Leave it in the ground? Oil sands extraction in the carbon bubble

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Abstract

This paper develops a model of oil sands development to investigate three related questions. First, we ask whether new oil sands developments would remain viable if current estimates of the social cost of carbon emissions were internalized into their cost structures. Second, we ask whether these same investments are likely to be viable should carbon policies consistent with achieving global climate change stabilization goals be imposed. Finally, we ask whether interactions between carbon policy and fiscal policy are responsible for the effects we observe. Our model assesses two types of oil sands investments which are representative of the projects currently expected to increase oil sands production by up to 300% from current levels of 2 million barrels per day by 2035. We find that these projects are, indeed, exposed to significant carbon policy risk. That risk arises mostly from potential changes in policies on life-cycle emissions, but these projects face limited risk when the policies are applied to production emissions as opposed to downstream emissions. Our results depend significantly on the tax and royalty regime under which oil sands production occurs in which decision-makers only face a portion of the true costs of carbon emissions, even when these costs would seem to be fully internalized through carbon prices. As such, we argue that models which do not consider these institutional details may overestimate oil production sensitivity to carbon policies.

Introduction

Oil sands production in the province of Alberta, Canada has grown rapidly over the past decade, and this rapid growth is expected to continue - forecasts see extraction increasing 300% from current rates of 2 million barrels per day over the next two decades (see Canadian Energy Research Institute (2013)). Alberta Energy Regulator (2013) currently estimates oil sands reserves at over 170 billion barrels, and the total quantity of oil in place in the oil sands at approximately 2 trillion barrels. The International Energy Agency concludes that if more than half of current global fossil fuel reserves, or a significant share of current global hydrocarbon resources, are extracted and burned, the world will be unable to meet climate change stabilization goals (see International Energy Agency (2013)). Compared to other global oil reserves, oil sands extraction and refining requires significantly more energy thus emits larger amounts of greenhouse gases (GHGs) (Charpentier et al. (2009); Howarth et al. (2011)). As a result, Hansen et al. (2013), amongst others, have argued that keeping global temperatures increases below 2^oC requires GHG emissions reductions so great that current reserves of energy-intensive resources, and in particular oil sands, should remain undeveloped. While oil sands reserves have received significant attention, Swart and Weaver (2012) show that their relative size is small relative to coal and other fossil fuel reserves. Recently, organizations including Carbon Tracker (Campanale and Leggett (2013)) have begun to raise the possibility that new energy investments, in particular oil sands investments, may not be viable in the face of eventual carbon policy changes and so become stranded assets - the so-called *carbon bubble*.

This paper seeks to answer three specific questions. First, we ask whether new oil sands developments are likely to represent a net social benefit. We test this by asking whether investment in these projects would remain viable if current estimates of the social cost of carbon emissions were internalized into their cost structures and into the price they receive for oil. Second, we ask whether these same investments are likely to be viable should carbon policies consistent with achieving global climate change stabilization goals be imposed. This allows us to address the *carbon bubble* hypothesis of Campanale and Leggett (2013), as we examine whether oil sands projects will yield a net benefit in an aggressive climate policy scenario, or whether they are likely to become stranded assets. Finally, we ask whether interactions between carbon policy and fiscal policy are responsible for the effects we observe. Since Alberta and Canada impose taxes and royalties on net revenues from oil sands production, and the royalty rates themselves adjust in response to changes in oil prices, new carbon costs are shared between those making the investment decision and governments, effectively preserving an externality problem even where climate change costs appear to be fully internalized.

To answer these questions, we develop a model of prototypical oil sands projects and use this model to quantitatively analyze the effect of greenhouse gas policies on commonly cited metrics of investment viability as well as on tax and royalty revenues accruing to governments. We parameterize our model using values from recent oil sands investments. We are able to have confidence in our estimates for three reasons: (1) new projects are primarily executed by publicly traded companies and so cost data for projects under development today are readily available; 2) Emissions data for oil sands projects are readily available from both provincial and federal governments in Canada; and (3) these data have been studied both in the academic literature and in the development of policies such as the European Union's proposed fuel quality directive and the evaluation of major energy projects such as the Keystone XL pipeline. While we draw our emissions data from a report prepared for the Government of Alberta by Jacobs Consultancy (2009), our parameters are consistent with those summarized by Lattanzio (2014), Brandt (2012), and Chan et al. (2012).

The remainder of the paper proceeds as follows. We first introduce our model of the oil sands development decision. We then characterize the relationship between carbon prices, carbon policy coverage, oil prices, and oil sands investment decisions. Next, we use these results to demonstrate the importance of the interaction between fiscal policies and carbon policies. Finally, we examine the viability of oil sands investments under policies which impose the estimated social cost of carbon and under International Energy Agency (2013)'s 450ppm carbon policy scenario.

Model of oil sands development

We develop a cash flow model of a prototypical oil sands project that accommodates a variety of project types. We model two specific projects: a bitumen mine and an *in situ* bitumen extraction facility which uses steam-assisted gravity drainage (SAGD) technology to extract deeper deposits which could not otherwise be mined. Each has an annual production capacity, an expected reserve life, estimated construction and operating costs, and associated production emissions data. Our model characterizes the cash flows over time for the project, and reports free cash flows resulting from the investment, as well as operating and capital costs, taxes, and royalties. Using these outputs we can determine whether an oil sands investment would be expected to significantly exceed a firms weighed average cost of capital,

Table 1: Oil sands model project assumptions

Property	**units**	**Bitumen mine**	**In-situ SAGD Extraction**
Bitumen Capacity	bbl/d	180,000	50,000
Diluted Bitumen Capacity	bbl/d	260,000	71,500
Initial Capital Cost	$ million	15,120	2,250
Operating Cost	$/bbl	20 25	
Sustaining Capital Cost	$/bbl	4	4
Construction time	years	4	3
Operating life	years	50	30
Operating Capacity Factor	%	100	92
Years to reach operating capacity	yrs	2	3
Debt share of building capital	years	25%	25%
Capital Cost Allowance (Class 41)	%of capital	95%	85%
Canadian Development Expense	%of capital	5%	15%
Commodity Prices and inflation			
West Texas Intermediate	$US/bbl	90	
AECO-C Natural Gas	$/GJ	4.25	
Diluted Bitumen	$/bbl	80.74	
Diluent	$/bbl	102.75	
$US/$Cdn	$	0.94	
All inflation rates	%	2%	

Notes: Where not specified, currency is Canadian dollars. All dollar figures are 2013 real dollars.

and thus whether it would be likely to be undertaken. In doing so, we indirectly assess the degree of carbon policy risk faced by these investments. We also track government revenue resulting from the project, thereby allowing us to assess returns outside of those earned by the firm. We use data from recent oil sands projects to parameterize our model, and these parameters are summarized in Table 1.

The parameters for the model bitumen mine are based on the newly-proposed Suncor Fort Hills project.Suncor (2013) This project is typical of a new generation of mines which will ship diluted bitumen directly to market. Older mines, including those owned by Suncor, relied on integrated upgraders to produce a market-ready product.[1] Currently, similar projects proposed by Total and Silverbirch as well as an ongoing expansion of Imperial Oil's Kearl

[1]While many characterize upgraders as a tool to add value to oil sands bitumen before selling to market, they were previously an essential complement to mined bitumen since the warm-water and napthenic froth treatment process used in these mines was not able to produce a bitumen of sufficiently low solids and water content to allow the product to be shipped via pipeline. New paraffinic froth treatment technologies have overcome this hurdle and negated the need for an upgrader.

project all employ comparable technology and will produce, in total, approximately 1 million barrels per day of bitumen and contribute approximately 15 $MtCO_2$ per year of greenhouse gas emissions if all are built. There are, currently, no new projects planned with integrated upgrading capacity, and so we do not model such a project in this paper.

Data for the *in situ* project is from Cenovus' Narrows Lake steam-assisted gravity-drainage (SAGD) project.Cenovus This technology uses two parallel, horizonal wells drilled into the bitumen deposit. The upper-most well is used to inject steam which renders the bitumen less viscous and able to flow down to the lower well through which it is produced to the surface. These projects tend to be smaller (note the capacity is less than 1/3 that of the mines), lower cost (capital per barrel per day of capacity of $45,000 compared to $84,000 for the bitumen mine), and have shorter reserve lives since there is a limited distance over which it's economical to transport steam from a central facility. Because *in situ* projects use natural gas to create steam, and use approximately three barrels of steam for each barrel of oil extracted, they are much more (2-3x) emissions-intensive means of bitumen production compared to mining.[2]

The projects receive revenue from the sale of bitumen, which must first be diluted with purchased natural gas liquids and then shipped as diluted bitumen. Using historic prices for light crudes, natural gas liquids, and diluted bitumen, we can derive a price for bitumen - over the past 4 years, from February 2010 to February 2014, bitumen has sold at an implied discount of approximately 32% to light oil. We make a slightly more favorable assumption of a discount of 28% for bitumen relative to Edmonton light oil looking forward, since this is consistent with forecasts from Sproule Associates, GLJ Petroleum Consultants, and other consultancies currently evaluating oil sands reserves.[3]

Operating costs for the projects are assumed to be constant in real dollar terms over the project life. Energy costs represent a significant share of the costs of the in-situ facility, which consumes natural gas to generate steam to extract oil, and we assume a constant (again in real dollar terms) gas price. The mine uses a significant quantity of diesel fuel, which we price at a premium of 20% to light oil. Both projects also have sustaining capital costs, which we assume can be treated as constant, annual costs attributable to each project.

[2]The Narrows Lake project expects to use a combination of standard steam injection and a combination of steam injection with solvents. We model only the traditional technology and associated expected productivity.

[3]See, for example, Suncor's annual report in which the volume and net present value of oil sands reserves is evaluated by Sproule Associates using these assumptions.

Fiscal Policies Affecting Oil Sands Projects

The oil sands resource, and in particular booked reserves of oil sands, are located largely within the province of Alberta.[4] Oil sands revenues are subject to Alberta's Oil Sands Royalty Framework as well as to corporate taxes at both the provincial (Alberta) and national (Canada) level. This fiscal framework is important for understanding the potential impact of greenhouse gas policies on oil sands investments as both taxes and royalties use net revenues as the tax base, and the royalty rate itself depends on the oil price, which is likely to be affected by greenhouse gas policy.

Alberta's oil sands royalty regime is two-stage system which initially collects a share of gross revenues and eventually shifts to a net-revenue royalty once the project has earned a cumulative rate of return equal to the government's long term bond rate. The gross revenue share payable to the province is a minimum of 1% when West Texas Intermediate oil prices, converted to Canadian dollars, are less than or equal to \$50/bbl, and this rate increases linearly to 9% for oil prices of \$120/bbl, and remains constant at higher prices.[5] The net revenue rate follows a similar schedule, with a minimum royalty share of 25% and a maximum royalty share of 40%. Of most importance to our analysis, the Government of Alberta has, to date, allowed environmental compliance costs and abatement expenditures to be attributable both for calculation of realized returns and for net revenue calculations. As such, higher GHG compliance costs will, all else equal, imply a longer period of time at the lower gross revenue royalty rate, and smaller net revenues for the purposes of calculating net revenue royalties. Further, insofar as downstream emissions policies lower the revenue from oil, they will lead lower to royalty rates, thereby providing a hedge for oil sands operators.

Corporate taxes are relatively simple, in that both levels of government use the same tax base with Alberta collecting 10% and the federal government collecting 15% of net revenues after royalties. For tax purposes, incurred costs including GHG compliance costs and abatement expenditures are deductible against income, although the timing of the deduction will vary - operating expenditures are deducted in the year in which they occur, while capital costs will be subject to a capital cost allowance rule.[6] GHG policies will interact with taxes

[4]There is some heavy oil extraction in the province of Saskatchewan which is similar both in resource quality and extraction technique to the oil sands, however we focus our analysis on Alberta-based projects.

[5]Firms may pay royalties in kind (with bitumen) or in cash, but for our purposes we treat royalties as a cash payment.

[6]We assume that capital expenditures, as specified in Table 1, is allocated to Class 41 of the Canadian capital cost allowance schedule, which allows expenditures to be deducted over time, with 25% of a declining balance pool becoming available for deduction in each year. The remainder of each project's capital expenditures are assumed to be deductible as they are incurred according to the Canadian Development Expense

Table 2: Life cycle emissions

Phase	Bitumen mine	In-situ SAGD	Arab Medium
Extraction	36.1	70.1	25.4
Transportation	6.1	6.1	14.2
Diluent recycle	3.6	3.6	0.0
Refining	87.4	87.4	65.5
Total Transportation and Refining	97.0	97.0	79.8
Fuel cycle + other	27.9	33.0	19.8
Combustion	374.4	374.4	374.4
Total Downstream	402.3	407.4	394.2
Total Emissions	535.4	574.5	499.4

Notes: Units are in g/bbl of oil produced. Source: Jacobs (2009), with author's calculations for conversion to bitumen basis.

in the same way as with royalties - as they erode the net revenue tax base, they reduce tax payments all else equal.

As the results below will show, the combined impact of tax and royalty policy on our results is important. The extant tax and royalty policies serve to shelter oil sands investments from approximately 50% of potential revenue losses due to increasing stringency of GHG policies.

GHG Emissions from Oil Sands Development

Life cycle GHG emissions from oil sands production are divided into three phases - extraction, transportation and refining, and combustion. Our data for life cycle emissions come from Jacobs (2009) which characterizes emissions for refined products sourced from oil sands and other crude oil streams. The emissions for each phase and project type are shown in Table 2.

The data are consistent with values summarized in Brandt (2011), Brandt (2012), Lattanzio (2014) and other studies of oil sands life cycle emissions, and our results are robust to significant changes in these individual estimates, within the bounds of estimates in studies cited by Brandt (2012), Lattanzio (2014), and others. We use the data above to identify the impact of GHG policies both on oil sands extraction costs, and on the revenue they are likely to receive from oil sales.

rules.

Oil sands project development

Oil sands production has grown significantly since it began in 1967 with a single commercial mining operation now owned by Suncor. Current production is approximately 2 million barrels per day, and this is expected to climb to over 3.5 million barrels per day by 2020 according to Alberta Energy Regulator (2013) and to between 4.8 and 6.8 million barrels per day by 2050 according to a set of forecasts published in Canadian Energy Research Institute (2013). This growth forecast is based on the financial viability of potential future oil sands projects in light of oil and natural gas prices forecasts. We use a model similar to those underlying these forecasts to test the potential sensitivity of these investments to changes in greenhouse gas policies.

We cite three key metrics for assessing the viability of the oil sands projects. One of the most common metrics used in oil sands (or any oil production) investment is the supply cost, defined as the real dollar (i.e. adjusted for inflation) oil price which, if held constant over the life of the project, will allow investors to earn a rate of return on capital which exceeds its opportunity cost. There is no single accepted value for the opportunity cost of capital on which to base our analysis, and our model can accommodate any value. For the purposes of this analysis, we use a nominal rate of return of 10% to calculate supply costs. We also show the internal rate of return and the after-tax profit (or free cash flow) per barrel produced for the projects. Each of these metrics will be highly dependent on the individual price forecast used. For our analysis, we'll use four different price forecasts - a flat, real dollar oil price set at $90 per barrel, the US Energy Information Adminstration price forecasts from the 2014 Early Release of the Annual Energy Outlook, and the International Energy Agency's 2013 forecast for world oil prices under their Current Policies and 450ppm climate stabilization scenarios.[7]

Oil sands project financial returns under business-as-usual assumptions, including a continuation of the of Alberta (2007) Specified Gas Emitters Regulation, are presented in Table 3. These figures, in particular the expected rates of return under $90 oil prices, show why oil sands development remains an attractive investment. The returns under price forecasts by both the EIA and the IEA are significantly higher, as both have oil prices increasing at above the rate of inflation. To make a desirable return on invested capital, the projects

[7]For each oil price forecast, we use the same assumptions with respect to relative oil product prices as outlined in Table 1, and assume that natural gas prices are constant at $4.50/GJ at Alberta's AECO-C pricing point. To adjust forecasts to local prices, we assume that the light oil price at Edmonton is at a $5/bbl discount to North Sea Brent in Canadian dollar terms.

Table 3: Supply costs, rates of return, and per-barrel revenues and costs for oil sands projects under current Alberta policies

	Bitumen mine	**In-situ SAGD Extraction**
Financial metrics		
WTI Supply cost	78.80	68.49
IRR @ $90 WTI	12.3%	18.5%
IRR EIA 2014 Early Release	14.8%	20.7%
IRR IEA Current Policies	18.5%	26.9%
Per barrel cash flows ($90 WTI)		
Total Revenue	67.46	67.46
Capital and Debt	8.18	8.19
Operating Costs	20.89	21.93
GHG Compliance Costs	0.03	0.03
Royalties and Taxes	20.92	21.04
Free Cash Flow	17.44	16.26

Notes: All scenarios assume that the existing Alberta Specified Gas Emitters Regulation remains in place and that compliance fees remain at the current level of $15 per tonne, and that these fees do not adjust with inflation.

require a price per barrel of less than $80 for crude oil, which is substantially lower than today's value or that predicted by almost any price forecast. Regardless of whether constant real dollar oil prices or the EIA's forecasts with increasing real dollar oil prices are used, oil sands projects rapidly pay off their invested capital and yield rates of return far above the opportunity cost of capital which are generally seen to be around 10%. These results are consistent with industry forecasts which show oil sand production growing to close to 7 million barrels per day by 2050 - levels 3 times greater than today. Canadian Association of Petrolem Producers (2013); Canadian Energy Research Institute (2013)

The effect of GHG costs on development

We impose two types of GHG policies on our model. We first impose policies on production emissions via a carbon tax payable on every tonne of emissions. Next, we impose carbon prices on refining and combustion of petroleum products. We assume that changes in carbon prices affect the realized price of oil for producers and affect different grades of oil differently depending on emissions associated with transportation, refining and combustion for the various products. For a given carbon price, t, we assume that the light oil price is reduced by $\delta t E_l$, where δ is a parameter characterizing *incidence*, the share of the increased cost of fuels which is borne by producers via a decrease in the oil price, and E_l are the emissions associated with the downstream use of light oil, shown in the bottom of the right-hand column of Table 2. Heavy oil, including oil sands diluted bitumen, will face additional downstream carbon costs, $\delta t E_h$, where E_h are the incremental emissions associated with transporting and refining heavier crude. We ignore, for the purposes of this analysis, any impacts from the redistribution of tax revenues to oil producers or consumers or any macroeconomic effects of the carbon taxes themselves. Our base case, shown above in 3, includes the of Alberta (2007) Specified Gas Emitters Regulation in Alberta, which is an intensity-based carbon emissions tax of $15/ton on any emissions over-and-above an emissions-intensity of 88% of each facility's year-3 average emissions intensity.

In the analysis below, we first test the sensitivity of oil sands project financial viability to both the price of carbon and the degree to which downstream carbon prices are also reflected in reduced oil prices. Next, we impose the upper and lower limits of the EPA's 2013 estimates of the social cost of carbon on both production and total life cycle emissions. Finally, we test the resilience of oil sands projects to the IEA's 450ppm combined oil and carbon price scenario.

GHG Prices Applied Upstream and Downstream

Oil sands project proponents frequently cite sensitivity analysis which suggests that their projects remain financially viable under significantly higher carbon prices than those currently in place in Alberta. Those contentions are supported by the results shown in Figure 1. This Figure shows the rates of return to both project types under carbon prices applied upstream only (top-row in each of the upper and lower panels) and applied downstream (remaining rows, where the percentages indicate the share of the carbon costs passed back to producers through lower oil prices).

Figure 1 shows that upstream carbon prices have very little impact on the viability of the projects: no matter the size of the carbon tax per ton of CO_2 emissions, both projects maintain rates of return in excess of 10%. This analysis supports a conclusion that the returns for mining or *in situ* oil sands investments are robust to carbon prices on production emissions alone of well above $100/tonne.

The viability of oil sands projects changes when downstream emissions, including refining and combustion, are brought into the equation and some of those costs are borne by producers (i.e. not compensated for by increased consumer petroleum product prices). In Figure 1, as

Oil sands project internal rates of return		Carbon Price ($CDN/tonne)					
		25.00	50.00	75.00	100.00	EPA SCC 3% avg.	EPA SCC 95th%
Incidence of downstream GHG price on upstream revenues	Mining (base case IRR of 12.54% under business as usual)						
	0%	12.35%	12.16%	11.96%	11.75%	12.41%	11.15%
	25%	11.77%	10.95%	10.08%	9.14%	12.12%	7.43%
	50%	11.17%	9.63%	7.87%	5.77%	11.82%	0.19%
	75%	10.53%	8.15%	5.08%	N/A	11.51%	N/A
	100%	9.87%	6.43%	N/A	N/A	11.20%	N/A
	In situ (base case IRR of 18.88% under business as usual)						
	0%	18.17%	17.45%	16.71%	15.96%	18.48%	14.35%
	25%	17.20%	15.39%	13.42%	11.26%	17.99%	6.95%
	50%	16.17%	13.07%	9.34%	4.36%	17.51%	N/A
	75%	15.09%	10.36%	3.46%	N/A	17.01%	N/A
	100%	13.93%	7.05%	N/A	N/A	16.49%	N/A

Figure 1: Impact of GHG price and Downstream Coverage on Project Returns

you read down any individual column, you see the impact on project returns as more and more of the cost of carbon is borne by producers. In the lowest row of each table, we see the scenario where consumer demand for oil is sufficiently elastic that there is no potential for firms to pass carbon costs through to them. Intuitively, the greater the share borne by producers or the larger is the carbon price, the less viable oil sands investments become, and project developers would make the decision on their own to leave the oil in the ground. Values given as N/A indicate that no positive discount rate would generate a net present value of profits of zero.

These results clearly show the importance of considering not just upstream GHG policies when evaluating oil sands investments, and also suggest that oil sands investments may not be robust to the types of global climate policies which will be required to meet goals such as 450ppm or even 550ppm stabilization in the long term. Put another way, as long as the producers' realized cost (i.e. actual foregone revenue) of carbon emissions exceeds about $35/tonne, oil sands returns in even the most attractive projects become questionable.

Oil sands development under a social cost of carbon

The second question we ask in this paper is whether oil sands investments would be viable if they internalized the total costs of the carbon emissions they generate. The social cost

Table 4: Supply costs, rates of return, and per-barrel revenues and costs for oil sands projects under Interagency Working Group on Social Cost of Carbon (2013) Social Cost of Carbon and International Energy Agency (2013) 450ppm scenario from the 2013 World Energy Outlook.

	Base Case	EPA SCC 3% average	EPA SCC 95th pctl.	IEA Current Policies	IEA 450ppm
Bitumen Mine					
Supply cost (10% IRR)	78.80	84.65	146.49	77.31	81.08
Internal rate of return	12.5%	11.2%	N/A	18.5%	14.2%
Per barrel cash flows					
Total Revenue	67.46	61.86	6.30	129.20	76.22
Capital and Debt	8.18	8.18	8.18	8.18	8.18
Operating Costs	20.89	20.62	18.41	23.53	21.22
GHG Compliance Costs	0.03	0.97	8.59	0.03	5.56
Royalties and Taxes	20.92	17.47	0.33	53.36	22.49
Free Cash Flow	17.44	14.62	(29.21)	44.11	18.77
***In situ* bitumen production**					
Supply cost (10% IRR)	68.49	74.47	141.25	67.20	72.47
Internal rate of return	18.8%	16.5%	N/A	26.9%	21.9%
Per barrel cash flows					
Total Revenue	67.46	62.00	3.62	121.28	78.57
Capital and Debt	8.19	8.19	8.19	8.19	8.19
Operating Costs	21.93	21.93	21.93	21.93	21.93
GHG Compliance Costs	0.03	1.38	13.21	0.03	7.29
Royalties and Taxes	21.04	17.23	0.05	50.71	23.25
Free Cash Flow	16.26	13.26	(39.77)	40.41	17.90

of carbon (SCC) provides a means to answer this question. The SCC is an estimate of the monetized value of damages, now and in the future, from an incremental increase – typically one metric ton – of CO_2 emissions in a given time period. If one were to release a ton of CO_2 into the atmosphere today, the SCC would be the sum of present and future incremental damages, incurred in multiple ways from changes in the climate, caused by that additional ton of CO_2. Consider a level of CO_2 emissions today, denoted E_0, that cause damages, denoted D_t, in all future periods $0 \leq t < \infty$. Then the SCC is given by the expression

$$\text{SCC} = \sum_{t=0}^{\infty} (1+\beta)^{-t} \frac{\partial D_t}{\partial E_0}, \tag{1}$$

where β, between 0 and 1, is the social discount factor.

The SCC can be thought of either as the damage from increasing or the foregone benefits from not reducing CO_2 emissions at the margin. In this sense, the question of whether or not the addition of incremental oil sands production has net social benefits can be answered using the SCC to value the damages from induced emissions. As such, it's a very useful metric in our context, as it allows us to asses whether a new oil sands facility, were it to have to account for the social costs of all its emissions, would remain a viable investment. The estimated social costs of carbon provide an alternative to our other estimates which test the viability of oil sands projects at a variety of carbon price levels.

The SCC has typically been estimated using integrated assessment models of climate and economy to perform the calculation in equation (1). A ranges of estimates exist for the SCC - see Stern (2007); Nordhaus (2011); Tol (2002a,b); Interagency Working Group on Social Cost of Carbon (2013) for some examples. Greenstone et al. (2013) review the basic methodology for developing a set of estimates for a given year, while Tol (2002a) and Tol (2002b) analyze the differences between dynamic and static estimates of marginal damages. We use the social cost of carbon as published by Interagency Working Group on Social Cost of Carbon (2013) for our analysis, and treat it as representative of the expected marginal damage from incremental emissions over time.

The results from our analysis are presented in both Figure 1 and Table 4. Interestingly, using the EPA's lower estimate of the SCC, we find that both bitumen projects remain viable even when these prices are applied across the entire life cycle, as shown in the columns labeled EPA SCC 3% avg. in 1. These estimates are generated using the EPA's most optimistic estimate of the social cost of carbon. The results are, predictably, reversed when one uses the EPA's 95th percentile estimates. Using these more conservative estimates, the projects remain marginally viable if the prices are only applied at the production stage, but generate negative cumulative operating revenue, and thus no return on invested capital, if they prices are applied to all life-cycle emissions.

Table 4 provides more detail on how the overall picture of oil sands investments changes from the base case with the imposition of the EPA social cost of carbon estimates over all emissions. In the second column, we see that imposing the EPA's lowest estimate of the social cost of carbon increases the supply cost for mined bitumen by almost \$8 per barrel over the life of the project, and reduces rates of return by over 1%. The *in situ* project is also significantly affected but remains viable and continues to have lower supply costs and higher rates of return than the mine. Both of these effects are due to the increase in GHG compliance costs and the decreases in revenue caused by the carbon charge, but these are buffered by the royalty and tax regime - royalties and taxes drop by over \$3 per barrel in response to the increased carbon charge, an impact we will discuss more below.

The 3rd results column in Table 4 shows the impact of having all emissions charged at the EPA's highest cost and assuming that none of these additional costs are borne by consumers - the most aggressive scenario in our paper. In this case, both projects generate negative total rents (free cash flows, taxes, and royalties), and thus would certainly not be built.

Our question in this section was whether oil sands projects would continue to be developed if the marginal costs of carbon emissions, as estimated by the Interagency Working Group on Social Cost of Carbon (2013) social costs of carbon, were internalized into their cost structures. The answer is ambiguous - if the lower estimates, which assume a 3% discount rate and average damages are valid, then yes, oil sands projects would continue. However, if higher damage estimates are deemed the correct standard, oil sands projects would only proceed if these costs were external to the investment decision.

Oil sands extraction under aggressive global carbon policy

The results shown above make it clear that the financial viability of oil sands projects under stringent global climate policy depends on the degree to which those climate policies impact the price received by producers for oil. In its annual World Energy Outlook, the International Energy Agency (2013) develops a scenario for world oil prices under a particular set of policies designed to stabilize atmospheric carbon dioxide concentrations at 450ppm. In this scenario, global oil consumption peaks in 2015, and declines through 2035, with oil prices declining in real terms to $100 per barrel for North Sea Brent crude by 2035. This scenario would also see upstream carbon prices imposed which begin at $15/tonne today and rise to $35/tonne by 2020 and to $125/tonne by 2035. We test whether, in such a policy environment, oil sands investments would remain viable. They also develop a *business-as-usual* scenario under which no new greenhouse gas policies are imposed.

In order to test the viability of oil sands projects under this scenario, we must make some assumptions as to both the policies imposed on oil sands and the evolution of the carbon and oil prices beyond 2035. For domestic policy, we assume that the carbon price schedule from the IEA's 450ppm scenario is applied as a tax on every tonne of emissions, such that the marginal and average costs of the policy are equal. Further, we assume that the carbon price continues to grow in real terms at 2% per year beyond 2035 (i.e. the nominal carbon price grows at a rate faster than inflation). These assumptions imply that the nominal price of carbon reaches almost $700 per tonne by 2067, the last year of operation for our longest-lived project. For oil prices, we assume that after 2035, prices are constant in real terms, or increasing with the rate of inflation. Other assumptions are identical to those used for the scenarios above. We make the same assumptions for the oil price scenario in the Current Policies, or *business-as-usual*, scenario - that prices increase at the rate of inflation after 2035.

The results here again are initially surprising but easily explained - the rates of return to oil sands investments under the 450ppm scenario are higher than under our baseline, due to a higher underlying oil price than our other analysis. As shown in the two rightmost columns of Table 4, the prices under the IEA scenarios are sufficiently high that, even in the 450ppm scenario, the projects we model earn higher rates of return, and pay more royalties and taxes, than under our base case assumptions with $90 oil prices.

These results make an important point and raise questions as well. First, they demonstrate the degree to which oil sands projects, for which costs are largely fixed, up-front capital, depend on the oil price net of the carbon price, and not intrinsically on one or the other. In International Energy Agency (2010), a specific evaluation of oil sands projects under the 450ppm scenario was performed, and the estimate was for oil sands production to peak at 3 million barrels per day before 2035. Given the returns we find in our analysis, it's difficult to reconcile how the impact of 450ppm policies as modeled by the IEA could reduce production growth that significantly below current forecasts.

Interaction effects of GHG prices and fiscal policies

The results above are, at least in part, due to the relationship between oil sands fiscal policy and carbon policy. As discussed above, oil sands royalties are structured as a price-dependent, two-stage regime. As GHG policies reduce net revenues, they will reduce the royalty (and corporate income tax) base, and will also reduce the rates at which royalties are charged on that base.

Evidence of the combined effect of these two policies is clear in the results presented in Table 4 where, for example, the bitumen mine pays an average of $20.92 per barrel in royalties and taxes under the current policy regime, and only $17.47 in royalties and taxes per barrel with the social cost of carbon applied to all emissions. The change in policies from the current policy in Alberta to the EPA's social cost of carbon applied to all emissions after-tax profits drop by $2.82 per barrel while royalties and taxes drop by $3.45 per barrel.

This has important implications beyond oil sands: global oil production forecasts under greenhouse gas policy tend to take supply costs in individual oil plays as given. This may not be accurate if a significant portion of these costs are due to local fiscal policies. As carbon policies become more aggressive, oil producing jurisdictions could certainly reduce royalties and/or severance tax rates to enable continued economic activity.

Implications for policy and future research

We asked whether oil sands would be left undeveloped in the presence of greenhouse gas mitigation policies which impose a higher price on carbon than is felt by producers today. Our results are mixed. We find that when the policies are applied only to production emissions, the implications for oil sands project returns are small so even high carbon prices would likely only lead to a slowdown in development or to more marginal resource deposits being left in the ground. However, if carbon prices are extended to cover downstream emissions, and in so doing reduce the producer price received for oil below what it would otherwise be, there is potential for carbon policy to markedly reduce oil sands development. We show that under the EPA's low estimates for the social cost of carbon, even if applied broadly, there would be little impact on current development decisions. This would likely change in the future, as the social cost of carbon increases at faster than the rate of inflation: some oil sands projects would certainly go undeveloped under such a regime, and the impact would accelerate over time. Finally, we show that higher carbon prices applied across the life cycle, as long as they have some impact on producer prices received for oil, could meaningfully impact oil sands development today, but that the overall oil price will continue to be the most important driver of investment.

Our analysis is limited by the fact that we consider individual projects in a vacuum, and so we do not capture deflationary effects of development slowdowns or the macro-economic impacts of carbon policies.[8] Oil sands production costs have increased rapidly in the past decade due to development pressure, and insofar as GHG policy reduced that development pressure, there would likely be some moderation of costs. As such, one direction for future work in this area is the aggregation of our project-level model to an industry-level model which accounts for local labour market impacts. Further, our analysis of the incidence of downstream emissions policies on oil markets is simplistic. Future work should examine global oil production opportunities under GHG pricing, and re-evaluate the oil sands' position on the global supply curve. Further assessment is also needed in terms of the long run demand for oil at various prices. Parts of our analysis portray situations where global oil prices rise by up to $50 per barrel relative to current forecasts. As substitutes for oil become more viable, the degree to which oil prices can increase without rapidly eroding the quantity demanded will change. Integrating these aspects of the local labour market and the global energy market will give a better impression of the degree to which cost increases in oil sands'

[8]The exception here is the IEA 450ppm scenario, from which the oil price forecast is internally consistent with the carbon price and other assumptions in their integrated model.

production will be reflected in changes in the price received for oil by producers.

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