% of DCF value given to projects expected to be in the regulatory application process within the next 0-24 months

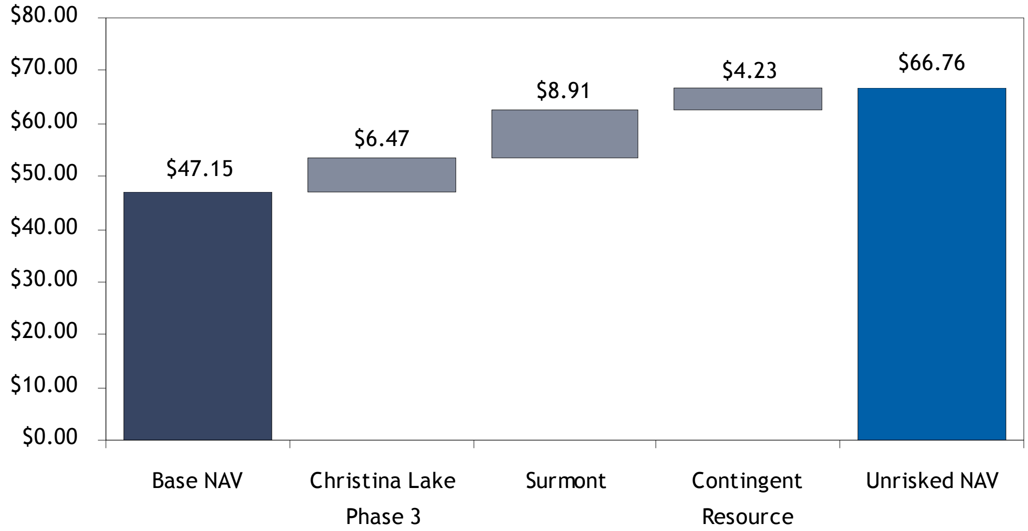
Assumptions:
- WTI crude oil assumptions: US$78.02, US$83.00, US$85.00 for 2010E, 2011E and 2012E forward respectively
- Henry Hub natural gas assumptions: US$4.54, US$5.00, US$5.50 for 2010E, 2011E and 2012E forward respectively
- US/CAD foreign exchange assumptions: $0.96, $0.95, $0.95 for 2010E, 2011E and 2012E forward respectively
- After tax discount rate assumption: 8.5%
- Long term operating cost assumptions: $11.00/bbl and $12.00/bbl for Christina Lake and Surmont respectively

Source: Company reports and RBC Capital Markets estimates

Unrisked NAV – Visible Value Upside Potential

Unrisking Christina Lake Phase 3, adding value for Surmont and value for Contingent Resources that have not been attributed to a project increases our calculation of NAV to $66.76/share. The Unrisked NAV is a good indication of upside potential because management continues to advance projects through the regulatory and development stages.

Exhibit 113: MEG Upside Potential- Base and Unrisked NAV



Source: Company reports and RBC Capital Markets estimates

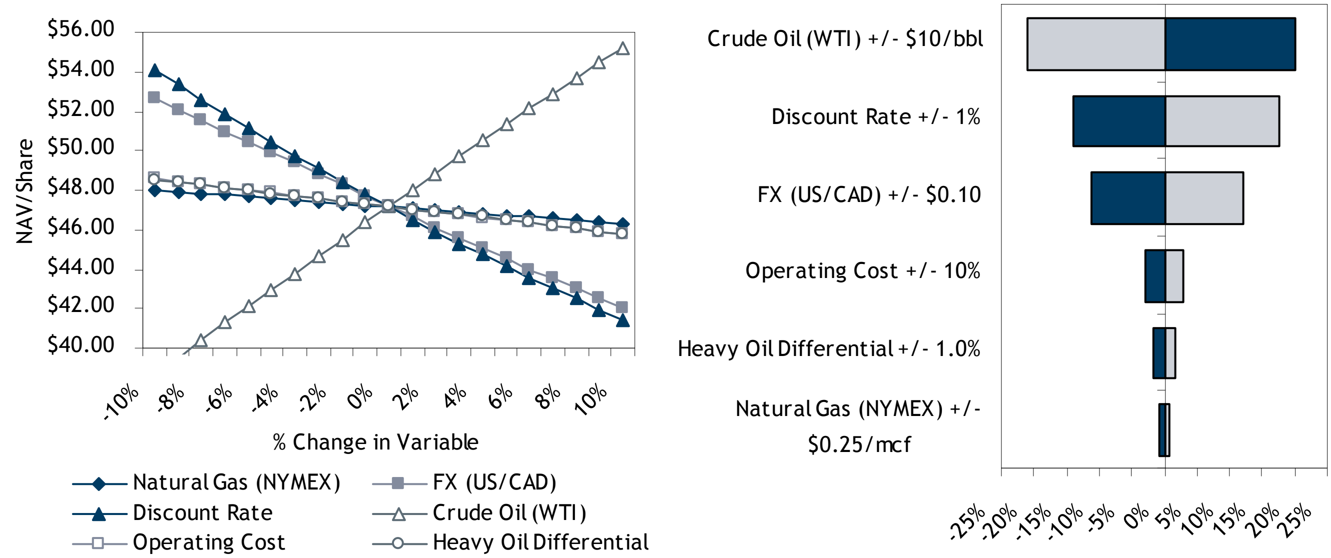
Contingent Resource Value

We assign a value of $0.50/bbl to Contingent Resources (Best Estimate) that have not been attributed to a specific development project. During 2010, market transactions varied based on several factors, ranging from a low of $0.14/bbl to a high of $1.84/bbl. We believe that $0.50/bbl fairly reflects value for Best Estimate Contingent Resources that have not yet been given development definition or have not yet entered into the regulatory process. We do not give value to the High Case Contingent Resource estimates, nor do we attempt to attribute value to possible or potential resources.

Sensitivities

MEG's NAV is most sensitive to changes in oil price, to which MEG's NAV has a positive correlation. All other variables have a negative correlation to NAV, starting with discount rate and the foreign exchange rate between the Canadian and U.S. dollars. The price of natural gas, fluctuations in operating costs and even heavy oil differentials do not affect asset value by as much as might be expected but are still important inputs to performance and value.

Exhibit 114: MEG - NAV Sensitivity



Source: Company reports and RBC Capital Markets estimates

Risks to Target Price

We consider MEG to be an early stage oil sands development company, albeit with somewhat less overall risk than some of its peers by virtue of having current production, cash flow and project financing in hand. We assign an Above Average risk rating to MEG.

We identify six key risks to our target price:

1. **Oil Prices –** MEG's production is 100% weighted to oil, and the company, to date, has not entered into any commodity price hedge contracts. While on one hand we appreciate the exposure this strategy gives shareholders to upward movements in oil price, there is no doubt that it also presents a greater degree of downside risk to cash flows and NAV calculations than if a moderate hedge policy was in place. As demonstrated in Exhibit 114, fluctuations in oil price represent the greatest effect on the NAV of the company. We assume a flat oil price of US$85.00/bbl from 2012 onward.
2. **Discount Rates** – We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations of E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk, lower reserve replacement and re-investment (i.e., exploration) risk than E&P companies. On the other hand, however, oil sands companies have greater regulatory, environmental and project execution risk during the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our target price, materially.
3. **Foreign Exchange Rates** – MEG's capital and operating costs are incurred in Canadian dollars, yet the company's production is priced in U.S. dollars. Fluctuations of the U.S./Canadian dollar exchange rate could greatly affect the value of future cash flows. Somewhat offsetting fluctuations in the exchange rate is the company's long-term debt, which is denominated in U.S. dollars. Therefore, a $0.01 increase in the Canadian dollar in relation to the U.S. dollar decreases our estimate of NAV by approximately $0.60/share (approximately $115 million), offset slightly by a decrease in the value of the U.S. denominated debt by approximately $0.05/share (approximately $10 million). We assume a flat US$0.95/C$1.00 exchange rate for the long term.
4. **Regulatory Risks** – With two phases of Christina Lake already developed and regulatory approval in hand for the next stage of development, MEG is not immediately affected by regulatory risk. Future stages of development beyond Phase 2B, however, require additional regulatory approvals. For instance, we included a risked value of $19.41/share for Phase 3 of Christina Lake, which we expect to receive regulatory approval within our 12-month target price horizon. The company's growth potential, as well as our perception of the company's value, would be materially affected should the regulatory process be delayed or not forthcoming.
5. **Financing Risks** – MEG is in an enviable position whereby we believe Phase 2B is currently fully funded with cash on hand, available borrowing facilities and expected cash flows during the next two to three years. Should capital costs escalate or oil prices or production rates significantly drop, however, make up financing may be required. If all else were constant, future phases of growth will also require financing. We expect Phase 3 and Surmont to be largely financed with a combination of cash flows and debt, because management targets a long-term debt-to-equity ratio of close to 50%.
6. **Environmental Risks** – Oil sands producers in general have come under significant scrutiny for environmental issues. While longer-term costs or product marketing concerns related to environmental issues are unclear at this time, they present a risk to the company's operations and our perception of the valuation of the company. Having said that, we note that MEG is engaged strictly in the development of In-Situ projects, which typically have less effect on land, air and water than oil sands mining projects. MEG is actually collecting Green House Gas (GHG) emission credits by virtue of generating clean electricity at its co-generation facility instead of drawing electricity off of the Alberta electricity grid, which is largely generated by coal. MEG also generates fewer emissions than comparable companies due to the company's low SOR. Without the benefit of the GHG credit, MEG's In-Situ production would be roughly average to most oil imported into the United States. Including the benefit of the GHG credit, MEG's production would be comparable with the cleanest oil fuel sources landed at U.S. refineries (see Exhibit 24).

Exhibit 115: MEG - Operational & Financial Summary

C$ millions, unless noted	2007	2008	2009	2010E	2011E	2012E
Production						
Bitumen (bbl/d)	0	1,323	3,467	20,581	25,000	23,743
Diluent Purchases (bbl/d)	0	497	1,422	9,654	12,313	11,694
Blend Sales (bbl/d)[1.]	**0**	**1,776**	**4,838**	**30,235**	**37,313**	**35,438**
Blend Ratio	n.a.	29%	30%	32%	33%	33%
YOY Production Growth (%)	n.a.	n.a.	162%	494%	21%	-5%
Bitumen (%)	n.a.	100%	100%	100%	100%	100%
Commodity Prices						
WTI Crude Oil (US$/bbl)	$72.25	$99.50	$61.81	$78.02	$83.00	$85.00
Ed. Par (C$/bbl)	76.05	102.75	66.48	77.69	86.05	88.16
Bow River Heavy (C$/bbl)	50.50	83.00	59.25	68.23	73.30	72.29
Exchange Rate (US$/C$)	0.93	0.94	0.88	0.96	0.95	0.95
Henry Hub - NYMEX (US$/mcf)	6.95	8.85	3.92	4.54	5.00	5.50
AECO (C$/Mcf)	6.60	8.15	3.94	4.05	4.37	4.90
Realized Pricing and Costs						
Blend Sales ($/bbl)	**n.a.**	**$63.86**	**$53.36**	**$63.25**	**$68.05**	**$66.95**
Bitumen Sales ($/bbl)	n.a.	44.99	45.01	55.69	66.92	64.21
Transportation & Selling ($/bbl)	n.a.	(19.83)	(10.24)	(1.69)	(1.51)	(1.52)
Royalties ($/bbl)	n.a.	(1.06)	(1.37)	(2.22)	(2.97)	(3.01)
Operating Costs ($/bbl)[2.]	n.a.	(123.87)	(51.75)	(16.95)	(13.55)	(13.77)
Netback ($/bbl)	**n.a.**	**(99.77)**	**(18.35)**	**34.83**	**48.89**	**45.92**
Consolidated Financials						
Blend Sales (net of royalties)	$0.0	$22.4	$54.4	$682.0	$899.7	$842.1
Other Income	16.8	13.7	7.6	34.5	31.4	27.2
Cost of Diluent	0.0	18.5	38.2	307.5	428.0	417.4
Operating and G&A	39.2	74.8	93.9	196.9	187.2	183.6
Interest	0.0	0.0	4.5	46.1	49.9	49.9
DD&A	0.2	0.3	3.1	120.1	150.0	144.0
Pre-Tax Income	0.0	(159.5)	65.3	6.0	86.1	45.2
Current Tax	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Tax	(4.7)	20.5	14.1	2.2	22.8	11.3
Net Income	**65.3**	**(180.0)**	**51.2**	**3.8**	**63.3**	**33.9**
Cash Flow From Operations	**3.0**	**(12.5)**	**(62.2)**	**114.9**	**248.1**	**201.2**
Capital Expenditures	**607.0**	**637.6**	**343.9**	**561.7**	**897.6**	**665.5**
Per Share Data						
Diluted CFPS ($/Share)	**$0.03**	**($0.10)**	**($0.45)**	**$0.64**	**$1.31**	**$1.06**
YOY Diluted CFPS Growth (%)	n.a.	-433%	350%	-243%	104%	-19%
Diluted EPS ($/Share)	**$0.56**	**($1.44)**	**$0.36**	**$0.02**	**$0.33**	**$0.18**
YOY Diluted EPS Growth (%)	n.a.	-357%	-125%	-94%	1490%	-46%
Weighted Avg Diluted Shares O/S (mm)	n.a.	n.a.	n.a.	189.5	189.5	189.5
Financial Leverage						
Net Debt	n.a.	n.a.	n.a.	(224.4)	437.1	913.4
Long Term Debt	n.a.	n.a.	n.a.	1,006.8	1,006.8	1,006.8

1. May not add due to injections or withdrawals from inventory
2. Power sales are netted against operating costs for the netback calculation

Source: Company reports and RBC Capital Markets estimates

Exhibit 116: MEG - Company Profile

Business Description

MEG Energy Corp. is a pure play oil sands company focusing in the Athabasca region of Alberta. The company's principal asset is its Christina Lake SAGD project. Phases 1 & 2A of MEG's Christina Lake are currently producing over the designed capacity of 25,000 bbls/d; phase 2B is expected to begin steaming in late 2013 adding another 35,000 bbls/d of production capacity. At full development, MEG estimates that its Christina Lake leases are capable of 210,000 bbl/d of bitumen production. MEG also holds 486,000 acres of additional land in the Athabasca region, with 2.368 billion bbls of attributed best estimate contingent resource. The company also owns a 50% interest in the Access Pipeline and Sturgeon Terminal, which transports diluent to Christina Lake and delivers bitumen blend to the Edmonton upgrading and refining hub.

Land Position

Key Areas	W.I.	Area	Details
Christina Lake	100%	51,200 acres	85 MW cogeneration facility
Surmont	100%	20,480 acres	Regulatory process begins 2H 2011
Growth Properties	100%	465,920 acres	81 core holes

Reserve & Resource Estimates (GLJ)

(mmbbl)	Reserves		Contingent Resources
	1P	2P	Best Estimate
Christina Lake	549	1,691	1,355
Surmont	-	-	647
Growth Properties	-	-	1,721
Total	**549**	**1,691**	**3,724**

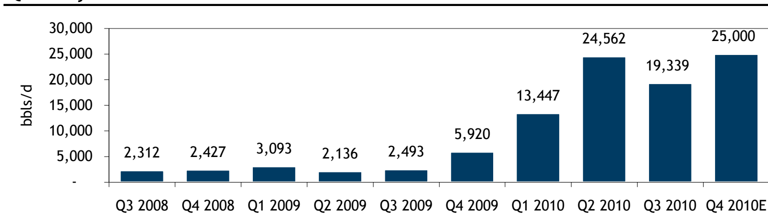
Management Team

Name	Position	Past Experience
William J. McCaffrey	Chairman, President & CEO	Manager Bus. Dev. & Growth, Amoco Canada
Dale Hohm	Chief Financial Officer	CFO of Enerflex Systems Ltd.
Grant W. Boyd	VP Growth & Emissions Mgmt.	Manager Oil Sands Ops at Husky Energy
James Kearns	VP Supply & Marketing	GM of ECL Environmental Services
Edward A. Semadeni	General Counsel	Senior Solicitor at ConocoPhillips
Richard F. Sendall	VP Bus. & Strategic Planning	Director, Heavy Oil Technology of Suncor
Bryan Weir	VP Projects	Director Firebag SAGD & Upgrading, Suncor
Suzanne Wilson	Director HR & Corp. Comms	General Manager of Operations at CIBC
Chi-Tak Yee	VP Reservoir & Production	Thermal Recovery, Petro-Canada & Esso
David J. Wizinsky	Corp. Secretary & Director	Co-founder of First Quantum Minerals Ltd.

Board of Directors

Name	Past Experience
William J. McCaffrey (Chairman)	Manager Bus. Dev. & Growth, Amoco Canada
David J. Wizinsky	Co-founder of First Quantum Minerals Ltd.
Boyd Anderson	VP Natural Gas Liquids, BP North America Inc.
Harvey Doerr	EVP Downstream and Planning, Murphy Oil
Peter R. Kagan	Managing Director, Warburg Pincus LLC
David B. Krieger	Managing Director, Warburg Pincus LLC
Hon. E. Peter Lougheed	Counsel, Bennett Jones LLP
James D. McFarland	President and CEO PanWestern Energy Inc.
Li Zheng	President, CNOOC Canada Limited
Robert B. Hodgins	Chairman, Calpine Power Income Fund

Quarterly Bitumen Sales Volumes



* Plant turnaround in Q3 2010

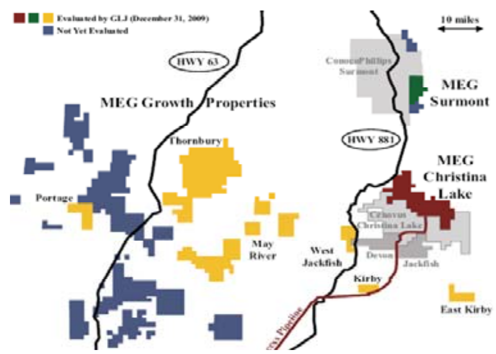
Recent News

Dec-10	Board Approves 2011 Budget, Phase 2B Cost Estimate
Sep-10	MEG announces new Board Member

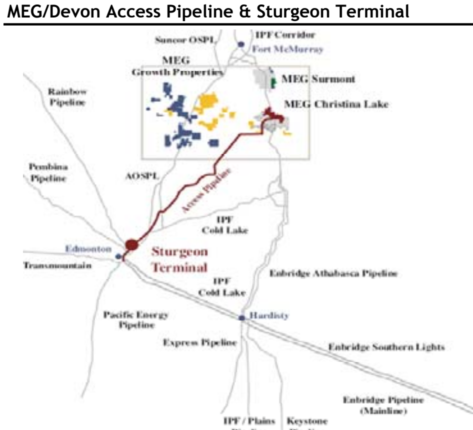
Potential Catalysts

Q1 2011	Christina Lake Phase 2B construction begins
Q3 2011	Expected approval for Christina Lake Phase 3
Q3 2011	Expected application for Surmont Project

MEG Energy Lease Map



MEG/Devon Access Pipeline & Sturgeon Terminal



Source: Company reports and RBC Capital Markets estimates

Exhibit 117: MEG - Financial Profile

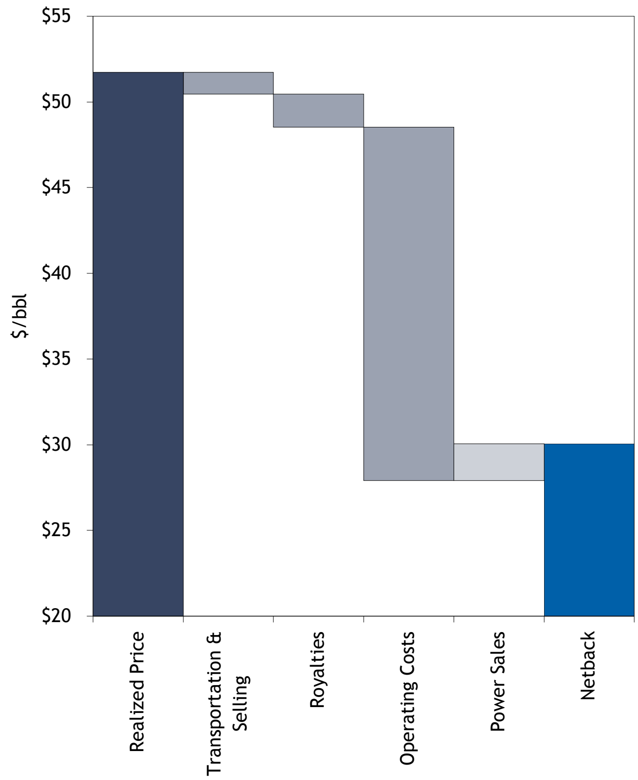
Insider Ownership

Management	Shares (M)	Options (M)	Total (M)	%of FD
William J. McCaffrey	1,161	1,683	2,843	1.4%
David J. Wizinsky	590	504	1,094	0.5%
James Kearns	53	586	639	0.3%
Dale Hohm	85	539	624	0.3%
Bryan Weir	7	389	396	0.2%
Richard F. Sendall	6	386	392	0.2%
Chi-Tak Yee	10	226	236	0.1%
Grant W. Boyd	6	180	186	0.1%
Edward A. Semadeni	4	127	131	0.1%
Suzanne Wilson	3	93	95	0.0%
Total Management	**1,924**	**4,713**	**6,636**	**3.3%**

Directors	Shares (M)	Options (M)	Total (M)	%of FD
Harvey Doerr	17	5	22	0.0%
Boyd Anderson	5	75	80	0.0%
James D. McFarland	4	5	9	0.0%
Robert B. Hodgins	1	5	6	0.0%
Peter R. Kagan	1	5	6	0.0%
David B. Krieger	1	5	6	0.0%
Hon. E. Peter Loughee	1	5	6	0.0%
Li Zheng	1	5	6	0.0%
Total Directors	**30**	**110**	**140**	**0.1%**
Total	**1,954**	**4,823**	**6,777**	**3.3%**

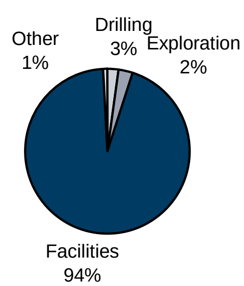
At Sep 30 2010, 13.3 million options were outstanding, weighted average exercise price $21.26

Q3 2010 Bitumen Netback



*Actual Q210 netbacks

2009 Christina Lake Capital Spending ($mm)



Interest Rate Hedges ($mm)

Amount	Remaining Term	Fixed Rate	Floating Rate
US$350	Remainder of 2010	5.29%	LIBOR
US$60	Remainder of 2010	4.85%	LIBOR
US$55	Remainder of 2010	4.83%	LIBOR
US$235	Remainder of 2010	4.80%	LIBOR
Weighted Avg		**5.05%**	

Operating & Financial Data

Production		FY 08	FY 09	Q1 10	Q2 10	Q3 10
Bitumen Production	(bbl/d)	1,323	3,467	13,398	24,412	19,339
Realized Pricing	($/bbl)	$47.46	$44.34	$58.10	$48.73	$51.73
Financials		**FY 08**	**FY 09**	**Q1 10**	**Q2 10**	**Q3 10**
Operating Cash Flow	($mm)	($12.5)	($62.3)	($9.6)	$45.3	$34.4
Diluted CFPS	($/share)	($0.10)	($0.45)	($0.06)	$0.26	$0.19
Net Income	($mm)	($180.0)	$51.2	($0.5)	($31.7)	$25.7
Diluted EPS	($/share)	($1.44)	$0.36	$0.00	($0.19)	$0.14
Capital Spending	($mm)	$637.7	$343.9	$90.5	$158.4	$97.0
Capex/CF	(x)	nmf	nmf	nmf	3.5 x	2.8 x

Source: Company reports, SEDI, RBC Capital Markets

OPTI Canada Inc. (TSX: OPC; $0.69)

OPTIons are Limited

Market Statistics		
Rating		Underperform
Risk		Speculative
Target Price		$0.60
Market Price		$0.69
Implied Return		-13.0%
Capitalization		
Diluted Shares O/S	(mm)	281.8
Market Capitalization	($mm)	$194.4
Net Debt	($mm)	$2,444.9
Enterprise Value	($mm)	$2,639.3

Net Asset Value		Base	Unrisked
Net Asset Value	($mm)	$194.6	$791.2
NAV/Sh	($/share)	$0.68	$2.78
P/NAV	(%)	101%	25%
Target Price/NAV	(%)	88%	22%
Resources			
Oil Sands EV[a]	($mm)		$2,639.3
2P Reserves	(mmbbl)		711
Contingent Resources[b]	(mmbbl)		1,114
EV/Bbl[c]	($/bbl)		$1.45

Operating & Financial		2007A	2008A	2009A	2010E	2011E	2012E
Total Production	(boe/d)	0	3,914	4,355	8,630	12,738	14,238
Operating Cash Flow	($mm)	($11.5)	$8.3	($255.7)	($383.6)	($242.3)	($126.8)
Diluted CFPS	($/share)	($0.06)	$0.04	($1.26)	($1.36)	($0.86)	($0.45)
Sensitivity to WTI	**(US$/bbl)**	**$60**	**$70**	**$80**	**$90**	**$100**	**$110**
NAV/Share	($/share)	($6.04)	($3.23)	($0.59)	$1.89	$4.19	$6.35
P/NAV	(%)	nmf	nmf	nmf	36%	16%	11%

(a) Adjusted to exclude the estimated value of non- oil sands assets
(b) Best Estimate
(c) Based on 2P reserves + best estimate Contingent Resources
Source: Company reports and RBC Capital Markets estimates

Investment Highlights

- **Insufficient financial liquidity presents clear and present danger** – We do not believe operations will improve quickly enough to alleviate the company's financial distress. We expect liquidity to be exhausted before Long Lake becomes cash flow positive ~2013E.
- **A strategic alternative is imperative but uncertain** – In our view, the only positive outcome of the ongoing corporate strategic review process would be a corporate sale. However, such an outcome cannot be predicted with certainty or timing. In our view, the company cannot solve its financial problems on its own accord, even with improved operations.
- **Speculative risk is not ideal for everyone** – The high level of financial leverage combined with the poor operational performance at Long Lake to date makes a favourable outcome of the ongoing strategic alternatives process highly uncertain. The sale of the company may provide upside potential to this distressed stock; however, the lack of a strategic solution creates significant financial challenges for the company by the end of 2011, if not sooner.
- **Growth is a catch-22** – The company needs production beyond Long Lake to generate free cash flow. However, an expansion at Kinosis would require incremental financing. If available, equity would be highly dilutive. If available, debt would be expensive and increasingly burdensome. We struggle to see how OPTI could sanction an expansion at Kinosis.
- **Valuation** – We believe that the value of Long Lake is effectively neutralized by the company's long term debt obligations. Our Base NAV includes a risked value for the company's interest in Kinosis, which has regulatory approval, on the basis that it may hold higher value to a potential acquirer. We calculate a Base NAV of $0.68/share and an Unrisked NAV of $2.78/share. We calculate a Base P/NAV ratio of 101% and an Unrisked P/NAV ratio of 25%. As our calculation of NAV is very close to zero due to the effect of the debt burden, a change in the long-term oil price assumption significantly affects our perception of NAV.
- **Recommendation** – Underperform, Speculative Risk, 12-month target price of $0.60/share. Our target price is based on a 0.9x multiple of our Base NAV calculation, which is below the peer group average multiple of 1.0x due to our concern over the company's high debt levels and financial liquidity.

Summary & Investment Thesis

We initiate coverage of OPTI Canada Inc. (OPC – TSX) with an Underperform (U) investment rating, a Speculative (Spec) risk rating and a 12-month target price of $0.60/share, which is based on a 0.9x multiple of a risked NAV analysis, which is below the peer group average multiple of 1.0x due to our concern over the company's high debt levels and financial liquidity.

In our opinion, OPTI has significantly over leveraged a poorly performing project. We do not believe operations will improve quickly enough to alleviate the financial stress on the company and we expect liquidity to be exhausted before the project becomes cash flow positive in the 2013 timeframe. We expect the company to exhaust its financial liquidity in approximately one year from now and we cannot be certain the company will be able to refinance debt upon expiry. We see value in the company's long-term assets, but believe that it will be difficult for OPTI to realize that value on its own accord. We view an investment in OPTI as being highly speculative on a corporate takeover, an event that cannot be predicted with certainty or timing, especially in the context of a strategic review process that has been ongoing for more than a year.

We believe it is reasonable to set our estimates based on historical performance trends. We anticipate a 2010 exit rate of ~30,000 bbl/d gross and we estimate 2011 production at Long Lake at 36,395 bbl/d gross, below the low end of Nexen's guidance of 38,000–45,000 bbl/d gross.

We estimate production rates need to be sustained at ~53,000 bbl/d gross (~18,500 bbl/d net) for OPTI to be cash flow neutral at the corporate level and at ~62,000 bbl/d gross (~21,700 bbl/d net) to be able to fund maintenance capital requirements. At current oil prices, we estimate that production at full design capacity of 72,000 bbl/d would provide OPTI with free cash flow of ~$90–100 million per year, which is not enough to finance expansion plans or make a significant reduction to debt levels.

At forecast 2011 production rates for Long Lake of ~36,400 bbl/d gross (~12,700 bbl/d net), we expect OPTI to exhaust its financial liquidity by year end 2011. Should the company gain extra time with reduced capital spending obligations or with proceeds from asset sales or the avoidance of the potentially costly settlement of the foreign exchange hedge and survive into 2012, the challenge becomes refinancing US$525 million of First Lien notes, due December 15, 2012 and a possible $400–500 million financing decision on Kinosis.

An expansion at Kinosis would require additional financing for OPTI. If available, equity would be highly dilutive. If available, debt would be expensive and increasingly burdensome. We struggle to see how OPTI could sanction an expansion at Kinosis.

We believe that the sale of additional joint venture working interests or assets would be a less than optimal solution for the company and for shareholders. We believe that a corporate sale would be the best possible outcome of the ongoing strategic review process. However, given the challenges of high debt leverage and poor operational performance at Long Lake to date combined with the less than optimum benefits to the company and shareholders of selling only working interests or undeveloped assets, a "status quo" outcome for OPTI is a distinct possibility. Should OPTI not find a suitable outcome inside the next 6 - 12 months, we expect a very negative outcome for shareholders.

Exhibit 118: OPTI - Pros & Cons

Pros	Cons
Large Resource Base - 1.114 billion barrels of Contingent Resource (Best Estimate) and 711 million barrels of reserves (2P) supports longer-term development opportunities	**Financial Liquidity -** OPTI is cash flow negative. We estimate that OPTI may exhaust its financial liquidity by Q4/11
Strategic Review Process - The ongoing process provides an opportunity for shareholders to realize value for longer-term assets	**Operational Performance at Long Lake** - Performance on every measure has been poor, making Long Lake a bottom quartile SAGD project (see Exhibits 31 & 32)
Regulatory Approval at Kinosis - Development at Kinosis has already been approved through the regulatory process. This should make this lease more attractive to potential acquirers	**Refinancing Risk on Short-Term Debt**- The company's revolving credit facility expires on December 15, 2011. At present only $10 million is drawn on this $190 million line but we estimate that the company will dip into this line before year end 2011. Extending the revolving credit facility will likely be an important financial event for OPTI
Improved Operational Reliability - The upgrader has been operating at a 90%+ onstream factor since the full turnaround in September of 2009.	**Refinancing Risk on Long-Term Debt**- The company has US$525 mm of debt maturing in December 2012, US$300 mm maturing in August 2013 and US$1,750 mm maturing in August 2014
Improving Production Rate - Production has risen to ~31,000 bbl/d gross (~10,850 bbl/d net)	**Financing Cost** - The company's latest debt issue had an 11% yield to maturity. The company is currently paying ~$65/bbl of interest expense
	Possible Need to Cover Expiry of Foreign Exchange Hedge - OPTI may be forced to cover the cost of a maturing foreign exchange rate hedge. Depending on exchange rates, OPTI may face a $60–90 mm cash charge in Q3/11
	Capital Costs - Possible plans to build incremental steam capacity for a net cost of ~$50 million
	Strategic Review Process May Yield No Bids - The process has been ongoing for more than a year. Given the poor operational performance of the project and the high debt burden of the company, a positive result from the process cannot be guaranteed

Source: Company reports and RBC Capital Markets

Potential Catalysts

Watch for the following near term catalysts:

- Possible tie in of additional well pairs on Pad 10 before year end
- 78 well pairs on production by year end
- 75 well pairs converted to ESP by year end
- Initiation of steaming of nine well pairs on Pad 11

Watch for the following catalysts in 2011:

- Tie in of well pairs on Pad 11, increasing producing well pairs to 90 by end of Q1/11
- Drilling of well pads 12 and 13
- Operational updates, likely co-incident with quarterly reporting or debt issuances
- Possible exhaustion of cash liquidity by mid year
- Possible need to cover expiry of foreign exchange hedge at end of Q3/11
- Expiry of revolving credit facility on December 15
- 90 well pairs on ESP by year end
- We estimate production to exit 2011 at ~40,000 bbl/d gross
- Possible exhaustion of all financial liquidity by year end 2011

Watch for the following catalysts in 2012:

- Possible first steam and tie in of 18 well pairs from Pads 12 and 13
- Possible sanction decision for Kinosis expansion
- Operational updates, likely co-incident with quarterly reporting or debt issuances
- Expiry of US$525 million first lien notes due December 15
- We expect Long Lake production to reach 50,000 bbl/d gross by exit 2012, which approaches CF break even for OPTI

Longer term, watch for the following catalysts:

- Operational updates, likely co-incident with quarterly reporting or debt issuances
- Expiry of US$300 million first lien note due August 15, 2013
- Expiry of US$1,750 million senior notes due December 15, 2014
- Possible achievement of reaching production design capacity at Long Lake in 2016

Exhibit 119: OPTI - Potential Catalysts

2011E	2012E	2013E+
Q1 - Ongoing strategic review process	Q1 - Possible tie-in of Pads 12 & 13	Q3 2013 - Expiry of US$300 mm first lien note due August 15, 2013
Q1 - Tie-in of Pad 11	Q1 - Possible sanction decision on Kinosis expansion	Q3 2014 - Expiry of US$1,750 mm first lien notes due August 15, 2014
Q1 - Drill Pad 12 & 13	Q4 - Expiry of US$525 mm first lien notes due August 15	2015 - Possible achievement of reaching production design capacity at Long Lake of 72,000 bbl/d gross
Q2 - Possible exhaustion of cash liquidity by mid-year	Q4 - We estimate production to exit 2011 at ~50,000 bbl/d gross	
Q4 - Expiry of revolving credit facility on December 15		
Q4 - 90 well pairs on ESP by year-end		
Q4 - We estimate production to exit 2011 at ~40,000 bbl/d gross		
Q4 - Possible exhaustion of financial liquidity		

Source: Company reports and RBC Capital Markets estimates

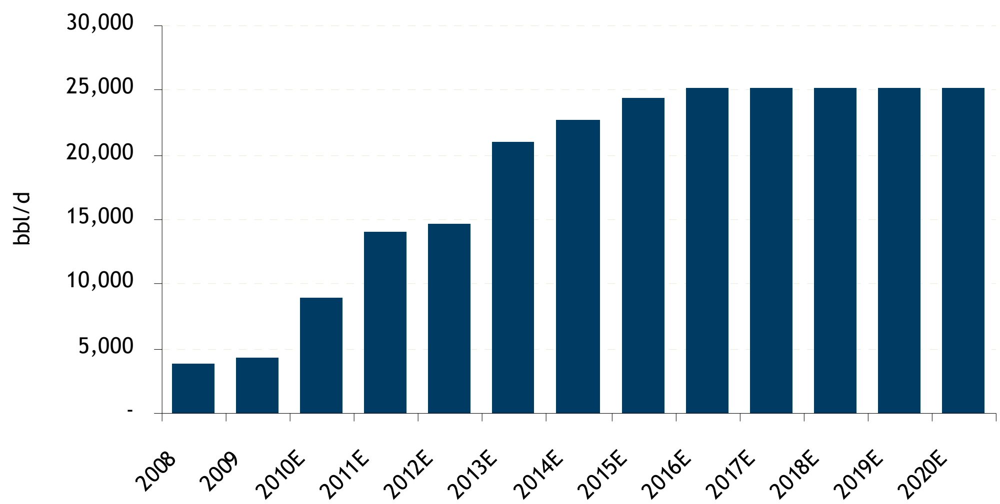
Company Overview

OPTI, established in 1999, is currently a 35% non-operated working interest joint venture partner with Nexen Inc. at Long Lake and on the Kinosis, Cottonwood and Leismer In-Situ oil sands leases in the Athabasca region of Alberta, located south of Fort McMurray. Long Lake is the first project to use the OrCrude™ process, which is a fully integrated process utilizing a 170 MW cogeneration facility, a gasification facility and an upgrader.

On November 11, 2008 management appointed advisors to assist the company in reviewing financing options. In conclusion of that review process, OPTI divested operatorship of the upgrader and an overall 15% working interest in Long Lake (and its other leases) to Nexen in January 2009 for consideration of $735 million thereby reducing the company's interest from 50% to 35%.

On November 3, 2009 management announced that the Board of Directors initiated a strategic review process, which remains ongoing.

Exhibit 120: OPTI Production Forecast



Source: RBC Capital Markets estimates

Long Lake JV – A Technically & Economically Challenged Project

Long Lake history – Long Lake is located ~40 km southeast of Fort McMurray. OPTI first entered into an agreement with Suncor Energy Inc. to earn a 50% W.I. in Lease 27. OPTI drilled evaluation wells and shot seismic to earn its 50%. In October 2001, Nexen Inc. acquired Suncor's remaining 50% W.I. in Lease 27. The joint venture partners subsequently acquired leases adjacent to Lease 27 to assemble the Long Lake lease area. The partners now hold ~71,000 gross acres (~25,000 net to OPTI) at Long Lake.

Late and over budget – The project received final regulatory approval in November 2003 and in February 2004 both OPTI and Nexen sanctioned the project. The project was scheduled for first steam in late 2006 with first upgraded bitumen scheduled by mid-2007. The Long Lake project began injecting steam in April 2007 and producing bitumen in November 2007. Commercial bitumen production was declared in mid 2008 and first upgrading began in January 2009, which was roughly 18 months past schedule. Project costs were estimated at ~$3.5 billion gross at time of sanction, but the final project cost was ~85% over budget at ~$6.5 billion gross, increasing estimated capital intensity from ~$48,600/bbl/d to $90,000/bbl/d.

OPTImistic original design – The Long Lake project is designed to produce 72,000 bbl/d gross of bitumen (25,200 bbl/d net to OPTI) from 68 Steam Assisted Gravity Drainage (SAGD) well pairs with a designed SOR capacity of 2.7x at an operating pressure of 3,000 kPa.

At full design capacity, the gasification process utilizes the heaviest, least valuable, ends of the barrel as the fuel source to generate most of the required steam resulting in volumetric shrinkage in product for a design capacity of 58,500 bbl/d gross of upgraded synthetic oil (20,500 bbl/d net).

At full design rates, the joint venture partners expect to achieve operating costs of ~$25–30/bbl. Due to the high degree of fixed costs, we estimate operating costs at ~$46/bbl during 2011.

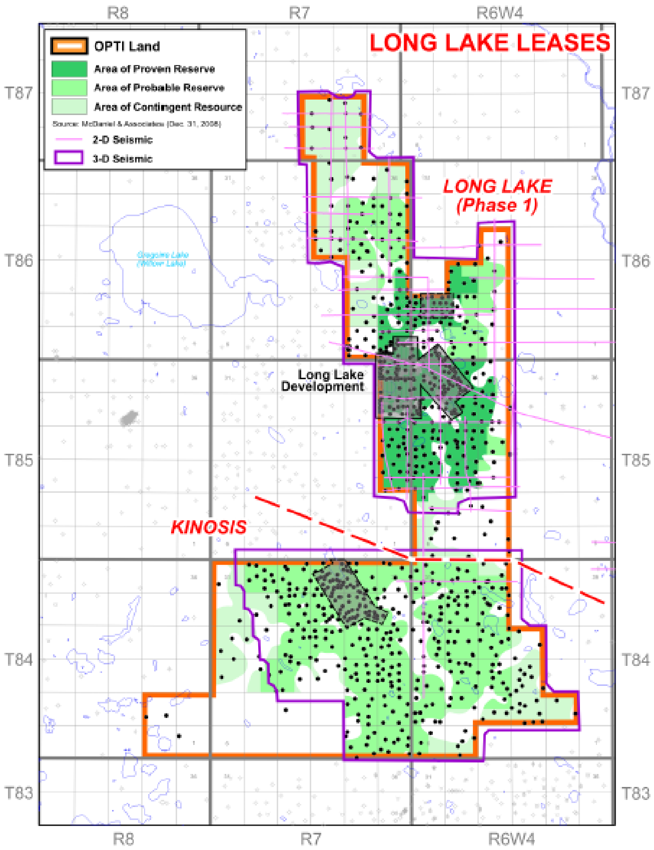
Design modifications have added 40 well pairs, steam capacity and ESPs – In 2004, Pad 10 (13 well pairs) was added to the design of the project, increasing total well pair count from 68 to 81 well pairs, to ensure sufficient productivity to achieve design production rates. In 2008, Pad 11 (10 well pairs) was added to the design of the project, increasing total well pair count to 91 well pairs, in an attempt to reach design production rates. One well pair has been lost due to completion problems and so the project currently has 90 well pairs. Partners are now planning to drill Pad 12 and 13, to add 18 well pairs in an attempt to reach facility design capacity of 72,000 bbl/d with 108 SAGD well pairs (see Exhibit 121). The addition of Pad 12 and 13 is expected to cost ~$250 million gross (~$90 million net), most of which is expected to be incurred in 2011 with first steam and first production in 2012. Initial design estimated the average rate per well pair at ~1,060 bbl/d. With the addition of Pads 12 & 13, estimated average rate per well pair has dropped to ~670 bbl/d.

During construction of the project, the design was modified by increasing steam generation capacity from ~190,000 bbl/d to 230,000 bbl/d for an increased design SOR of the facilities of 3.3x. Currently the JV partners are contemplating adding another OTSG (Once Through Steam Generator) to increase steam capacity to 270,000 bbl/d for an implied design SOR of 3.7x. The addition of the incremental steam capacity would cost ~$150 million (~$53 million net to OPC). While the project is currently operating at a SOR of ~5.0x, current production is not actually constrained by steam generation capacity. The project is currently generating approximately 163,000 bbl/d of steam, below steam generation capacity of 230,000 bbl/d.

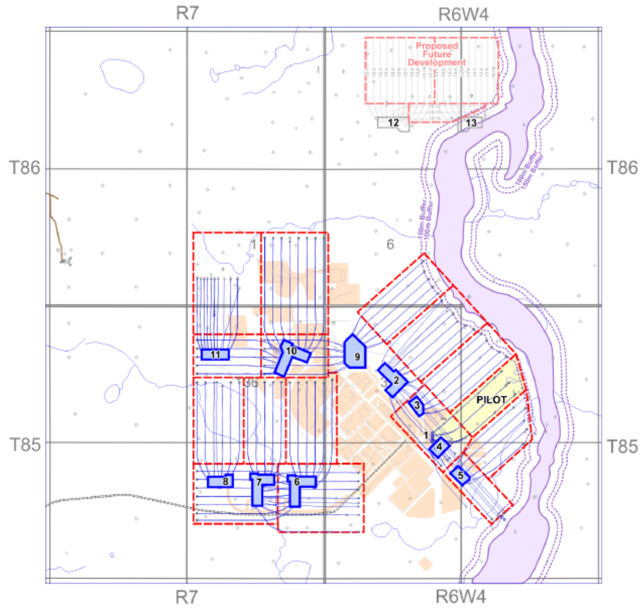
Early in the production ramp up the partners were targeting a high pressure production scenario. High pressure requires more steam but generally translates into higher production rates. It was soon discovered the high pressure resulted in steam loss to thief zones causing poor production response and high SOR's. In response, the partners moved to a lower pressure production environment by converting from gas lift to ESP's and reducing the injection pressure of the steam. The conversion to a lower pressure production environment has been achieving results, although very slowly. The joint venture partners are currently operating Long Lake at 2,750 kPa compared to native reservoir pressure of 1,200 kPa.

Exhibit 121: Long Lake & Kinosis Lease Areas

Long Lake & Kinosis Leases with Delineation & Project Areas



Long Lake Well Pad Layout

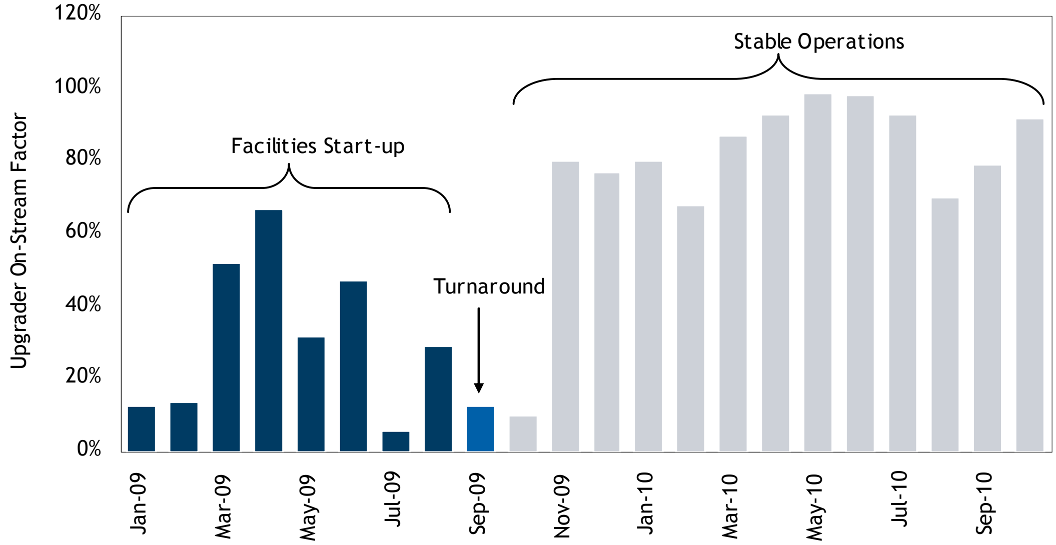


Source: Company reports

Slow production ramp up at Long Lake – For the first two and a half years of the project life, the facility suffered from reliability issues resulting in limited steam generation, slow production ramp up, frequent interruptions at the upgrader and a poor project SOR of 5.0 - 6.0x. One year after first steam the project was producing at approximately 10% of design capacity and two years after first steam the project was producing at ~20% of design capacity.

First turnaround was a treatment but not a cure for poor performance – The JV partners performed a full facility turnaround in September 2009. Following this turnaround, steam generation and bitumen production rates grew and upgrader utilization rates improved to the 80% and 90%+ level (see Exhibit 122). The project SOR, however, remains around 5.0x and overall bitumen production rates of ~31,000 bbl/d gross (~10,900 bbl/d net) have doubled but, three years following first steam production, is only ~40–45% of design capacity (see Exhibit 126).

Exhibit 122: Upgrader On-Stream Factor



Source: Company reports

We have modeled a full turnaround into our first quarter 2012 estimates – Another full facility turnaround is scheduled for April 2012, which will last up to a full month. We have modelled the turnaround into our first quarter 2012 estimates. The facility turnaround reduces our first quarter 2012 production estimate by ~13,000 bbl/d gross (~4,600 bbl/d net) and our full year production estimate by ~3,250 bbl/d gross (~1,200 bbl/d net). The facility turnaround results in lower year-over-year production growth from 2011 into 2012, somewhat distracting from underlying production growth that is more visible on a quarterly basis. However, we expect much slower production growth than predicted by the JV partners.

Third-party Bitumen running in upgrader – The partners have been taking third-party bitumen volumes to run through the upgrader, which needs to be close to half full in order to operate at moderate efficiency. The upgrader, however, is designed to process hot bitumen and therefore blending must be limited as blending third party bitumen volumes cool the overall mix making it increasingly difficult for the upgrader to process. The volume of third-party bitumen that the upgrader can process is therefore limited. The partners have been taking 8,000–10,000 bbl/d of third-party bitumen. For operational reasons, we do not expect higher volumes of third-party bitumen to be processed.

Kinosis - Financing Expansion Will be Difficult

Phase 1 moving toward sanction - Kinosis, which is located immediately south of Long Lake (see Exhibit 121) has received regulatory approval for development of up to 140,000 bbl/d (gross) of bitumen production. The partners have outlined a Phase 1 development of 40,000 bbl/d (gross), to be sanction ready by 2012. Nexen appears anxious to move this project forward. Because of current economic conditions with low light-to-heavy oil price differentials and low natural gas prices, the partners are framing the Kinosis development as a stand alone SAGD project. Building Kinosis as a stand alone SAGD project would simplify project execution and reduce capital intensity.

No upgrader required - The partners could add an upgrader, which has been approved through the regulatory process, at Kinosis at a future date should economic conditions once again favour upgrading long term. In the meantime, upgraded oil from Long Lake could be used as diluent to blend with Kinosis bitumen for shipping.

New financing would be needed, but can OPTI get it? - We estimate that a 40,000 bbl/d project would cost ~$1.2 billion (at $30,000 bbl/d), or approximately $420 million net to OPTI's 35% W.I. Based on our operational outlook, we do not expect Long Lake to provide any free cash flow to OPTI in the 2012 timeframe and as such we believe it would be difficult for OPTI to finance the

Kinosis project. If available, equity would be highly dilutive and the company does not need any more highly priced debt.

Value in Kinosis but OPTI may not be able to realize it – As discussed in the Valuation section, we have risked Kinosis in our Base NAV as we would expect a possible acquirer to allocate value to the resource and regulatory approvals at Kinosis but we find it difficult to see how OPTI will be able to extract value from this project itself.

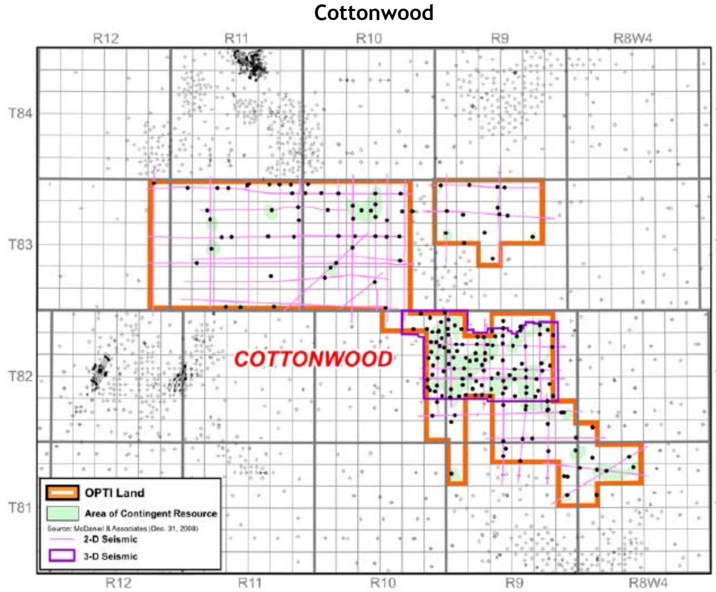
Cottonwood & Leismer – Well Defined but Needing Regulatory Approval

Contingent Resource estimate of 795 million barrels net – OPTI and Nexen hold 90,240 gross acres at Cottonwood and 85,760 gross acres at Leismer (31,584 acres and 30,016 acres net respectively). In the early years, the partners undertook extensive core hole and seismic evaluation work over both of these leases, drilling 458 core holes. McDaniel & Associates have assigned Contingent Resources (Best Estimate) of 591 million barrels net at Cottonwood and 203 million barrels net at Leismer.

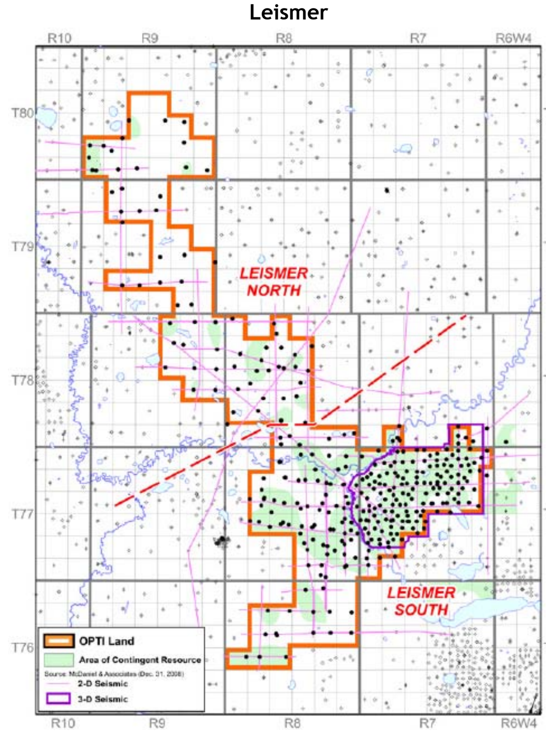
Value in the assets if they can be developed – A Contingent Resource allocation allows enough confidence to run a discounted cash flow model. We have used company estimates of 140,000 bbl/d gross (49,000 bbl/d net) potential at Cottonwood and 72,000 bbl/d gross (25,200 bbl/d net) potential at Leismer. At this time we do not expect OPTI to be in a position to advance these projects; however, we believe these assets hold value in a potential change of control situation that could be a possible outcome of management's strategic review process.

Exhibit 123: Cottonwood & Leismer Lease Areas

Cottonwood



Leismer



Source: Company reports

Key Issues

Performance at Long Lake – A Bottom Quartile Project

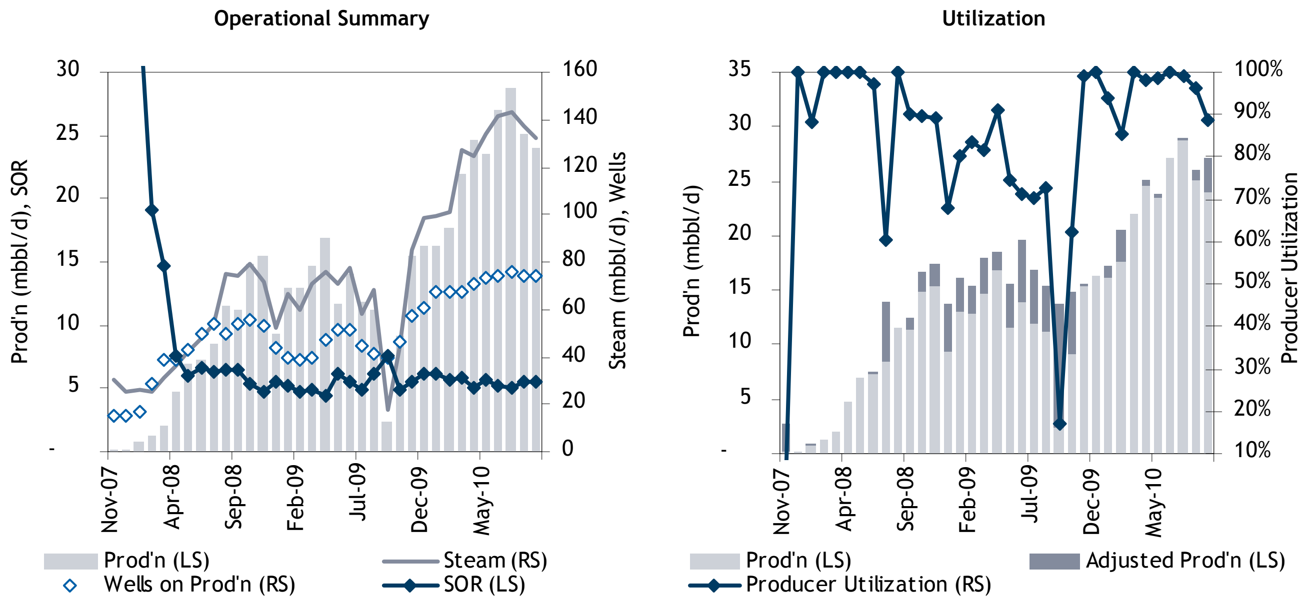
We estimate production rates need to be sustained at ~53,000 bbl/d gross (~18,500 bbl/d net) for OPTI to be cash flow neutral at the corporate level and at ~62,000 bbl/d gross (~21,700 bbl/d net) to be able to fund maintenance capital requirements.

Operational performance at Long Lake has been extremely poor on virtually every measure:

- **Schedule** – The project achieved first upgraded bitumen ~18 months behind schedule.
- **Cost** – The project was ~85% over budget, costing ~$6.5 billion compared to the budgeted $3.5 billion.
- **Ramp up** – After three years, production has reached only 40–45% of design capacity.
- **Rate per well** – The current rate per well is ~ 400 bbl/d from 78 well pairs with six well pairs steaming and six well pairs awaiting steam. The joint venture partners may initiate the drilling of an additional 18 well pairs, for a total of 108 well pairs, to reach designed production rates if wells reach ~660 bbl/d. Initial design anticipated full production rates with 68 well pairs producing at 1,060 bbl/d.
- **SOR** – The SOR is operating at ~5.0x compared to initial design expectations of ~3.0x.

Operational performance has improved – As Exhibit 125 demonstrates, operational reliability has improved following the September 2009 full facility turn around, as the partners were able to properly address a number of facility-related issues such as replacing malfunctioning valves and burner tips. Subsequent to the turnaround, reliability has improved, steam generation has increased and production rates have grown. However, while production rates have increased, SOR performance has only improved from ~6.0–5.0x. This could be in part related to the fact that the project continues to circulate steam in well pairs ahead of tie-in. The project will continue to circulate steam in well pairs for the foreseeable future as pads 11, 12 and 13 are drilled, steamed and tied in as producers and therefore we do not expect a rapid improvement in SOR over the next one to two years.

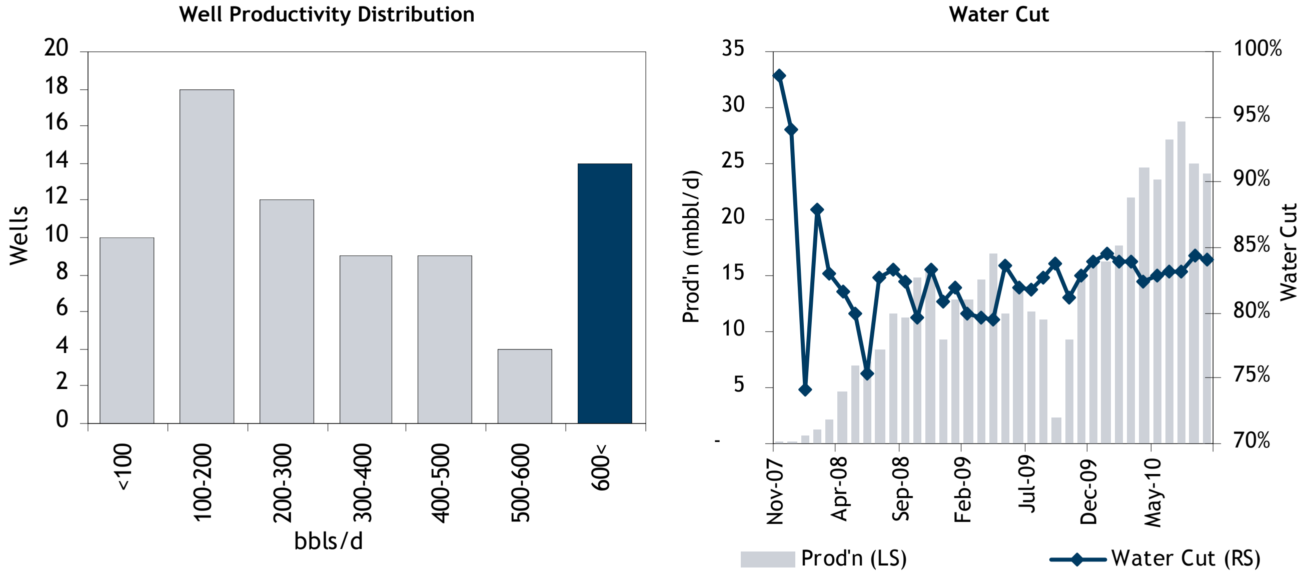
Exhibit 124: Long Lake Efficiency & Utilization



Source: Accumap and RBC Capital Markets

The average well is not good enough as evidenced by low rate & high water cut – The problem remains that the wells are not prolific enough. Even with the increase in well pair count, the average well needs to produce ~660 bbl/d in order to reach design capacity, however roughly only 20% of the total wells are producing at this level (see Exhibit 125). The average rate per well on the project is currently ~400 bbl/d. While it is good to see water cuts stabilize; we are somewhat concerned with project level water cut in the 80–85% range. While it is a function of economics largely determined by oil prices, the higher the water cut the higher the costs per barrel and the closer a well is to its economic limit. Most top quartile projects operate at ~70% water cut.

Exhibit 125: Long Lake Productivity Distribution & Water Cut

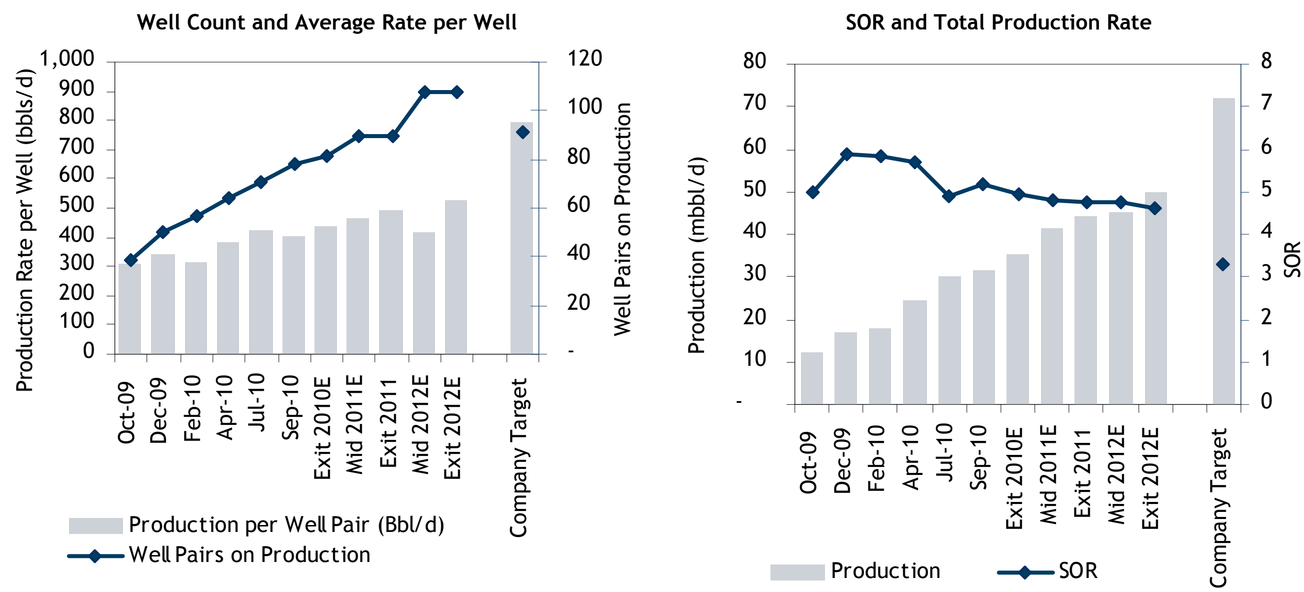


Note: To produce at nameplate capacity each well would need to produce at 972 bbls/d

Source: Accumap and RBC Capital Markets

Our estimates are based on historical performance – For operations to achieve higher rates more quickly than our estimates would suggest, a steep change from historical operational performance needs to occur. While the reservoir can be somewhat unpredictable, and rates may suddenly improve as the steam chambers in the well pairs continue to grow, we believe it is reasonable to set our estimates based on historical performance trends.

Exhibit 126: Long Lake Historical Performance and Estimates



Source: Company documents and RBC Capital Markets

We expect 2010 exit rates to miss guidance – Given the operational performance of Long Lake, we have taken what we believe to be a prudent operational outlook. We recognize that operations have improved since the time of the September 2009 facility turnaround. However, operations continue to disappoint relative to the guidance of the joint venture operator. The operator suggested a 2010 exit production rate of 40,000–60,000 bbl/d. We anticipate a 2010 exit rate of

~30,000 bbl/d. Nexen recently provided guidance of 38,000–45,000 bbl/d gross for 2011. We are estimating 2011 production at Long Lake at ~36,400 bbl/d gross (~12,700 bbl/d net).

We expect the project may reach design capacity mid 2015 – We build our production estimates on the recognition that production growth at Long Lake should continue to come from two sources:

- New well pair tie-ins;
  - The timing of new well pair tie-ins is fairly predictable, roughly three to six months following initial steam.
- Increased rate per well;
  - We have been careful to separate rate per well based on existing wells and new well pairs.

While it may appear in Exhibit 126 that rate per well pair decreases from time to time, the decrease is a reflection of the newest well pairs not contributing to overall production rates thereby reducing the apparent average rate per well. Behind the estimates, however, rate per well pair has been forecast to grow on existing wells with new wells taking the regular amount of time before contributing barrels. This is evidenced in our estimate of total production rate which continues to be upward sloping. In spite of our estimates of increasing rate per well pair at a steady pace similar to historical performance, and adding new well pairs, we do not expect production rate to reach design capacity of 72,000 bbl/d until 2015, roughly seven to eight years following first steam.

Foreign Exchange Rate Hedge

OPTI previously entered into a foreign exchange rate hedge on US$620 million, locking the C$/US$ exchange rate at C$1.19/US$1.00 with an expiry of December 31, 2010.

Management of OPTI offset the effect of $200 million of this hedge in August of this year by entering contracts with an exchange rate of C$1.06/US$1.00. The company will incur a cash charge of ~$25 million in the fourth quarter to settle the foreign exchange hedge on the $200 million. The counter party and OPTI have extended the terms of the original contract to September 30, 2011 at an adjusted rate of C$1.21/US$1.00. We expect this contract to settle at the end of the third quarter at a cash cost of $60–90 million. A $0.01 change in the foreign exchange rate swings the cash effect of the hedge by ~$4 million.

Long Term Debt & Financial Liquidity - The Clock is Ticking…Fast!

OPTI has an over-leveraged balance sheet effectively erasing all project value. The company has ~$2.6 billion in long-term debt and ~$200 million in positive working capital for a net debt balance of ~$2.4 billion. We calculate a DCF of Long Lake of $2.4 billion net to OPTI's 35% W.I.

Exhibit 127: Long Term Debt

Instrument	Rate, Maturity	Currency		Amount
Revolving Credit Facility	Due December 2011	C$	10	mm
First Lien Notes	@ 9.00% due Dec 15, 2012	US$	525	mm
First Lien Notes	@ 9.75% due Aug 15, 2013	US$	300	mm
Secured Notes	@ 8.25% due Dec 15, 2014	US$	1,000	mm
Secured Notes	@ 7.785% due Dec 15, 2014	US$	750	mm
Total		**US$**	**2,585**	**mm**

Source: Company reports and RBC Capital Markets

The cost of OPTI's debt has increased to more than 11% – On August 11, OPTI closed two debt issuances. The company issued US$100 million (face value) First Lien Senior Secured notes due December 15, 2012 and US$300 million (face value) First Lien Senior Secured notes due August 15, 2013. The notes have a stated rate of 9.0% and 9.75% but a yield to maturity of 9.2% and 11.2% respectively. At current production rates, OPTI is paying ~$65.00/bbl in interest expense. At full design capacity, OPTI would be paying ~$24.00/bbl in interest expense.

Unsustainable liquidity – Proceeds of this latest financing were used to repay ~$50 million of short-term debt, to establish an interest escrow account of US$87 million relating to the company's 2013 notes and to provide liquidity for general corporate purposes. In essence, because the project is cash flow negative, we believe that the company is issuing debt in order to be able to pay its interest payments on existing debt.

The company currently has ~$340 million in cash plus available borrowing facilities of ~$180 million on its revolving credit facility (due December 15, 2011) and the ~$90 million interest escrow account for total remaining liquidity of ~$600 million. The problem, however, is that we do not expect the company to have cash flow positive operations until 2013, after we expect the company's current liquidity to be entirely exhausted.

Current operations are cash flow negative – At current production rates of ~30,000 bbl/d gross (~10,500 bbl/d net), operations are roughly breakeven at the field level, meaning that current revenues cover operating and royalty costs but not corporate expenses or capital costs. The largest corporate level expense for OPTI is interest expense, which is approximately $225 million per year. Adding G&A, diluent and transportation expenses increases corporate level expenses to ~$300 million per year. In addition, we estimate annual maintenance capital spending at ~$40 million before any specific project spending, such as the estimated ~$90 million net capital required to drill well pads 12 and 13 or the ~$50 million required to build additional steam capacity.

We estimate that financial liquidity is exhausted by year end 2011 – A wide range of scenarios exist, but we make the following estimates with respect to when the company exhausts its current cash liquidity:

- OPTI may exhaust cash liquidity by the end of Q3/11 – At forecast operations without any specific project spending such as adding new steam generation.
- OPTI may exhaust cash liquidity by the end of Q2/11 – At forecast operations adjusted to include new steam generation.

Should the company be able to draw upon its revolving credit facility, which is due December 15, 2011, and should that revolver be renewed for another year, we estimate that:

- OPTI may exhaust all liquidity by year end 2011 – At forecast operations without any specific project spending such as adding new steam generation.

Surviving into 2012 would only present the added challenge of refinancing US$525 million of First Lien notes, due December 15, 2012 and a possible $400–500 million financing decision on Kinosis.

Given the high level of production required to just become cash flow break-even, we do not believe that OPTI will be able to improve operations sufficiently to operate itself out of its current liquidity challenge or the existing debt burden.

Ongoing Strategic Review Process - Value is in the Eye of the Beholder

Management announced the appointment of advisors to a strategic review process on November 3, 2009. The ongoing strategic review process is in follow up to a previous review of financing options that resulted in OPTI reducing its joint venture working interest from 50% to 35%.

Possible outcomes from the strategic review process:

- Sale of additional working interests in the JV
- Sale of assets
- Corporate sale
- Status quo

Selling working interests is not the fix – Simply stated, aside from gaining time we do not expect that the sale of assets or working interests achieves the goal of making OPTI a stronger company. Given that we calculate the DCF value of Long Lake is essentially equivalent to the value of the outstanding debt, proceeds from a sale of working interests at fair value would not get the company any further ahead for shareholders. It would just make the company smaller.

Selling assets is not the fix – The sale of longer-term assets could generate funds that could be applied against debt but by the nature of the assets being undeveloped we do not expect that proceeds from the sale (see Exhibit 128) of the assets would be sufficient to dramatically change the company's high debt burden. The sale of the long-term assets would also stunt any possible future growth for the company thereby making the company a less attractive investment or takeover candidate.

A corporate sale would be best, but not easy – We believe that the most desirable outcome for shareholders would be a corporate sale of the company. The sale of the company, given the high debt obligation and poor operational performance, is clearly not a guaranteed outcome.

In our view, a potential acquirer would need to have the following unique qualities:

- **A large and strong balance sheet –** Repay or refinance OPTI's debt at lower rates, which could save the acquirer ~$100–200 million per year in interest charges.
- **A willingness to be non-operator –** Perhaps a foreign company that wants exposure to the oil sands in Canada but perhaps without the local experience.
- **A greater interest capturing resources than current production** – A willingness to be patient to resolve operational issues.

Status quo is a likely outcome – Given the challenges of high debt leverage and poor operational performance at Long Lake to date combined with the less than optimum benefits to the company and shareholders of selling only working interests or undeveloped assets, the status quo outcome for OPTI is a very distinct possibility. Should OPTI not find a suitable outcome inside the next 6 - 12 months, we expect a very negative outcome for shareholders.

Valuation

Base vs Unrisked NAV – Upside Potential Tied to Future Projects

Debt significantly erodes all project value at current oil prices – Our Base NAV for OPTI is primarily supported by the company's interest in the developed Long Lake asset, which we calculate at $8.43/share of value given our production and cost outlook. The company's positive net working capital netted off debt is worth ($8.59/share). While we usually allocate 100% DCF value for projects with regulatory approval on the assumption the projects will be advanced and built, we have risked these values for Kinosis by 50% due to the company's financial challenges and our belief that the projects will likely not be built by OPTI. We have included a value of $0.84/share for Kinosis in our Base NAV.

DCF and resource value yield very similar values for long term assets – Our Unrisked NAV also includes DCF value of $1.25/share for the company's other identified project areas at Leismer and Cottonwood, which have not yet entered into the regulatory application stage. While we used a DCF valuation approach for the assets at Leismer and Cottonwood, the implied resource value of this approach calculates to ~$1.39/bbl. We have used a resource value of $0.50/bbl for companies who have Contingent Resource without project definition based on recent transaction history. This DCF analysis verifies that $0.50/bbl is a reasonable valuation for Contingent Resource (Best Estimate). Had we used a resource valuation of $0.50/bbl in place of the DCF analysis, it would have increased our calculation of Unrisked NAV by $0.14/share.

We calculate a Base NAV of $0.68/share. **Our $0.60/share target price is based on a 0.9x multiple of our Base NAV calculation, which is below the peer group average multiple of 1.0x due to our high concern over the company's debt levels and financial liquidity.**

Exhibit 128: OPTI - NAV Summary

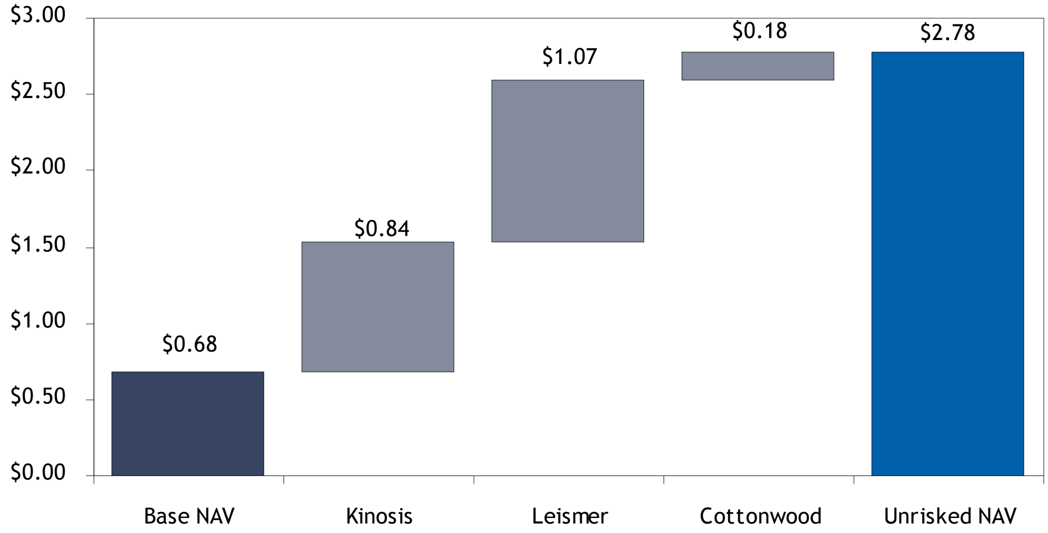
Project	Reserve / Resource Est. mmbbl	Project PV $mm	Implied PV/bbl $/bbl	W.I. %	Risk Factor %	Base NAV $mm	Base NAV $/share	Base NAV % NAV	Unrisked NAV $mm	Unrisked NAV $/share	Unrisked NAV % NAV
Projects - Producing											
Long Lake	1,269	$6,856	$5.40	35%	100%	$2,400	$8.43	1233%	$2,400	$8.43	303%
Total	**1,269**	**$6,856**	**$5.40**			**$2,400**	**$8.43**	**1233%**	**$2,400**	**$8.43**	**303%**
Projects - Reg. Approval											
Kinosis Phase 1	478	$466	$0.98	35%	50%	$82	$0.29	42%	$163	$0.57	21%
Kinosis Phase 2	478	$384	$0.80	35%	50%	$67	$0.24	35%	$134	$0.47	17%
Kinosis Phase 3	478	$342	$0.72	35%	50%	$60	$0.21	31%	$120	$0.42	15%
Kinosis Phase 4	243	$178	$0.73	35%	50%	$31	$0.11	16%	$62	$0.22	8%
Total	**1,677**	**$1,371**	**$0.82**			**$240**	**$0.84**	**123%**	**$480**	**$1.69**	**61%**
Projects - Pre Reg. Application											
Leismer	1,689	$869	$0.51	35%	0%	$0	$0.00	0%	$304	$1.07	38%
Cottonwood	580	$150	$0.26	35%	0%	$0	$0.00	0%	$52	$0.18	7%
Total	**2,269**	**$1,019**	**$0.45**			**$0**	**$0.00**	**0%**	**$357**	**$1.25**	**45%**
Total Projects	**5,214**	**$9,246**	**$1.77**			**$2,639**	**$9.28**	**1357%**	**$3,236**	**$11.37**	**409%**
Corporate Adjustments											
Net Working Capital						$194	$0.68	100%	$194	$0.68	25%
Long Term Debt						($2,639)	($9.27)	-1356%	($2,639)	($9.27)	-334%
Total Corporate						**($2,445)**	**($8.59)**	**-1257%**	**($2,445)**	**($8.59)**	**-309%**
Net Asset Value						**$195**	**$0.68**	**100%**	**$791**	**$2.78**	**100%**

Risk Factors:
- 100% of DCF value given to producing projects and projects that have received regulatory approval
- 50% - 0% of DCF value given to projects in the approval/regulatory application process due to corporate liquidity risk

Assumptions:
- WTI crude oil assumptions: US$78.02, US$83.00, US$85.00 for 2010E, 2011E and 2012E forward respectively
- Henry Hub natural gas assumptions: US$4.54, US$5.00, US$5.50 for 2010E, 2011E and 2012E forward respectively
- US/CAD foreign exchange assumptions: $0.96, $0.95, $0.95 for 2010E, 2011E and 2012E forward respectively
- After tax discount rate assumption: 8.5%
- Long term operating cost assumption: $22.50/bbl

Source: Company reports and RBC Capital Markets estimates

Exhibit 129: OPTI Upside Potential – Base and Unrisked NAV



Source: Company reports and RBC Capital Markets estimates

Relative Valuation – The Stock Appears Expensive

OPTI is currently trading at an 101% P/NAV ratio (Base) and a 25% P/NAV ratio (Unrisked). Peer group average valuations are 86% P/NAV (Base) and 49% P/NAV (Unrisked).

While we see potential upside value to OPTI's current share price, we believe that upside potential can only be realized in one of three ways:

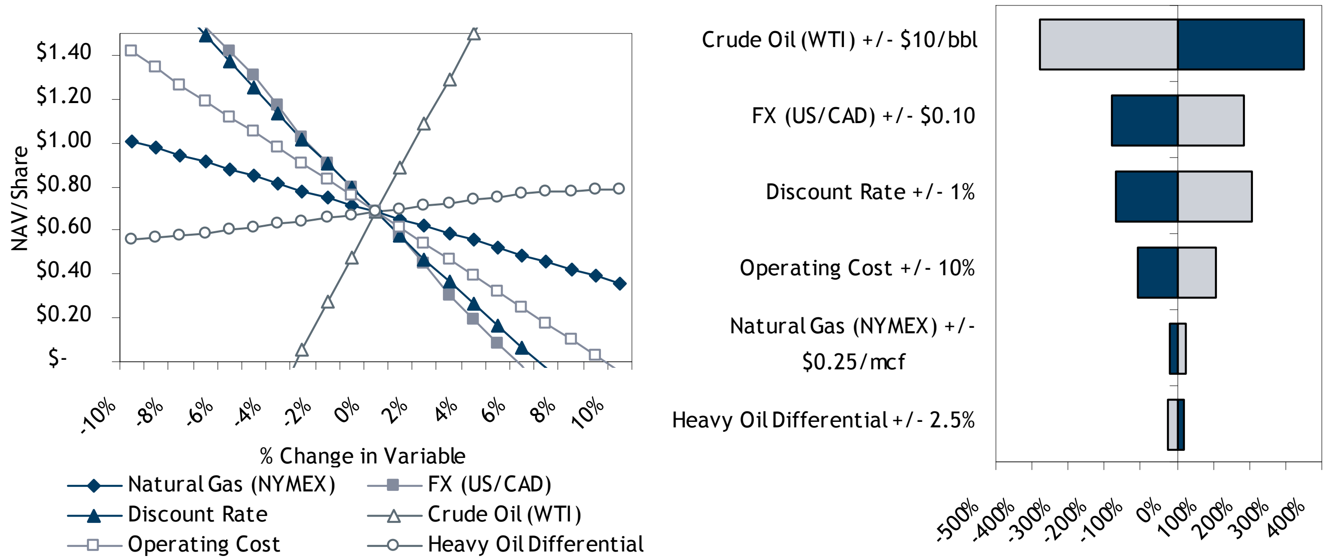
- The sale of OPTI to an acquirer willing to pay for captured resources and future project potential.
- Operational results that improve more quickly than we have forecast as evidenced by higher and more reliable production rates and lower SOR.
- A willingness on the part of investors to discount a higher long-term oil price.

We believe investors are tentatively pricing the stock at full Base NAV value in anticipation of capturing upside potential from a corporate change of control transaction. We maintain a speculative risk rating because we believe the likelihood of the company making significant operational improvements in the near term is low and the predictability of a change of control event is indeed highly speculative in terms of both timing and valuation.

Sensitivities – Debt Leverage Causes Highly Sensitive Valuation

OPTI's NAV is positively correlated to, and highly sensitive to, changes in the long-term oil price. In fact, because of the high debt leverage of the company, OPTI is more sensitive to oil price than most other oil sands companies (see Exhibit 130). Our calculation of NAV is negatively correlated to changes in the discount rate, the Canadian/US dollar exchange rate, operating costs, heavy oil differentials and natural gas prices. Next to oil price, the company's NAV is most sensitive to the discount rate and the exchange rate.

Exhibit 130: OPTI - NAV Sensitivity



Source: Company reports and RBC Capital Markets estimates

Risks to Target Price

We have initiated coverage of OPTI Canada with a Speculative (Spec) risk rating. In general, the company is exposed to a higher degree of risk due to the company's high debt leverage, low level of financial liquidity and poor operational performance.

We identify six key risks to our target price:

1. **Oil Prices** – OPTI's production is 100% weighted to oil. To mitigate this risk, the company entered into oil price hedge contracts on 3,000 bbl/d at US$65.33/bbl that expire at year end 2010. At current oil prices, these contracts would result in a loss of ~C$6 million in the fourth quarter. As demonstrated in Exhibit 130, fluctuations in oil price represent the greatest effect on the NAV of the company. While all oil sands companies are sensitive to oil price, OPTI is more sensitive than most given the company's high degree of financial leverage. We assume a flat oil price of US$85.00/bbl from 2012 onward, which is an oil price very close to calculating a zero value Base NAV. Fluctuations up or down from US$85.00/bbl create large swings in our NAV calculation.

2. **Discount Rates** – We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations of E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk and lower reserve replacement and re-investment (i.e., exploration) risk than E&P companies. However, oil sands companies have greater regulatory, environmental and project execution risk over the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our target price, materially.

3. **Foreign Exchange Rates** – Capital and operating costs will be incurred in Canadian dollars, yet the company's production is priced in U.S. dollars. Fluctuations of the U.S./Canadian dollar exchange rate can greatly affect the value of future cash flows. To offset this foreign exchange rate risk exposure, the company has structured its $2.2 billion of debt in U.S. dollars. OPTI also has a foreign exchange hedge that was entered into when the Canadian dollar was much weaker against the U.S. dollar and therefore if forced to settle this hedge contract, which expires at the end of the third quarter of 2011, we estimate the company would incur a cash charge of $60–90 million. We assume a flat US$0.95/C$1.00 exchange rate long term.

4. **Financial Leverage, Liquidity & Financing Risks** – OPTI has financial liquidity to see the company through its existing operations to year end 2011. At current, and near-term forecasted production levels, the company does not generate enough cash flow to cover operating and financing costs. As such, we expect it to be difficult for the company to finance its 2011 capital budget and the ~$150 million (~$50 million net) steam facility expansion at this time or a new project expansion at Kinosis. Assuming that management will want to be financially prepared before exhausting liquidity, we expect the company to conclude its strategic alternatives process or structure additional financing by mid 2011. The ability of the company to repay or refinance US$525 million of first lien debt expiring December 2012 is a material and significant risk to the company. The ability of the company to meet its interest payment obligations and to refinance any maturing debt issues presents a significant financial burden to OPTI. The financial health and outlook of OPTI significantly influences our perception of viability and value of the company.
5. **Regulatory Risks –** OPTI, with Long Lake already developed and regulatory approval in hand for the next several possible stages of development at Kinosis, is not immediately affected by regulatory risk. However, future stages of development beyond Kinosis require regulatory approval. For instance, we have included a risked value of $0.84/share for Kinosis in our Base NAV, an incremental $0.84/share of value for Kinosis in our Unrisked NAV and a value of $1.25/share for Cottonwood and Leismer in our Unrisked NAV. The company's growth potential as well as our perception of the company's value in the event of a change of control event would be materially affected should the regulatory process be delayed or not forthcoming.
6. **Environmental Risks** – Oil sands producers in general have come under increased scrutiny for environmental issues. While longer term costs or product marketing concerns related to environmental issues is unclear at this time, it does not present a risk to the company's development plans or our perception of the valuation of the company. We note that OPTI is engaged in the development of In-Situ oil sands, which typically have less effect on land, air and water than oil sands mining projects. However, the company is also engaged in upgrading, which does result in higher emissions. Higher emissions is also caused from the gasification process that utilizes the energy of the heaviest ends of the barrel in place of cleaner burning natural gas. While emissions are higher with OPTI's fully integrated upgrading process, the process also lends itself to carbon capture. The cost of implementing carbon capture is uncertain at this time.

Exhibit 131: OPTI - Operational & Financial Summary

C$ millions, unless noted	2007	2008	2009	2010E	2011E	2012E
Production						
Bitumen Production - Gross (bbl/d)	0	7,827	12,444	24,657	36,395	40,681
Working Interest	0	50%	35%	35%	35%	35%
Bitumen Production - Net (bbl/d)	**0**	**3,914**	**4,355**	**8,630**	**12,738**	**14,238**
PSC & PSH Sales (bbl/d)	n.a.	15,450	7,100	8,854	12,738	14,238
YOY Production Growth (%)	n.a.	n.a.	11%	98%	48%	12%
Bitumen (%)	n.a.	100%	100%	100%	100%	100%
Commodity Prices						
WTI Crude Oil (US$/bbl)	$72.25	$99.50	$61.81	$78.02	$83.00	$85.00
Ed. Par (C$/bbl)	76.05	102.75	66.48	77.69	86.05	88.16
Bow River Heavy (C$/bbl)	50.50	83.00	59.25	68.23	73.30	72.29
Exchange Rate (US$/C$)	0.93	0.94	0.88	0.96	0.95	0.95
Henry Hub - NYMEX (US$/mcf)	6.95	8.85	3.92	4.54	5.00	5.50
AECO (C$/Mcf)	6.60	8.15	3.94	4.05	4.37	4.90
Realized Pricing and Costs						
Revenue[1.] ($/bbl)	**n.a.**	**nmf**	**$91.67**	**$78.72**	**$85.32**	**$89.61**
Royalties ($/bbl)	n.a.	nmf	(1.20)	(2.79)	(4.81)	(5.38)
Operating Costs ($/bbl)	n.a.	nmf	(92.24)	(67.16)	(46.08)	(41.92)
Diluent & Feedstock ($/bbl)	n.a.	nmf	(64.28)	(23.66)	(14.63)	(13.85)
Transportation Costs ($/bbl)	n.a.	nmf	(8.26)	(5.73)	(5.97)	(6.35)
Netback ($/boe)	**n.a.**	**nmf**	**(74.31)**	**(20.63)**	**13.84**	**22.10**
Consolidated Financials						
Revenue (net of royalties)	$0.0	$187.2	$138.9	$226.9	$366.7	$428.2
Other Income	13.3	17.2	5.0	8.1	7.6	9.5
Diluent Purchases	0.0	164.5	102.2	74.5	68.0	72.0
Operating and G&A	14.2	101.4	163.7	226.6	232.2	237.8
Interest	11.9	39.4	172.1	224.7	225.2	223.2
DD&A	2.0	17.1	26.1	53.6	85.0	90.0
Pre-Tax Income	(18.6)	(592.3)	(234.1)	(359.4)	(328.9)	(218.4)
Current Tax	0.0	0.0	0.0	0.0	0.0	0.0
Deferred Tax	(9.1)	(115.8)	72.0	(31.0)	(92.1)	(61.1)
Net Income	**(9.5)**	**(476.5)**	**(306.2)**	**(328.4)**	**(236.8)**	**(157.2)**
Cash Flow From Operations	**(11.5)**	**8.3**	**(255.7)**	**(383.6)**	**(242.3)**	**(126.8)**
Capital Expenditures	**1,108.0**	**890.0**	**158.0**	**78.3**	**159.8**	**52.9**
Per Share Data						
Diluted CFPS ($/Share)	**($0.06)**	**$0.04**	**($1.26)**	**($1.36)**	**($0.86)**	**($0.45)**
YOY Diluted CFPS Growth (%)	n.a.	nmf	nmf	nmf	nmf	nmf
Diluted EPS ($/Share)	**($0.05)**	**($2.43)**	**($1.51)**	**($1.17)**	**($0.84)**	**($0.56)**
YOY Diluted EPS Growth (%)	n.a.	nmf	nmf	nmf	nmf	nmf
Weighted Avg Diluted Shares O/S (mm)	188.6	205.8	203.3	281.8	281.8	281.8
Financial Leverage						
Net Debt	1,464	2,778	2,105	2,547	2,951	3,132
Long Term Debt	1,735	2,618	2,273	2,639	2,639	2,639

1. Revenue includes revenue from all products: PSC, PSH, Bitumen and power. Netbacks are calculated per bbl of bitumen produced.
Source: Company reports and RBC Capital Markets estimates

Exhibit 132: OPTI - Company Profile

Business Description

OPTI Canada Inc. is an integrated oil sands company focused in the Athabasca region, near Fort McMurray, Alberta. OPTI's principal asset is a 35% non-operated interest in the Long Lake SAGD project. The on-site Long Lake upgrader is the first to utilize OPTI's OrCrude™ gasification and hydrocracking process. Long Lake began producing bitumen in 2008 and announced first production of 39° API Premium Sweet Crude (PSC™) in January 2009. Also in January 2009, while reviewing the company's strategic alternatives, OPTI sold 15% of the Long Lake project and joint venture lands, including Cottonwood and Leismer, to Nexen Inc. for $735 million.

Land Position

Key Areas	W.I.	Gross Acres	Net Acres
Long Lake	35%	71,040	24,864
Leismer	35%	85,760	30,016
Cottonwood	35%	90,240	31,584
Other	35%	12,800	4,480
Total	**35%**	**259,840**	**90,944**

Reserve & Resource Estimates (McDaniel & Associates)

(mmbbl)	Reserves		Contingent Resources
	1P	2P	Best
Long Lake	194	711	153
Leismer	-	-	167
Cottonwood	-	-	591
Other	-	-	203
Total	**194**	**711**	**1,114**

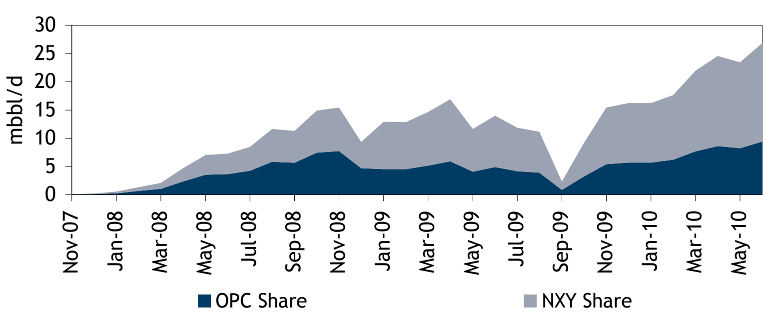
Management Team

Name	Position	Experience
Christopher Slubicki	President & CEO	Vice Chairman of Scotia Waterous
Travis Beatty	VP Finance & CFO	Director Planning, OPTI Canada
Joe Bradford	VP Legal & Admin	Senior VP, Advanced Biodiesel Group
Al Smith	VP Marketing	Mgr of Market Dev. at Chevron

Board of Directors

Name	Experience
James M. Stanford (Chairman)	President, CEO and Director of Petro-Canada
Christopher Slubicki	Vice Chairman of Scotia Waterous
Ian W. Delaney	Chairman and CEO of Sherritt Intl Corp.
Charles Dunlap	CEO and Pres. of Pasadena Refining System Inc.
David Halford	EVP, Finance and CFO of ENMAX Corporation
Edythe (Dee) Marcoux	Chairman and CEO of Ensyn Energy

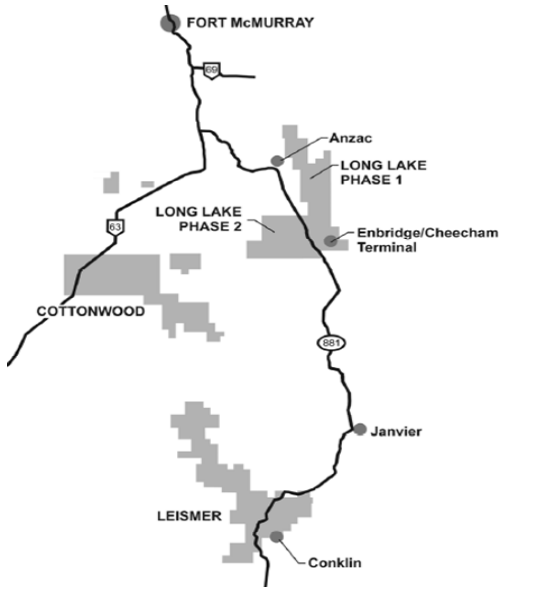
Long Lake Production Profile



Recent News

Aug-10	Announces $400 mm debt financing
Jun-10	Announces change to Board of Directors
Apr-10	Long Lake update, 18,700 bbls/d in Q1
Nov-09	Announces review of strategic alternatives

OPTI Canada Lease Map



OrCrude Process

OPTI's proprietary OrCrude process, combined with existing commercial technologies such as gasification and hydrocracking, produces premium synthetic sweet crude oil The asphaltenes are converted to a low-energy synthetic fuel gas. The main benefits of the process are that the project requires less purchase of natural gas; the process makes all the hydrogen needed, and is more energy efficient. Gasifying the bottom of the barrel can result in an energy utilization of over 90%, significantly higher than conventional coking technologies. The reduced dependence on purchasing natural gas (the single largest and most variable component of in-situ operating costs) gives the OrCrude process a strong competitive advantage, more so at times of high natural gas prices. Premium Sweet Crude also has a marketing advantage. The sulphur content is less than 10 parts per million, and 70% of the barrel can be refined into diesel, jet fuel and gas oil.

Source: Company reports and RBC Capital Markets

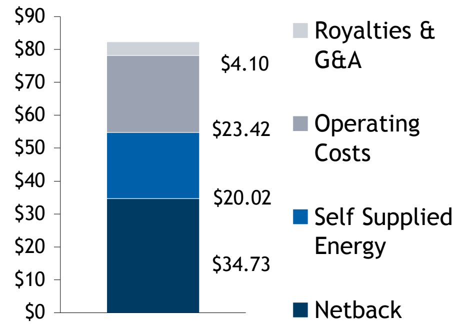
Exhibit 133: OPTI - Financial Profile

Insider Ownership

Management	Shares (M)	Options (M)	Total (M)	%of FD
Christopher Slubicki	163	1,414	1,577	0.6%
Travis Beatty	16	247	263	0.1%
Al Smith	29	192	221	0.1%
Joe Bradford	10	200	210	0.1%
Total Management	**229**	**2,228**	**2,457**	**0.9%**

Directors	Shares (M)	Options (M)	Total (M)	%of FD
James M. Stanford	128	87	215	0.1%
Ian W. Delaney	92	57	149	0.1%
Charles Dunlap	11	50	61	0.0%
Edythe (Dee) Marcoux	8	43	51	0.0%
David Halford	2	29	31	0.0%
Total Directors	**241**	**266**	**507**	**0.2%**
Total	**469**	**2,494**	**2,963**	**1.0%**

Potential Netback (Management Estimates)



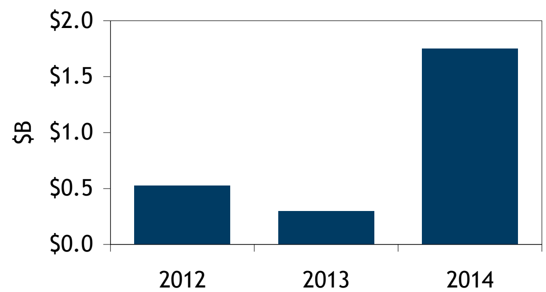
Assumptions: US$75 WTI, US$6.25 NYMEX; $0.90 FX
30% Heavy-to-Light diff, pre-payout royalties

Debt Facilities

Facility	Amount	Interest Rate	Maturity Date	Interest Payment
First Lein Notes	US$525	9.000%	Dec-12	$47.25
First Lein Notes	US$300	9.750%	Dec-13	$29.25
Senior Notes	US$1,000	8.250%	Dec-14	$82.50
Senior Notes	US$750	7.875%	Dec-14	$59.06
Total	**US$2,575**	**8.47%**		**US$218.1**
Credit Facility	$190	Floating	Dec-11	n.a.

At Sep 30 2010, 2.8 million options were outstanding at a weighted average exercise price of $4.42

Debt Maturity Schedule



Selected Quarterly Operating & Financial Data

Production		Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Q1 10	Q2 10	Q3 10
Bitumen Production	(bbl/d)	13,192	13,443	14,263	8,506	13,606	18,700	24,900	26,400
Realized Pricing	($/bbl)	nmf	$39.50	$60.45	$63.81	$73.08	$77.00	$73.33	$66.00

Financials

Cash Flow	($mm)	$15.0	($31.0)	($58.6)	($81.9)	($84.2)	($84.8)	($111.4)	($94.5)
Diluted CFPS	($/share)	$0.08	($0.15)	($0.29)	($0.40)	($0.41)	($0.30)	($0.40)	($0.34)
Net Income	($mm)	($470.0)	($97.9)	($8.8)	$11.6	($211.1)	($50.1)	($152.3)	($46.1)
Diluted EPS	($/share)	($2.41)	($0.48)	($0.04)	$0.06	($1.04)	($0.18)	($0.54)	($0.16)
Capital Spending	($mm)	$90.7	($609.8)	($6.1)	$31.1	$21.5	$30.2	$18.4	$112.3
Capex/CF	(x)	6.0 x	nmf	nmf	nmf	nmf	nmf	nmf	nmf
Net Debt	($mm)	$2,777.7	$2,128.2	$2,102.5	$1,999.2	$2,104.7	$2,175.1	$2,332.1	$2,444.9
Net Debt/CF	(x)	185.0 x	nmf	nmf	nmf	nmf	nmf	nmf	nmf
Debt/Capitalization	(%)	52%	0%	59%	61%	53%	0%	58%	67%

Source: Company reports, SEDI and RBC Capital Markets

SilverBirch Energy Corp. (TSX-V: SBE; $7.20)

Standing on the Shoulders of Giants

Market Statistics			Net Asset Value			
Rating		Sector Perform			Base	Unrisked
Risk Qualifier		Speculative	Net Asset Value	($mm)	$424	$546
Target Price		$8.00	NAV/Sh	($/share)	$8.05	$10.36
Market Price		$7.20	P/NAV	(%)	89%	69%
Implied Return		11.1%	Target Price/NAV	(%)	99%	77%
Capitalization			**Resources**			
Diluted Shares O/S	(mm)	50.0	Oil Sands EV[(a)]	($mm)		$316.4
Market Capitalization	($mm)	$360.0	2P Reserves	(mmbbl)		n.a.
Net Debt	($mm)	($43.6)	Contingent Resources[(b)]	(mmbbl)		891
Enterprise Value	($mm)	$316.4	EV/Bbl[(c)]	($/bbl)		$0.36

Operating & Financial		2007A	2008A	2009A	2010E	2011E	2012E
Total Production	(boe/d)	n.a.	n.a.	n.a.	0	0	0
Operating Cash Flow	($mm)	n.a.	n.a.	n.a.	($1.4)	($5.5)	($6.6)
Diluted CFPS	($/share)	n.a.	n.a.	n.a.	($0.04)	($0.11)	($0.11)
Sensitivity to WTI	**(US$/bbl)**	**$60**	**$70**	**$80**	**$90**	**$100**	**$110**
NAV/Share	($/share)	($17.58)	($7.10)	$2.79	$12.39	$21.29	$29.83
P/NAV	(%)	nmf	nmf	39%	172%	296%	414%

(a) Adjusted to exclude the estimated value of non- oil sands assets
(b) Best Estimate
(c) Based on 2P reserves + best estimate Contingent Resources

Source: Company reports and RBC Capital Markets estimates

Investment Highlights

- **Exploration success could reshape SilverBirch** – Exploration success this winter could set the stage for a 250-million-barrel discovery and a 20,000 bbl/d In-Situ project as early as 2015.
- **Mining project moving forward –** The preliminary cost estimate for Frontier/Equinox is expected by late 2010 or early 2011. We expect a positive resource estimate revision of up to 600 million barrels net to SilverBirch is possible in early 2011. Management anticipates filing its regulatory applications by mid-year 2011 for a 290,000 bbl/d (gross) development with first production by 2020.
- **Expect a financing within 12-15 Months –** SilverBirch has sufficient liquidity to move Frontier into the regulatory process and to complete this winter season of exploration. We expect the company to seek new financing by late 2011 or early 2012.
- **Speculative risk –** The long-duration nature of the company's asset base makes our calculation of NAV very sensitive to oil price and discount rate assumptions. Purchasing the stock at this point introduces a high degree of exploration risk at Lease 418/271. The company also has a high degree of regulatory risk, long-term financing risk and execution risk.
- **Valuation ahead of results –** We believe the current stock price is reflecting investor anticipation of exploration success on the company's core hole winter program, which we have not factored into our NAV or our 12-month target price. We calculate the stock to be trading at a P/NAV ratio of 89% (base) and 69% (Unrisked). We calculate a Base NAV of $8.05/share and an Unrisked NAV of $10.36/share. We have not factored exploration success at Lease 418/271 into our NAV, but it could provide as much as $2.30/share upside potential based on our assumptions of resource potential.
- **Recommendation** – Sector Perform, Speculative Risk, 12-month target price of $8.00/share. Our $8.00/share target price is based on a 1.0x multiple of our base NAV, which is in line with the peer group average.

Summary & Investment Thesis

We initiate coverage of SilverBirch Energy Corp. (TSXV: SBE) with a Sector Perform, Speculative Risk rating and a 12-month target price of $8.00 per share, based on a 1.0x multiple of our risked NAV analysis, which is in line with the peer group average.

In our view, SilverBirch has exposure to significant exploration upside potential that we have not reflected in our NAV or our target price. The company will be moving its Frontier and Equinox mining projects into the regulatory process; however, it will likely be a 10-year wait to first production. We anticipate a possible positive revision to Contingent Resources and news of the company's winter exploration program, both of which could meaningfully impact our view of valuation.

We estimate that the exploration efforts on lease 418/271 could discover 250 million to 275 million barrels of recoverable bitumen – We are encouraged that the same geotechnical team that worked up the Lease 421 area play concept for UTS is behind Lease 418/271. Based on very generic (and conservative) assumptions, we estimate the lease could contain 250 million to 275 million barrels of recoverable bitumen based on 10 prospective sections, average pay thickness of 20 metres, average porosity of 30%, average bitumen saturation of 70% and an average recovery factor of 35%. A resource discovery of this size could potentially support a development of 20,000 bbl/d for up to 30 years.

A discovery of 250 million to 275 million barrels would have an implied value of ~$2.30/share based on our applied value of $0.50/bbl for Contingent Resource (Best). However, we remind investors that this lease has not yet been drilled and that the soonest an official Contingent Resource (Best) estimate could be attained would be the third quarter of 2012.

Pending exploration success, first production could be achieved by 2015 – The company is undertaking what could be a very meaningful exploration program on Lease 418/271. Success here could result in production in 2015 to 2017.

Portfolio of long-duration assets is highly sensitive to oil price – SilverBirch has a long-duration, high-growth-potential portfolio of oil sands development projects. The company's most advanced project is the Frontier/Equinox mining project, which is approaching the regulatory-application stage. The project will not likely be in production until 2020. However, the production potential of the full development plan is 240,000 bbls/d gross (120,000 bbls/d net) at Frontier and 50,000 bbls/d gross (25,000 bbls/d net) at Equinox. The long-duration nature of the portfolio makes the asset value highly sensitive to changes in oil prices.

We have estimated a capital intensity of $80,000/bbl/d for the mine and extraction facilities at Frontier, a cost estimate that we made based on Imperial Oil's (TSX: IMO) Kearl non-upgraded mine project which that company's management estimated at $72,000/bbl/d. We have inflated the cost estimate of Imperial's Kearl project by ~10% to factor in possible inflationary pressure between now and the time of the Frontier project. We estimate Phase 1 of Frontier will cost $3.2 billion net to SilverBirch ($6.4 billion gross), which presents a significant financing challenge in the 2015 time frame.

Positive revision to Contingent Resource (Best Estimate) possibly up by two-thirds – Management expects that the company may have a positive revision of almost two-thirds to its Contingent Resource estimate (best) at Frontier as the revised mine plan will include core wells from last winter season and a total volume to bitumen-in-place (TV:BIP) ratio of 16:1.

12-15 months of liquidity – We estimate that SilverBirch has sufficient capital liquidity to pursue its spending plans until the end of the first quarter of 2012 and we expect the company will need another injection of funds by late 2011 or early 2012. The company has no outstanding debt.

An updated resource estimate is expected by early 2011 – This resource update will come in conjunction with the updated Norwest mine-pit design that incorporates the 68 wells drilled in the 2009/2010 winter program and a 16:1 TV:BIP ratio. Management expects the Contingent Resource estimate could increase by up to 600 million barrels net to SilverBirch, moving the best estimate up to the level of the current High Estimate.

Exhibit 134: SilverBirch - Pros & Cons

Pros	Cons
Production Growth Potential – SilverBirch has captured a project portfolio that is expected to deliver 290,000 bbls/d gross (145,000 bbls/d net to SilverBirch)	**Long Lead Time to First Production** – Production from Frontier/Equinox is likely in the 2020 time frame. Pending In-Situ exploration success at Lease 418/271, production is not likely until 2016+
Current Liquidity - The company is financed for its spending plans to the end of Q1/12	**Future Equity Dilution** – The company's long term financing requirements mean likely equity dilution long term
Oil Weighting – Our view of long term oil prices supports the development of SilverBirch's assets	
Potential Resource Upside – Potential to add up to 600 million net barrels of Contingent Resource by way of a revised mine plan at Frontier/Equinox	
Exploration Potential – Winter drilling on Lease 418/271 could indicate significant resource potential and a possible In-Situ development opportunity	
Zero Debt Balance – The company has no outstanding debt and no immediate plans to issue debt	

Source: Company reports and RBC Capital Markets

Potential Catalysts

Watch for the following near-term potential catalysts at Frontier/Equinox in the coming quarters:

- Completion of the DBM and preliminary cost estimate by late 2010 or early 2011.
  - We estimate a capital cost intensity of $80,000/bbl/d for a total Phase 1 cost estimate of $6.4 billion gross ($3.2 billion net) for production and extraction capacity of 80,000 bbls/d with no upgrading.
- An updated Contingent Resource estimate is expected in the first quarter of 2011.
  - This update will come in conjunction with the updated Norwest mine-pit design that incorporates the 68 wells drilled in the 2009/2010 winter program and an expected TV:BIP ratio of 16:1. We expect the resource estimate could increase by up to 600 million barrels net to SilverBirch, moving the best estimate up to the current high estimate.
- Filing of the regulatory application by mid-year 2011.

Watch for the following near-term potential catalysts at Lease 418/271 in the coming quarters:

- Start-up of the exploration drilling program before year end and continuing through the first quarter of 2011.
  - Management is targeting a drilling density of approximately two wells per section by the end of this winter season.
- Results from the program are expected in the third quarter of 2011.
  - Pending success this winter, we expect a similar program next winter.

We expect the company to be back in the market for financing by late 2011.

Longer term, the company could be in a position to book Contingent Resources at Lease 418/421 by mid 2013, at which point it could be ready to prepare and file its regulatory application for the lease. Regulatory approval for Frontier/Equinox is anticipated by late 2013 or early 2014.

Exhibit 135: SilverBirch - Potential Catalysts

2011E	2012E	2013E+
Q1 – DBM study completed, preliminary cost estimate for Frontier & Equinox	Q1 – Engineering and pre-development works for Frontier and Equinox projects	Q1 2013 – Book Contingent Resource at Leases 418/271
Q1 – Winter core hole drilling focused on Leases 418/271 (initiated in Q4/10)	Q3 – Engineering and development works for Lease 418/271 projects	2013 – Regulatory application for commercial project at Leases 418/271
Q1 – Resource update for Frontier & Equinox		2013/2014 – Regulatory approval and sanctioning of Frontier and Equinox projects
Q3 – Regulatory application for 290,000 bbls/d (gross) Frontier and Equinox projects		2014+ – Sanctioning In-Situ project on Leases 418/271
Q3 – Preliminary results following winter drilling at Leases 418/271		2016+ – First bitumen at Lease 418/271
Q4 – Continued winter core hole drilling at Leases 418/271		

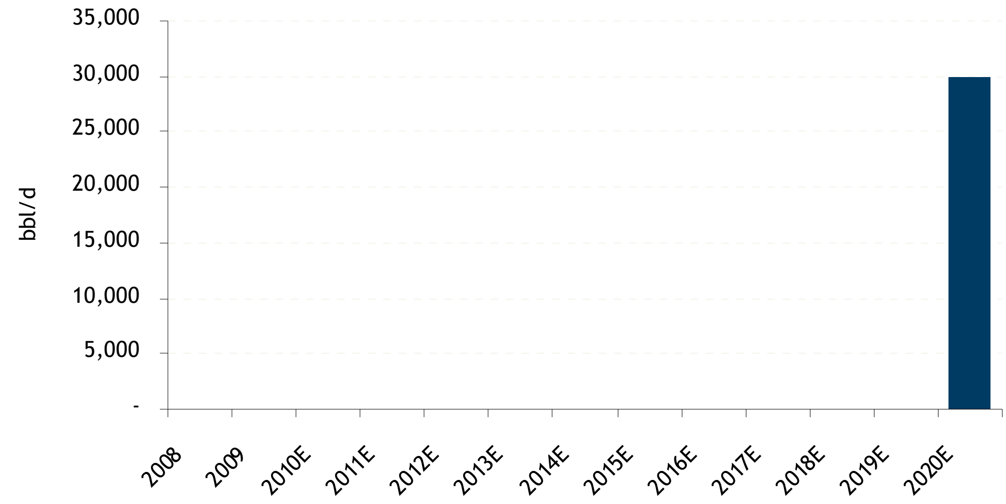
Source: Company reports and RBC Capital Markets estimates

Company Overview

Plan of Arrangement, Asset & Project Summary

SilverBirch Energy was formed on October 1, 2010 by way of a plan of arrangement between UTS Energy Corporation and Total E&P Canada Ltd. SilverBirch has ~$53 million of cash and a portfolio of oil sands leases with exposure to both mining and In-Situ projects. SilverBirch is the only small company with oil sands mining leases.

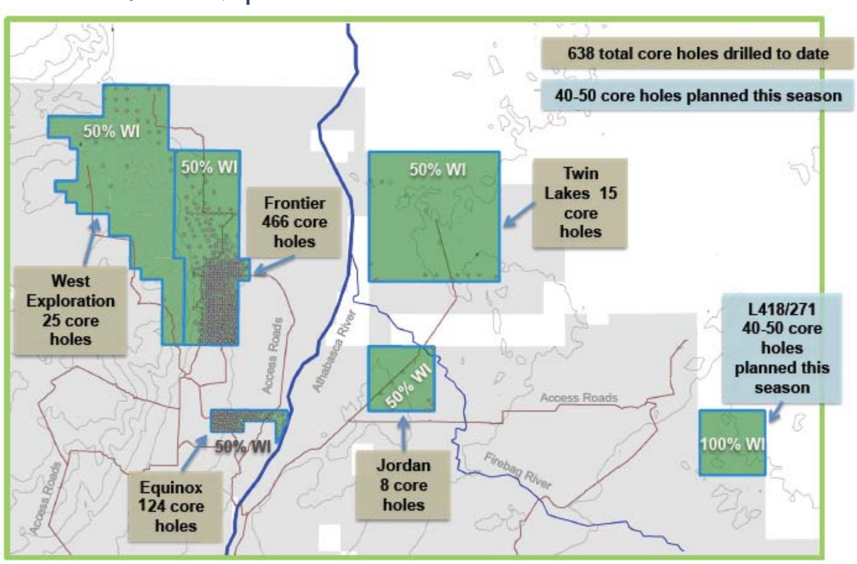
Exhibit 136: SilverBirch - Production Forecast



Source: RBC Capital Markets estimates

The company's leases, located north of Fort McMurray, Alberta, provide it with both mining and In-Situ development opportunities. The company holds a 50% working interest on mining leases with Teck Resources. SilverBirch also holds a 50% working interest with Teck on leases northwest of the Frontier mineable area in the Birch Mountains that are believed to hold In-Situ oil sands potential. In addition, the company holds Lease 418/271 at a 100% working interest, which will be tested this winter for In-Situ potential with a 40-50 well core hole program.

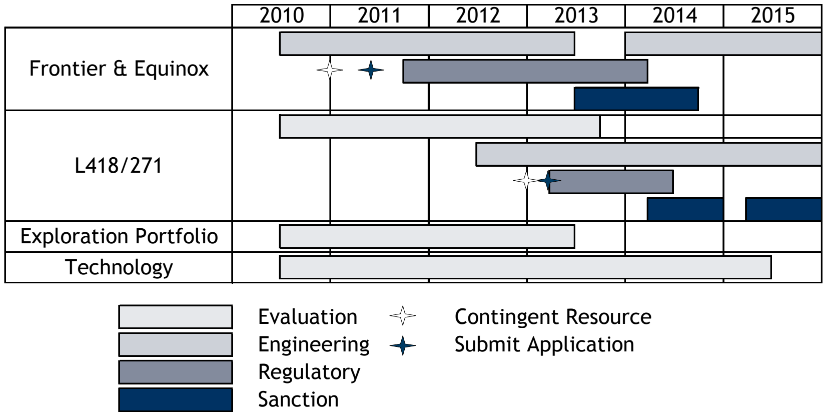
Exhibit 137: Lease Map & Delineation



Source: Company reports

The company has impactful plans and a well defined development schedule, but first production is five years away pending exploration success and 10 years off based on tangible projects in hand.

Exhibit 138: Corporate Development Schedule



Source: Company reports and RBC Capital Markets estimates

Frontier & Equinox Mining Leases – Moving Forward

The Frontier and Equinox projects are the most advanced in the company's portfolio. At Frontier, Teck Resources and UTS Energy assembled six oil sands leases covering an area of 65,280 acres at Crown land sales in late 2005 and 2006. These leases have an initial term of 15 years. At Equinox, the partners share lease 14, which is 7,146 acres. Lease 14 has an initial term expiring in 2015.

The partners have drilled 466 core holes at Frontier and 124 core holes at Equinox. This drilling density is higher than the level required to move this project into the regulatory process.

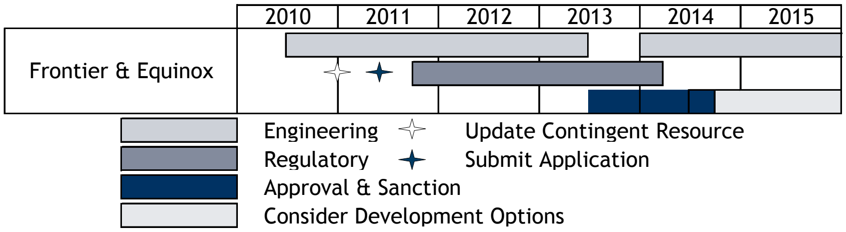
We expect the regulatory application for Frontier and Equinox to be filed in mid-2011. Regulatory approval for mining projects can take 30 to 36 months; therefore, approval is expected in late 2013 or early 2014. The regulatory application is expected to be for three phases of 80,000 bbls/d for total production at Frontier of 240,000 bbls/d gross (120,000 bbls/d net) and for Equinox to be treated as a satellite mine development (effectively a Frontier Phase 4) with up to 50,000 bbls/d gross (25,000 bbls/d net) production. The application will not include upgrading, significantly reducing capital intensity as well as the environmental footprint when compared to fully integrated mining projects.

Capital Spending Ramp Up to Follow Regulatory Approval

We do not expect the partners to spend much on front-end engineering work until project approval has been received. We expect SilverBirch to spend approximately $10 million to $12 million on early planning and the design basis memorandum (DBM) between now and the end of the first quarter of 2012. The front end engineering and design (FEED) is expected to begin following receipt of regulatory approval, which management has estimated to cost approximately $100 million gross ($50 million net).

We have estimated a capital intensity of $80,000/bbl/d for the mine and extraction facilities, a cost estimate that we believe is reasonably inflated from Imperial Oil's (IMO-T) Kearl non-upgraded mine, which has an estimated capital intensity of $72,000/bbl/d. We estimate Phase 1 of Frontier to cost $3.2 billion net to SilverBirch ($6.4 billion gross), which presents a significant financing challenge in the 2015 time frame.

Exhibit 139: Frontier & Equinox Development Schedule



Source: Company reports and RBC Capital Markets estimates

Resource Estimates - Set to Increase by up to Two-Thirds

An updated resource estimate is expected by early 2011 – This resource update will come in conjunction with the updated Norwest mine-pit design that incorporates the 68 wells drilled in the 2009/2010 winter program and a 16:1 TV:BIP ratio. Management expects the Contingent Resource estimate could increase by up to 600 million barrels net to SilverBirch, moving the best estimate up to the level of the current high estimate.

Sproule Unconventional has assigned the 1.780 billion barrels gross (891 million barrels net) of Contingent Resource (Best Estimate) to the Frontier and Equinox leases based on the extensive core hole evaluation work done to date and a 12:1 TV:BIP ratio development plan. We focus on the best estimate for In-Situ projects; however, with mining projects we are more willing to consider upside potential in certain circumstances. In this case, the high estimate reflects the Contingent Resource estimate if the partners were to increase their TV:BIP (total volume to bitumen in place) ratio from the regulated 12:1 minimum to 16:1, which could be justified with current oil prices. In this case, SilverBirch would increase its Contingent Resource estimate by 64%, to 1.464 billion barrels net to the company. Norwest is preparing a mine-pit design at a 16:1 TV:BIP, which SilverBirch plans to file with its regulatory application. Therefore, Sproule Unconventional will have an opportunity to increase its Contingent Resource estimate (best) accordingly based on the mine-plan design.

Exhibit 140: Mineable Contingent Bitumen Resources (mmbbls)

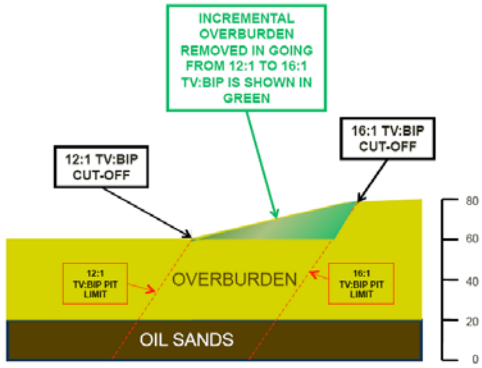
	Gross			Net to SilverBirch		
	Low	**Best**	**High**	**Low**	**Best**	**High**
Frontier	930	1,450	2,550	465	725	1,275
Equinox	230	330	380	114	166	189
		1,780			**891**	

Source: Company reports

Increasing TV:BIP - It's an Economic Decision

The notion behind increasing the TV:BIP ratio from 12:1 to 16:1 is to recover more oil sands by moving more overburden. This is purely an economic decision as it costs more to move greater amounts of overburden, but is economically worth it if the price of oil justifies the incremental expense. Management estimates an incremental $2/bbl to $3/bbl of operating costs to realize an increased recovery at a 16:1 TV:BIP ratio. We feel comfortable that these higher resource estimates could be achievable for SilverBirch given our long-term view of oil prices.

Exhibit 141: Moving from 12:1 to 16:1 TV:BIP



Source: Company reports

Lease 418/271In-Situ Potential - Quarter Billion Barrel Potential?

The company plans to drill 40 to 50 core holes on Lease 418/271 this winter season, which should provide a very good initial understanding of the lease in terms of resource potential and its suitability for In-Situ development. Shell drilled two wells on this lease in 1974 and 1975, one on section 23 and one on section 30. Both wells were drilled to a total depth of ~150 metres, intersecting the McMurray formation, which UTS believes is at a depth of 100 metres to 125 metres. Based on correlating data from the two old wells to ERT (electrical resistivity tomography) data, management reports possible pay thickness of ~25 metres and a primary area of interest of 10 to 15 sections.

We estimate the lease could hold 250 million to 275 million barrels of recoverable bitumen – We are encouraged that the same geotechnical team that worked up the Lease 421 area play concept for UTS is behind Lease 418/271. UTS drilled 59 core holes into the Lease 421 area (~two wells per section) and divested its 50% WI in the lease to ExxonMobil/Imperial Oil in November 2009 for proceeds of $250 million.

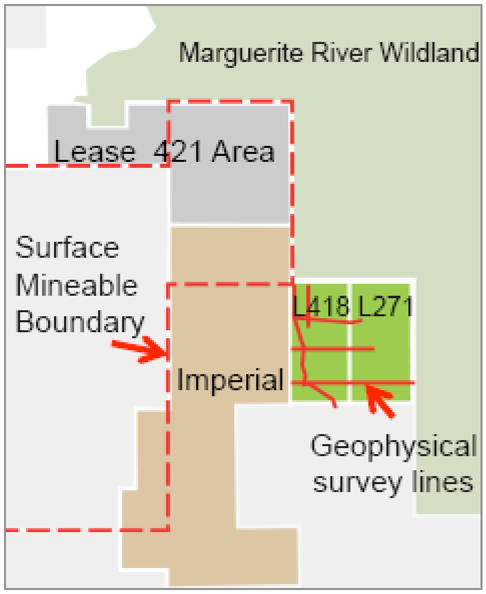
Based on very generic assumptions, we estimate the lease could have up to 250 million to 275 million barrels of recoverable bitumen. We assumed 10 prospective sections, average pay thickness of 20 metres, average porosity of 30%, average bitumen saturation of 70% and an average recovery factor of 35%.

A resource discovery of this size could possibly support a development of 20,000 bbls/d for up to 30 years.

A discovery of 250 million to 275 million barrels would have an implied value of ~$2.30/share based on our applied value of $0.50/bbl for Contingent Resource (best). However, we remind investors that this lease has not yet been drilled and the soonest a Contingent Resource (Best) Estimate could be attained would be the third quarter of 2012.

We believe management would prefer to develop the lease rather than sell it. We believe that development of an In-Situ program would have many benefits to SilverBirch, including quicker progression to first production, a 100% working interest and lower capital requirements versus the company's mining projects at Frontier and Equinox.

Exhibit 142: Lease 418 & 271

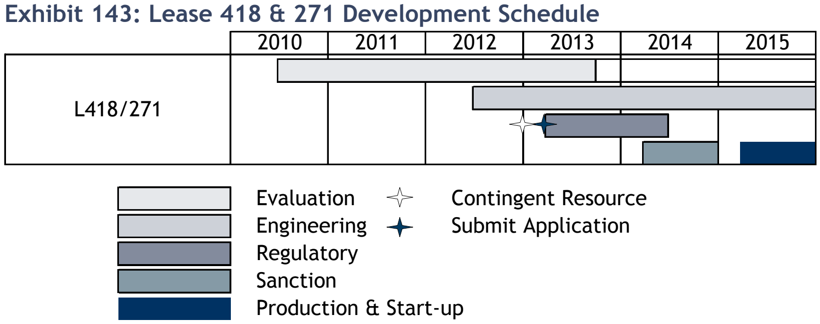


Source: Company reports

Timing – Best-case Scenario Indicates Production in Five Years

The evaluation and development schedule gives investors an indication of the best-case scenario for project development. The best-case scenario suggests production as early as 2015, but should evaluation drilling or the regulatory process take longer than expected, first production could be delayed by one or two years into 2017-2018.

Exhibit 143: Lease 418 & 271 Development Schedule



Source: Company reports and RBC Capital Markets estimates

Key Issues

Time to First Production – Five to 10 Years

Based on the company's current project inventory, first production at Frontier is expected in 2020, a significant time for investors to wait for production and cash flow. In part, the long lead time at Frontier has encouraged management to pursue exploration on Lease 418/271. A suitable In-Situ discovery could accelerate the company's development window to first production. **Pending exploration success, management is targeting first production on Lease 421/271 in 2015-2016.** While this may be possible, we expect that schedule represents the best-case scenario in terms of evaluation work, the regulatory process and construction/start-up. Should resource evaluation take one more winter to achieve a level suitable to make a regulatory filing or should the regulatory process take 18 to 24 months versus the 12 months budgeted, first production may be in 2017 or even 2018, pending a successful exploration program this winter. Either way, because the company is in the pre-regulatory application stage, investors are being asked to wait five to 10 years for first production and cash flow.

Liquidity – Cash Call Likely Inside 12 Months

The design of the plan of arrangement created SilverBirch with sufficient financial liquidity to see the company through the regulatory-filing stage for Frontier/Equinox and through the initial exploration season at Lease 418/271.

The company has ~$53.5 million of cash, which we expect will provide it with sufficient liquidity to pursue its capital-investment plans to the end of the 2011/2012 winter evaluation program at the end of the first quarter of 2012. SilverBirch plans to spend ~$15 million on its core hole evaluation program at Lease 418/271 this winter; we estimate a similar budget again next winter. SilverBirch plans to spend approximately $11 million to advance its design basis memorandum (DBM) at Frontier/Equinox by the end of the first quarter of 2012. In addition, the company spends approximately $6 million per year on G&A. We expect the company will need additional financing by the end of the first quarter of 2012 and thus may be back in the market seeking additional equity by the fourth quarter of 2011 pending suitable market conditions. SilverBirch has no debt.

Valuation

Approach & Methodology – NAV-based Approach

Net asset value is our preferred method of valuation for oil sands companies with projects that have enough definition surrounding scope, timing and capital cost expectations. We apply a risk factor to projects that are in the regulatory process, or that we expect will be during our 12-month target price window. We also include value for resources not assigned to specific development projects, unevaluated lands and corporate adjustments such as cash and debt. Our base NAV is our evaluation of what we believe investors should be willing to pay for the stock. We reserve the flexibility of applying a multiple to our NAV to adjust for intangible qualities and therefore this is the basis of our 12-month target price. Our Unrisked NAV includes upside potential based on our Unrisked valuation of all projects regardless of their stage of development or regulatory process and includes value for additional resources that do not have development project definition. The Unrisked NAV can be thought of as a potential take-out value for the company in the event of a change-of-control event.

Base vs. Unrisked NAV – Upside Potential for New Discoveries & Derisking Projects

We have not given any value in our NAV for potential exploration success – Our base NAV for SilverBirch is supported primarily by a risked value for the full development of Frontier and Equinox. Since no drilling has been done on Lease 418/271, and therefore no estimate of resource is available, we are only able to provide land value to the company's exploration leases. We have assigned a value of $125/acre to unexplored leases, which is a slight discount to the 2010 average year to date of ~$150/acre and in line with the 2009-2010 average Crown land sale price for leases in the Athabasca region. The company's positive net working capital is currently worth $0.83/share. We calculate a base NAV of $8.05/share. **Our $8.00 target price is based on a 1.0x multiple of our base NAV calculation, which is in line with the peer group average.**

Exhibit 144: SilverBirch - NAV Summary

Project	Resource Est. mmbbl	Project PV $mm	Implied PV/Bbl $/bbl	W.I. %	Risk Factor	Base NAV $mm	Base NAV $/share	Base NAV % NAV	Unrisked NAV $mm	Unrisked NAV $/share	Unrisked NAV % NAV
Frontier & Equinox											
Frontier Phase 1 (Pre-Application)	483	$358	$0.74	50%	75%	$134	$2.55	32%	$179	$3.40	33%
Frontier Phase 2 (Pre-Application)	483	$271	$0.56	50%	75%	$101	$1.93	24%	$135	$2.57	25%
Frontier Phase 3 (Pre-Application)	483	$202	$0.42	50%	75%	$76	$1.44	18%	$101	$1.92	19%
Equinox Satellite (Pre-Application)	332	$141	$0.43	50%	75%	$53	$1.00	12%	$71	$1.34	13%
Total Projects	**1,782**	**$973**	**$0.55**			**$365**	**$6.92**	**86%**	**$486**	**$9.23**	**89%**
Undeveloped Land	**Leases**	**Acres**	**$/Acre**	**W.I.**	**Risk Factor**	**$mm**	**$/share**	**% NAV**	**$mm**	**$/share**	**% NAV**
100% Owned	418, 271	23,040	$125	100%	100%	$3	$0.05	1%	$3	$0.05	1%
Twin Lakes	509-511, 837	92,160	$125	50%	100%	$6	$0.11	1%	$6	$0.11	1%
Jordan	422, 423	23,040	$125	50%	100%	$1	$0.03	0%	$1	$0.03	0%
Greater Frontier	see map	94,080	$125	50%	100%	$6	$0.11	1%	$6	$0.11	1%
Total Land		**232,320**				**$16**	**$0.30**	**4%**	**$16**	**$0.30**	**3%**
Corporate Adjustments						**$mm**	**$/share**	**% NAV**	**$mm**	**$/share**	**% NAV**
Net Working Capital					100%	$44	$0.83	10%	$44	$0.83	8%
Long Term Debt					100%	$0	$0.00	0%	$0	$0.00	0%
Total Corporate						**$44**	**$0.83**	**10%**	**$44**	**$0.83**	**8%**
Net Asset Value						**$424**	**$8.05**	**100%**	**$546**	**$10.36**	**100%**

Risk Factors:

100% of DCF value given to producing projects and projects that have received regulatory approval
75% of DCF value given to projects expected to be in the regulatory application process within the next 12 months

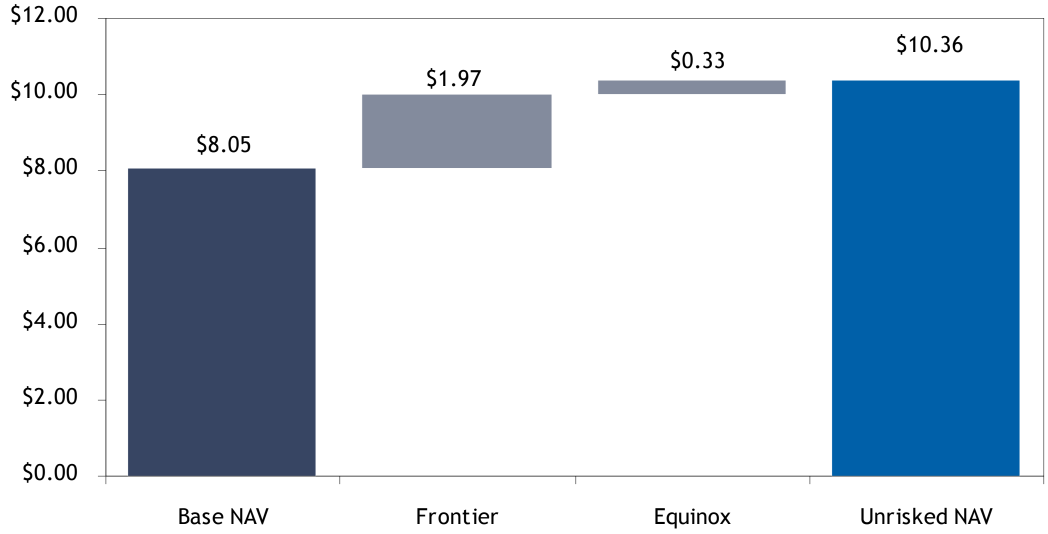
Assumptions:

WTI crude oil assumptions: US$78.02, US$83.00, US$85.00 for 2010E, 2011E and 2012E forward, respectively
Henry Hub natural gas assumptions: US$4.54, US$5.00, US$5.50 for 2010E, 2011E and 2012E forward, respectively
US/CAD foreign exchange assumptions: $0.96, $0.95, $0.95 for 2010E, 2011E and 2012E forward, respectively
After tax discount rate assumption: 8.5%
Long term operating cost assumption: $14.00/bbl

Source: Company reports and RBC Capital Markets estimates

On an Unrisked basis, we calculate a net asset value of $10.36/share, which includes Unrisked values for Frontier and Equinox.

Exhibit 145: SilverBirch Upside Potential – Base and Unrisked NAV



Source: Company reports and RBC Capital Markets estimates

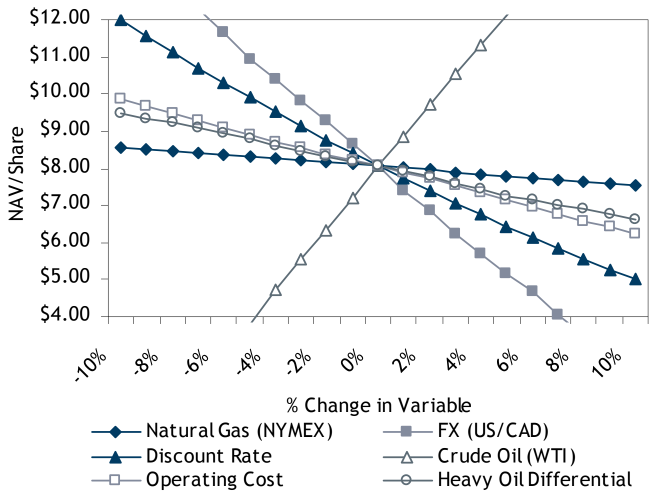
Relative Valuation – The Stock Appears Expensive

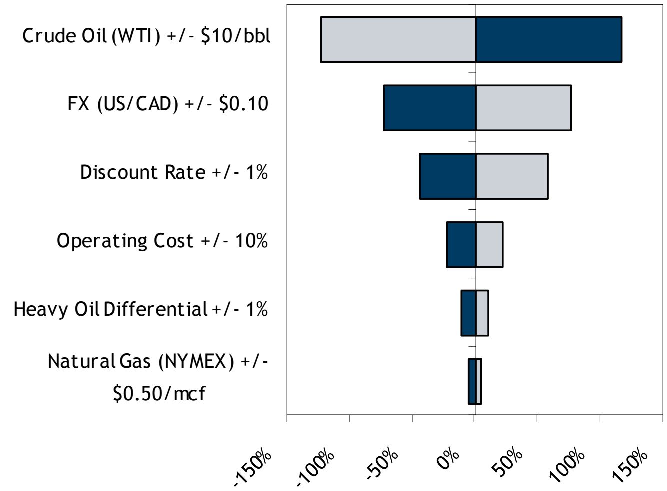
SilverBirch is currently trading at a P/NAV ratio (Base) of 89%, indicating to us that investors may be pricing in partial success from this winter's drilling program. The stock is trading at a 69% P/NAV ratio (Unrisked). Peer group average valuations are 86% P/NAV (Base) and 49% P/NAV (Unrisked). We feel it is too premature to include value beyond land for Lease 418/271; therefore, indications of success could provide upside potential to our NAV calculations.

Sensitivities

SilverBirch's NAV is positively correlated to, and is most sensitive to, changes in the long term oil price. In fact, because of the long-duration nature of the company's assets, SilverBirch is more sensitive to oil prices than most other oil sands companies (see Exhibit 146). Our calculation of NAV is negatively correlated to changes in the discount rate, the Canadian/US dollar exchange rate, operating costs, heavy oil differentials and natural gas prices. Next to oil prices, the company's NAV is most sensitive to the discount rate and the exchange rate.

Exhibit 146: SilverBirch - NAV Sensitivity





Source: Company reports and RBC Capital Markets estimates

Risks to Target Price

We are initiating coverage of SilverBirch Energy with a Speculative risk rating. SilverBirch is exposed to a higher degree of risk than many of its peers due to the early stage of the regulatory process, exploration exposure, future financing requirements and project-execution uncertainty.

We identify six key risks to our target price:

1. **Oil Prices** – The company's asset base, and therefore the NAV calculation, is 100% weighted to oil. As demonstrated in the NAV sensitivity chart (Exhibit 146), fluctuations in oil prices represent the greatest impact on our calculation of NAV for the company. We assume a flat oil price of US$85.00/bbl from 2012 onward.
2. **Discount Rates** – We assume an 8.5% discount rate in our NAV calculations, which is the same discount rate RBC applies to NAV calculations of E&P companies. Risks are unique to each company and to each type of company. In general, we believe that oil sands companies have lower reserve risk and lower reserve-replacement and re-investment (i.e. exploration) risk than E&P companies. On the other hand, oil sands companies have greater regulatory, environmental and project-execution risk over the long term than the typical E&P company, which reflects the long-term nature of the oil sands asset base. Small fluctuations in discount rate assumptions would change the NAV calculation, and thus our target price, materially.
3. **Foreign Exchange Rates** – The company's future costs are denominated in Canadian dollars, yet production will be priced in U.S. dollars. Fluctuations in the exchange rate can greatly impact the value of future cash flows and thus our NAV calculation. We assume a flat US$0.95/C$1.00 exchange rate long term.
4. **Regulatory Risks** – SilverBirch is an early stage oil sands development company that is currently in the pre-regulatory stage on each of its projects; therefore, it is exposed to a high degree of regulatory risk. SilverBirch plans to file its application for its Frontier/Equinox mining project by mid 2011. Approvals for Frontier/Equinox could take up to 30 to 36 months. The company's growth profile as well as our perception of the company's value would be impacted materially should regulatory approvals be delayed or withheld.
5. **Financing Risks** – We believe SilverBirch has sufficient financial liquidity to see it through its spending plans to the end of the first quarter of 2012. Assuming that management will want to be financially prepared before running out of funds, we expect the company to seek financing by mid to late 2011. The ability of the company to raise funds will be influenced by its exploration success this winter on Lease 418/271 and by general market conditions. Longer term, we estimate the company's share of Frontier Phase 1 capital at $3.2 billion. Even a smaller In-Situ development at Lease 418/271 could easily be in the range of $300 million to $400 million. SilverBirch has significant potential financing needs over the next several years and the success of that financing could significantly change our perception of value of the company.
6. **Environmental Risks** – Oil sands producers have come under increased scrutiny due to environmental issues. While longer-term costs or product-marketing concerns related to environmental issues are unclear at this time, we don not believe they present a risk to the company's development plans or our perception of the valuation of the company.

Exhibit 147: SilverBirch - Operational & Financial Summary

C$ millions, unless noted	2007	2008	2009	2010E	2011E	2012E
Production						
Bitumen (bbl/d)	n.a.	n.a.	n.a.	0	0	0
Diluent Purchases (bbl/d)	n.a.	n.a.	n.a.	0	0	0
Blend Sales (bbl/d)	**n.a.**	**n.a.**	**n.a.**	**0**	**0**	**0**
Blend Ratio	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
YOY Production Growth (%)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Bitumen (%)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Commodity Prices						
WTI Crude Oil (US$/bbl)	$72.25	$99.50	$61.81	$78.02	$83.00	$85.00
Ed. Par (C$/bbl)	76.05	102.75	66.48	77.69	86.05	88.16
Bow River Heavy (C$/bbl)	50.50	83.00	59.25	68.23	73.30	72.29
Exchange Rate (US$/C$)	0.93	0.94	0.88	0.96	0.95	0.95
Henry Hub - NYMEX (US$/mcf)	6.95	8.85	3.92	4.54	5.00	5.50
AECO (C$/Mcf)	6.60	8.15	3.94	4.05	4.37	4.90
Realized Pricing and Costs						
Blend Sales ($/bbl)	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**
Bitumen Sales ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Transportation & Selling ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Royalties ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Operating Costs ($/bbl)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Netback ($/bbl)	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**n.a.**
Consolidated Financials						
Blend Sales (net of royalties)	n.a.	n.a.	n.a.	$0.0	$0.0	$0.0
Other Income	n.a.	n.a.	n.a.	0.1	0.5	0.4
Cost of Diluent	n.a.	n.a.	n.a.	0.0	0.0	0.0
Operating and G&A	n.a.	n.a.	n.a.	1.5	6.0	7.0
Interest	n.a.	n.a.	n.a.	0.0	0.0	0.0
DD&A	n.a.	n.a.	n.a.	0.0	0.0	0.0
Pre-Tax Income	n.a.	n.a.	n.a.	(1.4)	(5.5)	(6.6)
Current Tax	n.a.	n.a.	n.a.	0.0	0.0	0.0
Deferred Tax	n.a.	n.a.	n.a.	0.0	(1.6)	(1.9)
Net Income	**n.a.**	**n.a.**	**n.a.**	**(1.0)**	**(3.9)**	**(4.7)**
Cash Flow From Operations	**n.a.**	**n.a.**	**n.a.**	**(1.4)**	**(5.5)**	**(6.6)**
Capital Expenditures	**n.a.**	**n.a.**	**n.a.**	**(8.5)**	**(23.0)**	**(23.0)**
Per Share Data						
Diluted CFPS ($/Share)	**n.a.**	**n.a.**	**n.a.**	**($0.04)**	**($0.11)**	**($0.11)**
YOY Diluted CFPS Growth (%)	n.a.	n.a.	n.a.	n.a.	nmf	nmf
Diluted EPS ($/Share)	**n.a.**	**n.a.**	**n.a.**	**($0.03)**	**($0.08)**	**($0.08)**
YOY Diluted EPS Growth (%)	n.a.	n.a.	n.a.	n.a.	nmf	nmf
Weighted Avg Diluted Shares O/S (mm)	n.a.	n.a.	n.a.	50.0	50.0	63.1
Financial Leverage						
Net Debt	n.a.	n.a.	n.a.	(43.63)	(15.09)	(18.96)
Long Term Debt	n.a.	n.a.	n.a.	0.0	0.0	0.0

Source: Company reports and RBC Capital Markets estimates

Exhibit 148: SilverBirch - Company Profile

Business Description

SilverBirch Energy is a pure play oil sands company focused on the exploration, delineation and development of mining and in-situ assets in the Athabasca region of Alberta's oil sands. The company was formed from the spin off assets of UTS Energy Corp after the sale of UTS's 20% interest in the Fort Hills Project to Total Canada SA. SilverBirch's assets include two leases that have been identified as surface mineable project areas which are 50% held by Teck Resources, and a number of in-situ leases, some of which are held in the joint venture with Teck Resources, and some of which are 100% owned. The company's focus is to progress with the regulatory process of their Frontier and Equinox projects while exploring the other assets for potential in-situ project areas.

Land Position

Key Areas	W.I.	Gross Acres	Net Acres	Recovery Method
Frontier	50%	65,280	32,640	Mining
Equinox	50%	7,146	3,573	Mining
Other	100%	232,320	127,680	In-situ
Total	**54%**	**304,746**	**163,893**	

Contingent Resource Estimates (Sproule)

	Low	Best	High
Frontier	465	725	1,275
Equinox	114	166	189
Other	-	-	-
	579	**891**	**1,464**

Core Hole Drilling Program

Lease	Pre 09/10	09/10 Season	Total	10E/11E
West of Athabasca River				
Equinox Project	124	-	124	
Frontier Project	398	68	466	
Other	25	-	25	
East of Athabasca River	23	-	23	40-50
Total	**570**	**68**	**638**	**40-50**

Management Team

Name	Position	Experience
Howard J. Lutley	President and CEO	President of Norwest Corp.
Wayne Bobye	VP and CFO	Director & President Waymar Energy Inc.
Susan Pain	VP, Finance	Senior Controller, UTS Energy
Phil Aldred	VP, Resources	Oil Recovery, Encana Corp.
Cam Bateman	VP, Projects	Fuel Supply, TransAlta Utilities Corp.
Jina Abells Morissette	VP, Legal and Admin	Senior Legal Counsel, Husky Energy Inc.

* All management were previously members of the UTS Energy management team

Board of Directors

Name	Experience
Howard J. Lutley	President of Norwest Corp.
Donald R. Ingram	Senior VP, Husky Energy Inc.
Bonnie D. DuPont	Group VP Corporate Resources, Enbridge Inc.
Douglas H. Mitchell	Co-Chair, Borden Ladner Gervais LLP
Glen D. Roane	VP & Director TD Asset Management Inc.
Gregory A. Boland	President & CEO West Face Capital Inc.
Martin Frass Ehrfeld	Partner, Children's Investment Fund Mgmt

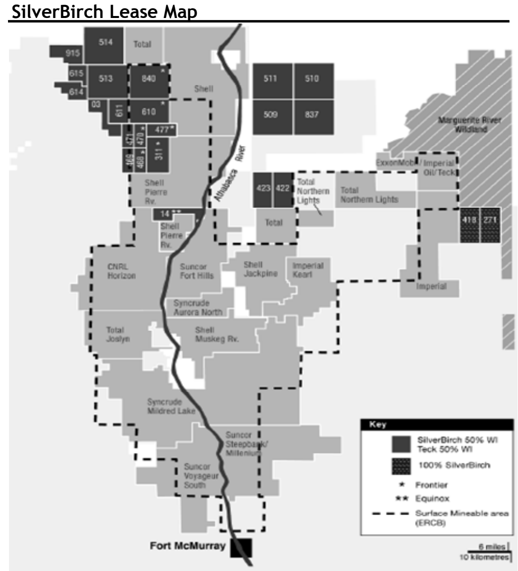
Pro Forma Balance Sheet as at June 30, 2010 ($mm)

ASSETS		LIABILITIES & SHAREHOLDERS' EQUITY	
Current Assets		**Liabilities**	
Cash & Cash Equivalents	$40.9	Future Income Taxes	$51.8
Accounts Receivable	$12.6		$51.8
	$53.5	**Shareholders Equity**	
Property, Plant & Equipment	$208.4	Share Capital	$210.1
	$261.9		**$261.9**

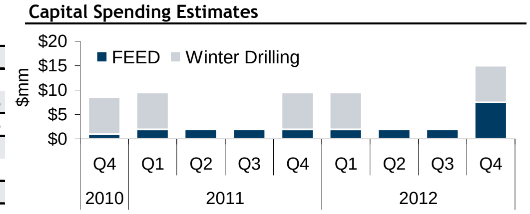
Proposed Frontier & Equinox Project Timeline

Q2 2008	Filed public disclosure
2008 - 2009	Terms of reference for EIA
2008 - 2010	Environmental baseline studies
2010 -2011	Mine Plan
2011 -2011	DBM study
2012 -2011	EIA study
2013 -2011	Socio-economic analysis
Q3 2011	ERCB application
2011 - 2014	Regulatory review process
Q2 2014	Regulatory approval
2013 - 2019	Engineering and construction
2019	Commissioning and start up
Mid 2019	First bitumen production

SilverBirch Lease Map



Capital Spending Estimates



Source: Company reports and RBC Capital Markets

Appendix I: Private Companies

Information contained in this report with respect to private companies may be less reliable than information with respect to public companies, due to the fact that private companies are not subject to the same legal standards of disclosure. Comments and expectations related to private companies represent company management's views expressed in presentations and available on their web site. They do not represent the opinions of RBC Capital Markets.

Laricina Energy Ltd. (Private Company)

Piloting the Grosmont Bitumen Carbonates

Capitalization		
Last Financing Price[(a)]	($)	$30.00
F.D. Shares Outstanding	(mm)	59.5
Market Capitalization	($mm)	$1,784.4
Net Debt	($mm)	($390.0)
Enterprise Value	($mm)	$1,394.4

Resources		
Oil Sands EV[(b)]	($mm)	$1,394.4
2P Reserves	(mmbbl)	36
Resources[(c)]	(mmbbl)	4,549
Exploitable OBIP	(mmbbl)	11,011
EV/Bbl[(d)]	($/bbl)	$0.30

Key Areas & Potential[(e)]	Start-up	(bbl/d)
Saleski	2010	270,000
Germain (Grand Rapids)	2012	177,700
Poplar Creek	2014	20,000
Conn Creek	2015	30,000
Burnt Lakes	2015	60,000
Germain (Winterburn)	2021	40,000
Other	n.a.	n.a.

Key Personnel	Position
Glen Schmidt	President & CEO
Dave Theriault	SVP In Situ and Exploration
Neil Edmunds	VP Enhanced Oil Recovery
Karen Lillejord	VP Finance and Controller
Marla Van Gelder	VP Corporate Development
Derek Keller	VP Production
George Brindle	VP Facilities

(a) Share price at last (non flow-through) equity issue dated August 27, 2010.
(b) Adjusted to exclude the estimated value of non-oil sands assets.
(c) Best Estimate Contingent and Prospective Resources.
(d) Based on 2P reserves + Best Estimate Contingent and Prospective Resources.
(e) Gross production potential as per GLJ Report based on Best Estimate SAGD, effective March 1, 2010.
Source: Company reports

Company Summary

- Laricina has raised a total of approximately $800 million with private placements since November 2005, $326 million of which was raised in the third quarter of 2010.
- Management has estimated year end working capital of $340 million.
- Although the company has exposure to well established reservoirs like the McMurray and Grand Rapids Formations, the bitumen carbonate reservoir, which has not yet been commercially developed by the industry, also presents large resource and production potential for Laricina.
- At Saleski, first steam at the pilot is scheduled before year-end 2010 and management expects first production is expected in early 2011.
- Laricina plans to file a regulatory application amendment before year-end 2010 seeking approval for an expansion to 12,500 bbl/d project at Saleski as a first-stage commercial development and with targeted first commercial production from the Grosmont carbonate by late 2013.
- At Germain, the company has received regulatory approval for a 5,000 bbl/d SC-SAGD (solvent cycle) commercial demonstration project. Field construction is expected to begin in the first quarter of 2011 and first production from a 10-well pair pad expected to start up by late 2012.
- At Germain, Laricina expects the first commercial stage expansion to be 30,000 bbl/d and to start up by 2015. The company is planning two future phases of 60,000 bbl/d for a production capacity at Germain of 155,000 bbl/d gross (approximately 150,300 bbl/d net to Laricina's 96% W.I.) based on the initial EIA filing.

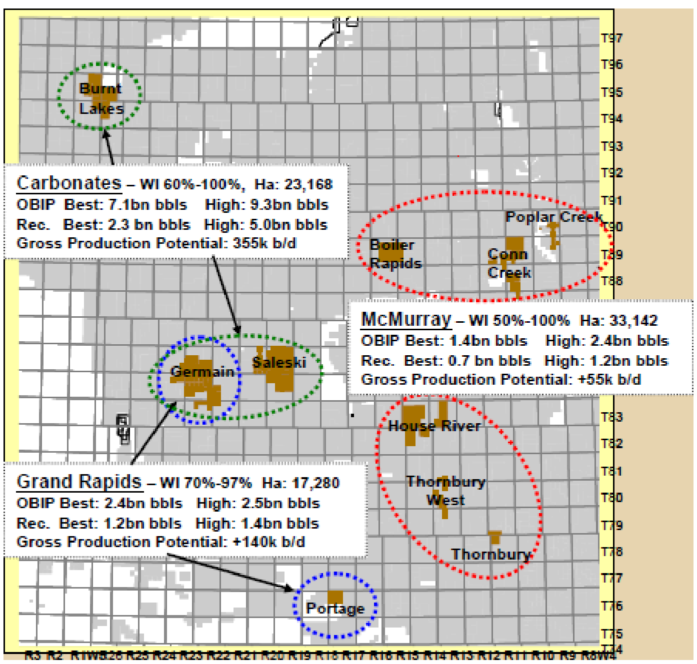
Company Overview

Laricina, formed in November 2005, remains a private company. The company has raised a total of approximately $800 million with private placements, $326 million of which was raised in the third quarter of 2010. The company has estimated exit 2010 working capital of $340 million, to fund its planned 2011 capital program. Laricina may position itself to become a publicly traded company when investment needs for the Saleski and Germain projects begin to accelerate as the projects move toward commercial development.

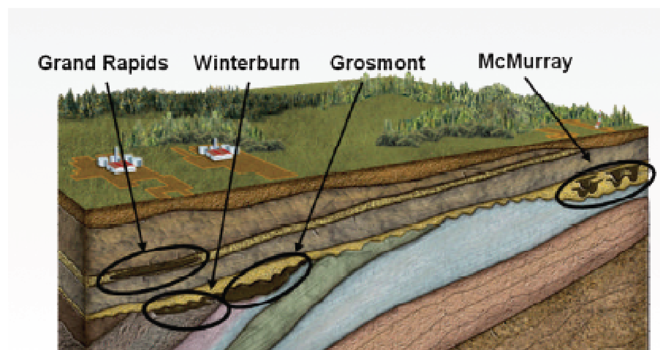
Five core areas with three play types – The company has 183,500 acres of net oil sands leases with five core areas: Germain, Saleski, Burnt Lakes, Poplar and Conn Creek (see Exhibit 149). The company is initially focusing its efforts on the Grosmont bitumen carbonate potential at Saleski and the development of the Grand Rapids at Germain. The company also has exposure to the Winterburn bitumen carbonate reservoir at its Germain and Grosmont at its Burnt Lakes leases. At Germain and Portage, the company has exposure to the Grand Rapids Formation. At its Boiler Rapids, Conn Creek, Poplar Creek, House River, Thornbury and Thornbury West leases, the company has exposure to the McMurray Formation. Although the company has exposure to well established reservoirs like the McMurray and Grand Rapids formations, the Grosmont carbonate reservoir, which has not yet been commercially developed by the industry, presents large resource and production potential for Laricina.

Exhibit 149: Laricina Leases

Lease Holdings



Formation & Production Potential Summary



Core Project Areas	Formation	Potential [1] (Gross bopd, SAGD/CSS basis)
Saleski	Grosmont C&D	270,000
Germain	Grand Rapids & Winterburn	217,700
Burnt Lakes	Grosmont D	60,000
Conn Creek	McMurray	30,000
Poplar Creek	McMurray	20,000

Source: Company reports

Saleski - Pilot Testing the Grosmont Bitumen Carbonates

The first horizontal well to test the Grosmont bitumen carbonates – Laricina holds a 60% W.I. at Saleski while the remaining 40% W.I. is held by Osum Oil Sands Corp., another private company. In the third quarter of 2009, the partners received regulatory approval for a 1,800 bbl/d SAGD pilot project at Saleski that will be the first horizontal well pilot of SAGD in the Grosmont carbonates.

On track for first steam at Saleski before year end – Currently, all wells have been drilled, all modules are on site, the pilot facility is approximately 95% mechanically complete and approximately 86% of the electrical work is complete. Operating staff are in place for first steam that is expected before year-end 2010. Management expects first production in the first half of 2011.

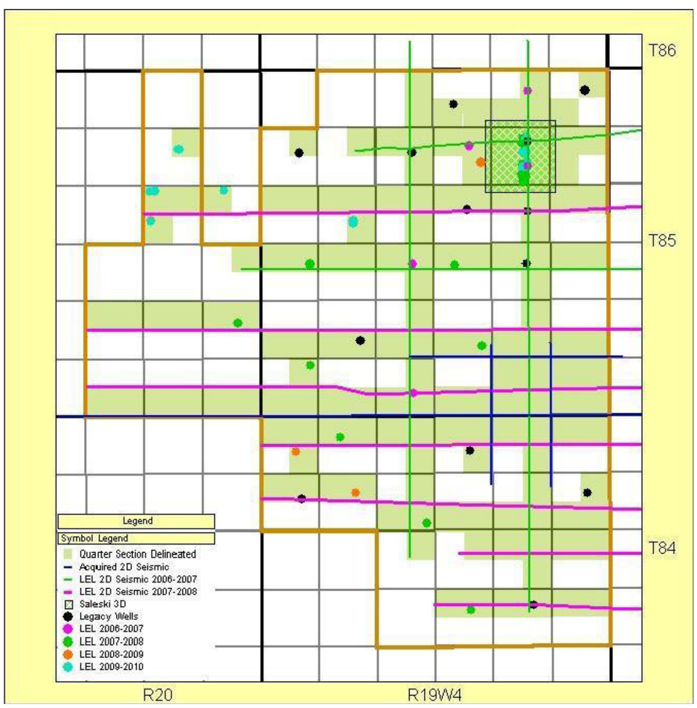
Staged pilot to test SAGD and SC-SAGD – Two of the SAGD well pairs have been drilled in the Grosmont D zone, and one well pair has been drilled in the Grosmont C zone. The pilot is expected to start up with SAGD at the D1 well pair in the Grosmont D zone with observation wells monitoring the migration of heat in the reservoir. The company will steam the Grosmont D zone for approximately one year to monitor steam chamber development and temperature migration. The pilot will later test the Grosmont C zone with the C1 well pair followed by the SAGD start up of the D2 well pair. Following the establishment of performance curves on the wells based on SAGD, management expects the pilot to transition to a test of solvent injection called SC-SAGD. Management expects the well pairs to transition through SAGD to SC-SAGD through 2012 and 2013.

Potential benefits of SC-SAGD – The effectiveness of SC-SAGD could materially affect project economics at the commercial development stage. The use of solvents could reduce capital and operating costs, and increase recoverable resources. The combination of steam and solvent could result in a quicker production response than cold solvent alone.

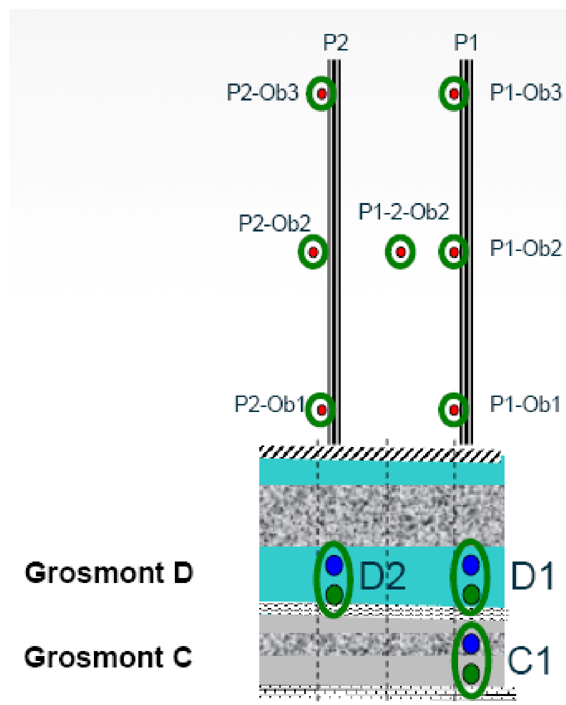
Targeting commercial development for 2013 – Laricina plans to file a regulatory application before year-end 2010 seeking approval for an expansion to 12,500 bbl/d project as its first-stage commercial development with targeted first commercial production from the Grosmont carbonate by late 2013 or early 2014. The application will include the use of SC-SAGD. Based on the size of the resource at Saleski, Laricina is considering staged growth of 20,000–60,000 bbl/d phases with ultimate production capacity estimated at Saleski of 270,000 bbl/d gross (162,000 bbl/d net to Laricina). Management is targeting a long-term capital intensity of around $25,000 bbl/d.

Exhibit 150: Saleski

Lease Delineation



Pilot Well Confirguration



Source: Company reports

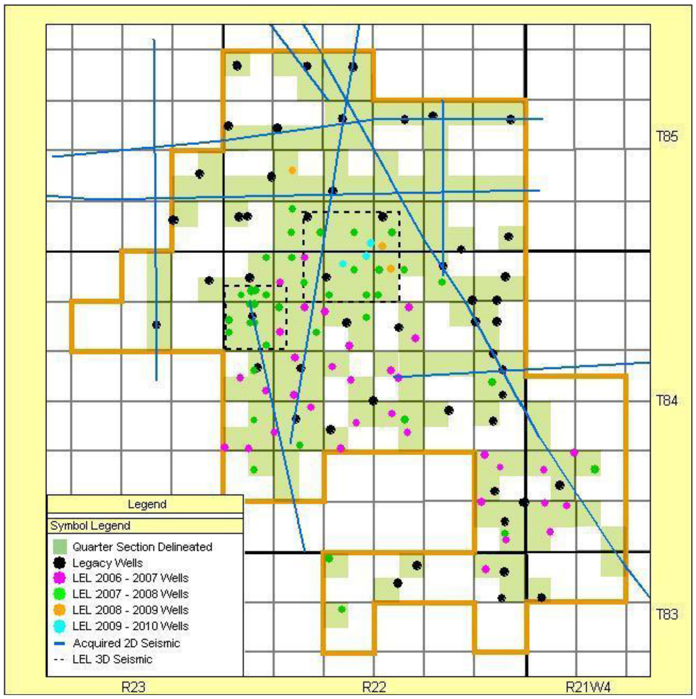
Germain - Grand Rapids Development Underway

The Germain lease is located approximately 130 km southwest of Ft. McMurray – At Germain, the primary target is the Grand Rapids Formation, which can be found at a depth of 225 metres with a reservoir thickness of 10–25 metres. The secondary target at Germain is the Winterburn carbonate, which is deposited 200 metres below the Grand Rapids. The company has 127 delineation wells into the Grand Rapids and 17 delineation wells into the Winterburn carbonate. The overall core hole density is 1.8 wells/section over the lease with four wells/section over the initial development area.

5,000 bbl/d Commercial Development underway – The company has received regulatory approval for a 5,000 bbl/d SC-SAGD commercial demonstration project. Field construction is expected to begin in the first quarter of 2011, and first production from 10-well pairs (one pad) is expected to start up by late 2012. Management estimates that go forward facility and well costs are estimated at nearly $300 million.

Planned Development of 155,000 bbl/d – Laricina expects the first commercial stage expansion to be 30,000 bbl/d and to start up by 2015. The company is planning two future phases of 60,000 bbl/d for a production capacity at Germain of 155,000 bbl/d gross (approximately 150,300 bbl/d net to Laricina's 96% W.I.) based on the initial EIA filing.

Exhibit 151: Germain



Source: Company reports

Exhibit 152: Laricina - Company Profile

Business Description

Laricina is a privately held Calgary-based company focused on capturing opportunities in the unconventional and oil sands areas of Western Canada. The company has established five development areas comprising Germain, Saleski, Burnt Lakes, Poplar Creek and Conn Creek. Laricina is a leader in the emerging carbonate plays with significant Grosmont bitumen carbonate resource potential at Saleski. As JV partners with Osum Oil Sands Corp., Laricina will be piloting in the Grosmont carbonates this winter. Laricina has experienced engineering and geological teams who have direct experience in 49 commercial oil sands projects already operating or under construction.

Recent News

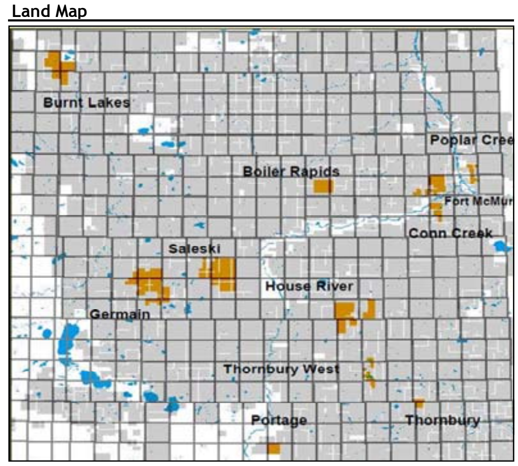
Oct-10	Receives approval for Germain SC-SAGD Project
Oct-10	Completes $15.7 mm flow-through financing
Aug-10	Completes equity financings for total $76.2 mm
Jul-10	Secures $250 mm financing from CPPIB
Jun-10	Awarded $16.5 mm for ESEIEH from CCEMC
Apr-10	Receives Approval for Saleski Pilot Solvent Use
Winter-10	Completes Drilling of Well Pairs at Saleski
Winter-10	Completes Construction of 32-km Road at Saleski
Nov-09	Files Commercial Demonstration Amendment

Land Position

Area	Formation	W.I.	Net Acres	Start Up	Capacity (bbl/d)
Saleski	Grosmont	60%	25,430	2010	270,000
Germain	Grand Rapids	96%	38,714	2012	177,700
Poplar Creek	McMurray	50%	2,886	2014	20,000
Conn Creek	McMurray	100%	24,038	2015	30,000
Burnt Lakes	Grosmont	100%	28,414	2015	60,000
Germain	Winterburn*	94%	42,219	2021	40,000
Other	McMurray/G.R.	93%	58,957	n.a.	n.a.

*In addition to Germain lands where Laricina holds the Grand Rapids & Winterburn rights

Land Map



Reserve & Resource Estimates (GLJ)

(mmbbl)	Exploitable OBIP			Recoverable Resources		
	2P + Best	3P + High	SC-SAGD	Best	High	SC-SAGD
Grosmont/Winterburn	7,227	9,310	7,227	2,565	4,986	3,027
Grand Rapids*	2,376	2,472	2,376	1,259	1,558	1,538
McMurray/Wabiskaw	1,408	2,358	1,408	725	1,324	725
Total	**11,011**	**14,140**	**11,011**	**4,549**	**7,868**	**5,290**

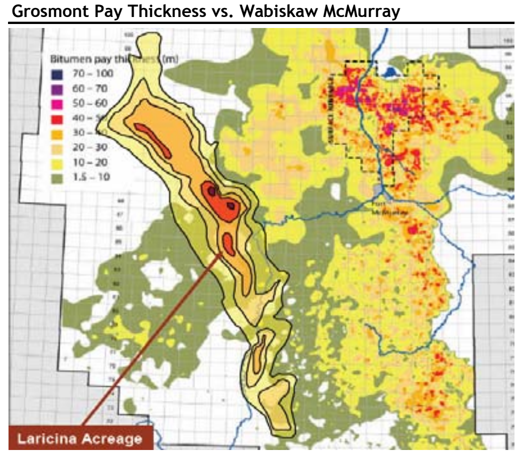
* Laricina has been assigned 36 mmbbls of 2P reserves and 43 mmbbls of 3P reserves at Germain

Potential Catalysts

Q4 2010	Complete Saleski pilot construction and commissioning
Q4 2010	Saleski pilot start-up
Q4 2010	Initiation of winter drilling program at Saleski, Germain and Burnt Lakes
Q4 2010	Application amendment to increase production at Saleski to 12,500 bbl/d
Q2 2011	Germain plant construction begins, natural gas tie-in, power interconnection
Q1 2012	Saleski second stage solvent start up
Q2 2012	Saleski first commercial phase engineering
2H 2012	Germain commercial demonstration start up
2014	Begin Phase 1 of ESEIEH[1.] pilot project
2014	Advance 2nd Phase IETP[2.] funding application for Saleski Pilot

1. ESEIEH stands for Enhanced Solvent Extratcion Incorporating Electromagnetic Heating
2. IETP stands for Innovative Energy Technologies Program

Grosmont Pay Thickness vs. Wabiskaw McMurray



Management Team

Name	Position	Past Experience
Glen C. Schmidt	President and CEO	CEO, Deer Creek Energy
David J. Theriault	Senior VP In Situ and Exploration	President, Triangle Three Engineering
Neil R. Edmunds	VP Enhanced Oil Recovery	Reservoir Engineering, Encana Corp
Karen E. Lillejord	VP Finance and Controller	Controller, Deer Creek
Marla Van Gelder	VP Corporate Development	Financial Analysis, Deer Creek Energy
Derek A. Keller	VP Production	Business Development Mgr, Murphy Oil
George C. Brindle	VP Facilities	Consulting Engineer

Board of Directors

Name	Experience
Brian K. Lemke (Chairman)	Independent Businessman
Jeff Donahue	Sr Principal - Principal Investments, CPP Investment Board
S. Barry Jackson	Chairman, TransCanada Corporation
Gordon J. Kerr	President and CEO, Enerplus Resources Fund
Jonathan C. Farber	Managing Director, Lime Rock Partners
Robert A. Lehodey, Q.C.	Partner, Osler, Hoskin & Harcourt LLP
Glen Russell	Principal, Glen Russell Consulting
Glen C. Schmidt	President and CEO, Laricina Energy Ltd.

SC-SAGD Technology

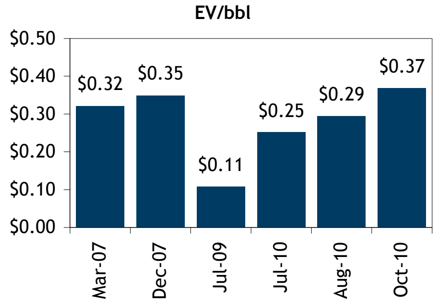
Stage 1: SC-SAGD Heavy Solvent Injection Co-injection of steam and solvent into the reservoir at normal SAGD injection rates. The preferred solvent for the initial phase is a heavier hydrocarbon (>C5). Steam and heavy solvent co-injection is continued until about 25-30% of the oil in place has been recovered.

Stage 2: SC-SAGD Heavy and Light Solvent Injection Steam injection and solvent will be changed in response to performance in order to optimize bitumen and solvent recovery. The solvent composition will likely progress from heavy (>C5 or similar) to lighter solvent such as C3.

Stage 3: SC-SAGD Blowdown Additional solvent is recovered, or scavenged, along with a portion of the bitumen remaining in the reservoir. Solvent recovery is completed through a combination of methane injection and reservoir depressurizing. The recovered solvent may be used in subsequent phases.

Source: Company reports

Exhibit 153: Laricina - Financial Profile

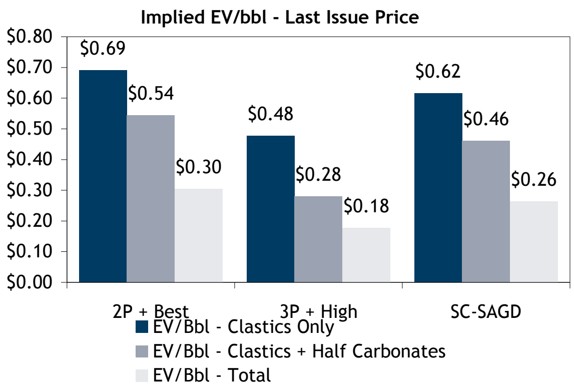


Selected Financing History

Date	Type	Issue Price	Amount ($mm)	Resource (bn bbl)*	EV/Bbl
Oct-10	Flow-Through	$35.00	$15.7	4.6	$0.37
Aug-10	Common	$30.00	$76.2	4.5	$0.29
Jul-10	Common	$30.00	$250.0	4.5	$0.25
Jul-09	Common	$15.00	$83.8	4.1	$0.11
Dec-07	Common / F.T.	$32.50 /$40.60	$176.7	3.2	$0.35
Mar-07	Flow-Through	$25.00	$21.6	2.3	$0.32
Dec-06	Common	$12.50	$80.0	2.3	$0.16
Sep-06	Flow-Through	$12.50	$15.0	1.2	$0.22
Dec-05	Common	$4.56 **	$77.5	1.2	$0.08
			$796.5		

* Best estimate contingent and prospective resource

** Weighted average price



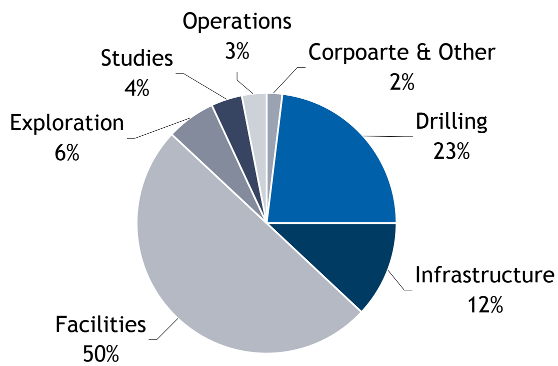
Net Resource Summary (mmbbl)

	2P + Best	3P + High	SC-SAGD
Clastics - Wabiskaw/McMurray	725	1,324	725
Clastics - Grand Rapids	1,295	1,601	1,538
Carbonates - Grosmont/Winterburn	2,565	4,986	3,027
Total	**4,585**	**7,911**	**5,290**
@ Last Common Issue Price of $30/share			
EV/Bbl - Clastics Only	$0.69	$0.48	$0.62
EV/Bbl - Clastics + Half Carbonates	$0.54	$0.28	$0.46
EV/Bbl - Total	**$0.30**	**$0.18**	**$0.26**
@ Last Flow-Through Issue Price of $35/share			
EV/Bbl - Clastics Only	$0.84	$0.58	$0.75
EV/Bbl - Clastics + Half Carbonates	$0.66	$0.34	$0.56
EV/Bbl - Total	**$0.37**	**$0.21**	**$0.32**

Selected Quarterly Financial Data

(Thousands except per share values)	Q4 08	Q1 09	Q2 09	Q3 09	Q4 09	Q1 10	Q2 10	Q3 10
Working Capital	$111,530	$90,879	$86,094	$160,804	$149,320	$109,378	$92,802	$381,697
Revenue	$787	$245	$80	$111	$122	$107	$118	$912
G&A	$1,132	$1,249	$1,013	$1,400	$1,910	$1,883	$2,034	$1,882
Net Income (Loss)	$7,343	-$897	-$864	-$1,140	-$1,574	-$1,585	-$1,731	-$1,026
Cash Flow from Operating Activities	-$46	-$401	-$453	-$931	-$1,202	-$1,138	-$1,178	-$259
Capital Expenditures	$12,086	$19,758	$4,440	$4,444	$11,028	$39,562	$15,147	$25,308
Shares Issued, Net of Share Issuance Costs	$0	$0	$0	$80,235	$1,120	$0	$0	$314,720
Number of Shares O/S - Basic	34,748	34,748	34,790	40,380	40,480	40,491	40,522	51,416

2010 Capital Program ($140 mm)



Source: Company reports

Osum Oil Sands Corp. (Private Company)

The Only Junior in the Cold Lake Region

Capitalization		
Last Financing Price	($)	$13.00
F.D. Shares Outstanding	(mm)	92.4
Market Capitalization	($mm)	$1,201.2
Net Debt	($mm)	($245.0)
Enterprise Value	($mm)	$956.2

Resources		
Oil Sands EV[(a)]	($mm)	$956.2
2P Reserves	(mmbbl)	320
Contingent Resources[(b)]	(mmbbl)	2,144
OBIP	(mmbbl)	10,000
EV/Bbl[(c)]	($/bbl)	$0.39

Key Areas & Net Potential[(d)]	(bbl/d)
Liege	40,000
Saleski	50,000
Saleski JV (net)	110,000
Taiga	42,500

Key Personnel	Position
Steve Spence	President & CEO
Peter Putnam	Senior VP, Geoscience
Andrew Squires	Senior VP, Saleski Projects
Rick Walsh	EVP Operations & Development
Jeffrey MacBeath	VP, Finance

(a) Adjusted to exclude the estimated value of non-oil sands assets.
(b) Best Estimate Contingent Resources.
(c) Based on 2P reserves + Best Estimate Contingent.
(d) Production potential as per GLJ resource report dated January 1, 2010.
Source: Company reports

Company Summary

- The company has raised about $475 million of capital with a series of seven private placements, of which the most recent was November 2010 when Osum raised $100 million at $13.00/share.
- The company holds a 40% W.I. on the Saleski bitumen carbonate joint venture that is operated by Laricina Energy Ltd., and the company holds leases with 100% exposure to bitumen carbonates on its adjoining Saleski and Liege leases.
- Osum holds a 100% W.I. on its Taiga lease in the Cold Lake region of Alberta.
- The company reports 320 million barrels of 2P reserves and 2.144 billion barrels of Best Estimate Contingent Resources (GLJ).
- GLJ estimates that the resource base is capable of supporting more than 240,000 bbl/d of production.
- The company filed its regulatory application for a 35,000 bbl/d SAGD-CSS project and a 40 MW co-generation facility at Taiga in the fourth quarter of 2009. Management expects the regulatory application to be approved in mid 2011.
- Management is targeting first production at Taiga in early 2014.
- Management estimates a SOR of 3.0–3.6x and plans to build facilities to support a SOR of 3.7x.

Company Overview

Osum was formed as a private company in mid 2005. The company has raised approximately $475 million of capital with a series of seven private placements.

The company holds a 40% W.I. on the Saleski bitumen carbonate joint venture that is operated by Laricina, and the company holds leases with 100% exposure to bitumen carbonates on its adjoining Saleski and Liege leases. Osum is focusing its efforts on its Taiga project in the Cold Lake region of Alberta.

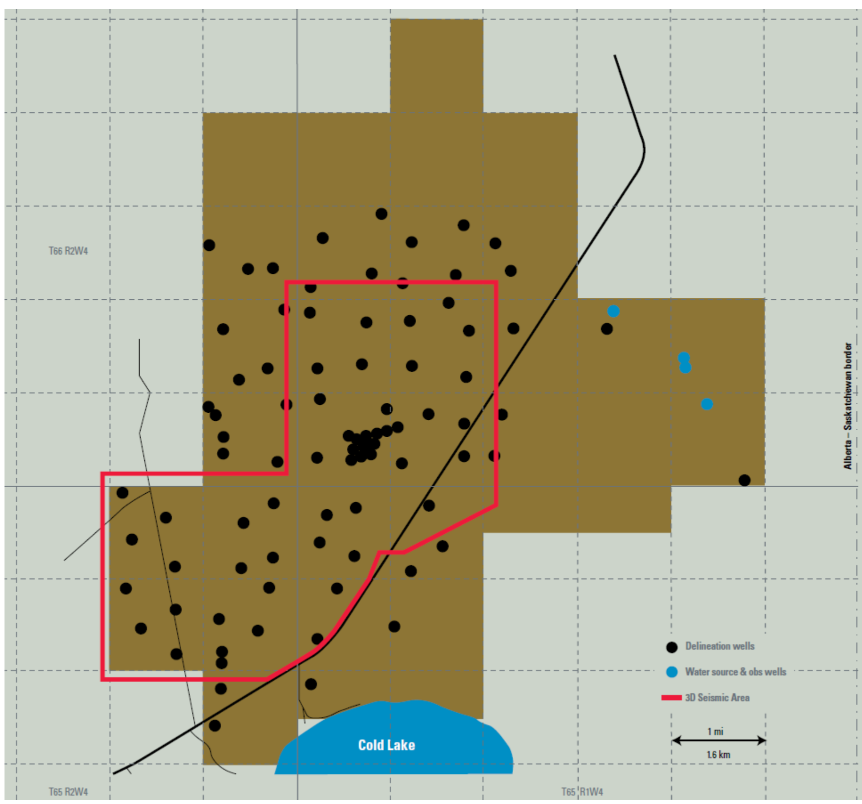
The company reports 320 million barrels of 2P reserves and 2.144 billion barrels of Best Estimate Contingent Resource net to Osum's W.I. (GLJ). GLJ estimates that the resource base is capable of supporting more than 240,000 bbl/d of production.

Taiga

The company filed its regulatory application for a 35,000 bbl/d SAGD-CSS project and a 40 MW co-generation facility at Taiga in the fourth quarter of 2009. Management expects the regulatory application to be approved in mid 2011. Osum is targeting first production in early 2014. Management is planning the project in two stages of 17,500 bbl/d. The co-generation facility is planned in conjunction with Phase II. Phase II is planned to follow Phase I by about two years.

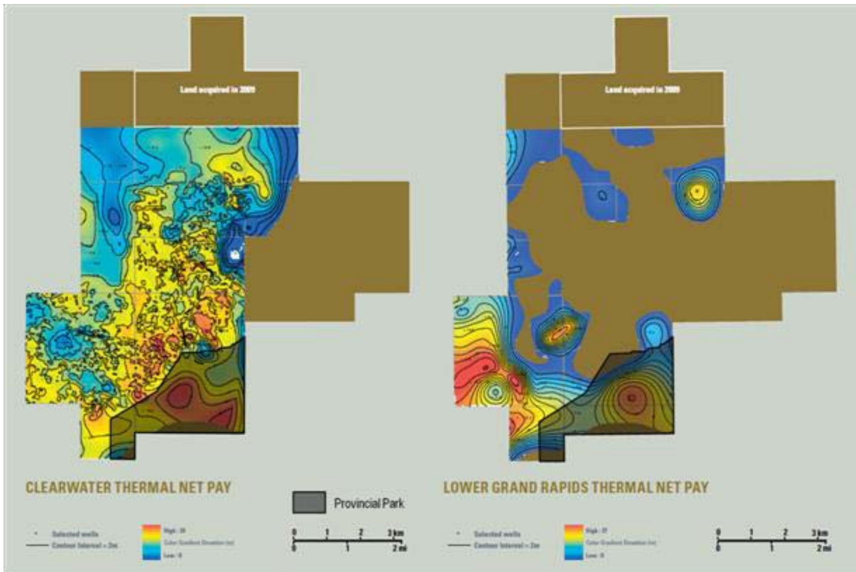
Initial development will target the Clearwater formation, but Osum also has plans to develop the Lower Grand Rapids formation. Management estimates a SOR of 3.0–3.6x and plans to build facilities to support a SOR of 3.7x. Because the produced bitumen in the Cold Lake region has a high gas concentration that can be separated, captured and re-used in the process, management estimates that the effective SOR would be closer to 2.8–3.0x. Osum has secured a brackish water source and plans to recycle more than 90% of its water. Land usage has also been taken into consideration, so the project has been designed to minimize the surface effect on land.

Exhibit 154: Taiga Lease - Delineation



Source: Company reports

Exhibit 155: Taiga Lease – Net Pay of Clearwater and Lower Grand Rapids



Source: Company reports

Bitumen Carbonates

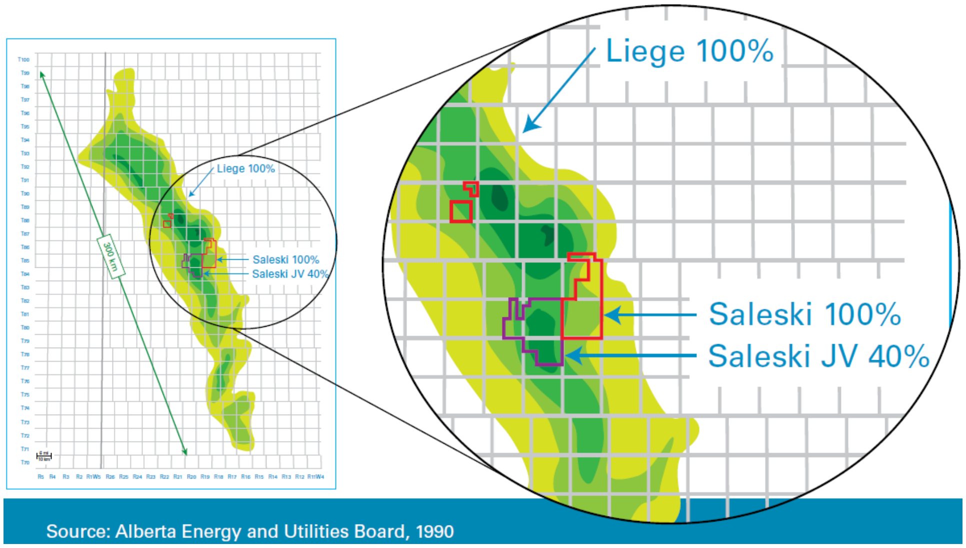
Osum holds a 40% W.I. in the Saleski joint venture lease, which is 60% owned and operated by Laricina. Osum also owns 100% W.I. in the adjacent Saleski lease and two leases at Liege, which also have exposure to the Grosmont carbonates. According to GLJ, Osum has exposure to 2.0 billion barrels of Contingent Resource in the carbonates (Best Estimate recoverable).

Osum is estimated to have exposure to 972 million barrels recoverable bitumen on the Saleski joint venture lease net to the company's 40% W.I. Management estimates the production potential of the lease at 270,000 bbl/d gross (108,000 bbl/d net).

According to GLJ, the estimated recoverable resource potential on the company's 100% owned Saleski lease is 594 million barrels with an estimated production potential of 50,000 bbl/d. At Liege, GLJ has provided a Best Estimate of Contingent Resource at 435 million barrels with an estimated production potential of 40,000 bbl/d.

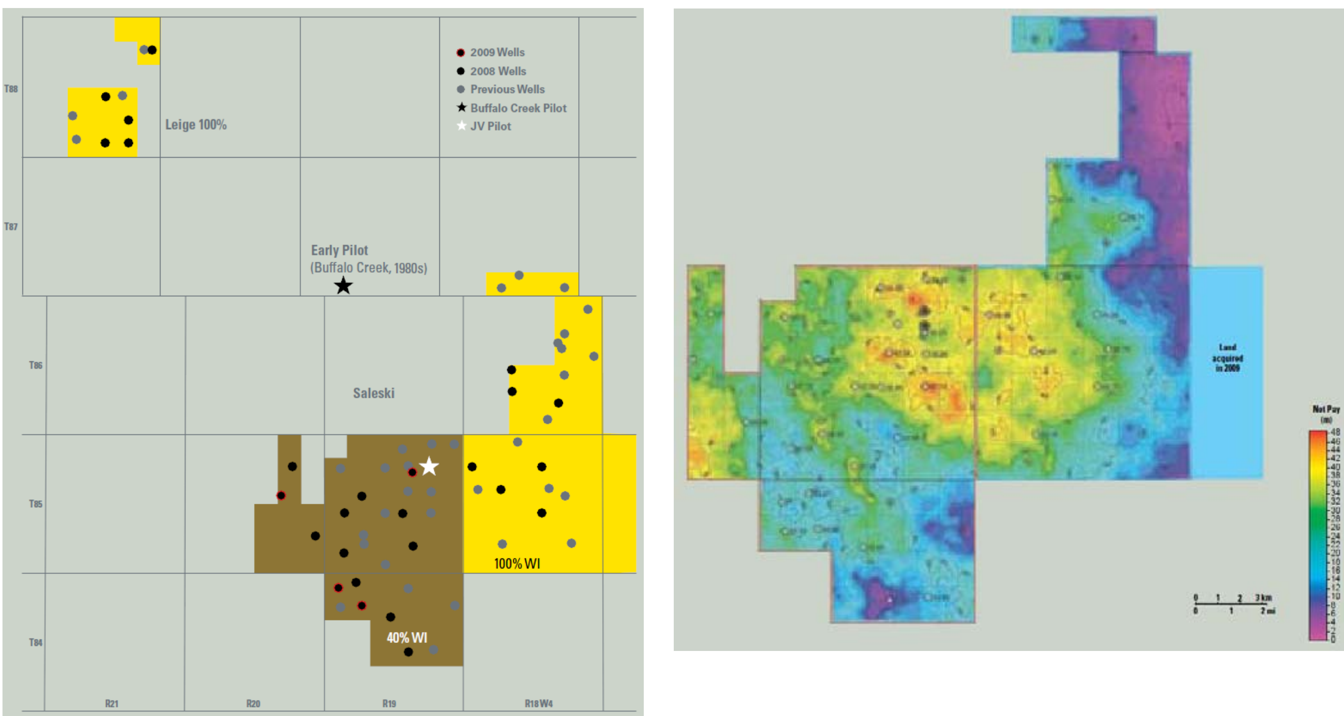
Evaluation work is most advanced on the Saleski joint venture lease; however, Osum has conducted delineation drilling and 3D seismic on its Saleski 100% W.I. lease and delineation drilling at Liege. The company is planning additional delineation drilling this winter on its Saleski 100% lands. Osum has conducted similar lab tests on core samples from its 100% W.I. Saleski lease because the joint venture partners' (Laricina and Osum) tests conducted on the core samples from the Saleski joint venture lease produced similar results.

Exhibit 156: Saleski and Liege Leases



Source: Company reports

Exhibit 157: Saleski Delineation & Isopach



Source: Company reports

Underground Mining – Osum management has reduced its emphasis on the use of underground mining. The application of underground mining is not a part of the current development plan for Taiga or Saleski, both of which are planned to be developed with conventional drilling technologies.

Exhibit 158: Osum - Company Profile

Business Description

Osum is a pure play oil sands and unconventional oil company with four projects concentrated in two areas of Alberta, Canada. Osum is the only junior oil sands company with a project in the Cold Lake thermal trend. No piloting is required at Cold Lake, streamlining the front end development process. Osum is joint venture partners with Laricina at Saleski, however, with adjacent 100% owned lands Osum is the third largest resource holder in the bitumen-bearing Saleski Carbonates, after Shell and Husky.

Land Position

Key Areas	W.I.	Net Acres	Details
Saleski	100%	37,120	Core Well this Winter
Liege	100%	7,680	Partially Delineated
Saleski JV	40%	16,954	Laricina Energy (60%)
Taiga	100%	18,560	Fully Delineated

Reserves & Resources (GLJ)

(mmbbl)	Reserves	Contingent Resources			BOIP
	2P	Low	Best	High	
Saleski	n.a.	n.a.	594	1,345	4,500
Liege	n.a.	134	435	940	1,600
Saleski JV	n.a.	148	972	1,681	3,000
Taiga	320	293	143	247	2,000
Total	**320**	**575**	**2,144**	**4,213**	**11,100**

Potential Catalysts

2010	Saleski JV pilot start up anticipated (year end)
2011	Regulatory approval for 35,000 Bbl/d Taiga Project expected
2012	Commercial delineation of Saleski 100% lands
2012	Taiga project construction planned
2013	Begin steaming reservoir at Taiga project
2013	Commercial application for 100% WI project at Saleski
2014	First Bitumen at Taiga Project

Key Milestones & Uses of Funds

2010	Cold Lake FEED
2009-2011	Saleski JV pilot construction
2011	Saleski JV operations
2009-2011	Other studies, engineering, etc.
2011	General and administrative expenses

Management Team

Name	Position	Past Experience
Steve Spence	President & COO	Shell Canada
Peter Putnam	Senior VP, Geoscience	Husky Oil
Andrew Squires	Senior VP, Saleski Projects	Paramount Resources
Rick Walsh	EVP Operations & Development	Suncor Energy
Jeffrey MacBeath	VP, Finance	PrimeWest Energy Trust

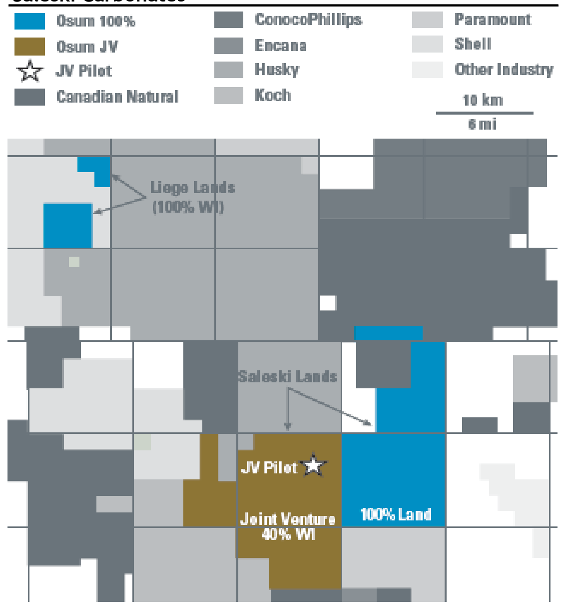
Board of Directors

Name	Experience
Richard. Todd (Chairman)	Chariman, President & CEO, Mustang Resources
Vincent Chahley	MD Corp. Finance, FirstEnergy Capital Corp.
George Crookshank	Former CFO, OPTI Canada
William Friley	Chariman, TimberRock Energy Corporation
David Foley	Senior MD, Blackstone Capital Partners VLP
Jeffrey Harris	MD, Warburg Pincus LLC
David Krieger	MD, Warburg Pincus LLC
Cameron McVeigh	Founder, Camcor Capital
John Zahary	President & CEO Harvest Energy

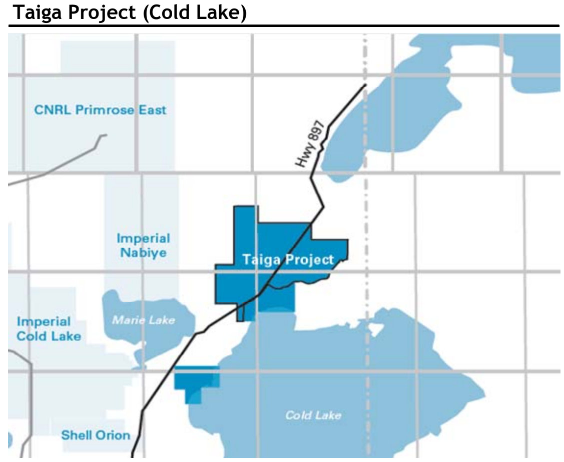
Recent News

Mar-10	Announces 2P Reserves Booking
Jan-10	Files Application for the Taiga Project
Nov-09	Welcomes Rick Walsh as New VP, Projects

Saleski Carbonates



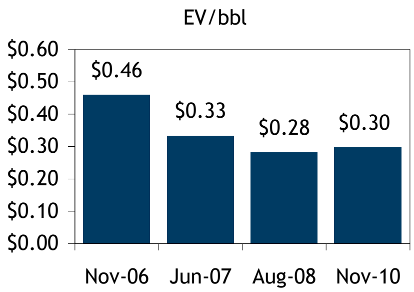
Taiga Project (Cold Lake)



Source: Company reports

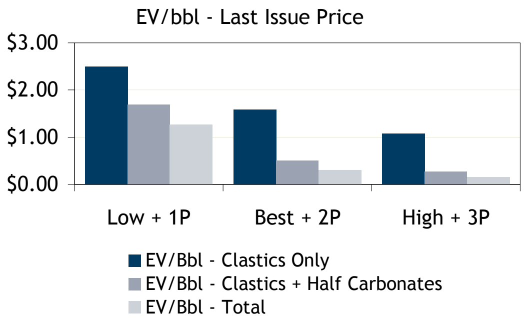
RBC Capital Markets®

Exhibit 159: Osum - Financial Profile



Financing History

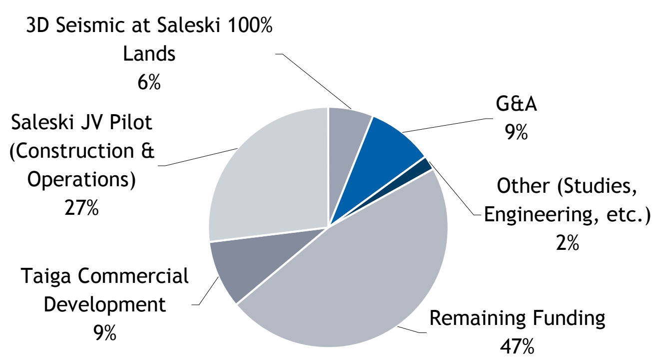
Date	Type	Issue Price	Amount ($mm)	Resource (bn bbl)*	EV/bbl
Early-06	Convertible Debentures	N/A	$8.0	n.a.	n.a.
Mid-06	Common	$1.10	$7.0	n.a.	n.a.
Nov-06	Common	$3.00	$26.0	0.18	$0.46
Jun-07	Common	$9.00	$41.0	1.10	$0.33
Late-07	Flow-Through	N/A	$15.0	1.10	n.a.
Early-08	Credit Line	N/A	$15.0	1.52	n.a.
Aug-08	Common	$10.50	$275.0	1.52	$0.28
Nov-10	Common	$13.00	$100.0	2.46	$0.30
		Total	**$487.0**		



Net Resource Summary (mmbbl)

	Low + 1P	Best + 2P	High + 3P
Clastics - Cold Lake	293	463	682
Carbonates - 100% Owned	134	1,029	2,285
Carbonates - Joint Venture	148	972	1,681
Total	**575**	**2,464**	**4,648**
EV/bbl @ Last Issue Price of $13.00/Share			
EV/Bbl - Clastics Only	$2.50	$1.58	$1.07
EV/Bbl - Clastics + Half Carbonates	$1.69	$0.50	$0.27
EV/Bbl - Total	**$1.27**	**$0.30**	**$0.16**

2010 Capital Budget



Source: Company reports

Sunshine Oilsands Ltd. (Private Company)

1,000,000 Plus Acres of Leases in the Athabasca Region

Capitalization			Resources		
Last Financing Price[a]	($)	$6.00	Oil Sands EV[b]	($mm)	$493.9
F.D. Shares Outstanding	(mm)	90.7	2P Reserves	(mmbbl)	54
Market Capitalization	($mm)	$544.4	Contingent Resources[c]	(mmbbl)	2,185
Net Debt	($mm)	($50.5)	PIIP	(mmbbl)	43,842
Enterprise Value	($mm)	$493.9	EV/Bbl[d]	($/bbl)	$0.22

Key Areas & Potential[e]	Start-up	(bbl/d)
Muskwa	2010	3,000
West Ells	2013	120,000
Legend Lake	2013	60,000
Thickwood	2014	50,000
Harper	n.a.	200,000
Portage/Pelican Lake	n.a.	15,000

Carbonate Potential[e]	Start-up	(bbl/d)
Various Leases	n.a.	632,000

Key Personnel	Position
John Kowal	Co-CEO
Doug Brown	Co-CEO and COO
Tom Rouse	CFO
David Sealock	EVP Corporate Operations
Songbo Cong	VP Facilities Engineering
Dan Dugas	VP Field Operations
Jason Hancheruk	VP Regulatory
Tony Sabelli	VP Drilling and Construction
Al Stark	Controller

(a) Share price at last (non flow-through) equity issue.
(b) Adjusted to exclude the estimated value of non-oil sands assets.
(c) Best Estimate Contingent.
(d) Based on 2P reserves + Best Estimate Contingent.
(e) Gross production potential as per management estimates; Key Areas represent clastic potential only (carbonate potential stated separately).
Source: Company reports

Company Summary

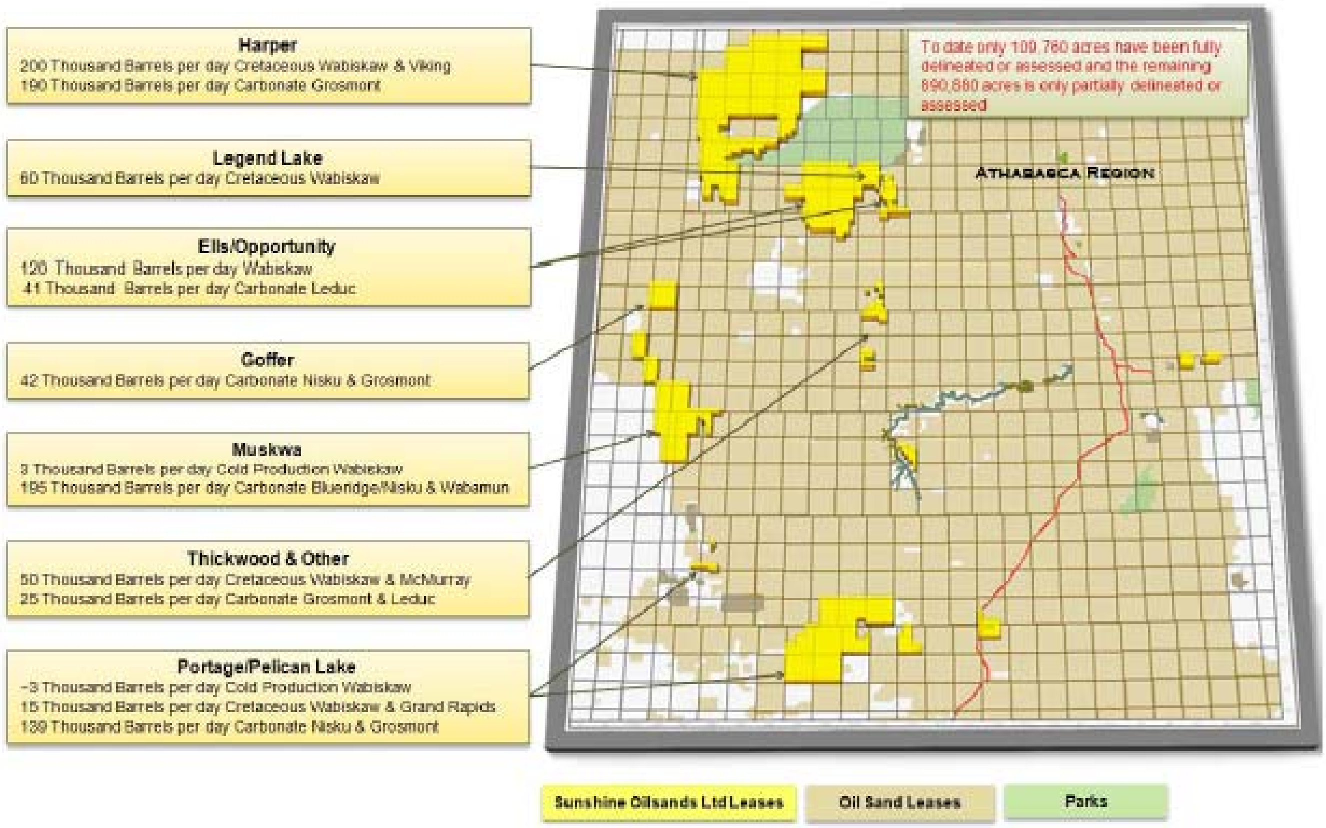
- Sunshine owns a 100% W.I. in 1,078,705 acres of oil sands leases focused on seven operational areas: Harper, Legend Lake, Ells and West Ells, Goffer, Muskwa, Thickwood and Portage and Pelican lease areas.
- The company focuses its operations on conventional heavy oil, cretaceous sandstone (SAGD) and bitumen carbonates.
- GLJ Petroleum Consultants Ltd (GLJ) has assigned 2.185 billion barrels of Contingent Resource (Best Estimate) net to Sunshine.
- Sunshine is targeting 3,000 bbl/d of primary heavy oil from the Muskwa region by 2012 as a quick means to generate cash flow. The company is targeting 2010 exit rate production of 200 bbl/d with more than 700 bbl/d behind the pipe.
- Management estimates production potential of its core cretaceous sandstone assets to be 200,000 bbl/d with the multiphase development of Ells, Legend Lake and Thickwood regions.
- At Ells, the company submitted a regulatory application on March 31, 2010 and anticipates receiving regulatory approval for the West Ells project in the second quarter of 2011. First steam of Phase 1 and Phase 2 is expected at the end of the first quarter 2013 and 2014, respectively. The initial phases represent the first 10,000 bbl/d of a total planned capacity of 90,000 bbl/d for West Ells by 2025.
- At Legend Lake, management expects the application for the first phase of commercial development to be submitted in 2011 with regulatory approval expected in 2012. The initial phase represents the first 10,000 bbl/d of a total planned capacity of 60,000 bbl/d for Legend Lake area by 2020.
- At Thickwood, the first regulatory application is expected to be submitted in 2012. The initial phase represents the first 10,000 bbl/d of a total planned capacity of 50,000 bbl/d for Thickwood by 2019.

Company Overview

Sunshine has raised a total of $219 million since it was established as a private company in February 2007. As of September 2010, the company had $60 million of cash and no debt.

Sunshine owns a 100% W.I. in 1,078,705 acres of oil sands leases focused on seven operational areas: Harper, Legend Lake, Ells and West Ells, Goffer, Muskwa, Thickwood and Portage and Pelican lease areas. The company's operations are focused on conventional heavy oil, cretaceous sandstone (SAGD) and bitumen carbonates. GLJ has assigned 2.185 billion barrels of Contingent Resource (Best Estimate) net to Sunshine.

Exhibit 160: Sunshine Leases



Source: Company reports

Conventional Heavy Oil – Non-Thermal

Sunshine is targeting 3,000 bbl/d of primary heavy oil from the Muskwa region by 2012. While small, this project is being pursued primarily as a means of generating cash flow. In addition to Muskwa, management believes that the Portage and Pelican Lake area offers conventional heavy oil potential.

At Muskwa, management expects to finish drilling 16 wells by the end of 2010, of which six wells are completed and producing, thereby achieving a year-end 2010 exit production rates of more than 200 bbl/d of cold flow production with more than 700 bbl/d behind the pipe from the Wabiskaw Formation. In addition to conventional heavy oil production potential, the region is expected to offer bitumen carbonate opportunities. The company currently has completed construction of its first six-well pad, with four wells completed and producing. Management anticipates having all six wells producing by year-end 2010.

As of July 31, 2010, GLJ has assigned 107 million barrels of Contingent Resource (Best Estimate) to the lands in the Portage and Pelican Lake area based on thermal extraction and 6.8 million barrels of Contingent Resource (Best Estimate) to the lands at Muskwa based on cold flow extraction.

Cretaceous Sandstone - SAGD

Management plans to develop SAGD projects in this region in a staged and scalable fashion in order to manage project timing and cost pressures. Sunshine is limiting the maximum size for any development phase to 20,000 bbl/d. Management estimates production potential of its cretaceous sandstone assets to be 200,000 bbl/d with multiphase development of the Legend Lake, Ells and Thickwood regions.

Ells – The company submitted a regulatory application for a 10,000 bbl/d SAGD project at West Ells on March 31, 2010. Management anticipates receiving regulatory approval for the West Ells project in the second quarter of 2011 with first steam of Phase 1 and Phase 2 expected at the end of the first quarter of 2013 and 2014, respectively. The initial phases of six stages represent the first 10,000 bbl/d of a total planned capacity of 90,000 bbl/d for West Ells by 2025. As of July 31, 2010, GLJ has assigned 756 million barrels of Contingent Resource (Best Estimate) and 54 million barrels of 2P reserves to the company's leases at Ells. GLJ has assigned 127 million barrels of Contingent Resource (Best Estimate) at West Ells. Management estimates its capital intensity at Ells is $33,255 bbl/d.

Exhibit 161: Ells Development Schedule

	First Steam	Design Capacity (bbl/d)
West Ells Phase 1	2013	5,000
West Ells Phase 2	2014	5,000
West Ells Phase 3	2018	20,000
West Ells Phase 3 Expansion	2020	20,000
West Ells Phase 4	2024	20,000
West Ells Phase 4 Expansion	2025	20,000
Total		**90,000**

Source: Company reports

Legend Lake – Application for the first phase of the Legend Lake commercial development is expected to be submitted in 2011, and management anticipates receiving regulatory approval in 2012. The initial phase of five stages represents the first 10,000 bbl/d for a total planned capacity of 60,000 bbl/d for Legend Lake to be achieved by 2020. As of July 31, 2010, GLJ has assigned 321 million barrels of Contingent Resource (Best Estimate) to the company's leases at Legend Lake. Management estimates its capital intensity at Legend Lake at $35,690 bbl/d.

Exhibit 162: Legend Lake Development Schedule

	First Steam	Design Capacity (bbl/d)
Legend Lake Phase 1	2013	10,000
Legend Lake Phase 2	2016	10,000
Legend Lake Phase 2 Expansion	2017	10,000
Legend Lake Phase 3	2020	20,000
Legend Lake Phase 3 Expansion	2021	10,000
Total		**60,000**

Source: Company reports

Thickwood – The first regulatory application is expected to be submitted in 2012, and management anticipates receiving regulatory approval in 2013. The initial phase of three stages represents the first 10,000 bbl/d of a planned capacity of 50,000 bbl/d for Thickwood development by 2019. As of July 31, 2010, GLJ has assigned 470 million barrels of Contingent Resource (Best Estimate) to the company's leases at Thickwood. Management estimates its capital intensity at Thickwood at $32,904 bbl/d.

Exhibit 163: Thickwood Development Schedule

	First Steam	Design Capacity (bbl/d)
Thickwood Phase 1	2014	10,000
Thickwood Phase 2	2017	20,000
Thickwood Phase 2 Expansion	2019	20,000
Total		**50,000**

Source: Company reports

Bitumen Carbonates

The company filed a regulatory application in October 2008 for a bitumen carbonate pilot project at Harper to evaluate the potential of the Grosmont carbonate reservoir; the application was approved on November 27, 2009. The company's Harper pilot, which is expected to be initiated this winter, will be the first step in the future development of these lands. The pilot is designed to prove mobility and provide data on thermal response of the reservoir. A planned 2010 seismic program will identify targets and guide future core hole programs.

As of July 31, 2010, GLJ has partially assessed the lands in the Harper area as containing 331 million barrels of Contingent Resource (Best Estimate).

Exhibit 164: Sunshine - Company Profile

Business Description

Sunshine Oilsands Ltd. is focused on the development of over one million acres of oil sands and heavy oil leases in the Athabasca oil sands region. The company's assets are grouped into three distinct business segments: Conventional Heavy Oil, Cretaceous Sandstone and Carbonates. Sunshine has received approval for 1,080 bbl/d primary recovery project on its Muskwa lands, and also submitted a regulatory application to develop a commercial SAGD project at West Ells.

Resource Estimates (GLJ)

(mmbbl)	3P	Contingent Resources Best Estimate	PIIP Clastics
Ells (& West Ells)	69.6	882.9	5,211
Harper		331.5	17,624
Thickwood		469.9	2,131
Legend Lake		320.9	1,121
Saleski*			762
East Long Lake		34.5	162
Crew Lake			321
Portage			5,583
Pelican Lake		107	384
Muskwa	0.5	6.8	9,318
Goffer		31	1,225
	70	2,185	43,842

Management Team

Name	Position	Past Experience
John Kowal	Co-CEO	CFO for Total E&P Canada & Deer Creek Energy
Doug	Co-CEO and COO	VP Flint Energy Services
Tom Rouse	CFO	CFO for Patch International
David Sealock	EVP, Corporate Ops	VP of Corporate Services with MegaWest Energy
Dr. Songbo Cong	VP, Facilities Engineering	Principal Project Engineer, Honeywell Intl.
Dan Dugas	VP, Field Ops	Operations Supervisor for EnCana, Foster Creek
Jason Hancheruk	VP, Stakeholder Affairs	Integrity Land
Tony Sabelli	VP, Drilling & Construction	GM, Drilling & Completions, CNRL
Al Stark	Controller	Finance Director for Rally Energy Corp.

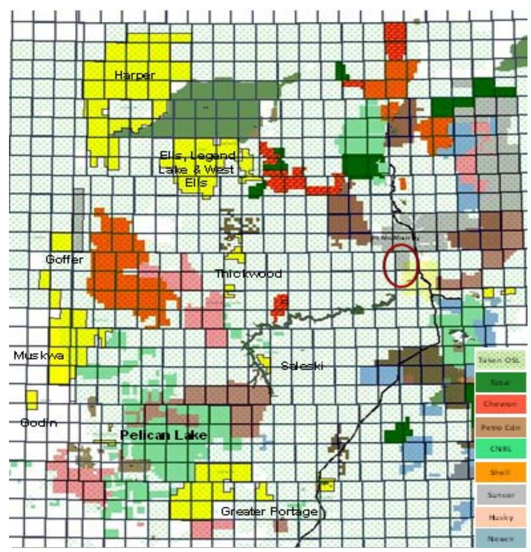
Recent News

Mar-10	Submits Commercial 10,000 Bbl/d SAGD
Jan-10	Receives Regulatory Approval for Muskwa
Dec-09	Carbonate Pilot Application Approved by
Financing	
Q2 2010	Subscription agreement: $83.4 MM @ $6.00/sh
Q2 2010	Flow through financing: $3.8 MM @ $6.50/sh
Q4 2009	Flow through financing: $2.0 MM @ $6.00/sh
Q3 2009	Subscription agreement: $35 MM @ $5.25/sh

Board of Directors

Name	Experience
Michael J. Hibberd (Co-Chairman)	Co-Chairman and Co-CEO of Sunshine
Songning Shen (Co-Chairman)	CoChairman of Sunshine
Tseung Hok Ming	Chairman, Orient Holdings Group Ltd.
Kevin Flaherty	Managing Director of Savitar Acquisitions PTE Ltd.
Raymond Fong	CEO for China Coal Corporation
Zhijun Qin	President of GPT Group Ltd.
Mike Seth	President of Seth Consultants Ltd.
Greg Turnbull	Managing Partner with McCarthy Tétrault LLP

Sunshine Lease Map



Director Ownership

Name	Shares (mm)	% of Basic	Options * (mm)	Total (mm)	% of F.D.
Michael J. Hibberd	2.1	3.0%	2.1	4.2	4.6%
Songning Shen	2.0	2.9%	2.1	4.1	4.6%
Tseung Hok Ming	6.7	9.4%	0.2	6.9	7.6%
Kevin Flaherty	0.2	0.3%	0.1	0.3	0.3%
Raymond Fong	0.3	0.5%	0.1	0.4	0.5%
Zhijun Qin	0.8	1.1%	0.1	0.9	0.9%
Mike Seth	0.0	0.0%	0.1	0.1	0.1%
Greg Turnbull	0.5	0.6%	0.1	0.6	0.6%
Total	**12.6**	**17.8%**	**4.9**	**17.5**	**19.2%**

* Includes all dilutive instruments

Source: Company reports

JACOS – Japan Canada Oil Sands Ltd. (Private Company)

Waiting for Regulatory Approval at Hangingstone

Key Areas	W.I.
Chard*	25-100%
Corner	12-100%
Hangingstone	75-100%
Liege	25%
Thornbury	25%

Key Personnel	Position
Toshiyuki (Toshi) Hirata	President
Yukio Kishigami	Executive VP
Brian Harschnitz	Senior VP
Bruce Watson	VP Finance & Administration
Shinichi Takahata	VP, GeoScience
Tony Nakamura	VP, Technical
Gerard Bosch	VP, Marketing & Business Development

* JACOS has various W.I. in the Chard lease area
Source: Company reports

Company Overview

The company's focus is the JACOS Hangingstone area. JACOS holds a 100% W.I. at the Hangingstone SAGD Demonstration area (3.75 sections) that is located approximately 50 km southwest of Fort McMurray. JACOS owns a 75% operated W.I. in the Hangingstone expansion area with Nexen Inc. holding the remaining 25% W.I.

JACOS has captured approximately 1.7 billion barrels of Contingent Resource (Best Estimate) over its 114,000 acres of leases. JACOS holds a number of leases at various W.I., ranging among 12% to 100% W.I. JACOS owns a 25% W.I. in natural gas leases at Liege; however, this production has been shut in by the ERCB because the natural gas overlies bitumen reservoirs.

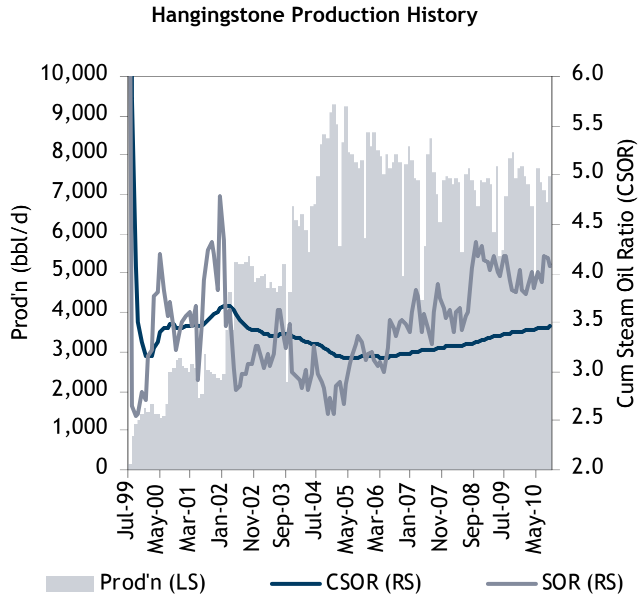
JACOS is a 100% owned subsidiary of CANOS, which is a consortium that is 88% owned by JAPEX, which is a publicly traded energy company in Japan, and 12% owned by various corporate investors. JAPEX itself is 34% owned by the Japanese Government and 66% owned by public investors.

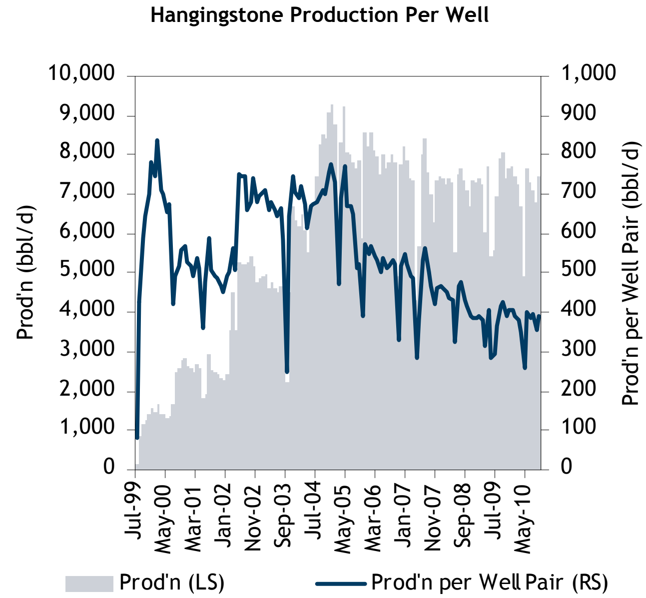
Hangingstone Demonstration Plant

Production History – The 10,000 bbl/d Hangingstone demonstration facility came on stream in mid 1999. The company has 20 producing wells with plans to drill two wells this winter. Full development of the Demonstration project is 23-well pairs.

Operational Highlights – Production is currently averaging about 7,500 bbl/d. Project production peaked at approximately 9,000 bbl/d in late 2004 and has since been on a shallow decline. The project SOR has averaged round 3.5x. Average production per well has declined to approximately 400 bbl/d from a peak of nearly 800 bbl/d, demonstrating the maturing of the company's first project. Maturity of the field could also be seen by the gradually increasing SOR, which has increased to about 4.2x presently from a low of 2.6x in late 2004. Producing pressures are approximately 4,500 kPa. JACOS is considering methods to reduce operating pressures as a means of improving its SOR. The company will install one ESP before year-end 2010 to study the possible application in the expansion. In addition, JACOS is proceeding with non-condensable gas co-injection.

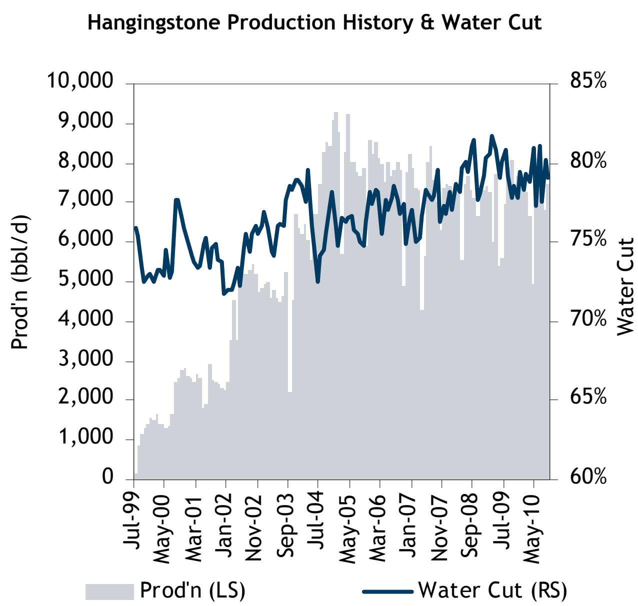
Exhibit 165: Production History & SOR

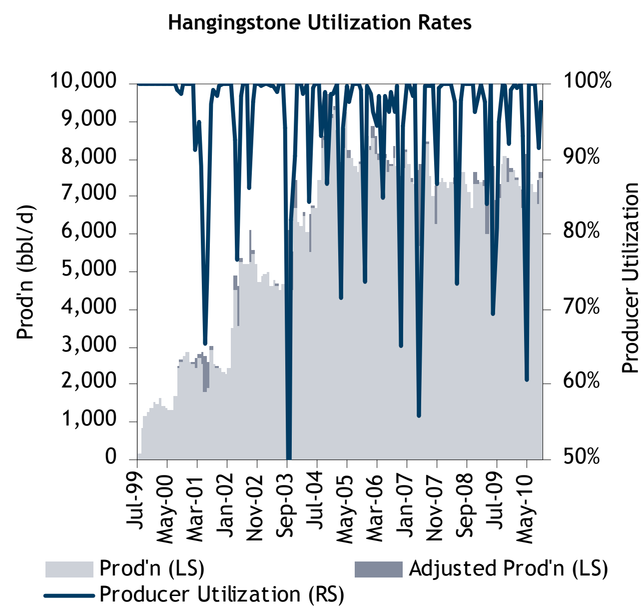




Source: Accumap and RBC Capital Markets

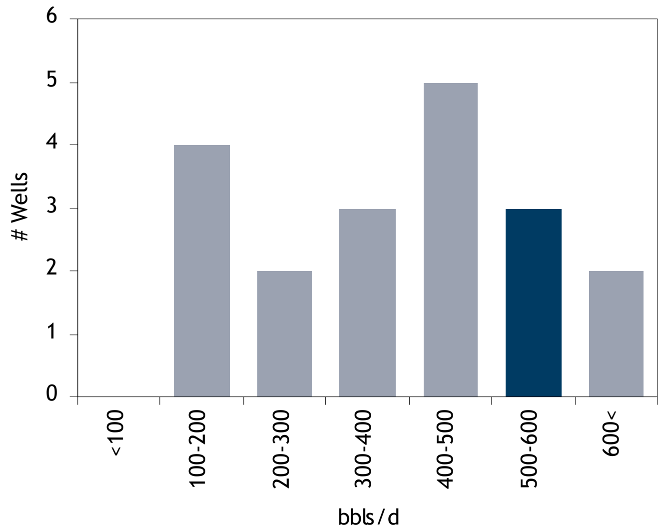
Exhibit 166: Water Cut & Utilization Rates

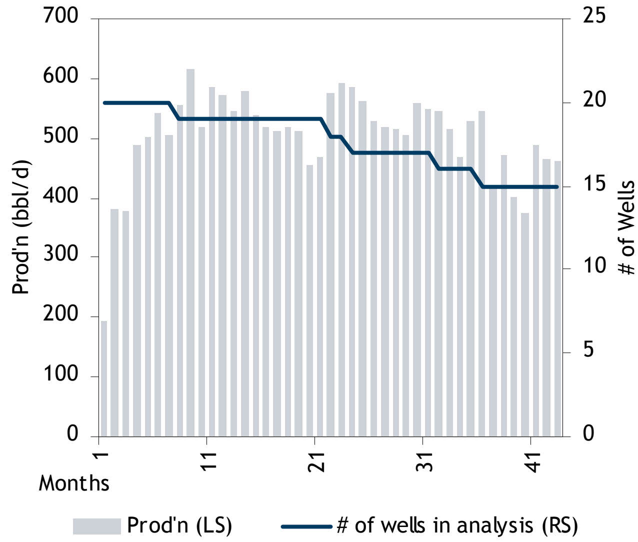




Source: Accumap and RBC Capital Markets

Exhibit 167: Well Productivity Distribution & Type Well Performance





Note: To reach nameplate capacity each well would need to produce 526 bbls/d

Source: Accumap and RBC Capital Markets

Hangingstone Expansion – up to 35,000 bbl/d

The joint venture partners are currently working on the up to 35,000 bbl/d Hangingstone Expansion project. The project application is currently in the regulatory process. The application was filed in the second quarter of 2010; therefore, management expects regulatory approval in the third quarter of 2011. No long lead items have been ordered; however, the partners are running a parallel front end engineering and design (FEED) process. Project sanction is expected before year-end 2011. The partners are scheduling first steam at the expansion in the third quarter of 2014 with production by year-end 2014. JACOS is currently considering pipeline and rail transportation options. The company would likely not own any pipeline solutions.

The Hangingstone Expansion is targeting up to 35,000 bbl/d gross (up to about 26,250 bbl/d net to JACOS) with approximately 60-well pairs initially for an implied average rate per well pair of about 600 bbl/d. A total of 175-well pairs are expected during the full life of the project.

Reservoir conditions in the expansion area are similar to those in the development area, with good cap rock, no top gas, no bottom water and reservoir thickness of 15–25 metres.

Exhibit 168: JACOS - Company Profile

Business Description

Japan Canada Oil Sands Ltd. (JACOS) is a pure play oil sands exploration and production company with a three decade history in the Athabasca oil sands. In 1978 JACOS farmed in on leases held by Petro-Canada (Suncor), Canadian Occidental (Nexen Inc.) and Esso (Imperial Oil) to form what is referred to as the PCEJ group. The company was involved through JAPEX in the research and development of in-situ technology, including the Underground Test Facility (UTF Project) in 1992. JACOS now holds rights to over 114,000 acres of land in five areas in the Athabasca region including Hangingstone, Chard, Corner, Thornbury and Liege.

Corporate Structure

Japan Canada Oil Sands Ltd. (JACOS) is a 100% owned subsidiary of Canada Oil Sands Co. Ltd. (CANOS), a Japanese subsidiary of Japan Petroleum Exploration Co. (JAPEX). JAPEX is an E&P company traded on the Tokyo Stock Exchange.

Recent News

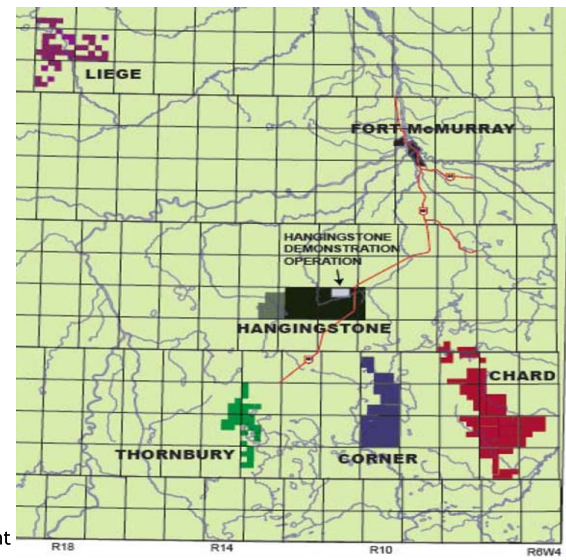
Jun-10	Submits regulatory application for expansion
Feb-09	AB Environment issues Final Terms of Reference
May-08	Announces proposed expansion for Hangingstone

Leases & Partners

Key Areas	W.I.	Partners
Chard*	25-100%	Imperial (var.), Nexen (var.), Suncor (var.)
Corner	12-100%	Imperial (Varies), Nexen (Varies)
Hangingstone	75-100%	Nexen (25%)
Liege	25%	CNRL (75%)
Thornbury	25%	Imperial (25%), Nexen(25%), Suncor (25%)

* JACOS has various working interests in the Chard lease area

JACOS Lease Map



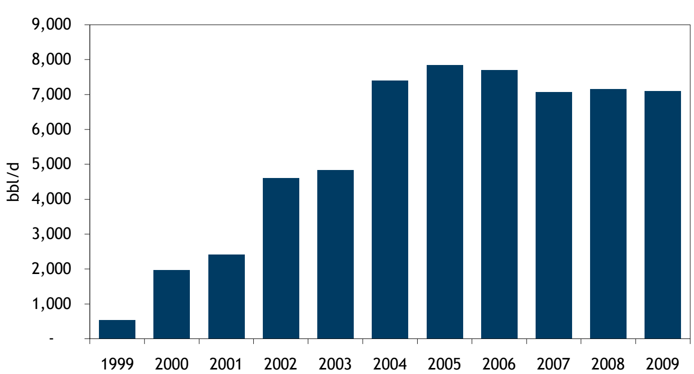
Potential Catalysts

Q3 2011E	Expected regulatory approval of Hangingstone Expansion
Q1 2012E	Hangingstone expansion drilling and construction begins
Q4 2014E	Expected first bitumen from Hangingstone Expansion

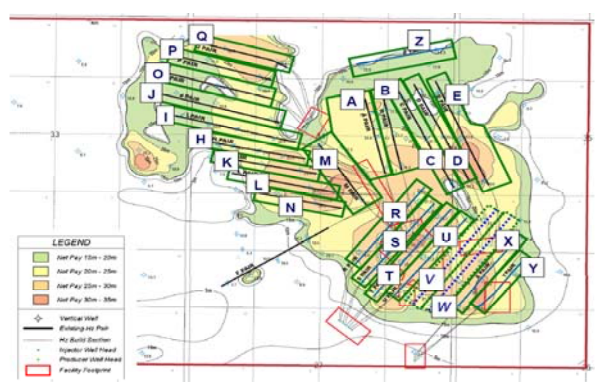
Management Team

Name	Position
Toshiyuki (Toshi) Hirata	President
Yukio Kishigami	Executive Vice President
Brian Harschnitz	Senior Vice President
Bruce Watson	Vice President Finance & Administration
Shinichi Takahata	Vice President, GeoScience
Tony Nakamura	Vice President, Technical
Gerard Bosch	Vice President, Marketing & Business Development

Hangingstone Production Profile



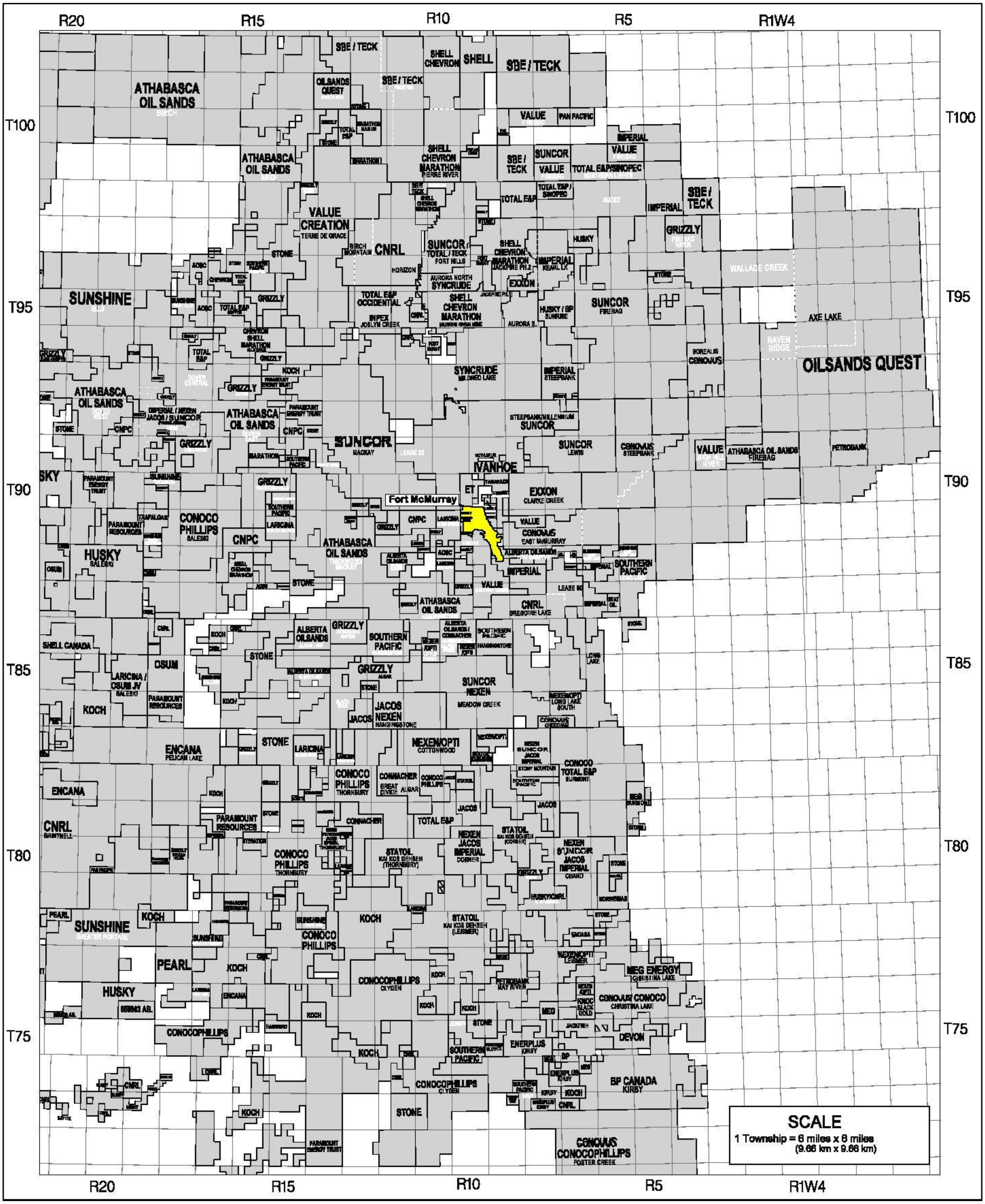
Hangingstone Phase I Net Pay Map



Source: Company reports

RBC Capital Markets®

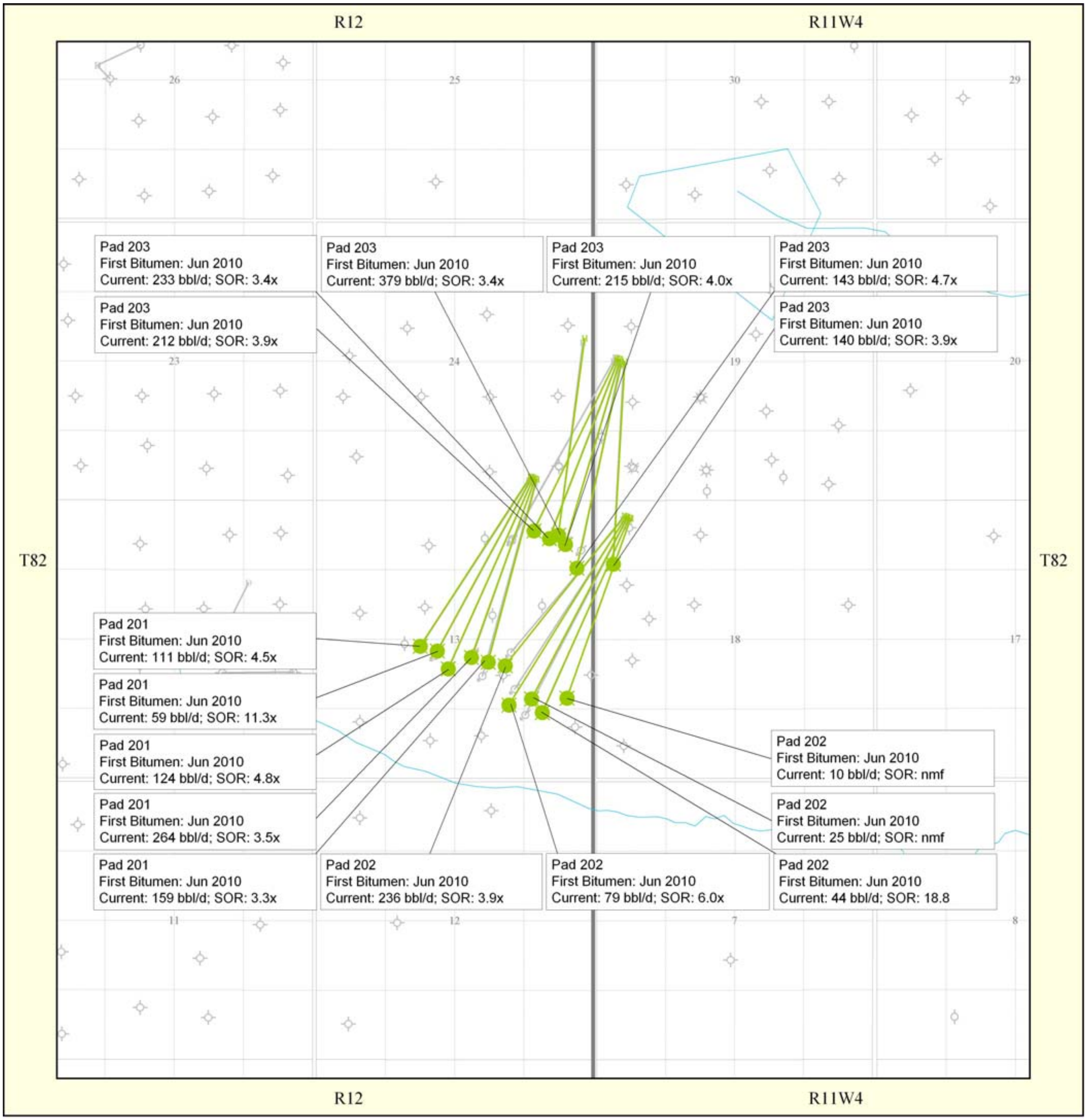
Appendix II: Oil Sands Lease Map



Source: Company reports and RBC Capital Markets

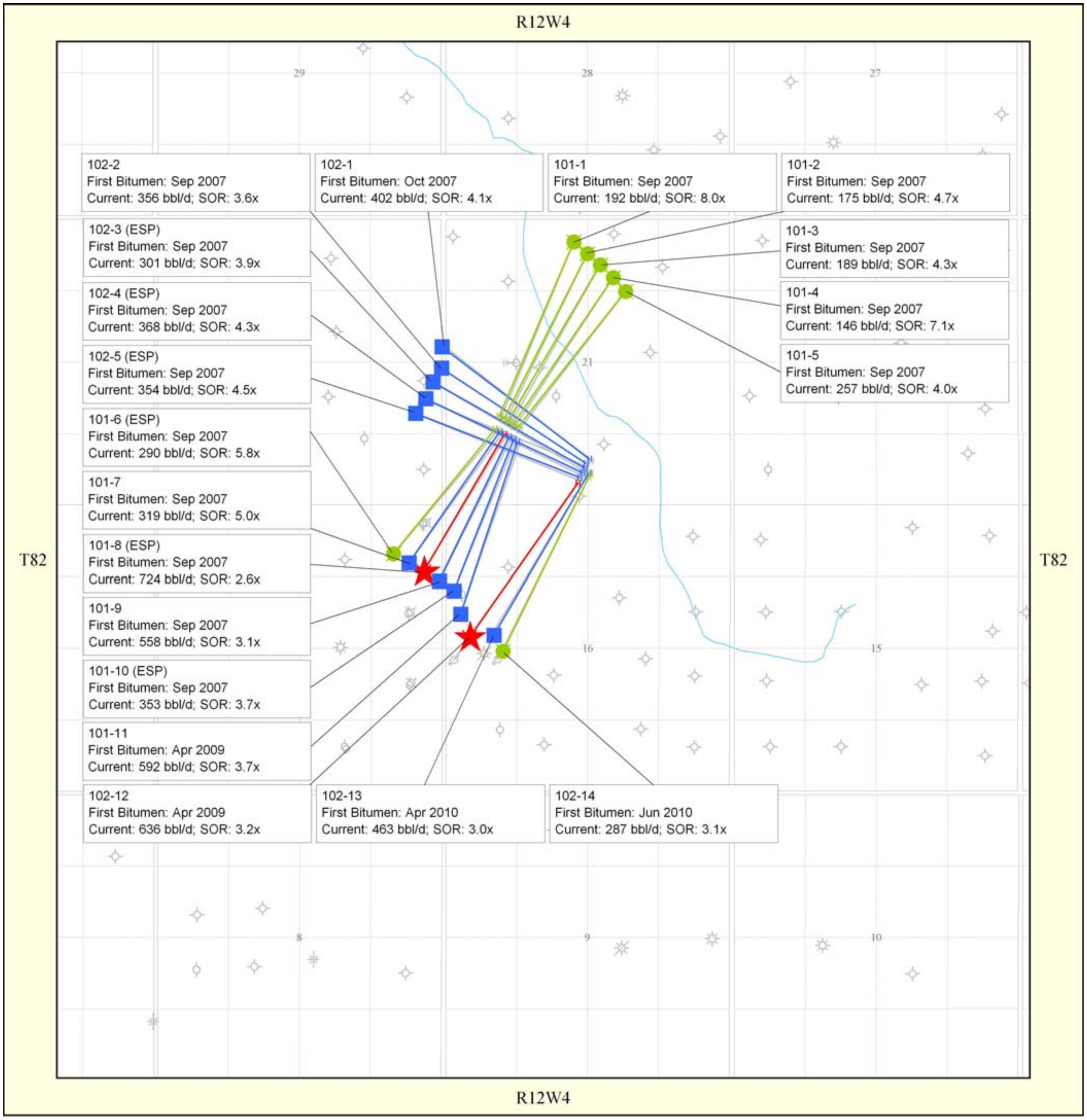
Appendix III: Project Well Configuration Maps

Connacher Algar Well Configuration



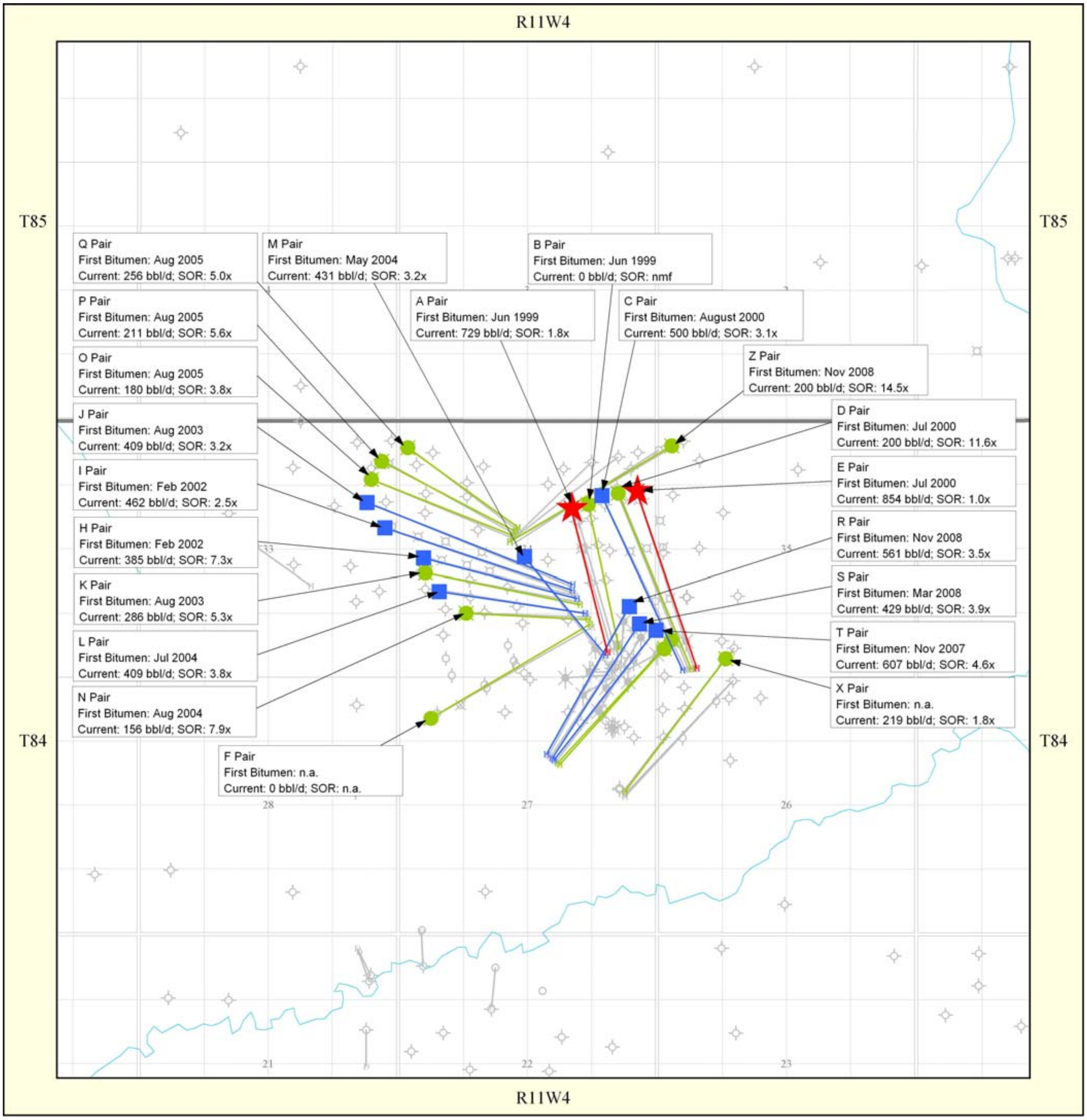
Source: Accumap and RBC Capital Markets

Connacher Pod One Well Configuration



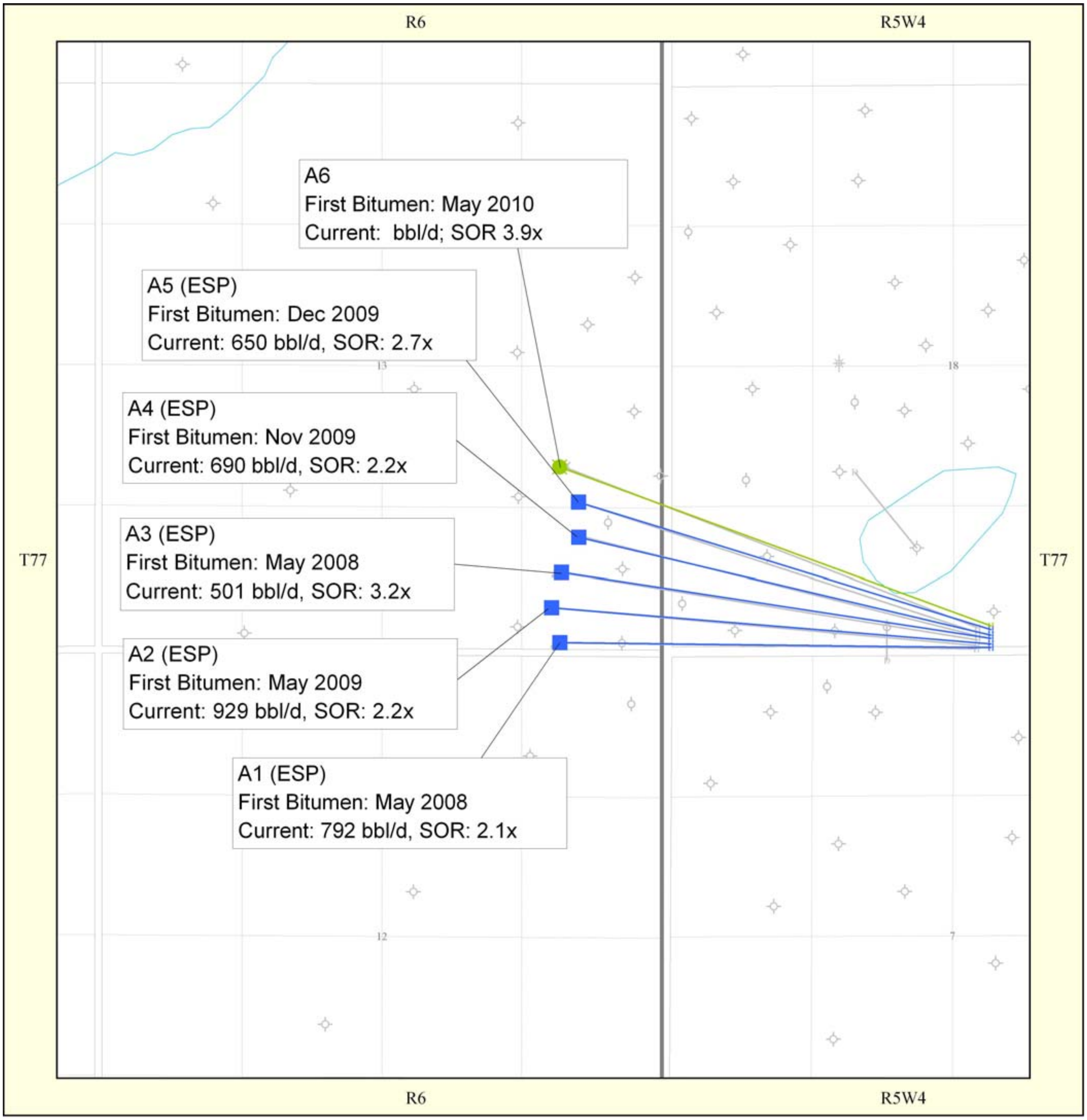
Source: Accumap and RBC Capital Markets

JACOS Hangingstone Well Configuration



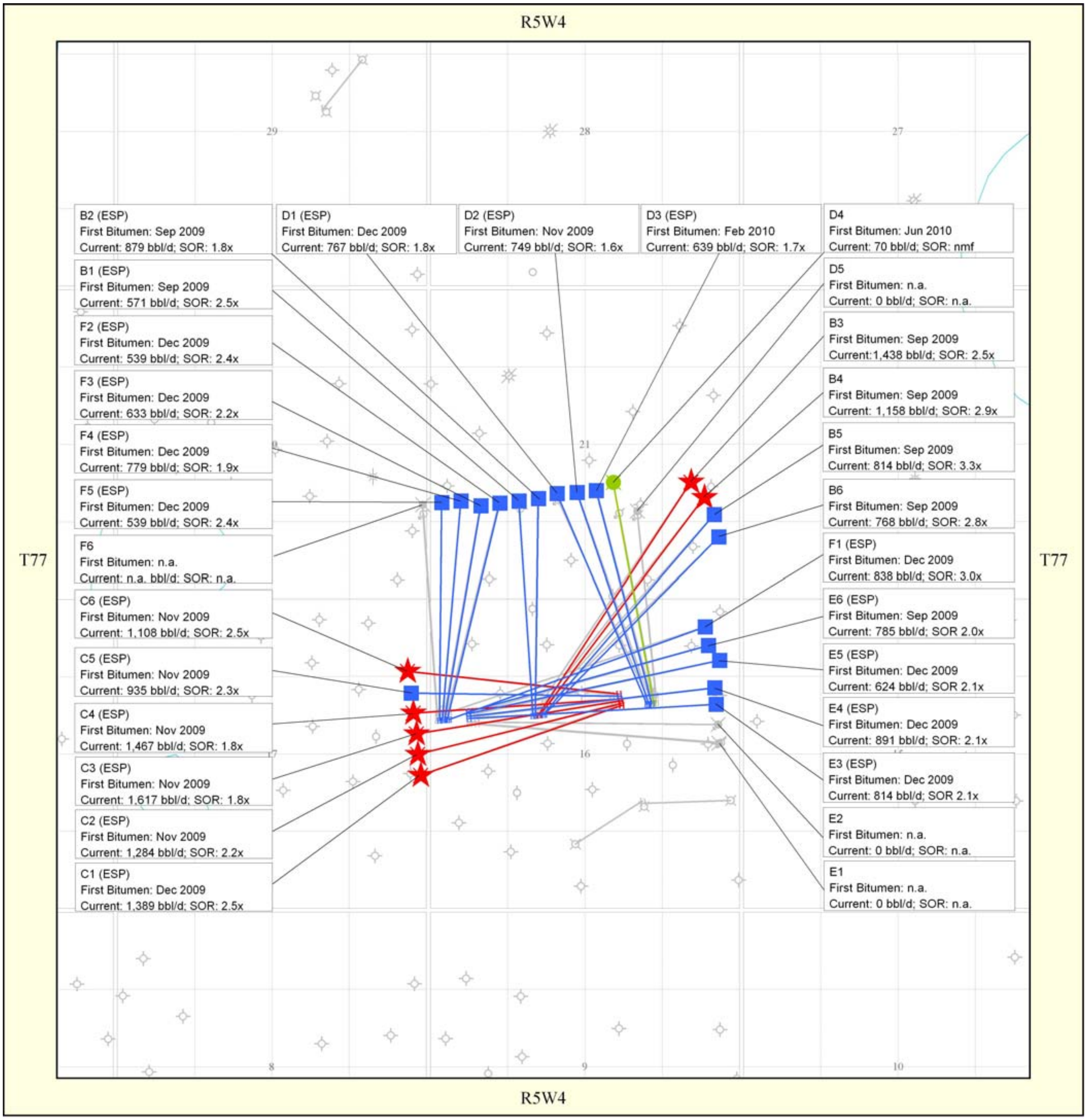
Source: Accumap and RBC Capital Markets

MEG Christina Lake Phase 1 Well Configuration



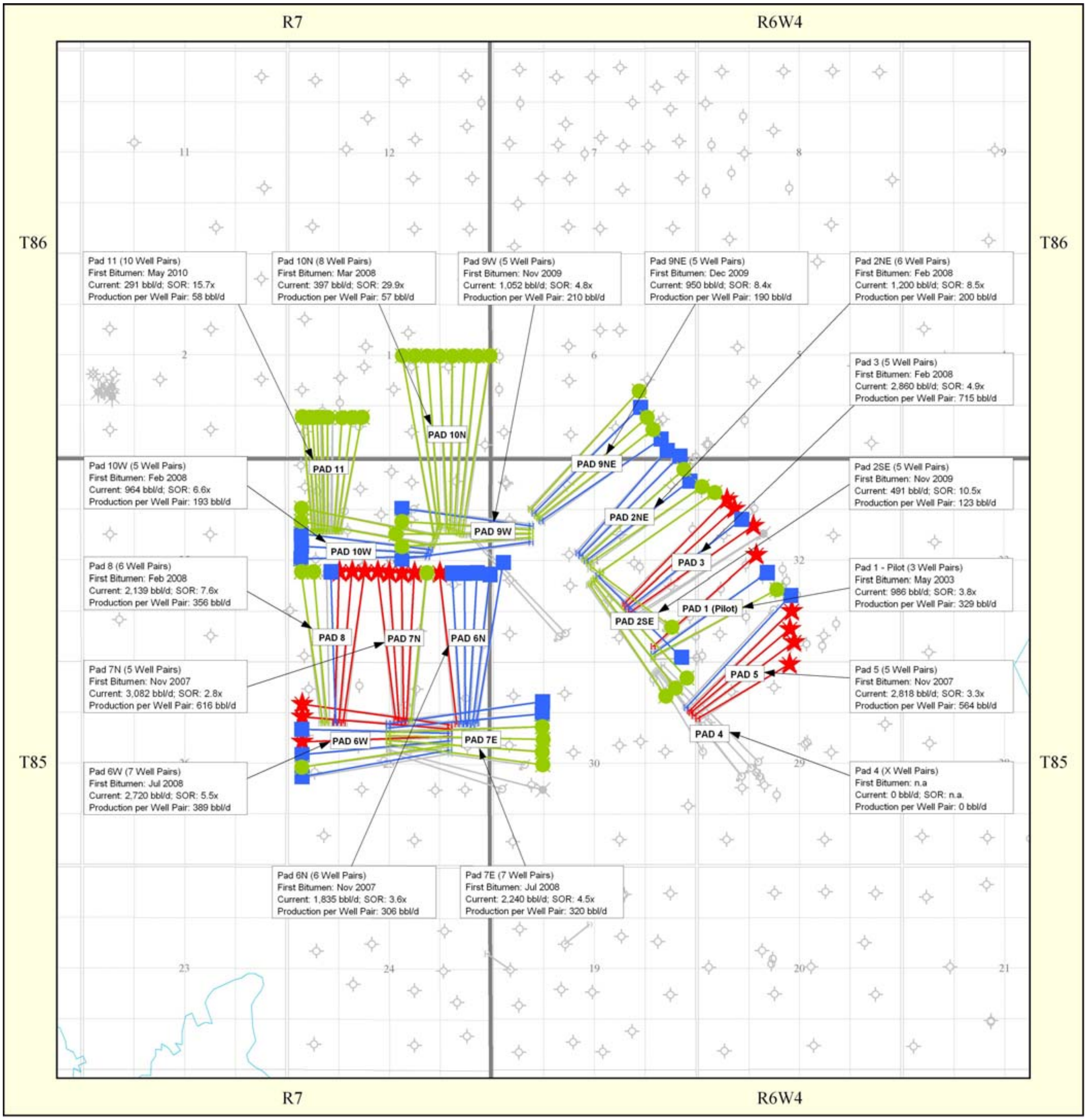
Source: Accumap and RBC Capital Markets

MEG Christina Lake Phase 2 Well Configuration



Source: Accumap and RBC Capital Markets

OPTI Canada and Nexen Long Lake Well Configuration



Source: Accumap and RBC Capital Markets

Appendix IV: Oil Sands M&A Transaction History

Announced Date	Acquirer	Seller	Transaction Type	Project Type	Working Interest	Enterprise Value ($mm)	Resource Estimate Per	2P Reserves (mmbbls)	Recoverable Resources (mmbbls)	Proved + Probable ($/bbl)	Recoverable Resources ($/bbl)
Developed/Producing Project Precedents											
2010-04-12	Sinopec	Syncrude Interest (ConocoPhillips)	Acquisition	Mining	9.03%	$4,650	McDaniel	536	1,040	$8.68	$4.47
2009-10-09	Southern Pacific Resource	Senlac Project (Encana)	Acquisition	In-Situ	100%	$90	McDaniel	13	20	$7.04	$4.42
2008-12-17	Nexen Energy	Long Lake (OPTI Canada)	Joint Venture	In-Situ	15%	$735	McDaniel	241	903	$3.05	$0.81
2007-07-31	Marathon Oil Corporation	Western Oil Sands (excluding Western Zagros)	Acquisition	Mining	100%	$6,637	GLJ/MRO	560	1,985	$11.85	$3.34
2006-11-29	Canadian Oil Sands Trust	Syncrude Interest (Talisman)	Acquisition	Mining	1.25%	$475	Company	65	113	$7.33	$4.22
2006-10-22	Royal Dutch Shell	Shell Canada Limited	Acquisition	Mining/In-Situ	100%	$5,035	Company	394	1,319	$12.78	$3.82
2006-10-05	ConocoPhillips	F.C. / C.L. Interests (EnCana)	Joint Venture	In-Situ	50%	$4,014	McDaniel	357	3,587	$11.24	$1.12
2003-07-10	Canadian Oil Sands Trust	Syncrude Interest (EnCana)	Acquisition	Mining	3.75%	$414	Company	229	364	$1.81	$1.14
2003-02-03	Canadian Oil Sands Trust	Syncrude Interest (EnCana)	Acquisition	Mining	10%	$1,071	Company	610	972	$1.76	$1.10
Non-Thermal Heavy Oil/SAGD											
2006-05-08	Shell Canada	BlackRock Ventures Inc.	Acquisition	Non-thermal	100%	$2,397	Sproule	210	718	$11.43	$3.34
Development Project Precedents											
2010-11-22	PTTEP	Statoil Canada Ltd.	Acquisition	In-Situ	40%	$2,280	Undisclosed	n/a	1,240	n/a	$1.84
2010-09-27	Southern Pacific Resource	North Peace Energy	Acquisition	In-Situ	100%	$14	Sproule	n/a	105	n/a	$0.14
2010-09-21	Canadian Natural Resources	Kirby (Enerplus)	Acquisition	In-Situ	100%	$405	GLJ	n/a	520	n/a	$0.78
2010-09-13	Athabasca Oil Sands Corp	Excelsior Energy	Acquisition	In-Situ	100%	$89	McDaniel	n/a	183	n/a	$0.49
2010-08-06	Harvest Operations	BlackGold Project (KNOC)	Acquisition	In-Situ	100%	$374	GLJ	259	289	$1.44	$1.29
2010-07-07	Total S.A.	Fort Hills Project (UTS)*	Acquisition	Mining	20%	$510	Sproule	n/a	678	n/a	$0.75
2010-03-19	Southern Pacific Resource	MakKay & Ells (Bounty Developments Ltd.)	Acquisition	In-Situ	20%	$33	McDaniel	14	49	$2.44	$0.67
2010-03-15	BP PLC	Terre De Grace (Value Creation)	Joint Venture	In-Situ	75%	$900	McDaniel	n/a	2,015	n/a	$0.45
2010-03-11	Devon	Kirby (BP)	Joint Venture	In-Situ	50%	$650	Company	n/a	625	n/a	$1.04
2009-11-02	Imperial Oil / ExxonMobil	Lease 421 (UTS)	Acquisition	In-Situ	50%	$250	Company	n/a	400	n/a	$0.63
2009-08-31	PetroChina International	MacKay River & Dover (AOSC)	Joint Venture	In-Situ	60%	$1,955	GLJ/DeGolyer	n/a	3,019	n/a	$0.65
2008-06-23	Occidental Petroleum Corp	Joslyn (Enerplus)	Acquisition	Mining/In-Situ	15%	$500	GLJ	64	370	$7.87	$1.35
2008-05-29	Ivanhoe Energy	Talisman	Acquisition	In-Situ	75%-100%	$105	Sproule	n/a	300	n/a	$0.35
2008-04-28	Total S.A.	Synenco ***	Acquisition	Mining	100%	$300	Norwest	n/a	649	n/a	$0.46
2007-12-05	BP PLC	Sunrise Interest (Husky)	Joint Venture	In-Situ	50%	$1,218	Company	500	1,600	$2.44	$0.76
2007-09-19	Petro-Canada / Teck Cominco	Fort Hills Project (UTS)	Partnership	Mining	10%	$706	Sproule	n/a	470	n/a	$1.50
2007-05-31	MEG Energy	Surmont Lease (Paramount)	Acquisition	In-Situ	100%	$302	McDaniel	n/a	409	n/a	$0.74
2007-05-14	Petrobank	WHITESANDS Insitu Ltd. (Richardsons)	Acquisition	In-Situ	16%	$120	McDaniel	4	96	$29.66	$1.25
2007-04-27	Statoil ASA	North American Oil Sands	Acquisition	In-Situ	100%	$2,200	GLJ	103	2,200	$21.36	$1.00
2007-04-19	Teck Cominco	Lease 14 (UTS)	Partnership	Mining	50%	$200	Company	n/a	200	n/a	$1.00
2007-03-22	Enerplus Resources	Kirby Oil Sands Partnership	Partnership	In-Situ	90%	$183	GLJ	n/a	220	n/a	$0.83
2006-07-24	Korea National Oil Corp.	Black Gold Lease (Newmont)	Acquisition	In-Situ	100%	$308	McDaniel	n/a	305	n/a	$1.01
2006-03-29	North American Oil Sands	Kai Kos Dehseh Proj. (Paramount)	Acquisition	In-Situ	50%	$345	GLJ	n/a	444	n/a	$0.78
2005-09-06	Teck Cominco	Fort Hills Project (UTS/PCA)	Partnership	Mining	15%	$475	Norwest	n/a	425	n/a	$1.12
2005-08-02	Total S.A.	Deer Creek Energy Ltd.	Acquisition	Mining/In-Situ	100%	$1,537	Norwest	251	2,199	$6.13	$0.70
2005-05-31	Sinopec	Northern Lights Project (Synenco)	Partnership	Mining	40%	$105	Company	n/a	486	n/a	$0.22
2005-04-12	CNOOC Ltd.	MEG Energy Corp.	Partnership	In-Situ	16.69%	$150	GLJ	n/a	334	n/a	$0.45
2005-03-01	Petro-Canada	Fort Hills Project (UTS)	Partnership	Mining	60%	$300	Norwest	n/a	1,699	n/a	$0.18
2004-04-19	UTS Energy Corporation	Fort Hills Project (Koch)	Acquisition	Mining	78%	$125	Norwest	n/a	2,209	n/a	$0.06
2002-08-07	Enerplus Resources Fund	Joslyn Project (Deer Creek)	Partnership	Mining/In-Situ	16%	$21	Company	n/a	288	n/a	$0.07
2001-10-29	Nexen Energy	Long Lake project (OPTI)	Joint Venture	In-Situ	50%	$30	McDaniel	n/a	650	n/a	$0.05
1999-12-06	Western Oil Sands	AOSP project (Shell Canada)	Partnership	Mining	20%	$75	GLJ	336	336	$0.22	$0.22
1999-12-01	Deer Creek	Purchase of Joslyn Lease 24 (Talisman)	Acquisition	Mining/SAGD	100%	$26	Company	546	1,800	$0.05	$0.01

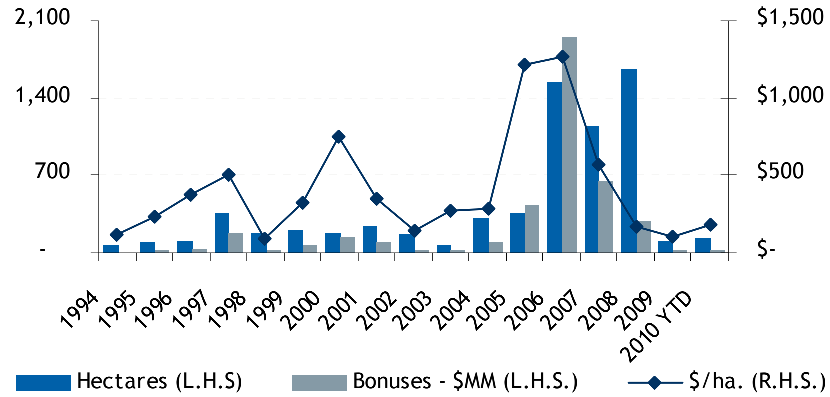
All amounts in Canadian dollars
Source: Company Reports, RBC Capital Markets Estimates
Notes:
*Athabasca EV includes the present value of interest savings from the PetroChina Loans, excludes the PV of the Put/Call option
**UTS EV adjusted for the Fort Hills earn in commitments where necessary
***Synenco had 649.2 MMBbls (net) of Contingent Resource based on Norwest analysis. Internal estimate of recoverable resource ~800 MM, which would imply an EV/Recoverable of $0.29/Bbl.

Development Projects Only	
2010 AVG:	$0.92
2009 AVG:	$0.64
2008 AVG:	$0.69
2007 AVG:	$0.95
2006 AVG:	$0.87
2005 AVG:	$0.50
Pre 2005 AVG:	$0.05

Source: Company reports and RBC Capital Markets

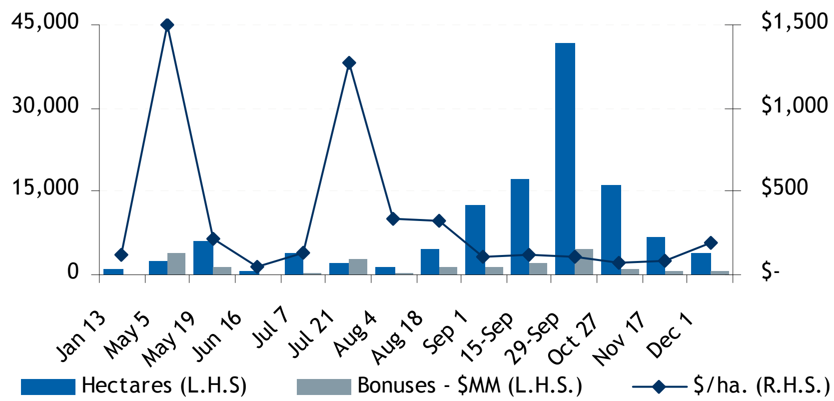
Appendix V: Historical Land Sales

Oil Sands Land Sales (1994-2010)



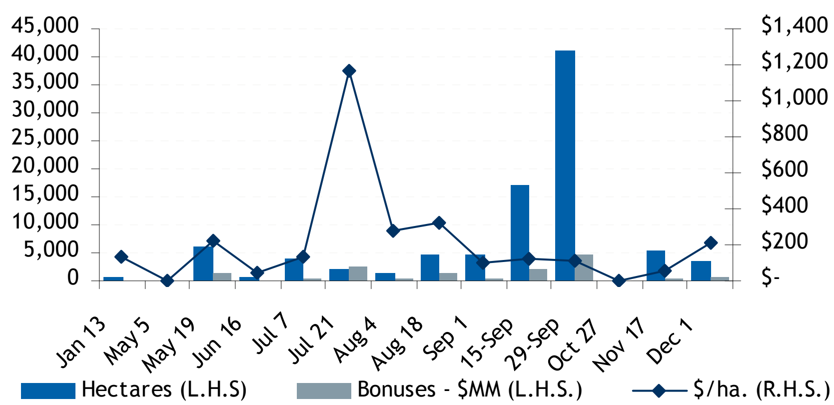
Source: Alberta Department of Energy

2010 YTD Oil Sands Land Sales



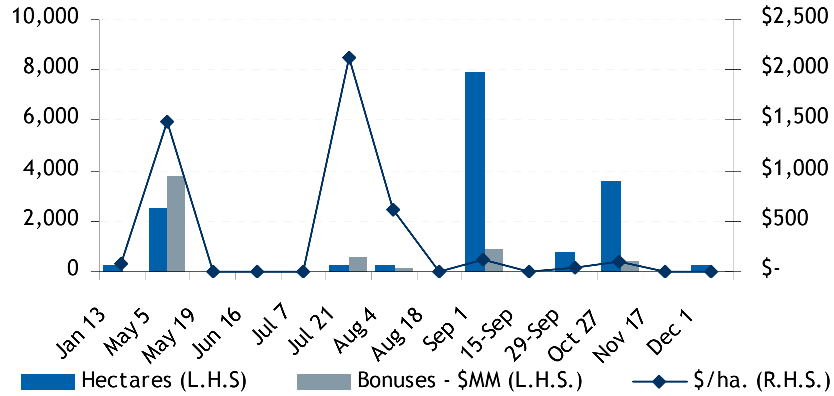
Source: Alberta Department of Energy

2010 YTD Oil Sands Land Sales (Athabasca Region)



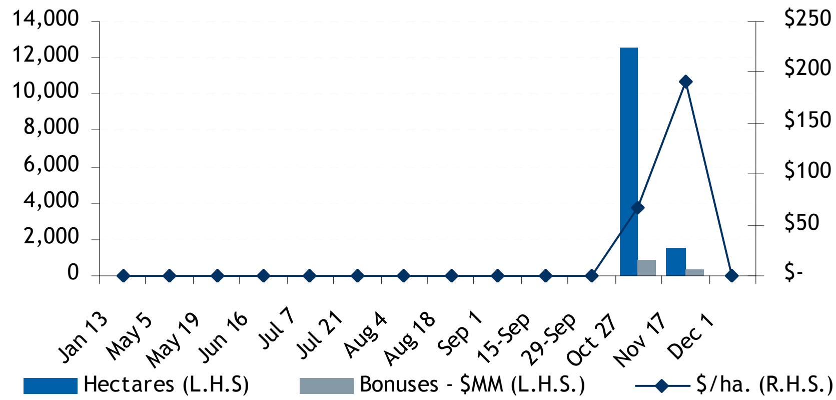
Source: Alberta Department of Energy

2010 YTD Oil Sands Land Sales (Cold Lake Region)



Source: Alberta Department of Energy

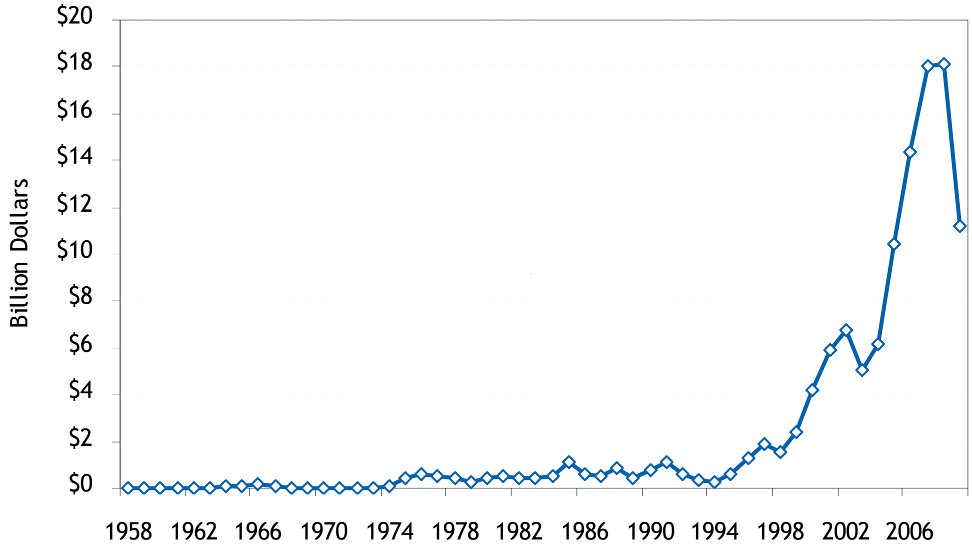
2010 YTD Oil Sands Land Sales (Peace River Region)



Source: Alberta Department of Energy

Appendix VI: Historical Capital Spending

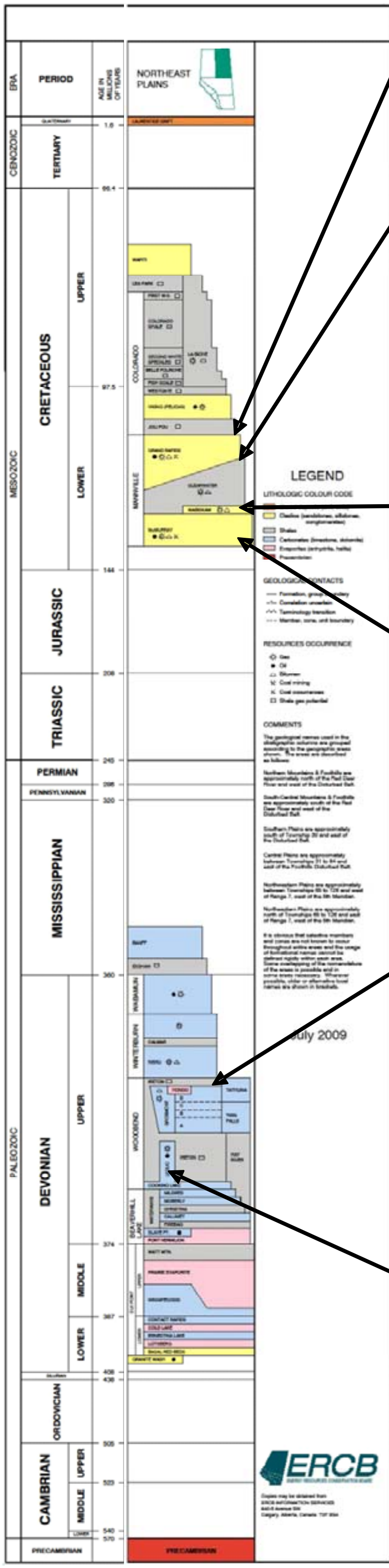
Oil Sands Capital Spending



Source: Canadian Association of Petroleum Producers

Appendix VII: Table of Formations

Oil Sands Table of Formations



Grand Rapids (Clastics): The Grand Rapids formation may not reach the thicknesses of the McMurray, but is generally found in a more homogeneous depositional environment with typical pay thicknesses of 10-25 metres. Laricina is targeting the Grand Rapids formation at its Germain project.

Clearwater (Shale): In the Athabasca Region, the Clearwater formation typically acts as the containment zone, or cap rock to the underlying Wabiskaw or McMurray zones. The Clearwater can reach thicknesses of 85 metres and thins out to five to six metres in the Cold Lake Region. The Clearwater Shale is not found south of Edmonton. In the Cold Lake Region, the Clearwater can be produced but because of its thickness is often developed with CSS. Osum is targeting the Clearwater formation at its Taiga project and plans to use SAGD.

Wabiskaw: The Wabiskaw is a thin sandstone formation, often containing bitumen. The Wabiskaw is often, but not always, found with the lower McMurray. Sunshine Oilsands is targeting the Wabiskaw formation at its West Ells lease.

McMurray: The McMurray is the formation most often targeted for development. The formation can reach thicknesses of 60 metres, but typically thins to the west and to the south. When found at depth, the McMurray formation is typically developed with SAGD due to its suitable thickness which is often >20 metres. The McMurray is mined north of Ft. McMurray. The McMurray is a water wet clastic/sandstone formation. The formation often shows variability with several different depositional characteristics such as stacked channel sands.

Grosmont (Carbonates): The Grosmont is a bitument bearing carbonate reservoir, making for unique recovery challenges. The reservoir is typically deep and thick, found at depths of 325 metres with an average thickness of 120 metres. The Grosmont is subdivided into the Lower A, B, C and D zones. The C and D zones have the best reservoir characteristics and highest bitumen content. The reservoir is characterized by having high vertical permiability and high porosity. Laricina is targeting the Grosmont carbonate reservoir with a pilot test this winter.

Leduc (Carbonates): In our context, the Leduc is a bitumen bearing carbonate reservoir. The reservoir can have a thickness of 100-150 metres. The Leduc bitumen carbonate reef structure is almost entirely under the control of Athabasca Oil Sands, which is just beginning to evaluate the play. Athabasca is planning to drill two test wells this winter to test the reservoir's response to steam and conductive heat with a SAGD and TAGD pilot wells.

Source: Company Documents, ERCB and RBC Capital Markets

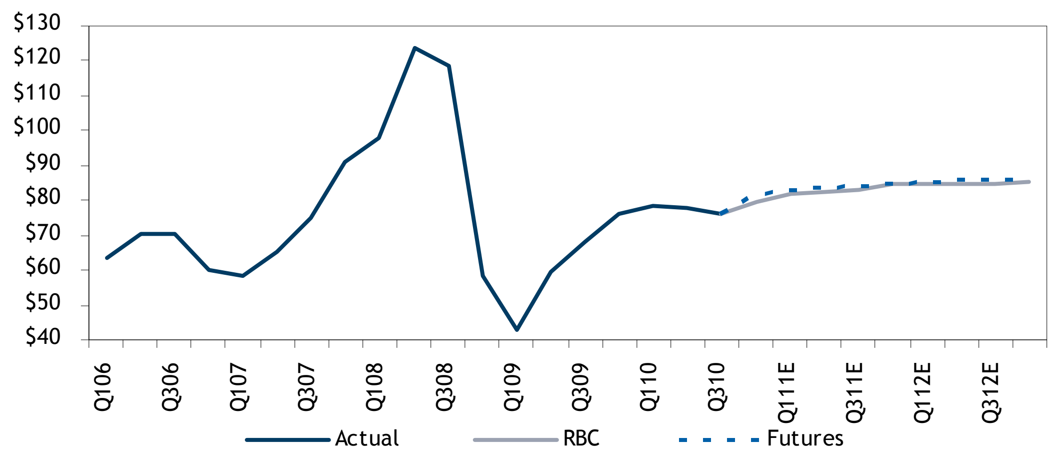
Appendix VIII: Pricing Assumptions

Price Assumption Summary

Crude Oil	2008	2009	2010E	2011E	2012E	2013E+
WTI - NYMEX (US$/Bbl)	$99.50	$61.81	$78.02	$83.00	$85.00	$85.00
Exchange Rate (US$/C$)	$0.94	$0.88	$0.96	$0.95	$0.95	$0.95
Trans. Diff. (US$/Bbl)	-$1.20	-$3.28	-$3.13	-$1.25	-$1.25	-$1.25
Ed. Par (C$/Bbl)	$102.75	$66.48	$77.69	$86.05	$88.16	$88.16
Light/Heavy Diff. (C$/Bbl)	-$20.15	-$9.13	-$11.99	-$12.75	-$15.87	-$15.87
Light/Heavy Diff. (%)	19.6%	14.0%	15.6%	14.8%	18.0%	18.0%
Bow River Heavy (C$/Bbl)	$83.00	$59.25	$68.23	$73.30	$72.29	$72.29
Condensate (% Premium to WTI)	105%	109%	106%	109%	109%	109%
Condensate (US$/Bbl)	$104.83	$67.37	$82.57	$90.47	$92.65	$92.65
Natural Gas						
US - Henry Hub - NYMEX (US$/Mcf)	$8.85	$3.92	$4.54	$5.00	$5.50	$5.50
Exchange Rate (US$/C$)	$0.94	$0.88	$0.96	$0.95	$0.95	$0.95
Cdn NYMEX Equivalent (C$/Mcf)	$9.39	$4.45	$4.71	$5.26	$5.79	$5.79
AECO Basis Diff. (US$)	-$1.15	-$0.45	-$0.64	-$0.85	-$0.85	-$0.85
CDN - AECO (C$/Mcf)	$8.15	$3.94	$4.05	$4.37	$4.90	$4.90

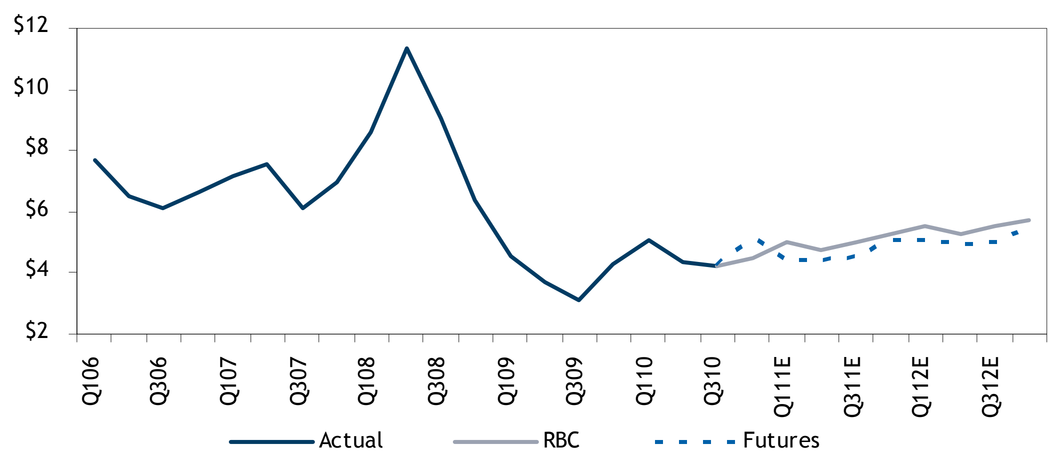
Source: RBC Capital Markets estimates

WTI Oil Price Assumptions



Source: RBC Capital Markets estimates

Henry Hub Natural Gas Price Assumptions



Source: RBC Capital Markets estimates

Required Disclosures

Non-U.S. Analyst Disclosure

Mark Friesen and Sam Roach (i) are not registered/qualified as research analysts with the NYSE and/or FINRA and (ii) may not be associated persons of the RBC Capital Markets, LLC and therefore may not be subject to FINRA Rule 2711 and NYSE Rule 472 restrictions on communications with a subject company, public appearances and trading securities held by a research analyst account.

Conflicts Disclosures

This product constitutes a compendium report (covers six or more subject companies). As such, RBC Capital Markets chooses to provide specific disclosures for the subject companies by reference. To access current disclosures for the subject companies, clients should refer to https://www.rbccm.com/GLDisclosure/PublicWeb/DisclosureLookup.aspx?entityId=1 or send a request to RBC CM Research Publishing, P.O. Box 50, 200 Bay Street, Royal Bank Plaza, 29th Floor, South Tower, Toronto, Ontario M5J 2W7.

The analyst(s) responsible for preparing this research report received compensation that is based upon various factors, including total revenues of the member companies of RBC Capital Markets and its affiliates, a portion of which are or have been generated by investment banking activities of the member companies of RBC Capital Markets and its affiliates.

RBC Capital Markets is currently providing Sunshine Oilsands Ltd. with non-securities services.

RBC Capital Markets has provided Sunshine Oilsands Ltd. with non-securities services in the past 12 months.

A member company of RBC Capital Markets or one of its affiliates received compensation for products or services other than investment banking services from Sunshine Oilsands Ltd. during the past 12 months. During this time, a member company of RBC Capital Markets or one of its affiliates provided non-securities services to Sunshine Oilsands Ltd..

A member company of RBC Capital Markets or one of its affiliates managed or co-managed a public offering of securities for Laricina Energy Ltd. in the past 12 months.

A member company of RBC Capital Markets or one of its affiliates received compensation for investment banking services from Laricina Energy Ltd. in the past 12 months.

RBC Capital Markets has provided Laricina Energy Ltd. with investment banking services in the past 12 months.

Information contained in this report with respect to private companies may be less reliable than information with respect to public companies, due to the fact that private companies are not subject to the same legal standards of disclosure. Comments and expectations related to private companies represent company management’s views expressed in presentations and available on their web site. They do not represent the opinions of RBC Capital Markets.

Distribution of Ratings

For the purpose of ratings distributions, regulatory rules require member firms to assign ratings to one of three rating categories - Buy, Hold/Neutral, or Sell - regardless of a firm's own rating categories. Although RBC Capital Markets' ratings of Top Pick/Outperform, Sector Perform and Underperform most closely correspond to Buy, Hold/Neutral and Sell, respectively, the meanings are not the same because our ratings are determined on a relative basis (as described above).

Distribution of Ratings RBC Capital Markets, Equity Research			Investment Banking Serv./Past 12 Mos.	
Rating	Count	Percent	Count	Percent
BUY[TP/O]	656	50.30	195	29.73
HOLD[SP]	591	45.40	123	20.81
SELL[U]	56	4.30	10	17.86

Conflicts Policy

RBC Capital Markets Policy for Managing Conflicts of Interest in Relation to Investment Research is available from us on request. To access our current policy, clients should refer to https://www.rbccm.com/global/file-414164.pdf or send a request to RBC CM Research Publishing, P.O. Box 50, 200 Bay Street, Royal Bank Plaza, 29th Floor, South Tower, Toronto, Ontario M5J 2W7. We reserve the right to amend or supplement this policy at any time.

Dissemination of Research and Short-Term Trading Calls

RBC Capital Markets endeavors to make all reasonable efforts to provide research simultaneously to all eligible clients, having regard to local time zones in overseas jurisdictions. RBC Capital Markets' equity research is posted to our proprietary websites to ensure eligible clients receive coverage initiations and changes in ratings, targets and opinions in a timely manner. Additional distribution may be done by the sales personnel via email, fax or regular mail. Clients may also receive our research via third-party vendors. Please contact your investment advisor or institutional salesperson for more information regarding RBC Capital Markets' research. RBC Capital Markets also provides eligible clients with access to SPARC on the Firm's proprietary INSIGHT website. SPARC contains market color and commentary, and may also contain Short-Term Trade Ideas regarding the publicly-traded common equity of subject companies on which the Firm currently provides equity research coverage. SPARC may be accessed via the following hyperlink: www.rbcinsight.com. A Short-Term Trade Idea reflects the research analyst's directional view regarding the price of the subject company's publicly-traded common equity in the coming days or weeks, based on market and trading events. A Short-Term Trade Idea may differ from the price targets and recommendations in our published research reports reflecting the research analyst's views of the longer-term (one year) prospects of the subject company, as a result of the differing time horizons, methodologies and/or other factors. Thus, it is possible that a subject company's common equity that is considered a long-term 'sector perform' or even an 'underperform' might be a short-term buying opportunity as a result of temporary selling pressure in the market; conversely, a subject company's common equity rated a long-term 'outperform' could be considered susceptible to a short-term downward price correction. Short-Term Trade Ideas are not ratings, nor are they part of any ratings system, and the Firm generally does not intend, nor undertakes any obligation, to maintain or update Short-Term Trade Ideas. Securities and Short-Term Trade Ideas discussed in SPARC may not be suitable for all investors and have not been tailored to individual investor circumstances and objectives, and investors should make their own independent decisions regarding any securities or strategies discussed herein.

Analyst Certification

All of the views expressed in this report accurately reflect the personal views of the responsible analyst(s) about any and all of the subject securities or issuers. No part of the compensation of the responsible analyst(s) named herein is, or will be, directly or indirectly, related to the specific recommendations or views expressed by the responsible analyst(s) in this report.

Disclaimer