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Should Alberta upgrade oil sands bitumen? An integrated life cycle framework to evaluate energy systems investment tradeoffs

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HIGHLIGHTS

- We develop a novel integrated partial cost-benefit analysis/LCA framework.
- We consider stakeholder perspectives, and technical and GHG price variations.
- Upgrading is typically less GHG-intensive than dilution per barrel of bitumen.
- Dilution is typically less GHG-intensive than upgrading per mega joule of gasoline.
- Even stringent GHG prices may not align preferences on energy systems investment decisions.

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ABSTRACT

The inclusion of greenhouse gas (GHG) emissions costs in energy systems investment decision-making requires the development of a framework that accounts for GHG and economic tradeoffs. This paper develops such a framework by integrating partial cost–benefit analysis with life cycle assessment to explore the question of whether bitumen should be upgraded in the Canadian province of Alberta to produce synthetic crude oil (SCO), or blended with light hydrocarbons to produce lower-quality diluted bitumen (dilbit). The net present value (NPV) of these options is calculated from the stakeholder perspectives of the oil sands industry, the Alberta public, and a climate-concerned Alberta resident. This calculation includes monetized GHG emissions costs stemming from a hypothetical economy-wide GHG price, and a sensitivity analysis explores the effects of variations in technical and economic conditions on stakeholders' preferences. We find that under most plausible sets of conditions, industry would prefer the dilution option, while the climate-concerned Alberta resident would prefer the upgrading option. In contrast, the preferences of the general Alberta public depend on the values of key variables (e.g., the SCO-dilbit price differential). Key drivers of differences among stakeholders' preferences include different perceptions of risks and responsibilities for life cycle GHG emissions.

1. Introduction

Energy companies and various levels of government must increasingly make investment decisions under the twin pressures of increasing reliance on non-conventional methods (e.g., thermal recovery and hydraulic fracturing to extract petroleum resources) and increasing attention to environmental consequences of energy production. Such investments require weighing substantial initial capital expenditures (sometimes on the order of billions of dollars) against projected revenues that are calculated using long-term forecasts about the behavior of volatile fuel prices and decisions made by other system actors. However, these forecasts are highly uncertain and are often incorrect (Smil, 2005). Climate policies add a further complication to the tradeoffs associated with these decisions by monetizing GHG emissions costs. Investors in energy systems must therefore decide how to allocate finite resources across a portfolio of potential projects, each with its own set of uncertain costs and benefits. The ramifications of these investments affect not only the company making the decision, but also the public through

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energy prices, tax/royalty revenues, and jobs and wealth created. This paper develops an integrated partial cost-benefit/life cycle assessment framework[1] to evaluate the tradeoffs associated with such an energy systems decision—whether to upgrade Alberta's oil sands bitumen within the province.

As of 2010, the bitumen production rate was 1.6 million barrels per day (bpd); approximately half of this output was refined and consumed within Canada, while half was exported to the United States as either diluted bitumen (dilbit) or upgraded synthetic crude oil (SCO) for further refining. Alberta's oil sands comprise approximately 15% of U.S. crude oil imports and 7% of the total U.S. crude oil consumption (Alberta Energy, 2011). Given the significance of the oil sands to North America's energy systems, decisions regarding how to develop this resource may lead to different long-term impacts for Alberta's wealth and environment, including its contribution to global GHG emissions. One such decision is whether to upgrade bitumen to SCO within the province or to blend it with lighter hydrocarbons to produce dilbit. Fundamentally, oil sands producers must reduce the density and viscosity of extracted raw bitumen by increasing its hydrogen–carbon ratio in order to produce crude oil. They can begin this conversion process through upgrading; although multiple upgrading configurations exist, they typically involve treating bitumen at high temperatures (around 500 °C) to “crack” (i.e., break) its long hydrocarbon chains and adding hydrogen to stabilize the resulting fragments (Rahimi and Gentzis, 2006; Alberta Culture and Community Services, 2009). Alternatively, bitumen may be diluted with naphtha, natural gas condensates, or even SCO to achieve the maximum allowable crude oil density and viscosity for pipeline transportation.

This decision involves economic and GHG tradeoffs. Specifically, upgrading requires large capital outlays to build and maintain the upgrader, and consumes substantial amounts of energy to produce heat, electricity, and hydrogen, leading to significant GHG emissions. On the other hand, the resulting SCO is typically higher in quality (measured by several parameters, including crude density) and is less energy-intensive to refine than dilbit, allowing oil sands companies to sell SCO at a higher price. In the alternative option, diluting bitumen needs little initial capital, but requires a company to continually buy diluent, exposing it to high operational expenses and the risk that prices of diluents may increase substantially. Refining a barrel of dilbit typically consumes more energy (and is thus more GHG-intensive) compared to a barrel of SCO, and requires refineries to invest in additional processing units, including a coker, that can convert heavier feedstocks (e.g., dilbit) into refined petroleum products (Fig. 1).

The decision of whether to upgrade therefore depends on market conditions regarding the capital costs of an upgrading facility and the future prices of diluent, SCO, and dilbit. Moreover, the prospect of North American climate policies further complicates the planning of future upgrading or dilution projects (e.g., Ministry of Energy and Mines, 2011; California Air Resources Board, 2011—see SI for a description).

The decision of whether to upgrade is not only for oil sands companies to make on an individual project basis; it is also one that the Alberta government seeks to influence on an industry level to maximize benefits for its citizens. In 2006, the provincial government announced that it would seek to increase the proportion of bitumen that is upgraded in Alberta, out of a desire to increase the number of local high-paying jobs that stem from developing the province's resources. This announcement was also responding to a public perception that upgrading bitumen allows Alberta to sell a value-added product, rather than “scraping off the topsoil” from its resources, in the words of former Premier Ed Stelmach (Kleiss, 2011). However, individual oil sands companies, seeking to maximize the net present value (NPV) of their investments, may arrive at different conclusions regarding the net benefit of upgrading. Ideally, Alberta's policies on oil sands development should be designed to align industry's decision-making with public preferences regarding the benefits and costs of developing the province's resources. Informing decision-making on an issue such as whether to upgrade therefore requires an analysis that weighs economic and environmental tradeoffs of available options (in this case, the focus of environmental tradeoffs is GHG emissions).

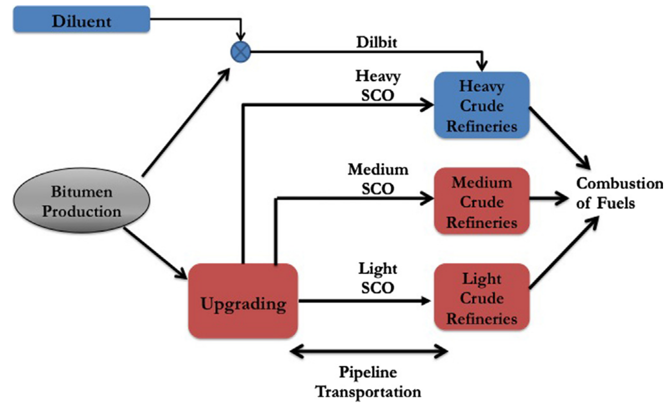

Fig. 1. Bitumen life cycle pathways for upgrading and dilution options. Bitumen may be blended with light hydrocarbon diluents (e.g., naphtha to produce diluted bitumen (dilbit) or upgraded to produce synthetic crude oil (SCO)). Dilbit is typically lower in quality than most forms of SCO (judged by several properties, including density and sulphur content), and must be processed by energy-intensive heavy crude refinery configurations. On the other hand, SCO may be refined by less energy-intensive configurations, depending on the level to which it is upgraded in the upstream portion of the life cycle.

A few studies have analyzed energy systems investments through similar integrated frameworks. Hardisty et al. (2011) employ life cycle assessment with an energy-economic analysis to evaluate multiple options for implementing carbon capture and storage (CCS) technology under different GHG prices. Similarly, Bergerson and Lave (2007) investigate investment decisions for coal-fired power plants under uncertain GHG-price policies, calculating the GHG emissions and supply costs associated with multiple plant configurations. Both studies evaluate results using industry and social discount rates, and find differences in the choices of these stakeholders under certain scenarios. However, both sets of authors address variability in technical and economic parameters through a set of discrete scenarios, as opposed to an analysis of a continuous range of parameter values. Further exploration of the relationships between economic and GHG emissions results and variation in such parameters can help clarify the most impactful factors.

An integrated partial cost–benefit/life cycle assessment framework has not been applied to oil sands investment decisions, but several studies have explored either the GHG impacts or economic considerations of these decisions (see Charpentier et al., 2009, for a comprehensive review of oil sands life cycle studies). For example, two recent consultant reports (Jacobs Consultancy, 2009; TIAX, 2009) compared the GHG impacts of multiple oil sands production pathways with those of other sources of crude oil. However, the studies presented point estimates of life cycle GHG emissions based on specific sets of assumptions, and therefore do not account for variability in crude properties and operating parameters. More

[1] For this study, we refer to a “partial” cost-benefit analysis as one that includes the elements of a financial cost–benefit analysis and some, but not all, elements of a social cost–benefit analysis. In this study, we monetize the costs of GHG emissions associated with oil sands products, but do not monetize other environmental or social impacts. We construct our partial cost–benefit analysis in this manner to examine the effect of a North American economy-wide greenhouse gas price on the decision of whether to upgrade bitumen, but acknowledge that other factors not included in this partial cost–benefit analysis may influence this decision.