Assessing Oil-Related Investments
Under a 2 C Global Objective

by

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Abstract

This research project analyzes the impact an international effort to stay within the 2 C climate constraint would have on global oil markets to 2050, with a focus on the economic outlook for Canadian oil sands investments. The approach involves (1) an historical analysis of past oil market conditions; (2) a survey of world-class energy-economy-emissions modeling groups; (3) a review of the latest analysis of the 2 C constraint conducted using these models; and (4) development of a graphics technique to illustrate key relationships between the 2 C constraint, the necessary global carbon price, the effect on the demand for refined products produced from oil, the effect on the oil price received by producers, and the resulting effect on investment prospects for the oil sands. The modeling results predict a rising carbon price on emissions would cause global oil demand to fall from almost 90 million barrels per day in 2014 to 63 in 2050. The falling demand would lead the average world oil price to fall below $40 per barrel well before 2050. The combination of low oil prices and higher production costs for relatively emission-intensive oil sands would render uneconomic new investment to further develop this resource, even in the near future.

Keywords: Energy-economy-emissions models; oil sands; climate change policy; unconventional oil; fossil fuels; pipelines.

To the memory of my uncle Brian Hope—

A man whom I admired and respected immensely. I wish I had the chance to share this project with him, as I know he would be proud of my accomplishment and interested in learning about this global challenge.

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AMPERE	Assessment of Climate Change Mitigation Pathways and Evaluation of the Robustness of Mitigation Cost Estimates
AR5	Fifth Assessment Report
BP	British Petroleum
CAFE	Corporate Average Fuel Economy
CAPP	Canadian Association of Petroleum Producers
CCS	Carbon capture and storage
CERI	Canadian Energy Research Institute
CO_2	Carbon dioxide
EEE	Energy-economy-emissions
EIA	U.S. Energy Information Agency
EMF27	Stanford Energy Modeling Forum Study 27
EOR	Enhanced oil recovery
FEEM	Fondazione Eni Enrico Mattei (research institute)
GHG	Greenhouse gas
IAMC	Integrated Assessment Modeling Consortium
IEA	International Energy Agency
IIASA	International Institute for Applied Systems Analysis
IPCC	Intergovernmental Panel on Climate Change
LTO	Light tight oil
mb/d	Million barrels per day
MIT	Massachusetts Institute of Technology
NEB	National Energy Board
OPEC	Organization of the Petroleum Exporting Countries
PIK	Potsdam Institute for Climate Impact Research
PNNL	Pacific Northwest National Laboratory
ppm	Parts per million
PDVSA	Petroleos de Venezuela
ROSE	Roadmaps towards Sustainable Energy futures project
RPP	Refined petroleum product
SAGD	Steam-assisted gravity drainage
WTI	West Texas Intermediate

1. Introduction

Carbon dioxide (CO_2) from burning fossil fuels is the most important of the human-produced greenhouse gases (GHGs) that are warming the planet, acidifying oceans, and causing other global-scale changes. After considering evidence from scientists and economists, global leaders agreed in 2009 that carbon and other GHG pollutants should be reduced such that warming from pre-industrial temperatures does not exceed $2^{o}C$. But the 'common property resource' nature of the atmosphere and the 'global public good' nature of the effort to reduce GHG emissions make the objective extremely challenging. Two decades of international negotiations have failed to reach a binding agreement on national emission limits and the creation of an enforcement mechanism to ensure compliance.

As a result, global annual CO_2 emissions from fossil fuels since the beginning of the industrial revolution continue to climb (see Figure 1-1) and as testament, in May 2013, CO_2 concentrations in the atmosphere exceeded 400 parts per million (ppm) for the first time in several hundred millennia (International Energy Agency [IEA], 2013a).

Figure 1-1: CO_2 emissions from the burning of fossil fuels (1850-2010).
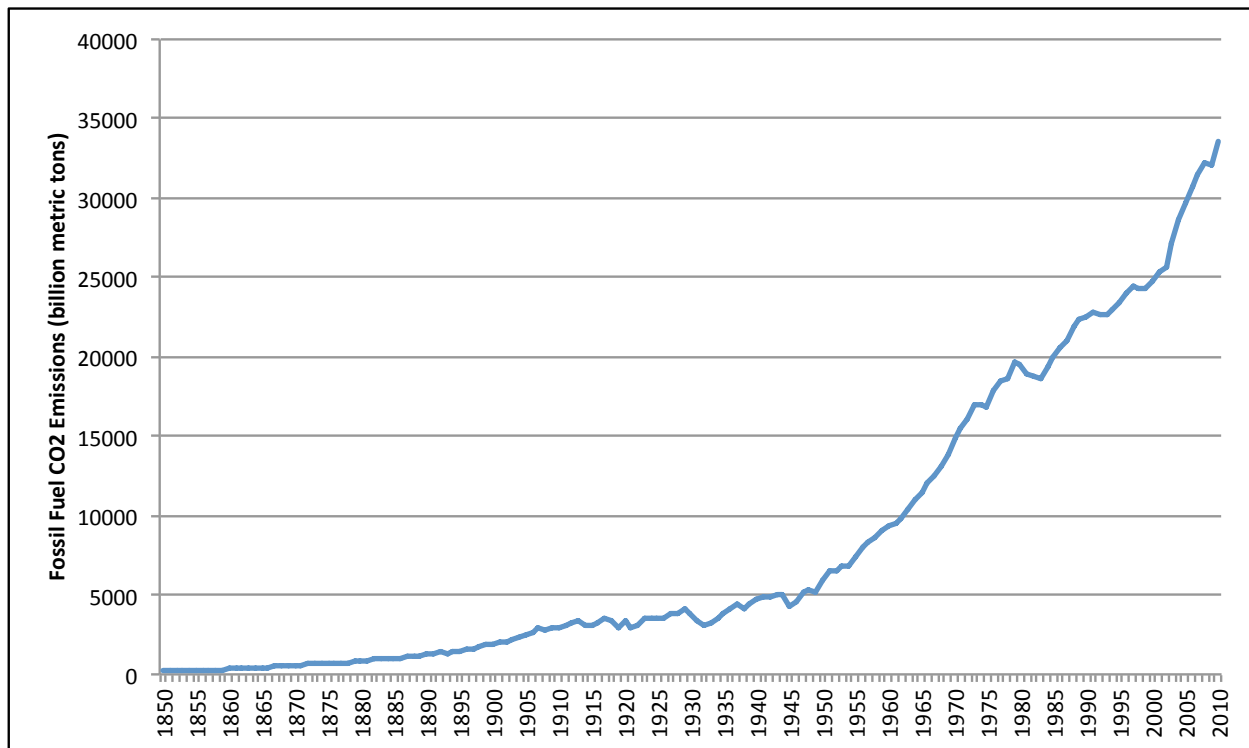
Data from Carbon Dioxide Information Analysis Center (CDIAC).

The 2 C target necessitates cooperation at all scales, and quickly. Stabilizing the atmospheric concentration of GHGs at 450 ppm can preserve about a 50% probability of not exceeding a global rise in

temperatures above 2° C. Taking into account a warming of nearly 1° C already, and inertia present in the climate system from past emissions, the world's most advanced carbon-cycle climate models indicate that this means GHG emissions must be reduced by 40% to 70% in 2050 from 2010 levels (Intergovernmental Panel on Climate Change [IPCC], 2014).

The concept of a planetary 'carbon budget' defines the amount of GHG emissions humans can cumulatively emit and still meet the 2 C target. This quantification of the maximum amount of emissions that can be emitted in the years to 2050 is possible because CO_2 and other GHG emissions persist in the atmosphere over long timespans. Adhering to the carbon budget could have a profound impact on energy markets because the global energy system is 82% dominated by fossil fuels, which in turn produce about two-thirds of global GHG emissions (IEA, 2013b). The IEA (2013a) estimates the energy sector can emit a maximum of 884 Gt of CO_2 by 2050 from 2012 without exceeding the planet's 2 C carbon budget. To have a realistic chance, global emissions must peak soon after 2020 (Riahi et al., 2013).

For more than two decades, Canada's government has acknowledged the country's responsibility to show leadership by reducing its domestic GHG emissions, and by pursuing ways to ensure that other jurisdictions join with, rather than free-ride on, its efforts (via negotiation of international climate agreements, or possibly by applying trade measures that raise the cost of high-emission imports). The Canadian government agreed at international negotiations in Copenhagen in 2009 with the 2 C target and reaffirmed commitments it had earlier made for reducing emissions by 2020 and 2050.[1]

Over the last decade, however, production innovations and favorable energy prices have created strong incentives for investments to expand Canada's production and transport of fossil fuels, whether for domestic consumption or export. This has triggered a debate about the social benefit of such investments. Since 2011, this debate has been especially intense over the development of new oil pipelines that would facilitate expansion of the Alberta oil sands by increasing access to North American and overseas markets. Many projects have been proposed, the most noteworthy being the Keystone XL pipeline to the United States, the Line 9 Reversal pipeline and the Energy East pipeline to central and eastern Canada, and the Northern Gateway pipeline and the Trans Mountain Expansion pipeline to the west coast.

These pipeline projects are supported by the Albertan government and in recent years by the Canadian government. In the exploitation of common property resources like the atmosphere, individual jurisdictions or regions may find that their jurisdiction-specific benefits from increasing carbon pollution

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[1] Note that even if all the countries that made commitments as part of the Copenhagen Accord achieved their promises, the global average temperature is likely to rise more than 2° C (Rogelj & Meinshausen, 2010).

exceed their jurisdiction-specific costs. This creates the incentive to act in ways that subvert the achievement of a public good that provides net benefits for humanity at a global scale – sometimes referred to as the "collective action problem" (Olson, 1965). Investments in fossil fuel infrastructure, such as oil pipelines to aid the expansion of oil sands production, are an example of this problem. While the net cumulative effect of investments like this may be negative, individual corporations and regional governments are likely to be net beneficiaries. They therefore have an incentive to ignore or even deny the net global effect of the investment path of which this investment would be one component.

Opposition to such projects may come from people who point out that one project should be evaluated as if it were but one of many similar projects in terms of the net global effect. In other words, humanity must constrain individual actions that have a "tragedy of the commons" effect on a common property resource like the global atmosphere (Hardin, 1968). But more often the opposition comes from people who, like the proponent, are focused on the local costs and benefits – economic activity versus local environmental and socio-economic impacts.

When opponents focus on local environmental impacts and risks from a pipeline, this reflects real concerns for protecting local environments. But it is also, at least for some opponents, a strategic recognition of the difficulty of motivating a significant portion of the public to oppose projects simply because of their contribution to the GHG problem. Many people are more easily mobilized to protect their local environment from immediate threats, especially when the direct net benefits of acting for a global objective may be negative in the absence of a firm global constraint.

In cases where the debate does turn to the GHG problem, project proponents and supportive governments have typically used three rationales to justify their investment.

1. Stopping their pipeline would not reduce emissions because other investments (pipelines, rail transport) would provide replacement capacity given that global energy markets are the key determinants of oil sands output.
2. Their pipeline and the production it enables contributes only a tiny percentage to global GHG emissions, so stopping it would have negligible effect.
3. The project would still occur under the 2 C constraint, given that no 2 C scenario suggests an immediate cessation of all global oil production.[2]

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[2] A fourth issue is whether the 2 C constraint is optimal for humanity, given that fossil fuels provide benefits and costs to humanity. In this work, the assumption is that the 2 C constraint was chosen after consideration of the costs

Arguments for and against rationale #1 turn on the likelihood of also preventing alternative investments to the pipeline in question, which in turn depends on complex political and legal questions. What legal recourse does a provincial government have to prevent one or several pipelines or oil ports approved by the federal government? What about a municipal government? What about a First Nations band? What about environmental organizations? Because the answers are hypothetical, they cannot be answered definitively without the hindsight of lengthy legal processes. And political questions are layered on top of the legal ones, since the legal efforts and policy acts of governments are influenced by political optics. For people focused on the climate issue, stopping the expansion of fossil fuel infrastructure is something they feel compelled to do in the absence of a firm global constraint on emissions. They may prefer to have this constraint, but in its absence they feel compelled to stop as many projects as possible (McKibben, 2013).

Rationale #2 is a red herring, as noted in the above discussion of a global public good. The exploitation of common property resources frequently involves multiple actors whose individual contributions are small, but which cumulatively cause the undesired outcome. In the 1970s and 1980s, each cod fishing boat off the Grand Banks could have claimed to be only a small contributor to the crash of cod stocks, yet allowing each to continue fishing led to that very outcome. Likewise, the GHG problem involves millions of GHG emitting activities all over the planet, each of which is a small contributor to the problem. The small size of the contribution is not a justification for continued emitting (IPCC, 2014).

Arguments for and against rationale #3 are complex because they require a detailed understanding of sources of GHG emissions, sources of supply and demand in global energy markets, and the costs of GHG emission reduction options. One might argue that global oil demand for transportation can rise, or at least remain stable, while GHG emissions are reduced dramatically in other sectors, such as electricity. Or, one might argue that oil output and GHG emissions from a particular supply source, such as the Alberta oil sands, could rise even while aggregate oil demand falls. The only way to evaluate this rationale is by recourse to the work of independent researchers who assess the likely evolution of global energy markets as humanity effectively pursues GHG reductions that would satisfy the 2 C constraint.

My goal in this research project is to assess this third rationale in the specific case of expansion of the Alberta oil sands, and the implications for new investments in oil pipelines that would facilitate that expansion. Thus, I explore how production of the oil sands and other unconventional oil resources would change in the global energy system to 2050, assuming effective climate policy is pursued collectively by

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of GHG emissions reduction against the costs (and especially catastrophic risks) of continued GHG emissions. This debate is well reviewed by Roemer (2010) and Nordhaus (2014).

the world's nations to meet the 2 C climate target. To this end, I combine experiences from the past several decades of the oil industry with global simulations by world-leading energy-economy-emissions (EEE) modelers, especially the results from a renowned multi-model comparison study. The impact of 2 C climate policy (carbon pricing or regulations for energy technologies or carbon) on individual oil resources is highly dependent on: (1) current and available supply quantities; (2) the supply and operating costs of the resource; (3) change in costs with carbon emission pricing and carbon capture and storage (CCS) technology; (4) resulting change in oil demand; and (5) comparison with the expected price producers would receive for their oil.

This resource information and market responses are represented through a set of future-period supply cost curves I have created for this project. These supply curves visually convey the impacts of a 2 C constraint on the likely production path of the oil sands, and hence help assess the prospects for additional pipeline capacity potentially serving that production. The decision to opt for a graphical method, as opposed to a numerical modeling method, was to focus my analysis on a few of the key relationships listed above in order to clearly communicate these relationships to non-energy experts. My goal is that the results of this analysis can help politicians, media and citizens meaningfully judge if the common rationalizations for expanding fossil fuel infrastructure are justifiable. As noted, I focus on the implications of the 2 C target on Alberta's oil sands, given the ambitious expansion plans of the industry in the last decade and the heated public policy debates about this expansion and associated investments currently occurring within Canada and the United States.

The project is organized as follows. Chapter 2 provides background information about the overall availability of oil resources, key oil price determinants, and modeling efforts that have focused on the 2 C target. Chapter 3 details the methodology, which incorporates past oil market dynamics, information received from survey questions sent to independent modeling teams, and the construction of global oil supply cost curve graphics. Chapter 4 is a three-part analysis that reveals the major oil market dynamics that would be expected with carbon pricing. Chapter 5 includes future-period graphics that portray oil price results and a discussion of the viability of individual oil resources in a 2 C scenario. Chapter 6 summarizes key findings and suggests areas of future study.

2. Background

This chapter provides background information pertinent to this study. First, I briefly discuss the different classifications of oil and the amount estimated to be available for human consumption, which shows that significant resource depletion is highly unlikely in the time frame of this analysis (2014 to 2050). Next, I explain oil price dynamics used to assess the impact of 2 C carbon policy on the viability of oil resources. To conclude the background chapter, I present the basic characteristics of energy-economy-emissions (EEE) models and the value of multi-model comparison studies for informing climate policy.

2.1 Fossil Fuel Availability

Fossil fuels are compounds consisting of carbon and hydrogen formed in the past from the remains of living organisms. The high energy density (the amount of energy stored per unit of mass or volume) of fossil fuels, which is released when ignited, makes them conducive to human activities and has spurred much technological innovation. Unfortunately, when combusted, fossil fuel derived products emit harmful air pollutants like nitrous oxides, sulfur dioxide, and of importance to this study, carbon dioxide, which is the principal GHG causing climate change.

Fossil fuel deposits can be described as 'conventional' or 'unconventional' resources, but the meaning of these terms is subject to change. For oil, the geological definition is based on the density and viscosity of the liquid. Conventional oil has a low viscosity (resistance to flow) and low density (high API gravity) (Meyer, Attanasi, & Freeman, 2007). Unconventional oil encompasses all denser, thicker petroleum liquid occurrences as well those which have traditionally been more difficult to extract and produce such as oil sands, light tight oil, extra-heavy oil, and oils extracted from kerogen-rich shale. Though useful conceptually, the boundary between conventional and unconventional oil varies by organization and country (Global Energy Assessment [GEA], 2012). For example, there is discrepancy in whether Arctic oil and deep offshore oil (depths of > 400 m) is conventional or unconventional because although the oil in place fits the geological definition of conventional oil, there is increased costs and complexity involved in bringing these less-accessible deposits into production. At the same time, sustained production and the associated innovations redefine marginal technologies and resources as mainstream over time. The important characterization is that conventional oil is the most accessible and least technically challenging to produce, whereas unconventional resources are generally more expensive because production is capital intensive and requires additional energy input (Owen, Inderwildi, & King, 2010).

The distinction between oil quantities that are classified as 'reserves' and those that are considered 'resources' is also variable (McKelvey, 1972). Shown in Table 2.1-1 are ranges of fossil fuel reserve and resource estimates reported in the GEA (2012), which defines resources as "detected quantities that cannot be profitably recovered with current technology, but might be recoverable in the future, as well as those quantities that are geologically possible, but yet to be found" (p. 434). Reserves are more certain and economically producible than resources, as they are those quantities geological and engineering information indicate can be recovered under existing market conditions. Estimates therefore must be revised periodically however due to advancements in extraction and production technologies, depletion of the non-renewable resource base, differences in reporting techniques, and changes in market conditions.

Table 2.1-1: Estimated fossil fuel reserves and resources in zetajoules (ZJ).[3]

Fossil Fuel	Type	Reserves (ZJ)	Resources (ZJ)	Total Reserves + Resources (ZJ)		
Oil	Conventional	4.9 – 7.6	4.2 – 6.2	9.1 – 13.8	24.1 – 34.2	404.9 – 695.2
	Unconventional	3.8 – 5.6	11.3 – 14.8	15.0 – 20.4		
Natural Gas	Conventional	5.0 – 7.1	7.2 – 8.9	12.2 –16.0	72.5 – 205.0	
	Unconventional	20.1 – 67.1	40.2 – 121.9	60.3 – 189.0		
Coal	-	17.3 – 21.0	291.0 – 435.0	-	308.3 – 456.0	

Data from GEA (2012).

The overall magnitude of the global fossil fuel reserve and resource base signals that its availability will not be constrained due to shortage in the foreseeable future. In the case of oil, consumption was approximately 91.3 million barrels per day (md/d) in 2013 (~0.2 ZJ for the year). Cumulative production since humanity first started using it as an energy source is estimated to be between 1.1 and 1.2 trillion barrels (6.3 - 6.9 ZJ). Conventional oil reserves alone could be greater than the amount already produced and this is with costs in the range of $5 - $40/b, which are significantly lower than oil prices have been since 2004. Adding in the supply potential of conventional resources as well as unconventional means there could be nearly five times as much oil still left in the earth's crust compared to what has been produced to date. Further, the quantity of fossil fuel liquids could be expanded through the application of processes such as Fischer-Tropsch synthesis to convert natural gas and coal into liquid fuels, known as 'synfuels' and this is already done at a commercial scale in some parts of the world, such as Qatar using natural gas and South Africa using coal.

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[3] The GEA (2012) resource data are not cumulative and so do not include reserves.

In summary, the total amount of oil reserves estimated to be available to supply the global energy system has increased over time as a result of discoveries, improvements in technology, and changes in market prices for energy products. Production and consumption of fossil fuels depletes the reserve base, but advancements in exploration and extraction technologies driven by market competition moves resources into the reserve category (Verbruggen & Marchohi, 2010). For example, the bitumen contained within the Canadian oil sands was only added to global oil reserve estimates in 1999 to reflect modern production potentials resulting from oil price increases and technology innovations. This change placed Canada's total oil reserves second to Saudi Arabia globally (nearly 174 billion barrels as of 2012) (British Petroleum [BP], 2014). In a similar fashion, Canada was soon superseded by Venezuela as more complete assessments of the amount of extra-heavy oil contained with the Orinoco Oil Belt increased its oil reserves to 297 billion barrels in 2010 from an estimate of 80 billion barrels only five years earlier. Now, global oil reserves stand to further increase as the same horizontal well technology used in the production of shale gas is unlocking previously inaccessible oil in low-permeability formations, known as light tight oil (LTO). The estimated amount of economical fossil fuel stock is thus a result of the interplay of resource depletion and technological change; this latter, spurred on by high oil prices, has for over a decade been the dominant factor (Méjean & Hope, 2008). As apparent from Figure 2.1-1, the growth in global proved reserves of oil tracks with the increase in oil consumption over the same period.

Figure 2.1-1: Oil reserves and consumption (1980-2012).
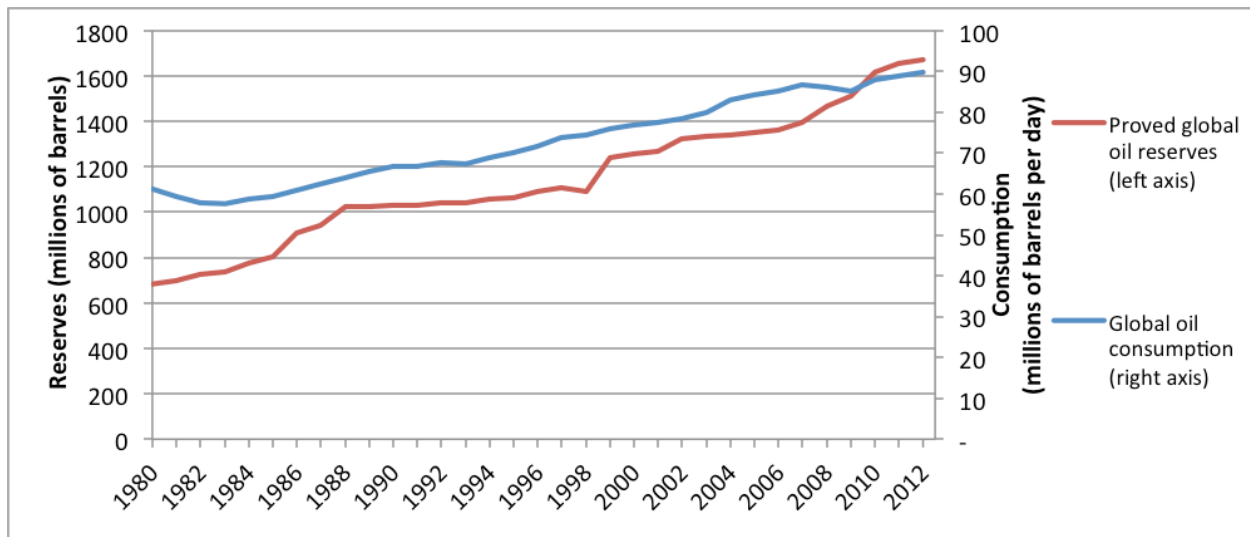
Data from BP (2014).

Despite these developments and the overall trend, peak oil is a popular topic of debate. M. King Hubbert (1956) is credited with establishing peak oil theory for his forecast that oil production in the continental United States would rise until sometime between 1965 and 1970 before declining. The

moderate success along with the relative simplicity of Hubbert's theory spurred geological analysts to apply many of the same techniques to project the future of global oil resource production (Campbell & Laherrère, 1998; Leigh, 2008). These assessments tend to focus on discovery rates and argue that societies should begin preparing for a future in which unabated growth in production and consumption of oil and gas has led to depletion (Aleklett & Campbell, 2003; Mohr & Evans, 2010). Hirsch, Bezdek, & Wendling (2005) even warn of impending political and societal chaos without government intervention to lessen the economic consequences of a long-lasting oil shortfall. While admitting the existence of unconventional sources of oil, advocates of peak oil are typically skeptical that market incentives can lead to unconventional sources being developed fast enough to offset conventional well declines (Murray & King, 2012; Höök & Tang, 2013).

History has shown, however, that markets can respond to shortages. For global oil production to resemble a bell-shaped curve by declining fairly rapidly after a maximum production output is reached would mean that the supply side of the oil market is completely unresponsive to changes in price. This assumption underestimates the potential for the 'principle of substitution' to continue to move resources into reserves and improve the economic viability of unconventional deposits. Predictions of prolonged periods of insufficient supply are highly contested by economists who maintain that, with many resource inputs to production, prices will climb in response to scarcity leading simultaneously to reduced demand or slower demand growth, on one side, and increased supplies of the resource and possibly substitutes on the other (Pindyck, 1978; Holland, 2008). In truth, the next least-costly oil-like substitutes for conventional oil have been discovered in immense amounts, and are already in development, but they are higher cost because of being less accessible or requiring additional processing. Sustained growth in the production of unconventional oil resources will depend on relative costs, prices, geopolitical factors, technological evolution, and climate policies.

2.2 Oil Price Determinants

The price of fossil fuels is the subject of much interest because of their position within industrialized economies as a prime input to production processes and services (Nordhaus, 1973; Arbex & Perobelli, 2010). One can expect, all else being equal, that if fossil fuel prices were to rise then the cost of transporting people and goods would increase, materials derived from energy-intensive industrial processes like aluminum and steel would become more expensive, and the cost for energy services like heating and electricity would climb. There is a dependence on inexpensive fossil fuels to meet many of the energy services of modern societies, which means forecasting their price trajectory holds relevance for

citizens, companies, and governments alike. In this section, I discuss oil price dynamics that are relevant in determining its production and demand trajectory in a 2 C scenario.

Economic Rents and Oil

An oil deposit is an asset because there is the prospect that this resource can earn a future financial return for its owner. Oil resource owners have the choice of either extracting and selling their oil in the present or keeping the oil underground under the expectation that it will appreciate in value (Solow, 1974). Hoteling (1931) pointed out that a non-renewable resource could garner a price above its cost of production if asset owners and prospective buyers believed that its value would be greater in the future because of the combination of scarcity and a high willingness-to-pay by future buyers. This excess return for a non-renewable resource is called 'scarcity rent,' a form of economic rent. As we shall see, it only exists at a given time as long as buyers and sellers believe the resource will have a greater value as it becomes scarce. Hoteling showed mathematically that if there were perfect competition, perfect knowledge about the resource, a fixed resource stock over time, no technological change, the only substitutes had much higher production costs, and the willingness-to-pay in future periods was known perfectly, then the scarcity rent and price of a non-renewable resource like oil should increase over time.

Figure 2.2-1 shows the price of oil, corrected for inflation, over the past 150 years. The price has not risen gradually as one might expect for a non-renewable resource, but of course all of Hoteling's critical conditions have not held over this time. However, there have been periods in which the price of oil did go above its cost of production. Analysts have argued that usually this was due to the belief of impending temporary oil shortages caused by geopolitical issues (Stevens, 1996). The unequal distribution of inexpensive oil on the earth's surface means that consumers in some regions are dependent upon political stability in other regions, which has not always been the case. When the price has remained high for an extended period, such as the recent high prices in the period 2002-2013, one could argue that the price of oil over this period contained some degree of scarcity rent. It is difficult to sort out, however, the extent to which this extra willingness-to-pay reflects a worry about long-term scarcity (the concern of Hoteling) or a more immediate, short-run concern for sudden scarcity caused by war or some other disruptive force.

Figure 2.2-1: Oil price per barrel in 2013 US dollars (1861-2013).
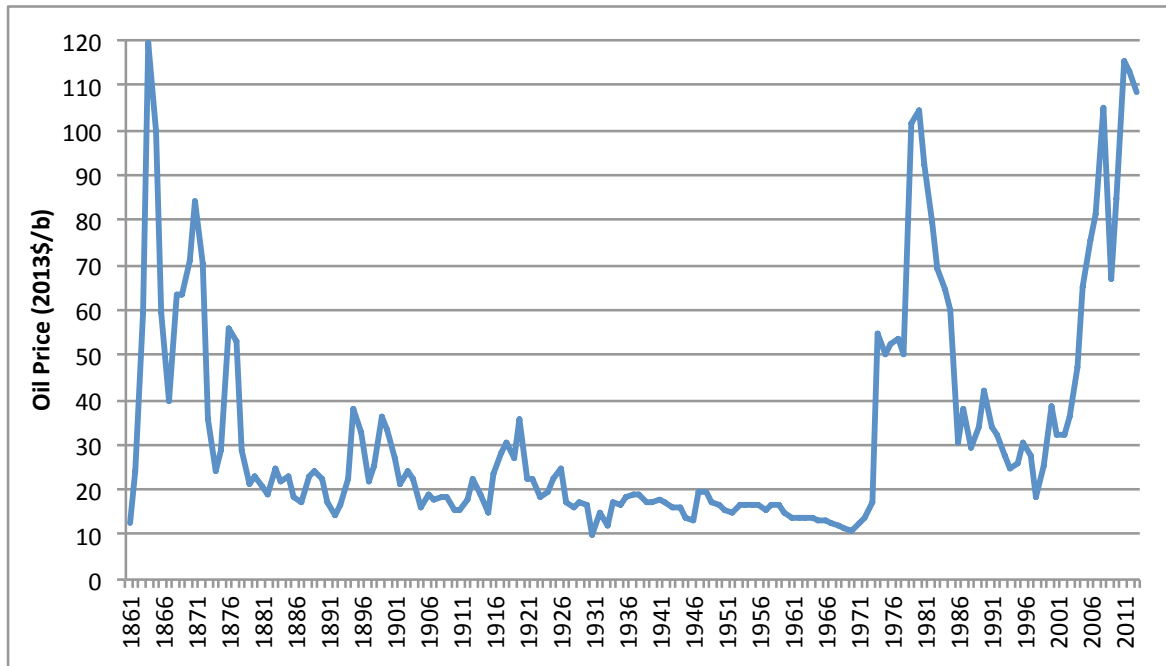
Note: Data from BP (2014). Crude oil prices from 1861-1944 based on US Average, 1945-1983 is Arabian Light, and 1984-2013 Brent dated.

Differences in the cost to produce refined petroleum products (RPPs) from various locations and qualities of oil can be used to estimate the contribution of scarcity rent to the oil price. Since scarcity rent is equal to the market price less production costs (including a return on capital) for the most expensive producer operating in the market, its estimation requires identification of that producer and its costs (Mueller, 1985). For the oil industry, production costs comprise capital costs (primarily costs for development drilling, processing equipment, production facilities, pipelines and abandonment) and operating costs (mainly incurred during oil field operation and transportation) (Aguilera, 2014). In general, the resources of high cost producers are of lower quality and require further energy and production inputs to produce RPPs such as gasoline, diesel or kerosene. This difference in production costs between the highest cost producer and all lower cost producers in the market is called differential rent (Ricardo, 1817). While scarcity rent relates to non-renewable resources, differential rent can exist with non-renewable and renewable resources, like food crops or fish harvests, as it simply reflects different costs of production due to the heterogeneous quality of the resource as found in nature.

Market Competition

Ever since the first oil crisis in 1973, the degree of competition in the global oil market has been a recurring topic of research in the economics literature. Economists have empirically tested the consistency

of alternative hypotheses of market power to explain the oil market's structure and the behavior of strategic producers. These hypotheses and variations of them include: (1) cartel in which a group of countries (OPEC) coordinate their production to influence price with all other suppliers being price-takers that produce close to capacity ('the competitive fringe'); (2) single price leader (Saudi Arabia) that has the ability to independently affect price; (3) competitive pricing model where supply and demand best describe changes in price; and (4) target revenue theory that argues domestic investment requirements dictate production rates. The question of whether effective collusion in the oil market exists (hypotheses 1 and 2) is of interest because dominant producers may use their market power to attempt to equate their marginal costs with marginal revenue. If this is the case, oil-importing countries would be subject to pay a price for oil that is largely determined by a small number of producers employing restrictive production and trade practices to raise prices and coordinating production increases to lower prices.

Despite decades of effort, a definitive economic model that experts agree represents the competitive nature of the oil market remains elusive. The results from the many statistical analyses conducted are often inconclusive, regularly conflict with one another, and different hypotheses tend to fit only specific time periods. In a seminal paper, Griffin (1985) tests multiple hypotheses on the period 1971-1983. Griffin concludes that a partial market-sharing model best fits the production behavior of OPEC, though he questions the strength of such a cartel given strong financial incentive for members to break agreed-upon production quotas. Applying a similar approach to export data that extends from 1973 to 2012, Alkhathlan, Gately, & Javid (2014) contend that Saudi Arabia has been consistent in its effort to maintain OPEC stability, but these actions are context dependent. They find evidence that Saudi Arabia, as the market leader, increases its exports to offset supply interruptions and responds to periods of reduced demand by restricting its output in cooperation with its OPEC partners. Smith (2005) is less convinced, stating, "[t]here is only weak evidence to indicate that Saudi Arabia has acted as a "leader" or dominant firm within the cartel, although that possibility cannot be formally rejected" (p. 75). According to statistical testing and characteristics that define commodity cartels, Alhajji & Huettner (2000) determine that OPEC does not fit the theory of a cartel. However, these authors do regard Saudi Arabia to be a dominant producer based on its relatively large market share, excess capacity, and flexible behavior. Still yet, the results of Lin (2009) suggest that there was collusion among OPEC producers up until 1990, but that the market has been competitive over the last twenty years. Huppmann & Holz (2012) developed partial equilibrium models to investigate the oil market's structure since 2005 and find that oil prices approximate the level that would be expected in a competitive market. In general, prices may have been influenced by OPEC enough to be detectable over short periods of time, but this power is limited and has declined since the 1970s (Radetzki, 2012; Goldthau & Witte; 2011).

I do not account for the potential for collusive behavior to influence oil prices in my 2 C analysis because the overriding influence on prices is likely the effect of declining demand on the marginal cost of supply. As the sample of literature on the subject indicates, researchers have not found evidence that uncompetitive factors have a major effect on the price of oil. Conversely, as detailed in section 4.1, the periods of low prices followed by high prices can be largely explained by supply and demand conditions; the exertion of market power is a poor indicator of oil prices compared to market fundamentals. While the oil market may not be perfectly competitive, 2 C climate policy will cause a steady decline in oil demand over several decades that should impact prices. In this sustained buyer's market, oil resources become plentiful while 2 C climate policy places upward pressure on prices for refined petroleum products, causing oil demand to decrease. As such, I focus on the extent to which 2 C climate policy is likely to eliminate any scarcity rent in what becomes a sustained buyers' market over the many decades during which humanity is dramatically reducing GHG emissions.

Supply Cost Curves

A global oil supply cost curve is a graphical depiction of oil resources and the costs associated with their production. The sources of oil are arranged in order from that with the lowest cost per unit to that with the highest, with the distance along the horizontal axis indicating the volume of each. In Figure 2.3-2, column A represents the lowest-cost resource and is of greater quantity in this case than column B, the resource with the second lowest costs. The columns increase in cost to column G, which is the highest cost resource in the market. In this example, demand does not support a price increase to enable the resource represented by column H to enter the market. If all resources are included in the supply curve, the total horizontal distance across the columns is the availability of the resource.

Figure 2.2-2: Exemplary supply cost curve of resources A to H with price level, P.
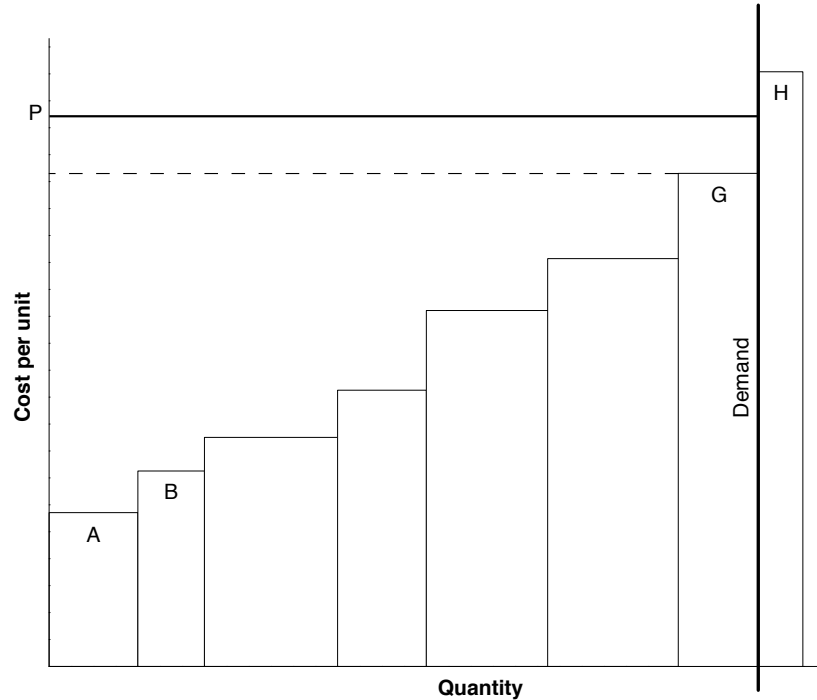
The economic rents potentially earned by oil resource owners at a particular price can be estimated from a global oil supply cost curve. The scarcity rent being earned by the owners of valued non-renewable resources is equal to the market price minus the costs of production for the resource with the highest cost of production to meet a given level of demand in the market. In Figure 2.2-2, this is the vertical difference between the price at P and the cost at column G, which is the highest cost producer needed to satisfy the market demand – as shown by the vertical solid line between producers G and H. The highest cost producer, G, earns no differential rents. The amount of differential rent earned by each lower cost producer is the difference between their cost of production and that of producer G. Thus, the differential rent of resource A is equal to the production costs of column G minus the production costs of A; low-cost resource owners obviously earn the greatest differential rent.

In a world focused exclusively on cost minimization, humanity would exploit a non-renewable resource like oil sequentially, from cheapest to most costly, thus 'climbing the supply curve' over time. In the real world, higher and lower cost resources are exploited simultaneously because some countries are willing to develop more expensive resources for energy security or macro-economic reasons, and because of high oil price expectations when some investments are made to develop new, high-cost oil resources. This real-world complexity is depicted in the global supply cost curves constructed for this research project, which are based on production rates of various types of conventional and unconventional oil

resources that are already in production in today's market. I use these graphical tools to distinguish and communicate the key relationships affecting the oil price and viability of oil resources in a 2 C scenario.

Climate Policies and Oil Demand

In this project, I analyze what would be expected to happen to the price of oil as its demand declines. Prices and demand for fossil fuels is contingent on the dynamic effects that would occur with a rising carbon price consistent with the 2 C target, which in turn requires stabilization of atmospheric GHG concentrations at roughly 450 ppm CO_2 equivalent in 2100. To estimate the impact of a 2 C carbon price pathway on oil resources, I assess the magnitude of the major responses that would be expected as the amount of emissions entering the atmosphere and oceans each year from human activities is reduced. I describe this process first and then explain why I used results from advanced modeling comparison studies to aid my quantification of these 2 C oil price effects.

The global 2 C climate target could be achieved through different types of policies. A market-based solution (a carbon price resulting from either carbon tax or cap-and-trade systems) is the most effective and economically efficient type of climate policy because the firm or household is free to choose whether to pay the cost of emitting or invest in a low-carbon alternative. Each firm and household best knows its costs of GHG reduction, so a carbon price enables each to make the technology and fuel choice that is optimal from its perspective, all the while achieving the global goal of reducing emissions on an optimal path from a global, societal perspective. An international and harmonized carbon price is achieved if governments throughout the world impose the same tax on carbon emissions. As the tax increases over time to cause global emission reductions in line with the 2 C pathway, it retains its efficiency because the emissions mitigated at each carbon price level would be the result of being more economical than paying the tax on carbon.

A carbon price can also be achieved by a cap-and-trade system. This involves each country setting a national cap on emissions (presumably determined through international climate negotiations) that are equal to the global 2 C carbon budget in the aggregate. Countries can then decide how to allocate permits that equal its cap. As with a carbon tax, this means that firms and households within countries will decide whether to do more or less emission reduction, leading to the buying or selling of permits. Trading could even potentially occur between firms in different countries, as currently occurs with the emissions trading system of the European Union (EU). Regional and large-scale cap-and-trade systems have already been used to address other environmental problems. One example is the US Acid Rain

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Program, which successfully lowered sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from the electricity sector at far lower-than-expected compliance costs (Napolitano et al., 2007).

Regulations on individual energy technologies, fuels, or sectors could also restrict GHG emissions, but the nature of the climate change problem makes this approach likely to be inefficient at inducing mitigation at the global scale. To design a suite of regulations that is economically efficient would require knowledge of the value that each emitter receives from emitting. However, this information is unlikely to be known precisely because emissions associated with human energy use come from diverse technologies in energy transformation, transportation, commercial and residential building, and industrial sectors in every region of the world. As a result, a global regulatory initiative will have higher global economic costs to achieve the 2 C target than a market mechanism. Further, all energy technologies or every sector would eventually need to be regulated because the 2 C target requires the virtual cessation of GHG emissions in the long term. Modelers use a single global carbon price as a simplified way of depicting how the global effort will be coordinated. I follow that assumption in this study. In reality, the outcome of international negotiations could well result in something less simple.

For this research project, I assume 2 C carbon pricing is applied to the emissions from all energy transformation and consumption processes in each sector throughout the global economy. The carbon price is projected to increase over time, which is shown by global analysis to lead to an emissions trajectory that is optimal in terms of its net present value (Nordhaus, 2014). This would result in the price of RPPs and other processed forms of fossil fuels becoming progressively more expensive, thus sustaining the transition to technologies and energy sources with low carbon intensities (amount of CO_2-equivalent emissions emitted per unit of useful energy). In this way, the price consumers pay for RPPs will increase as the carbon price is applied to the combustion emissions released through their burning, which make up an estimated 70-80% of total emissions associated with gasoline and diesel consumption.

With higher prices for RPPs induced by carbon pricing, global demand for oil would decline. Empirical studies tend to show that the demand for RPPs, hence the demand for oil, is relatively unresponsive to price changes. The reasons include the following. Oil provides the vast majority of energy for mobility with oil-based fuels accounting for 95% of total road transport energy use. The long-term dominance of the internal combustion engines that perform optimally with gasoline or diesel has created a 'locked-in' transportation system around which public infrastructure and the preferences, expectations, and habits of consumers have conformed (Unruh, 2000). A mass transition to a system based on a different fuel source and technologies requires overcoming what are primarily cost barriers, such as public charging facilities for electric vehicles (Unruh, 2002). Indeed, models indicate the

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transportation sector may be a relatively expensive sector to decarbonize, at least compared to electricity (Calvin et al., 2009; Chan et al., 2012).

But, the drastic cuts in carbon emissions needed for realizing the 2 C climate target means all uses of fossil fuels will be affected. The rate at which oil demand will decline in response to 2 C carbon pricing depends on the marginal cost of GHG abatement in each sector of the economy. In other words, demand for RPPs, and therefore oil, is contingent on the adjustments in energy related activities that would occur as a result of higher prices for RPPs and other useable energy derived from fossil fuels. Total oil demand would be expected to decrease because it becomes increasingly more costly for drivers to purchase RPPs that release carbon emissions during their production and end-use. The transition to a low-carbon transport sector is likely to include a combination of improvements in energy-efficiency (i.e. more fuel-efficient vehicles), shifts to modes of transport that are less emission-intensive (e.g. an uptake in public transit), reduced mobility demand (i.e. less travel), and adoption of vehicles that are powered by low- or zero-emission energy. Potential alternative fuels and technologies for transportation include plug-in hybrid-electric vehicles, battery-electric vehicles, hydrogen fuel cell vehicles, and low-carbon liquid fuels such as biofuels and natural gas-based liquids produced with CCS.

At the same time, developments in other energy sectors where oil is not a dominant energy source could indirectly affect its demand. The reason is that, with a rising carbon price and a fixed carbon budget, emissions reductions will initially come from sectors with the lowest costs to decarbonize, which means the remaining carbon budget is taken up by emissions that are more costly to reduce. Thus, if emissions from industry and electricity generation can be abated at a lower cost (through switches to low-carbon energy or adoption of mitigation technologies or energy efficiency) than transportation emissions, then the demand for oil may decline less quickly because RPPs continue to be viable in transportation, at least until the carbon price rises higher.

With the relative costs for energy from fossil fuels and low-carbon alternatives changing simultaneously and in different regions of the world, a pragmatic and consistent way to keep track of these changes was needed to assess the 2 C oil demand response for this project. Fortunately, as discussed in the next section, energy-economy-emissions models are capable of computing these dynamics and inform my analysis of the viability of oil sands in a 2 C scenario.

2.3 Modeling the 2 C Target

Models are a way to abstract from the complexities of the real world. Energy-economy-emissions (EEE) models have become standard tools to forecast the effects of policies on energy demand, economic output, and environmental pollution. In this section, I profile why EEE models offer the most systematic approach for quantitatively forecasting the effect of 2 C climate policy on energy markets, including oil markets. I then consider the benefits of comparative modeling exercises through an overview of results from prominent studies that have explored energy markets under a 2 C constraint, and conclude by noting the potential value in providing a more detailed representation of resource supply in the models.

EEE models are computer-based tools that represent the energy system and economic activity, and are linked to, or include, a climate system model. EEE models adhere to the interactions judged by modelers to be important between these highly complex systems while keeping account of the stocks and flows of physical and economic quantities between them (Nakata, 2004). For instance, EEE models can capture the multitude of key feedbacks that would occur if the price of oil increases, such as the oil industry working to increase supply to profit from the higher prices, investment potentially funneling into alternatives for RPPs, and consumers finding ways to use less oil. These models would also include the feedback of a high oil price on economic growth and GHG implications and thus, the contribution to the long-term global temperature increase. In effect, through an economy-wide framework, EEE models can reveal how interactions between various users and producers of energy (demand and supply side) would be expected to change over time in response to changes in relative costs and prices.

Commonly applied to the issue of climate change, the primary objective of EEE models is to produce scenarios of how the world might develop under different mitigation assumptions. The rich energy technology information represented in EEE models allows for analysis of technological improvements and the rate of capital stock turnover in response to climate policy. Through this analysis of the output of EEE models, the key energy efficiency, fuel shifts, and emission mitigation technologies for achieving climate targets can be determined and in turn, used to inform climate policy decision-making. Therefore, by running a scenario using an EEE model that limits global GHG emissions to a maximum that is consistent with the 2 C target, the critical trade-offs involved with such a shock on the global economy and energy system can be better anticipated.

Since EEE models have been constructed to assess the nexus between energy, emissions, and the economy, they are well suited for assessing how oil demand is likely to be impacted in a 2 C scenario. In a cost-effective 2 C pathway in which the least expensive options for reducing emissions are adopted in

the economy before more costly mitigation strategies, demand will decrease most dramatically for those fossil fuels that can be substituted at the lowest cost by a low- or zero-emission energy source. With detailed representation of energy demand and supply technologies, which include end-use, conversion, and production technologies that are available and emerging, EEE models can calculate the demand for oil and other fossil fuels along a 2 C pathway over a forecast period. Because they offer the only rigorous and independent determination of oil demand as global emissions decline, I base oil demand in this research project on EEE modeling results.

Several recent multi-model comparison studies have assessed the feasibility of the 2 C target by harmonizing some of the key technology and mitigation policy assumptions of the participating models. I discuss three such modeling comparison projects in relation to their contributions made in understanding energy market transformation for 2 C climate change mitigation. The data results from these comparison exercises informs my analysis and were submitted to the Integrated Assessment Modeling Consortium (IAMC) for review in the Fifth Assessment Report (AR5) of Working Group III of the IPCC. Informed by the results of these comparison studies, the IPCC (2014) suggests that the rate of decarbonisation in the transportation sector is likely to lag the rate in electricity generation due to challenges related to energy storage and the relatively lower energy density of low-carbon transport fuels (i.e. natural gas, biofuels, electricity, and hydrogen) compared to oil-based RPPs. That being said, a rising carbon price will have an immediate effect on the global demand trajectory for oil products, slowing the growth from what it otherwise would be and then causing that demand to fall in spite of globally growing population, income, mobility and total number of vehicles. For more specific aspects of the modeling work that is relevant to oil demand in a 2 C scenario, I refer to the published analysis papers from each comparison study (AMPERE, EMF27, LIMITS) below. Appendix A is a list of the models and versions involved in each modeling study and documented in the AR5 Scenarios Database.

Funded by the EU, AMPERE stands for *Assessment of Climate Change Mitigation Pathways and Evaluation of the Robustness of Mitigation Cost Estimates* and was a collaborative initiative consisting of 17 modeling teams. A robust finding from AMPERE is the enormity and immediacy 2 C requires. In a scenario in which annual emissions are about 22% higher in 2030 than presently (from about 50 Gt CO_2e to 61 Gt CO_2e), 70% of the cumulative emissions budget for 450-ppm CO_2e has already been released to the atmosphere (Riahi et al., 2013). A rapid movement to low-carbon technologies and early phase-out of fossil fuel infrastructure is then required to 2050. Indeed, two of the AMPERE models were unable to reach the 2 C target once emissions increased to this level in the short-term. This infeasibility of a solution may occur as a result of differences in the variety of mitigation options to stay within an overall emissions budget, constraints on the diffusion of technologies in the marketplace, or the need for extremely high

price signals under which the modeling framework can no longer be solved (Riahi et al., 2013). In another scenario where the EU leads on stringent climate policy and the rest of the world follows after 2030, the carbon price rises steeply to cause early retirement of fossil-based power plants that have been built in the rest of the world (Kriegler et al., 2014b). Thus, AMPERE shows that the 2 C target becomes more difficult and costly if either climate policy is too late or is fragmented. The mitigation costs of 2 C vary widely between the AMPERE models, however, as the carbon prices in the optimal 450-ppm scenario range from less than $100/t CO_2 to more than 10 times that amount indicating significant uncertainty in estimated marginal abatement costs.

The study coordinated by Stanford's Energy Modeling Forum (the study is called EMF27) emphasized the role of technologies in the transition to a low-emission energy system. The 18 models that took part in EMF27 were coordinated to a set of scenarios with specific technology availability, cost, and performance assumptions under three levels of climate policy (baseline, 550-ppm target, and 450-ppm target). The results suggest that the electricity generation sector is quickly decarbonized in the 450-ppm stabilization scenario as emissions reach zero or are net negative in 2050 (Kriegler et al., 2014c). For some of the models, the net negative emissions resulting from the production of bioenergy with carbon capture and storage (CCS) are assumed to be a less costly option than reducing emissions from non-electric energy end uses, particularly in the industry and transportation sectors. Although the models forecast emissions from transportation declining at a slower rate than electricity generation, the global carbon price still causes emissions to be lower than they otherwise would be. Interestingly, five of the models show annual electricity generation being lower under 450-ppm compared to baseline, which Krey et al. (2013) attribute to high cost assumptions for renewable energy. This occurs because demand for electricity is reduced in response to higher prices, offsetting any increased demand resulting from greater electrification in end-use sectors. In addition, the median annual rate of energy intensity reduction of the global system increases with 2 C climate policy to 2.3% per year, which is about 1% higher than the historical rate (Sugiyama et al., 2014).

In an extension of the EMF27 scenarios, McCollum et al. (2013b) employ the MESSAGE model to investigate electrification of the transportation sector for climate mitigation. The modelers find that constraining electrification of the transportation sector to a 5% maximum share of transport energy throughout the period to 2100 with 450-ppm climate policy results in oil-based fuels being substituted by biofuels and natural gas (for use as a gaseous fuel in certain transport applications and conversion to synthetic, low-carbon liquids produced with CCS). If transport electrification is allowed to reach a 75% share of transport demand, electricity consumption for all transport modes grows from about 0.8 EJ currently to 33.1 EJ in 2050. There is then a strong diversity in primary energy supply for transportation

because renewables are expected to comprise a large portion of electricity generation in a 2 C future. As well, with biomass resources not widely used in transportation, the industrial sector becomes the main recipient of biofuels for both energy use and as a feedstock for petrochemicals. Overall, these findings signal that 2 C climate policy will break the near complete dependence on combusting oil-based RPPs to meet mobility demand, even if the current liquid-based fuel delivery infrastructure endures through extensive use of biofuels and natural gas.

The LIMITS study aims to inform international climate negotiations of the potential range of 2 C emissions pathways and mitigation costs such action would entail, assuming policies are not started before 2020. Featuring six models, van der Zwaan et al. (2013) report divergence among the models by 2100 on the low-carbon technologies that are part of a 450-ppm scenario. For example, nuclear energy in GCAM and WITCH is the largest share of global electricity generation by 2100 whereas ReMIND and TIAM-ECM show solar supplying greater than 50% of total power production. All the LIMITS models show solar energy growing tremendously from less than 0.1 EJ/year currently, but the level reached by 2050 varies from 10 to 49 EJ/year. There is also some inconsistency between the models regarding which fuel types will be used in the transportation sector in a 2 C scenario, but they do agree that the consumption of RPPs will diminish. Although not part of the LIMITS study, Jaccard & Goldberg (2014) model various policy scenarios using a technology-rich model of the United States and point to electric and plug-in hybrid vehicles potentially displacing internal combustion engine vehicles due to optimistic technology assumptions and increasing consumer confidence in these newer technologies.

The three model comparison studies discussed each provide insight into the 2 C target by assessing its sensitivity to future developments. Since EEE models are abstractions of real systems, the added value of these comparison studies is the ability to identify modeling assumptions that have a strong influence on results as well as determine what outcomes are robust across all models in spite of their different assumptions and algorithms (Koelbl, van den Broek, Faaij & van Vuuren, 2014). The diversity of energy system transformations shown by the studies probe the extent to which the 2 C target may be achievable with different levels and combinations of fossil fuels, renewables, technologies, energy intensity improvements, and abatement cost sharing. Consistent across the studies is the carbon budget allowing limited variation in the timing of the peak in global emissions, cooperation from all major emitters to achieve deep emission reductions being required, and the optimal path involving fossil fuels gaining CCS and losing market share to low- and zero emission fuels and end-use technologies.

EEE models can be broadly classified based on their economic market endogeneity and optimization algorithm, which contribute to the variability in results from the modeling studies. The

partial equilibrium models, GCAM and POLES, describe energy conversion processes and energy markets in detail and assume a (price-elastic) demand forecast for energy services as a function of economic growth. In comparison, the general equilibrium models, MESSAGE, ReMIND, and WITCH, capture the full feedback effects between individual sectors and markets. Represented by intertemporal optimization, MESSAGE, REMIND, and WITCH are 'forward-looking' in the sense that production, consumption, and investment decisions by economic agents are made with clear foresight of future changes in the economy and therefore resources are allocated optimally over time given policy constraints. The dynamic recursive solution approach employed by GCAM and POLES means these models exhibit somewhat myopic behavior in that consumers do not alter their saving and consumption solely on expectations of future returns on investment or on expectations of future changes in prices. Model specifics such as technological detail in the energy sector, substitutability of energy carriers, temporal and regional coverage, representation of GHGs, and inclusion of climate feedbacks and land use emissions can be important factors influencing climate policy modelling results as well.

These models are continuously being improved. One direction of development pertinent to my study is the representation of oil resources, in particular geographical and quality differentiation. While the multi-model comparison studies discussed did not aim to provide a detailed assessment of the impact of 2 C climate policy on individual oil resources, assembling a large group of premier EEE models to participate in such a modeling initiative is likely not yet possible. Most do not currently possess the level of resource disaggregation necessary to adequately assess the impact on individual oil resources for comparison with results from other models.

But some researchers are beginning to assess the oil market with greater resource disaggregation. A modeling study by Chan, Reilly, Paltsev, & Chen (2012) focused on the prospects of the Alberta oil sands under global climate commitments. These modelers used a version of the global EEE model developed at MIT, called EPPA, which included elaborate representation of refining and oil production sectors as well as disaggregation of the oil sands into surface mining and in situ projects. These extensions allowed Chan et al. (2012) to account for how variations in carbon emissions associated with different bitumen production processes may impact the overall economic viability of this unconventional resources under carbon pricing. The authors concluded that even with a global GHG constraint somewhat less onerous than that implied by 2 C, the Canadian oil sands industry would contract, showing production falling to near zero by 2035.

More recently, two studies by McGlade & Ekins (2014; 2015) focus on the vast amount of oil resources that would not be produced when global warming is limited to 2° C. The authors find through

linking output from TIAM-UCL (a version of which contributed to EMF27) to a detailed oil field level model that extensive development of unconventional oil resources is inconsistent with a 2 C pathway. The availability of CCS is an important factor, however. McGlade & Ekins (2014) indicate that a rapid development of CCS in coal and gas fired electricity generation would allow a slower decrease in global oil consumption, enabling oil sands production to reach 4.1 mb/d in 2035. In contrast, in the authors' no-CCS scenario, no new oil sands capacity is built and 99% of Canada's unconventional oil resources are deemed 'unburnable' in the timeframe 2010 to 2050. Curiously, McGlade & Ekins report differing results concerning existing oil sands operations between their 2014 and 2015 articles even though they use TIAM-UCL to model the 2 C target in both. In their 2014 study, they explain that existing in situ and mining projects are able to continue because large capital expenditures have already been made, but in their 2015 article, they state "all bitumen production ceases by 2040" (p. 190). Given large sunk costs in oil sands processing facilities and pipelines, a complete cessation in production seems less likely, although this is difficult to ascertain because the authors do not report their model's projection of oil prices in either study. As for other oil resource categories, Arctic and kerogen oil are not produced while light tight oil, deepwater, and extra-heavy oil are produced in quantities below current supply projections because these higher cost resources are not as needed in a world that upholds its 2 C pledge.

The McGlade and Ekins studies are an example from a single model of some of the components of my study. Like them, I estimate the effect of the 2 C constraint on the demand for various types of conventional and unconventional oil resources. However, I have two additional goals. One is to estimate, using graphical and historical analyses, the likely effect of a rising carbon price and declining oil demand on the global price of oil. Another is to address modeling uncertainty by basing my oil analysis on a combination of simulations by several of the world's leading EEE models that participated in the modeling comparison studies reviewed. This helps to determine the extent to which uncertainties in model design can lead to different outcomes. Finally, through this process I hope to explore the possibility of circumstances in which Alberta oil sands could expand under a 2 C constraint.

3. Methods

In this research project, I follow an eclectic methodological approach to assess the degree to which the oil price and global oil demand changes caused by 2 C climate policy would likely impact oil sands production. This process involved (1) an historical analysis of the factors in past oil price movements and levels, (2) an informal survey of EEE modeling teams, (3) the development of a graphics technique that combines data from the models with lessons from my historical analysis, and (4) finally, use of the graphic approach to address uncertainties from the models and to explore a scenario with the highest potential for some increase in oil sands output. Figure 3-1 is an overview of my approach.

Figure 3-1: General approach to assess oil price and economic viability of oil-related investments.
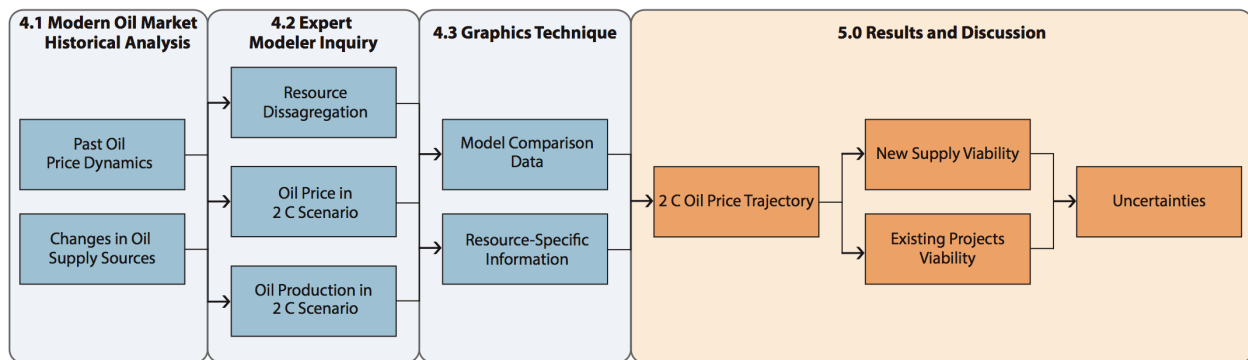
I first analyzed the changes that have occurred in the oil market since the early 1970s to understand how 2 C climate policy may affect the oil price and production from conventional and unconventional oil resources. I focus on the major supply-side and demand-side changes in the modern oil market that have arisen leading up to and following changes in the oil price. Through an historical perspective of past oil market conditions of volatility and relative stability, I clarify the early phases of the modern oil market, and its subsequent evolution, to understand the present context and inherent dynamics of the market. My historical analysis of the oil price bolsters this research project by providing an account of the ways in which a 2 C scenario would likely be a departure from the past as well as a repetition of some key past developments. In particular, I explore the essential conditions leading to a buyers' market in oil and a sellers' market in oil, and the likely effect of these markets on oil's price.

Next, through two questionnaires sent to a sample of the top independent modeling teams, I sought information about how their models, when faced with a 2 C constraint, determine a carbon price, a global demand for oil, and a price for oil. I chose these international modeling groups as potential contributors to this part of the study because of their participation in the AMPERE, EMF27, and LIMITS modeling studies, and in the case of the IEA and Massachusetts Institute of Technology (MIT), their

previous work in modeling the effects of climate policy on oil sands production. As shown in Table 3-1, in the first set of questions I asked the modeling teams about fossil fuel representation within their models and oil demand in a 2 C scenario. I was also curious about oil price implications of 2 C carbon pricing and identification of the mechanisms or assumptions within the models that might cause oil prices to be more responsive to scenarios in which demand is increasing than if demand is decreasing.

Table 3-1: Questions from initial questionnaire sent June 2013 to modeling teams.

Modeling Teams
International Institute for Applied Systems Analysis (IIASA), Fondazione Eni Enrico Mattei (FEEM), Potsdam Institute for Climate Impact Research (PIK), Pacific Northwest National Laboratory (PNNL), MIT, Enerdata, IEA
Questions
1. At what level of detail are fossil fuel resources represented in your model?
2. Are energy supply costs (from fossil fuels) disaggregated at the same level as the answer to 1?
3. What happens to the global demand for oil (or the sum of demand for petroleum products) and an international benchmark oil price(s) under the 2 C scenario, and what is the explicit or implicit carbon price that is required (especially to the year 2050)? If this demand for oil (or petroleum products) is disaggregated by region and/or resource, can you please provide this?
4. Is there anything in your model that would cause the own-price elasticity of demand for oil to be asymmetrical for rising versus falling oil prices?

A second round of survey questions were sent to the teams that answered the questions from the initial questionnaire. These follow-up questions are shown in Table 3-2 and queried modeling groups about oil price responses in a 2 C scenario, costs of oil production, and rates of production for conventional and unconventional oil. I reasoned that gaining information about the role of bioenergy with CCS to produce negative emissions when these EEE models run a 2 C scenario might be beneficial to my analysis because it could explain results in which there is not a substantive decline in fossil fuel consumption even though total emissions are decreasing. I also wanted modelers to provide a lower bound on oil prices within their models because this might be relevant to my 2 C analysis if oil demand declines low enough that prices are set by the operating costs of existing infrastructure. Finally, based on answers to the first round of questions, I discovered that the split between conventional and unconventional oil resources was a characteristic of several of the EEE models, and therefore I followed-up by asking about the cost assumptions between these two categories of oil and their production levels in a 2 C scenario. My intended purpose for designing and sending both rounds of questions was to identify the capacity of these models to effectively model oil sands production under a 2 C constraint and gain a better sense of the uncertainty associated with oil prices in a 2 C scenario based on the judgments of

experts operating leading EEE models.

Table 3-2: Follow-up questions sent August 2013 to modeling teams.

Modeling Teams
FEEM, PIK, PNNL, MIT, Enerdata
Questions
1. In immediate and/or delayed policy action scenarios consistent with a 2° C target, what is the price of oil to 2050? Is BioCCS (negative emissions) required to achieve the 450-ppm CO_2e stabilization target in these scenarios?
2. If climate policy causes the demand for oil to fall faster than the natural decline in oil production capacity (reduced production that would occur naturally with the exhaustion of existing sources and the retirement of existing infrastructure) how low can the oil price fall in your model? In other words, would the price of oil in your model fall to just the operating costs of the planet's existing oil production infrastructure? And how low is that price?
3. Could you provide the cost curves or data used to determine production of conventional and unconventional fossil fuels in 2 °C climate target scenarios? What is conventional and unconventional oil production in the years to 2050?

I then developed a graphics technique to communicate the key dynamics occurring in a 2 C scenario between sources of supply, global demand, carbon pricing and the resulting oil price. These graphics were the outcome of a three-step process. First, I accessed the Fifth Assessment Report (AR5) of Working Group III of the IPCC Scenarios Database to retrieve long-term sectoral GHG emission reductions, primary energy resources, and carbon price projections. To establish a broader context of the changes in energy use that would be expected in a 2 C scenario, I examined the range at which emissions in the main energy-consuming sectors of the economy are forecast to decrease and the corresponding change in the global energy supply mix based on the results from AMPERE, EMF27 and LIMITS contained within the database. I decided to focus on the results from these three modeling studies as I could compare and verify the scenario specifications used to generate these results through descriptions in corresponding publications. I chose to base oil demand and carbon price projections consistent with the 2 C target for this research project on EMF27 model runs because this modeling study offers the advantages of having the most participating models (including 5 of the 6 models that responded to the survey component of this study), a high variety of scenarios with harmonized technology and policy assumptions, and full flexibility of emissions reductions to ensure cost-effective mitigation efforts.

After collecting the 2 C model results data, I consulted IEA publications, journal articles, and industry reports to gather estimates of the current production rates and availability of the major individual oil resources supplying the market in 2013, their ranges in supply and operating costs, and their emission

intensities. I organized this information through a traditional global oil supply curve and a daily 'snapshot' global oil supply cost curve. The traditional supply curve visually conveys the long-term availability and costs of all known oil resources whereas the daily snapshot supply curve illustrates daily production rates and the costs associated with producing oil from resources currently in the market. Thus, the daily snapshot oil supply curve represents the 2013 oil market by depicting daily production levels and costs for each significant source of oil.

The third part of the graphics method involved incorporating the resource-specific information, 2 C modeling forecasts, and insights from my historical analysis into a set of daily snapshot oil supply curves for the years 2020, 2030, 2040, and 2050. I calculated the impact of 2 C carbon pricing on supply and operating costs for each resource to 2050 using well-to-tank emission intensities (emissions from production, refining, and distribution). I also considered the applicability of CCS to mitigate GHG emissions associated with conventional and unconventional oil production as a cost-effective option for producers to reduce their rising costs of production from a rising carbon price. As operating and supply costs increase with carbon pricing, the price of refined petroleum products like gasoline and diesel, will also increase, which will decrease the demand for oil from what it otherwise would have been. I signify this change in global demand for oil on the future-period graphics by superimposing a vertical demand line that is consistent with the mean 2 C scenario results from EMF27. Lessons from my historical analysis of the oil price informs my oil price trajectory to 2050 by taking account of how any level of scarcity rent comprising the oil price may be impacted by the introduction of 2 C climate policy and how low-cost oil producers would likely respond. In effect, I designed these graphics to show the expected change in the oil price and viability of individual oil resources as the carbon price consistent with 2 C ramps up and global oil demand contracts.

Finally, I assess the prospects of oil sands production in a global 2 C climate policy scenario through inspection of the future-period graphics and discuss the uncertainties that could create a different 2 C oil market than I have presented. I assume that if the supply costs (includes capital costs, operating costs, and a 10% real rate of return to the producer) for unconventional oil resources are higher than the price producers would receive for their oil, then the production of the resource is not likely to expand from current levels. As well, if operating costs for an oil resource are above the producer oil price in a given period, then I reason that production levels could decline as projects shut-in before the end of their planned operating life span.

4. Analysis

4.1 Modern Oil Market Historical Analysis

Past oil market dynamics may provide insight into future market dynamics if there is a global effort to limit GHG emissions and prevent global average temperatures from increasing more than 2° C. In this regard, the period 1973 to 2003 may be particularly relevant. Following high oil price and long run rising price expectations, policy measures to decrease demand among major oil consuming countries and the emergence of new and expanding sources of supply combined to produce 17 years of low prices, from 1986 to 2003. I conclude this retrospective analysis by discussing the price increase since 2003 and what this has meant for unconventional oil production.

The 1973-74 and 1979-80 Oil Shocks

At the time of the first oil shock in 1973, members of the Organization of Petroleum Exporting Countries (OPEC)[4] were producing more than half of global oil production (51% of 58.5 mb/d) and 84% of all oil traded internationally. The 1973 embargo on oil shipments to the United States during the Israeli-Arab conflict by Saudi Arabia and other Arab countries created a temporary shortage in supply. This tightening of the oil market resulted in prices quickly increasing from $3/b to $12/b ($55 in 2013$) by 1974. After the crisis subsided, prices slightly weakened (average of $52/b in 2013$), until the second shock in oil prices in 1979.

Even before the second oil price shock, it was widely assumed by market analysts that prices would need to rise further. Analysts at the newly created IEA in the late 1970s were convinced that a shortage driven by physical constraints, or possibly political circumstances, was near and forecast prices in the range of $50-$100/b by 1985 (Brodman & Hamilton, 1979). This notion of a supply shortage was supported by the reserve-to-production ratio in 1980 being less than 30 years, as shown in Figure 4.1-1 (BP, 2014). In preparation, oil companies slowly raised the level of their stocks in storage and refineries and collectively, the world's stock of extracted and stored crude oil increased by 0.76 million barrels from 1973 to 1981 (IEA, 2013c).

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[4] OPEC's membership has undergone some changes since its creation in 1960, but for data purposes, the current members of OPEC (Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela) are used here to define its production and exports over time.

Figure 4.1-1: World oil reserve-to-production ratio (1965-2013).
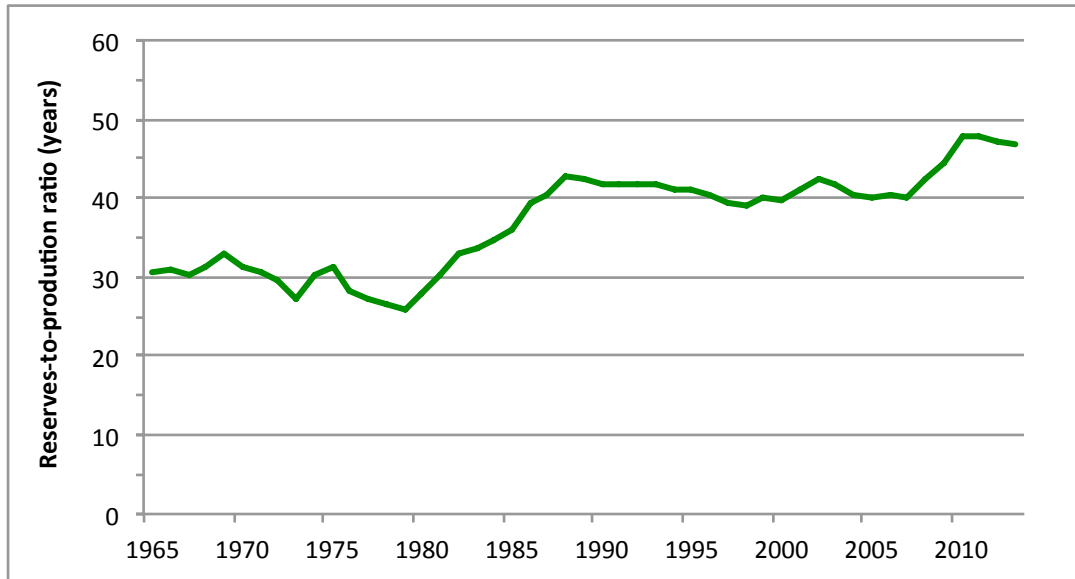
When Iran's production halted due to oil-worker strikes during the Iranian Revolution and again at the outbreak of war with Iraq, oil prices rose sharply. The oil price increased by more than $22/b in 2 years and in 1980 averaged $104/b (in 2013$). Importing countries reacted to the prospect of a destabilized Persian Gulf by increasing their oil stocks from an amount needed to cover 30 - 50 days of consumption to that of 180 days, which artificially increased demand at the same time as supply was constrained (Salvatore, 2012). To make up for the shortfall of approximately 9 mb/d in supply from Iran and Iraq, Saudi Arabia managed to increase its production to 11 mb/d, a level only recently matched.

Market and Government Responses

Oil prices tripling in 1973-74, and then nearly tripling again in 1980, initiated significant changes on both the supply-side and demand-side of the market. Naturally, production of higher cost oil resources accelerated globally as governments and companies sought to benefit from the high prices. Investments were supported by only a moderate weakening of oil prices from 1981 to 1985 (still averaging $73/b in 2013$). Development of off-shore Norwegian and British oil in the North Sea, conventional oil discoveries in Mexico, export expansion by the Soviet Union, and China developing its oil resources allowed these countries to become important producers. Table 4.1-1 shows the increase in oil production from 1973 to 1985 for these countries plus the relatively constant rate of production from sources in the United States and Canada.

Table 4.1-1: Non-OPEC oil production in million barrels per day (mb/d).

Country	1971	1973	1975	1977	1979	1981	1983	1985
China	0.8	1.1	1.5	1.9	2.1	2.0	2.1	2.5
Soviet Union	7.6	8.7	9.9	11.0	11.8	12.3	12.4	12.0
Mexico	0.5	0.5	0.8	1.1	1.6	2.6	2.9	2.9
Norway	0.006	0.03	0.2	0.3	0.4	0.5	0.7	0.8
United Kingdom	0.005	0.009	0.03	0.8	1.6	1.9	2.4	2.7
United States	11.2	10.9	10.0	9.9	10.1	10.2	10.2	10.6
Canada	1.6	2.1	1.7	1.6	1.8	1.6	1.7	1.8
TOTAL	21.6	23.3	24.2	26.5	29.5	31.0	32.5	33.3

Data from BP (2014).

Between 1971 and 1985, total non-OPEC oil production increased by 15.3 mb/d to 41.6 mb/d (a 58% increase in 14 years). Of this production in 1985, approximately 11.1 mb/d was exported– an increase of 165% from 1971.

The demand side response by consumers and firms in industrialized countries to the historic price jumps of the 1970s in the form of fuel switching and energy-efficiency proved to be substantial. Heavy fuel oil for electricity generation declined from being a source of 23% of the world's electricity in 1978 to 12% in 1985 as it was replaced by coal, natural gas, and nuclear power (IEA, 2013c). At the same time, homeowners quickly dropped furnace oil for their heating needs in favour of electricity and natural gas, which contributed to heating fuel oil consumption in Canada and the United States decreasing by about 44 million tonnes between 1973 and 1985 (a decline of 58% in 12 years).

These normal market responses to rising prices were augmented by the implementation of a variety of tax and regulatory policies aimed at stimulating energy conservation. For example, the US government introduced regulations forcing automakers to increase the fuel economy of their fleets. Greene (1998) argues that the Corporate Average Fuel Economy (CAFE) standards established in 1975 were effective in depressing the market for the least efficient vehicles and therefore oil. Actual and expected high fuel oil prices may also be important in driving technological progress in energy efficiency as Crabb & Johnson (2010) demonstrate through the use of a dynamic model that uses patent counts as a measure of energy efficiency innovation in the automotive industry. The high oil prices contributed – along with high interest monetary policies – to a global economic recession, and the combination of these factors caused global oil consumption to decline by 6.3 mb/d from 1979 to 1983 (a decrease of 10%). With recovery from the recession, demand increased slightly from 1983 to 1986, by 3.4 mb/d.

Due to declining global oil demand and increased production and exports from mostly higher cost producers, OPEC saw its share of more than 80% of all oil traded internationally in the 1970s shrink to

less than half of the global oil export market by 1985. Also apparent from Figure 4.1-2 is the fall of OPEC's share of global oil production, which hit a low of 28% in 1985.

Figure 4.1-2: OPEC market share of global oil exports and production.
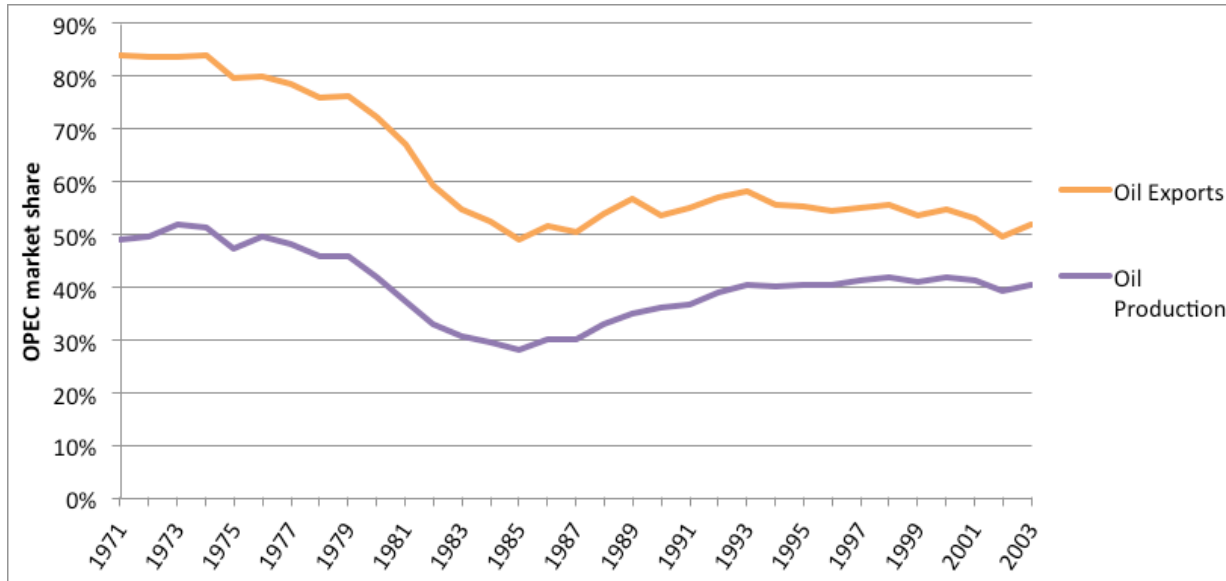
Based on crude oil, natural gas liquids, and feedstocks exports and production data from IEA World Energy Statistics and Balances 2013.

As the *de facto* lead OPEC producer, Saudi Arabia was particularly squeezed. Saudi Arabia's adherence to the official price system instituted by OPEC meant declining sales as other suppliers undercut the OPEC price on the spot market (Fattouh, 2011). By 1985, Europe, Japan, and the United States were purchasing 5.2 mb/d fewer barrels of Saudi Arabian crude oil than in 1979 (IEA, 2013c). Saudi Arabian crude oil production reached a low of 2.3 mb/d in August 1985, 8 mb/d less than the country was producing four years earlier (U.S. Energy Information Agency [EIA], 2014a). Consequently, Saudi Arabia's petroleum export revenues rapidly declined from a peak of $119 billion in 1981 to $18 billion in 1986 (OPEC, 1999). Within a few years of the second oil shock, the country had an unexpected public account deficit (Linderoth, 1992).

In late 1985, Saudi Arabia used its spare production capacity to saturate the market with cheap oil. The oil price fell by 50% over the first half of 1986 and averaged less than $15/b ($31/b in 2013$) for the year (EIA, 2014a). Within a year, Saudi crude oil exports rose by 1.5 mb/d (IEA, 2013c).

Figure 4.1-3: Oil prices (1971-2013).
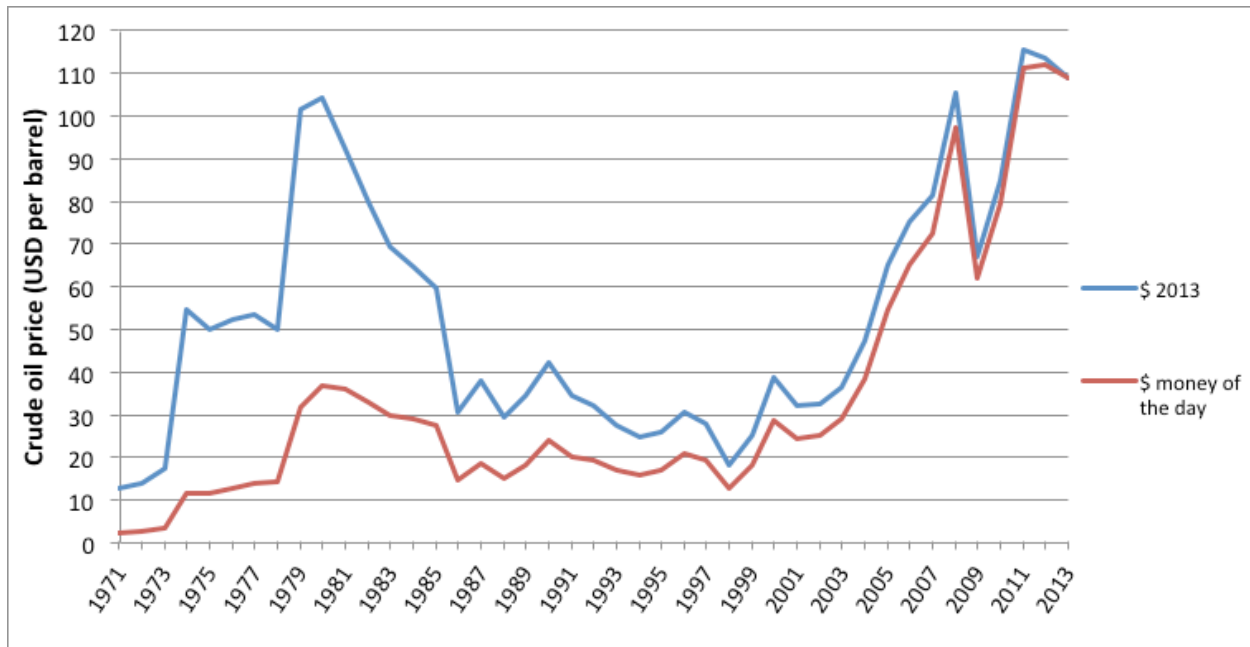
Note: Data from BP (2014). Prices from 1971-1983 based on Arabian Light and 1984-2013 are Brent prices.

As Figure 4.1-3 shows, world oil prices declined from 1981 to 1985, after the second price shock. This occurred in part by OPEC allowing small declines in negotiated prices and in part by some OPEC and non-OPEC suppliers undercutting these prices in order to retain customers in what was becoming a buyers' market. The Saudi decision to flood the market in 1986 in order to stop losing sales simply accelerated a price decline that was well underway.

By analyzing the export behavior of Saudi Arabia and the rest of OPEC, Alkhathlan, Gately, & Javid (2014) find evidence of the Saudis employing a 'tit-for-tat' strategy on several occasions in the late 1980s to encourage discipline within OPEC in regards to honoring agreed-upon production quotas.[5] By 1991, OPEC had increased its production by 8 mb/d from a low of 15.9 mb/d in 1985 and had regained some of its lost market share as shown in Figure 4.1-2 (controlling 55% of the export market in 1991) (IEA, 2013c). Oil prices did briefly increase to $33/b ($59/b in 2013$) at the onset of the Gulf War in 1990, but Saudi Arabia and other OPEC producers managed to increase output by 4.5 mb/d in six months to cover the shortfall left by Iraq and Kuwait (EIA, 2014a). Prices returned to pre-invasion levels by mid-1991 and fell to an all-time low following the Asian crisis of 1997-1998. Overall, however, prices from 1991-2003 were relatively stable at less than $29/b on average (2013$).

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[5] The tit-for-tat strategy in game theory is the simple strategy in which a player echoes what the other player did on the previous move (Axelrod, 1984). In the case of Saudi Arabia, this meant matching quota over-shipments by its OPEC partners but reciprocating when quotas were abided by.

Despite the low prices and income growth of greater than 5% per year among several Asian countries, global oil demand grew by less than 2% per year from 1986 to 2003 (an increase in consumption of about 1.2 mb/d per annum). Gately & Huntington (2002) applied an econometric model to the historic price spikes, and the 1981-1986 price decreases that followed, and found that demand in most countries is more responsive to price increases than price decreases. In other words, demand is not perfectly price-reversible– investments in energy efficient technologies and retrofits of existing capital are not reversed once prices fall back to lower levels.[6] Also potentially contributing to this asymmetric demand response to price ('elasticity') were continued government policies forcing greater energy efficiency for buildings, vehicles, and consumer appliances (Gillingham, Newell, & Palmer, 2006).

Another factor is that even though the oil price was declining in the late 1980s, it was still far above its level in 1970. It takes a long time for the economy to fully adjust to a price change because the turnover rates of some capital stocks are very long (Wirl, 1991). The vehicle stock takes about 15 years to turnover, major industrial plants more than two decades, and buildings and infrastructure even longer. Thus, oil price elasticity is higher in the long run than the short run.[7]

As global oil consumption grew slowly, but steadily, from 66.8 mb/d in 1990 to 80.2 mb/d in 2003, OPEC suppliers were able to meet more of this additional oil demand than non-OPEC producers because of their very low production costs. An EIA report from 1996 estimated that the costs for countries surrounding the Persian Gulf to develop conventional oil reserves to be as low as $0.90/b with operating expenses in the $1-2/b range (2013$). Saudi Arabia increased its production by 4.5 mb/d from 1989 to 2003 and OPEC members collectively increased their share of exports from 1986.

Entering production in the 1970s when price were high, North Sea oil is a prime example of a higher cost oil resource that was already producing oil when the price collapsed in 1986. Production growth from the principal suppliers of North Sea oil, the United Kingdom and Norway, slowed slightly in the late 1980s, but reached 6 md/d by 1996 (see Figure 4.1-4). In 1981, full-investment production costs for North Sea fields were estimated at $32-33/b (2013$), which was about $60/b below the oil price (Kemp, Hallwood & Wood, 1983). Decisions to invest were postponed when the price fell in 1986, but with the help of an ease in the tax burden, a number of technological improvements for offshore projects facilitated a reduction in the cost of adding North Sea capacity (Stevens, 1996). Plans for one such North

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[6] Also suppressing annual growth in oil demand was several western European governments increasing excise taxes on RPPs, which meant the drop in oil prices did not necessarily correspond with lower transportation costs for motorists.

[7] In the short-run, oil demand is estimated to be highly inelastic to changes in price (less than -0.1) while estimates of the long-run elasticity may be two to three times as large (Hamilton, 2009).

Sea project, the Kittiwake field, were revised between 1986 and 1987 to require only two-thirds the capital expenditure and 20% lower operating costs (Collingridge, Genus, & James, 1994) Rapid cost-cutting measures enabled the North Sea to remain a profitable investment opportunity for producers during this time of low prices, leading to continued production rate increases. Production is now, however, on a long-term decline owing to resource depletion.

Figure 4.1-4: Sum of U.K. and Norway oil production.
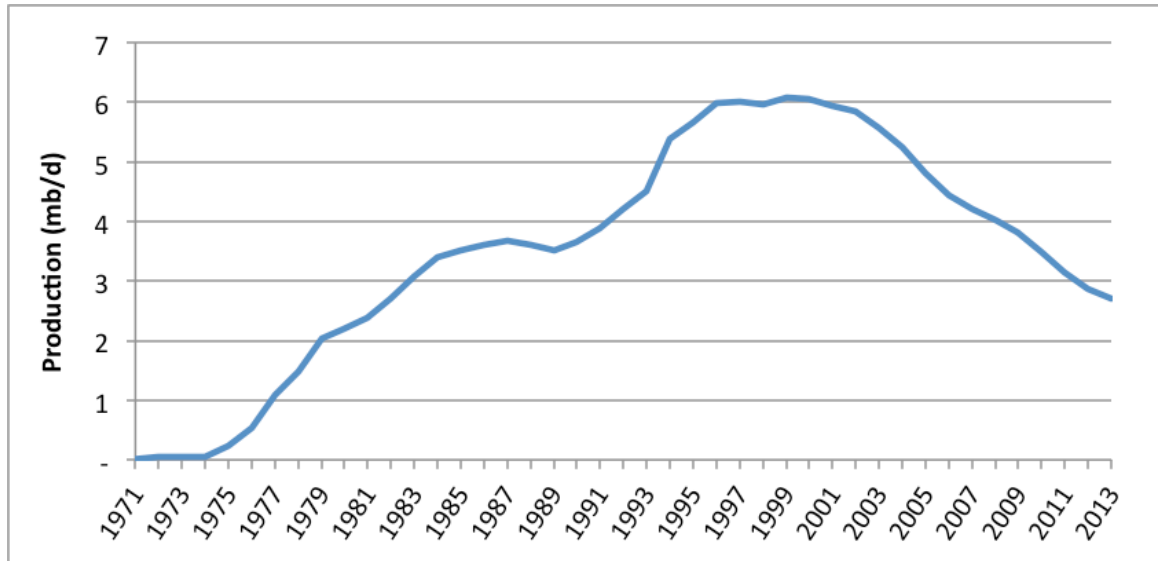
Data from BP (2014).

The Third Price Surge and the Growth of Unconventional Oil

The tightening of the oil market over the last decade has spurred production around the world. As the blue line of Figure 4.1-3 shows, oil prices leading up to and following the global financial crisis in 2009 have been as high or higher in real terms than they were during the 1979-1980 oil crisis. Although annual oil consumption is in decline or has remained flat in many industrialized countries, strong growth in energy demand among developing countries has contributed to global oil consumption increasing by more than 10 mb/d in 10 years. Hamilton (2009) examines this recent price run up and postulates that strong demand may have caused scarcity rent to become a permanent and more important factor in the price of oil than before.

The low oil prices during the mid-1980s and 1990s suppressed production growth from vast unconventional oil resources, but rising prices beginning in 2003 have improved their economic viability. Canada and Venezuela possess two of the three largest oil reserves in the world with estimates of 174 and

298 billion barrels, respectively (BP, 2014). As shown in Figure 4.1-5, oil sands production was less than 0.2 mb/d until 1985 and its rapid growth only started in the early 2000s as the oil price started to climb significantly. Production from in situ extraction methods (drilling wells and injecting steam to recover oil sands bitumen) recently surpassed the volume recovered through mining (open pit minding to extract bitumen that occurs near the surface). In 2013, oil sands production was about 1.9 mb/d.

Figure 4.1-5: Canadian oil sands production.
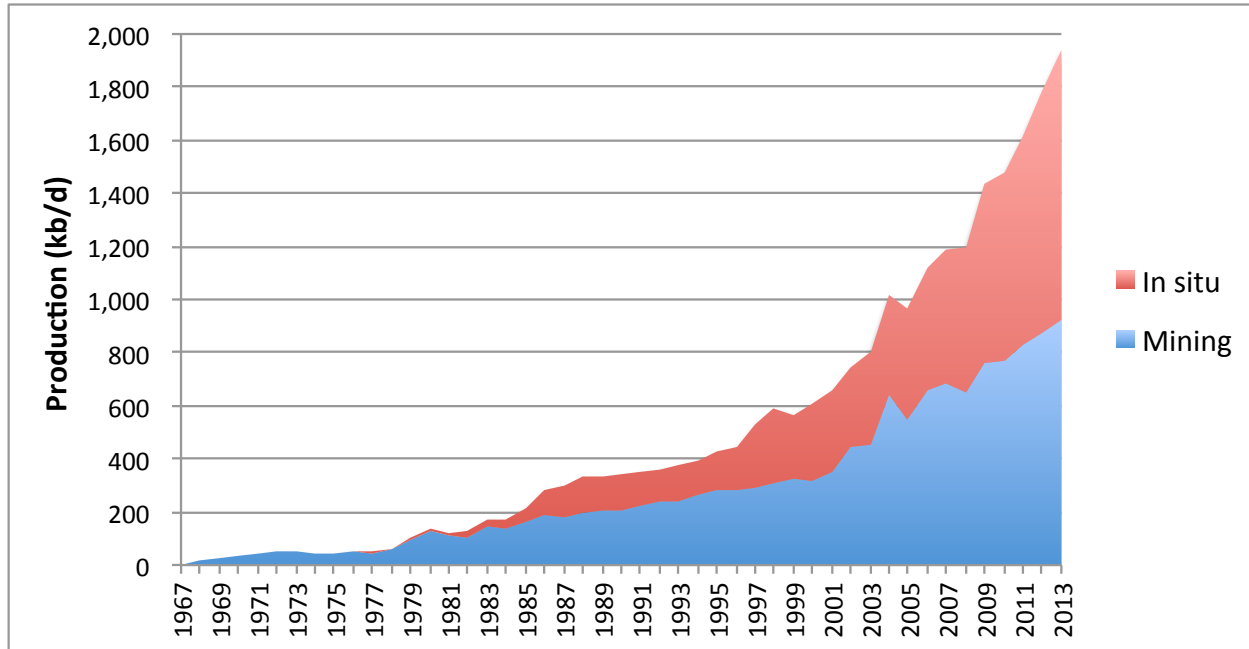
Data from Canadian Association of Petroleum Producers (CAPP) last updated April 22, 2014.

The oil sands were starting to grow before the oil price hikes because changes to provincial and federal government royalty and tax policies in the 1990s created a favorable investment climate for oil sands expansion. First, to free up capital for investment, the federal government extended to oil sands companies the ability to defer paying income tax on the income from their projects until after all capital costs had been written off.[8] Secondly, in 1997, the Alberta government applied a new generic royalty regime, which set a royalty of 25% on net project revenue after the recovery of all project costs (including 100% of capital, operating and development costs in the year incurred), and after the corporation had earned a rate of return on its investment.[9] According to the simulation modeling work of Plourde (2009), this generic royalty regime altered the distribution of oil sands economic rents in ways that strongly favored producers. In 2007, the preferential tax treatment was revoked and the royalty regime was altered.

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[8] Commissioner of the Environment and Sustainable Development, *2000 May Report of the Commissioner of the Environment and Sustainable Development, Chapter 3—Government Support for Energy Investments,* (Ottawa, Ontario: Government of Canada, 2000).
[9] Oil Sands Royalty Regulation, 1997 AR185/97

Meanwhile oil sands production had more than doubled from 1996 levels to 1.2 mb/d and the oil price had climbed to above $81/b.

The global oil price relative to the costs associated with producing bitumen for upgrading to synthetic crude oil affects the rate of growth in oil sands production. Figure 4.1-6 provides estimates of the range in supply costs (includes capital costs, operating costs, taxes, fixed royalties and a 10% real rate of return to the producer) for oil sands in situ and mining extraction methods from fifteen studies spanning thirteen years in West Texas Intermediate (WTI) equivalent oil prices.[10] While a number of other in situ techniques have been important methods of oil sands production in the past, only in situ steam-assisted gravitational drainage (SAGD) and mining supply costs are analyzed here because a vast majority of new oil sands capacity is expected to use these techniques.

Figure 4.1-6: Oil sands supply costs.
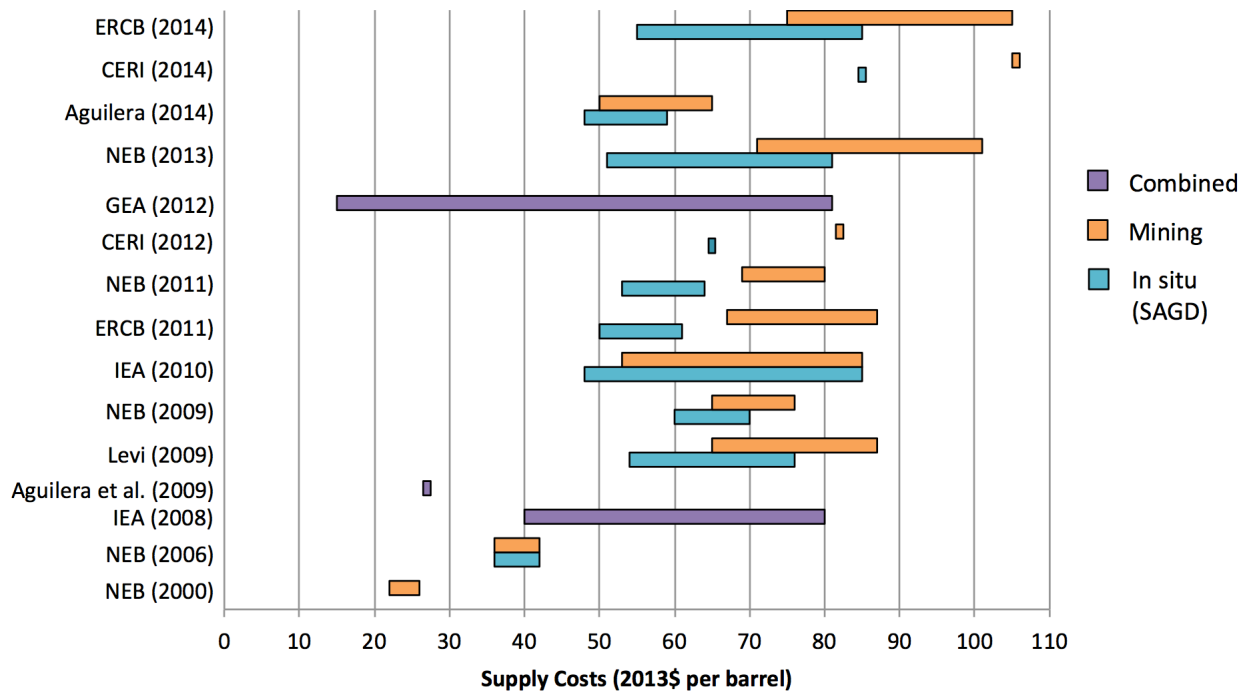
Note: Ranges from a number of research studies in ascending order of year. For combined, the distinction between in situ and mining supply costs was not made.

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[10] Supply costs do not incorporate the financial risk assessment conducted by companies to account for the potential for falling oil prices or rising costs and therefore may not be a true indication of the oil price necessary to attract oil sands investments.

Rapid investment driven by the climb in oil prices after 2002 is a major reason for the upward trend in oil sands supply costs.[11] Preceding the other studies by several years, the National Energy Board (NEB) (2000) provides the lowest oil sands supply cost estimate at $22-26/b for mining (SAGD recovery was not yet commercially proven). During the two years before this study (1998-1999), oil prices averaged $22/b. When the IEA reviewed oil sands costs in 2010, most new oil sands capacity was estimated to be profitable with oil prices in the $65-$75/b range because of "rapid cost inflation, labour shortages and saturated infrastructure" (p. 155). Oil prices in 2008-2009 averaged $86/b (roughly four times higher than 10 years earlier). Supply costs have since further escalated— with a $111/b price for oil in 2011-2012, Canadian Energy Research Institute (CERI) (2014) estimates SAGD supply costs at $85/b and mining at $106/b. The cyclical nature of costs is clear. Inverse to how North Sea oil costs declined during the low prices of the 1990s, oil sands producers since 2004 have enjoyed a period of high oil prices, which has resulted in rapid expansion and higher costs.

Based on the range in supply costs in Figure 4.1-6, it appears that if the price were to decline to the sub-$50/b level, it would likely become difficult for the oil sands to attract investment without major cost reductions. Some oil sands projects at various stages of the planning and approval process could potentially remain viable through strong downward pressure on capital costs and the removal of government royalties, but a best-case scenario for this industry would probably be the resource reverting back to pre-2002 growth rates. To account for the recent inflation of costs and the potential for governments to lower or eliminate royalties, I estimate supply costs in 2013 for this research project at $50-$80/b for in situ and $67-$97/b for mining.

In the case of Venezuela, its conventional crude oil is in a long-term decline and under-investment by its state oil company, Petroleos de Venezuela (PDVSA), has led to slow production growth from its vast heavy oil reserves. Venezuela's oil production has been consistently above 3 mb/d during Hugo Chávez's time as president, but production in 2013 is estimated to be the lowest since 1993 at 2.6 mb/d. The upgrading of extra-heavy oil remains at 0.5 mb/d (EIA, 2014b). The economy and people of Venezuela are highly dependent on oil revenues as "oil accounts for about 80% of Venezuela's exports, half of total government revenues, and one third of GDP" (Hammond, 2011, p. 356) However, PDVSA was overhauled following a strike in 2002, there has been insufficient re-investment in Venezuela's aging oil production infrastructure, and outside investment has left the country in the wake of royalty rate increases and nationalization of oil fields operated by foreign oil companies (EIA, 2014b; Hammond,

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[11] Another contributing factor is that oil sands mining began in the most choice locations (highest quality bitumen at the shallowest depths) and so new oil sands production is likely to come from more challenging areas (i.e. more remote, less geologically uniform, deeper bitumen).

2011). Despite these troubles, PDVSA has approved a number of projects in the Orinoco Belt, which could increase heavy oil production to more than 2 mb/d by 2017 (IEA, 2010). The IEA (2010) estimates that supply costs are comparable to those of the oil sands. With unconventional reserves comprising approximately 86% of PDVSA reserves, Venezuela stands to benefit from sustained high oil prices if it can raise the investment necessary to transition from a significant conventional oil supplier to an unconventional one.

Not missing the chance to benefit from high oil prices, countries with conventional oil reserves have increased their production rates to meet the unprecedented level of global oil demand in recent years. Russia's production has risen by 4.2 mb/d since 2000 to approach the 11.5 mb/d of Saudi Arabia. Oil production in the United States is also now more than 10 mb/d, in part, facilitated by advancements in light tight oil (LTO) recovery technology. In 2013, 29% of total U.S. oil production was provided by LTO. Given that the EIA (2013) recently estimated 345 billion barrels of LTO could be recovered globally using current technology (Russia, China, Argentina, and Libya were assessed to contain 161 billion barrels), there is a high long-term growth potential for LTO production, if prices support its development.

Implications for Climate Policy

There may be parallels between market developments in the period 1980-2002 and what might occur if governments achieve their commitment to limit temperatures to a 2 C rise, since this is likely to cause significant decreases in the demand for oil over a fairly short time. As Stoft (2008) argues, any international climate agreement is basically a "consumers' cartel" in the sense that, participating nations would in effect be pledging in concert to reduce their consumption of oil. The decline in oil demand following the 1979 price shock was the aggregate result of the response by consumers and industry to higher prices, heightened to some degree by the actions of governments aimed at influencing demand. Prices fell dramatically in 1986 and remained low for a decade and a half as weak demand growth combined with a surplus of supply to result in a long-term buyers' market. These historical oscillations in the oil price demonstrate the ability of spare supply capacity to lower prices in the short run and the power of demand to influence prices in the long run. If demand declines due to a global market-based approach aimed at successfully achieving the 2 C goal, relative costs of production and carbon intensities are indicators of how this global effort will affect the production rates of different oil resources.

4.2 Expert Modeler Inquiry

Responses to the initial survey and follow-up questions were received from six modeling groups and included information on the level of fossil fuel resource disaggregation within the models, data related to oil price and production trajectories in a 2 C scenario, as well as discussion of some of the modeling assumptions driving certain 2 C scenario results. Particularly telling from this survey information is the differences among the models in how oil prices are determined, which is an important consideration for addressing this project's central research question of which resources are likely to meet oil demand to 2050 if governments take action to limit the global rise in temperatures to below 2° C.

Table 4.2-1 includes the names of the six models and teams that replied to the survey as well as basic information about the number of regions and oil resource categories present within recent versions of the models. Accompanying is cumulative oil consumption forecast in the baseline (no climate policy) and 450-FullTech (climate stabilization at 450-ppm CO_2-equivalent concentration by 2100 and all technologies included) for five of the six models that participated in EMF27.

Table 4.2-1: Survey model information and cumulative oil consumption from EMF27 scenarios.

Model	Institute	Regional Representation	Oil Categories	Cumulative Oil Consumption (2010-2100) in billion barrels[12]	
				Baseline	450-FullTech
EPPA	MIT	16 regions	Conventional, extra-heavy, oil sands, and oil shale	-	-
GCAM	PNNL	14 regions	Conventional/ unconventional	3,548	2,574
MESSAGE	IIASA	11 regions	Conventional/ unconventional	4,141	1,605
POLES	EnerData	57 demand regions and 80 supply regions	Six (including oil sands/ extra-heavy oil)	3,066	2,260
ReMIND	PIK	11 regions	Region-specific extraction cost curves with different grades	3,011	2,006
WITCH	FEEM	12 regions	Supply cost curve with resources differentiated according to seven categories based on Rogner (1997)	4,337	1,962

Abbreviations: MIT (Massachusetts Institute of Technology); PNNL (Pacific Northwest National Laboratory); IIASA (International Institute for Applied Systems Analysis); PIK (Potsdam Institute for Climate Impact Research); FEEM (Fondazione Eni Enrico Mattei).

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[12] The amount of oil produced to date is approximately 1,136 billion barrels.

The six models each possess between 11 and 16 regions with the exception of POLES. Most of the models do not explicitly differentiate individual oil resources. WITCH employs a supply cost curve with seven categories from Rogner (1997), which has conventional and unconventional categories further divided into reserves, resources, and undiscovered resources. Likewise, ReMIND does not distinguish specific resource deposits, but rather has economic resource grades for each region. The oil grades in ReMIND are characterized by lower and upper costs, total recoverable amount, adjustment costs, decline rate and extra emissions of CO_2 from mining. GCAM and MESSAGE both have a simple division between conventional and unconventional oil whereas updated versions of EPPA and POLES represent individual oil resource categories with unique production costs. All of the models show significant difference between the amount of oil consumed in a 2 C scenario and the quantity consumed with no restrictions on emissions to 2100. On average, these five EMF27 models show about 1.5 trillion less barrels of oil demand in the 450-FullTech scenario than the baseline over the course of the century.

The models surveyed vary widely in how oil market prices emerge. Oil prices in WITCH develop endogenously through a fixed factor, a module that reflects the exhaustibility of oil, and by mimicking scarcity rent through a short-term cost-adder that increases production costs when demand rises too fast. POLES endogenously calculates fossil fuel prices to balance supply and demand, compares import and export capacities for each market to determine prices in the following period, includes a mechanism intended to mimic the behavior of OPEC as a strategic producer; however, oil prices in the long term depend primarily on the relative scarcity of oil reserves (i.e. reserve-to-production ratio). For ReMIND, flow constraints drive prices higher than would be suggested by the long-term oil extraction cost curves, which results in various grades being exploited at any given point in time. Oil price formation in GCAM is through a fixed mark-up over production costs with the initial period calibrated to historical prices. Total quantities of producible oil and assumptions on the technological progress of extraction technologies have a strong influence on the price level in MESSAGE. Transportation costs are a factor in oil prices for MESSAGE, POLES, and ReMIND and all of the models feature long-run extraction cost curves as part of price formation.

Since the cost of extraction is a major component of oil prices for the models, I created Figure 4.2-1 to illustrate the general change in costs as a function of cumulative consumption for four of the surveyed models. ReMIND shows a quick rise in the costs of oil extraction once 1.5 trillion barrels have been produced. Comparing with the cumulative oil consumption in Table 4.2-1, extraction costs in 2100 would be approximately $118/b for the baseline scenario and $62/b for 450-FullTech. The other three models show more modest extraction cost increases with cumulative consumption. GCAM has the highest projection of oil consumption in the 450-FullTech scenario, but extraction costs for the marginal

barrel in 2100 would still be lower than ReMIND and WITCH. MESSAGE assumes plenty of oil can be extracted at low cost as approximately 700 billion barrels are shown to have extraction costs below $10/b. Thus, a somewhat surprising finding is that there is variance in how oil prices are treated in the surveyed models and also in extraction costs, which are a major component of price formulation for many of the models.

Figure 4.2-1: Extraction cost curves.
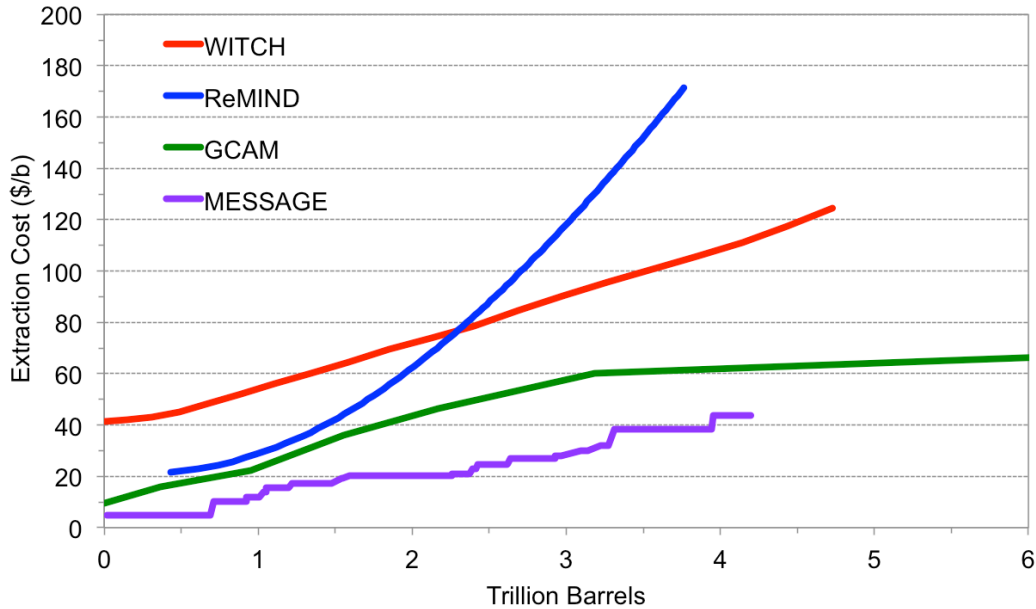
Two modeling teams supplemented their responses to the questionnaires with oil production and price pathways consistent with the 2 C target. While my focus in this study is on the oil market to 2050, these scenarios extend to 2100. I present the model projections to 2100 below to demonstrate the potential long-term outlook for oil production under a 2 C climate constraint, but recognize the increased uncertainty associated with modeling energy markets in the more distant future.

The FEEM modeling group made available the WITCH 2 C scenario data used to create Figure 4.2-2 showing oil as a primary energy source peaking in 2025 and then declining to 63.3 mb/d in 2050. Over the first half of the century, the oil price appears to be unresponsive to the change in oil demand as the price falls by $5/b at the introduction of the carbon price in 2015 and recovers slightly by 2020, but then does not deviate in either direction by more than $2/b from the $60/b level to 2050. However, this relatively stable oil price trajectory is the result of the countervailing effects of declining demand, which by itself would push the oil price down, and increasing costs of extraction as consumption depletes the lower cost resources on the upward sloping supply curve, which by itself would push the oil price up.

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After 2050, oil demand continues its steep decline (reaching less than 10 mb/d in 2080) and the oil price averages $66/b to 2100 as remaining demand is increasingly supplied by higher-cost, unconventional sources. Prices are much lower in this 2 C scenario than in a WITCH scenario with no constraint on emissions (Massetti & Sferra, 2010). Because WITCH differentiates resource categories based on grade, the model does not possess a high enough resolution of the oil supply sector to gauge the impact of 2 C climate policy on oil sands.

Figure 4.2-2: WITCH oil consumption and oil price in 2 C scenario.
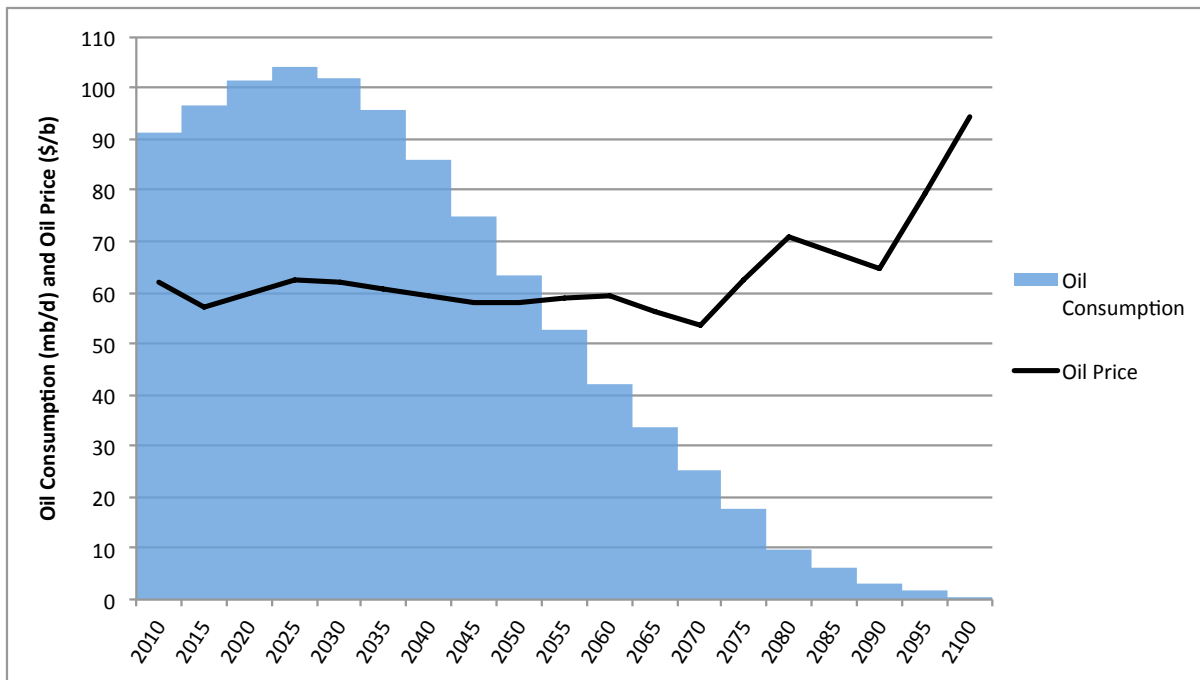
The EnerData modeling team provided the POLES data used to create the graphs in Figure 4.2-3, which show emissions from the major economic sectors on the left and oil prices, conventional oil production, and unconventional oil production on the right. The three scenarios are Baseline (no carbon pricing), a 2 C scenario (450-ppm), and a 2 C scenario with CCS in electricity unavailable. Emissions in the Baseline steadily increase and are 16 times higher than the 450-ppm scenario in 2050. These emission reductions are partially achieved through less oil use as conventional oil production is 35.9 mb/d higher, and unconventional production is 6.6. mb/d higher, in the Baseline than the 450-ppm scenario. For the 450-ppm scenario, oil production peaks at 89 mb/d in 2020 and declines by 29% during the following 30 years. Without CCS in electricity, oil production must decline even more rapidly (28.6 mb/d in 2050), as it is more costly to reduce emissions in the electricity sector and there is no prospect of having negative emissions through bioenergy with CCS. Global unconventional oil production between the two 450-ppm scenarios differs by less than 0.4 mb/d in 2050 with the 4 mb/d mark in the 450-ppm scenario not being

Figure 4.2-3: POLES scenarios results.
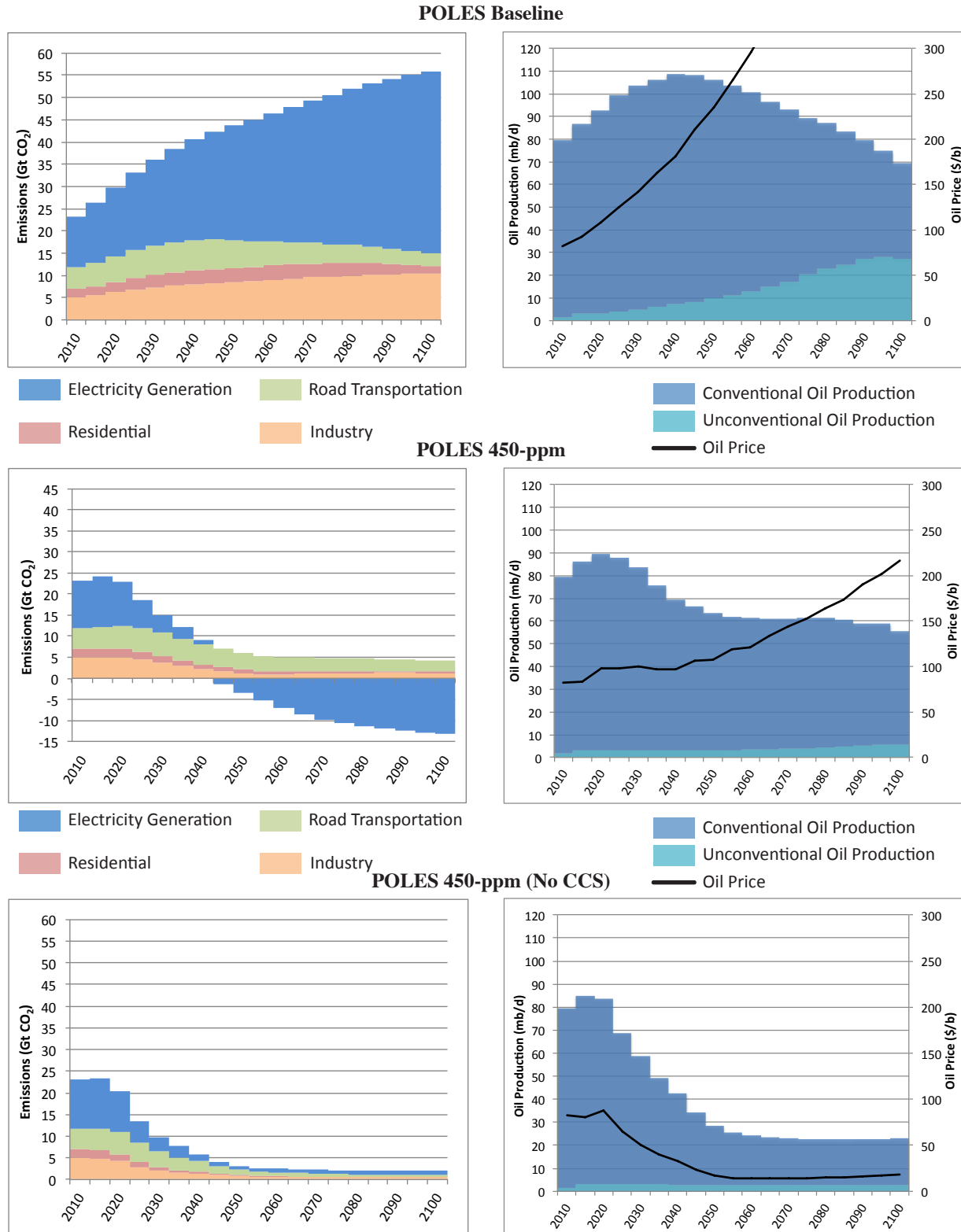
Notes: Origin of vertical axis for emissions of 450-ppm scenario is negative due to biomass production with CCS. Oil price in POLES Baseline rises higher than $300/b vertical axis after 2060.

surpassed until 2075.

Also apparent from Figure 4.2-3 is the link in POLES between future oil production and future oil prices. Oil prices in the 2 C scenario with CCS in electricity as an option are 31% higher in 2050 from 2010 and decline by 79% with no CCS over the same period. If no climate policy is pursued (Baseline), POLES forecasts oil prices climbing to $235/b in 2050. In the second half of the century, the POLES model shows oil prices that are far above the information that experts have provided on the cost of viable substitutes to depleting conventional oil (Jaccard, 2005; GEA, 2012). For instance, the process of converting coal to liquid fuels can allow coal to be used as a substitute for oil at costs below $100/b and these plants are already in commercial operation in South Africa and China (IEA, 2013d). The POLES model lacks such a backstop technology to replace oil for transportation and industrial uses, contributing to the implausible price forecast shown. Although a leading EEE model, I do not use these POLES price forecasts to inform my analysis because if conventional oil becomes increasingly scarce causing the price to rise well above $100/b, there are readily-available alternatives that could displace oil to some degree and cost-competitive unconventional oil (oil sands, LTO, extra-heavy oil) that is already in production at levels more than 2 mb/d greater than the 3.3 mb/d shown for the 450-ppm scenario in 2050. Still, these three POLES scenarios do highlight the general downward effect that 2 C climate policy might have both on oil prices and oil production, especially unconventional oil. Further, these effects are amplified if CCS in electricity is unavailable as emission reductions are forced to come from transportation, which suppresses demand for RPPs and therefore oil.

One of the lead modelers at the IEA explained in their response to the survey why oil sands production in its 2 C scenario from World Energy Outlook (2010) is estimated at 3.3 mb/d in 2035. The IEA's World Energy Model is informed by analysis of the investment decisions undertaken on a project-to-project basis and includes a component that restricts production from resources near the bottom of the supply cost curve. This can leave a gap in demand that resources higher up the supply curve then compete to fill, and is signaled by a price increase. Since the oil price in its 2 C scenario is $116/b in 2020 ($4/b lower than if 2 C climate policies are not adopted) and $109/b in 2035, oil sands projects already producing, or soon to enter production, are able to absorb the extra costs of carbon pricing and continue to produce because their capital expenditures are sunk (IEA, 2013b). In effect, with oil prices remaining above $100/b and the carbon price causing only a small increment in the cost per barrel supplied for oil sands producers, the IEA expects that oil sands production will grow slowly to 2035 in a 2 C climate policy scenario.

The discordant 2 C oil price forecasts suggests considerable uncertainty about the future price of oil and further refinement of the price determination components of most models is likely required before price estimates under such a shock can be considered credible. As part of EMF27, McCollum et al. (SM, 2013a) also recognize the differences in fossil fuel price formulation methods and resulting price discrepancies, noting that the price response to climate policies appears to be ambiguous across models at least with the work completed to date. The difficulty is that the effects a decline in demand for oil would have on its price is contingent on a host of factors. The future price depends on (1) rate of depletion, (2) ability with innovation and discovery to shift conventional and unconventional oil resources into oil reserves, (3) ability with innovation and investment to develop backstops (energy and technology substitutes for oil), (4) willingness of consumers to pay a premium for oil from politically-stable suppliers, and (5) effect of climate policy on RPP prices which feeds back upon the oil demand and thus the oil price through the interplay of the above factors. The impact of these factors on price can vary over time as well.

But the relative influence of these price determinants can be stated with some confidence and there are certain aspects of the oil market that are well accepted. There is a long-run floor and ceiling to oil prices. Production costs for the least costly conventional oil are about $20/b, and therefore prices below this level probably cannot be sustained. At the other extreme, prices much above $150/b are unlikely in the foreseeable future given the immense availability of oil and potential substitutes (GEA, 2012). Between the floor and ceiling, low prices can occur during a buyer's market (if innovation, discovery and substitution are causing a supply surplus) and high prices can last if demand growth is outstripping supply (a seller's market). I have constructed a set of global oil supply curves for this research project to disentangle the dynamic effects of the key factors expected to influence oil prices during a buyer's market caused by 2 C climate policy. This technique allows me to estimate an oil price trajectory consistent with the 2 C target and assess the economic viability of the oil sands and other unconventional oil resources to the year 2050. However, as part of this graphical approach, it was first necessary to attain robust modeling data detailing the cost-effective rate at which emissions in the major energy sectors would decline, and what this means for future global oil demand, in order for my analysis to be based on an accurate representation of the economy and hence, how this low-carbon transition would unfold.

4.3 Graphics Technique

I used the scenarios database containing long-term scenarios reviewed in the AR5 of Working Group III of the IPCC to gather sectoral GHG emission reduction, primary energy supply, and carbon price

projections. A majority of the scenarios in this database are results from multi-model comparison studies that explored the 2 C target of which results from AMPERE, EMF27 and LIMITS are analyzed here.[13] To provide broader context for oil supply in a 2 C scenario, I first examine the range at which emissions in the main energy-transforming and energy-consuming sectors are forecast to decline as well as the corresponding change in the global energy supply mix. Following this comparison of shifts in emission and primary energy, I analyze the impact of technology assumptions on oil supply and the carbon price levels estimated to be required for meeting the 2 C target. My use of oil demand and carbon pricing data generated by independent modeling teams operating state-of-the-art models helps to ensure that this step in assessing the viability of individual oil resources in a 2 C scenario is impartial and up-to-date.

Sectoral Emission Reductions

The rate at which models expect emissions to decline in the four major emission-emitting sectors of the economy in 2 C scenarios with full technology availability is indicative of the relative costs of emission abatement in each sector. As evident from the boxplots in Figure 4.3-1, the electricity generation sector is considered likely to decarbonize at a faster rate than the transportation, industry, and residential and commercial sectors. This finding is consistent across the modeling studies. From 2010 to 2050, AMPERE indicates a median decline in electricity emissions of 92%, EMF27 has a median reduction of 118% (-2,035 Gt CO_2 in 2050), and LIMITS of 115% during this 40-year timespan.

Compared to 2010, most of the models show emissions from the transportation sector slightly increasing to 2030 before beginning to decline. For the period 2020 to 2050, median transportation emissions for EMF27 and AMPERE decline from 6.9 Gt to 5.3 Gt and from 7.3 Gt to 6.7 Gt, respectively. From 2010 to 2050, LIMITS' median global emissions from transportation actually increase by 1 Gt in its 450-StrPol forecast in which there is fragmented, yet effective, action until 2020 at which time global climate policy is adopted to stabilize GHG concentrations at 450-ppm by 2100. It is important to note that this increase in transport emissions for LIMITS is still much lower than in the absence of climate policy as median emissions in 2050 are 4.5 Gt lower relative to its baseline scenario.

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[13] Energy trends and emission trajectories of the scenarios designed for the model comparison studies and analyzed here are consistent with the 2 C target as atmospheric GHG concentrations are stabilized at roughly 450-ppm CO_2 equivalent in 2100, which are likely to maintain warming below 2° C (IPCC, 2014). Overshoot of this forcing target before 2100 is allowed.

Figure 4.3-1: Ranges in global CO₂ emissions for 2 C scenarios from three EEE modeling studies.
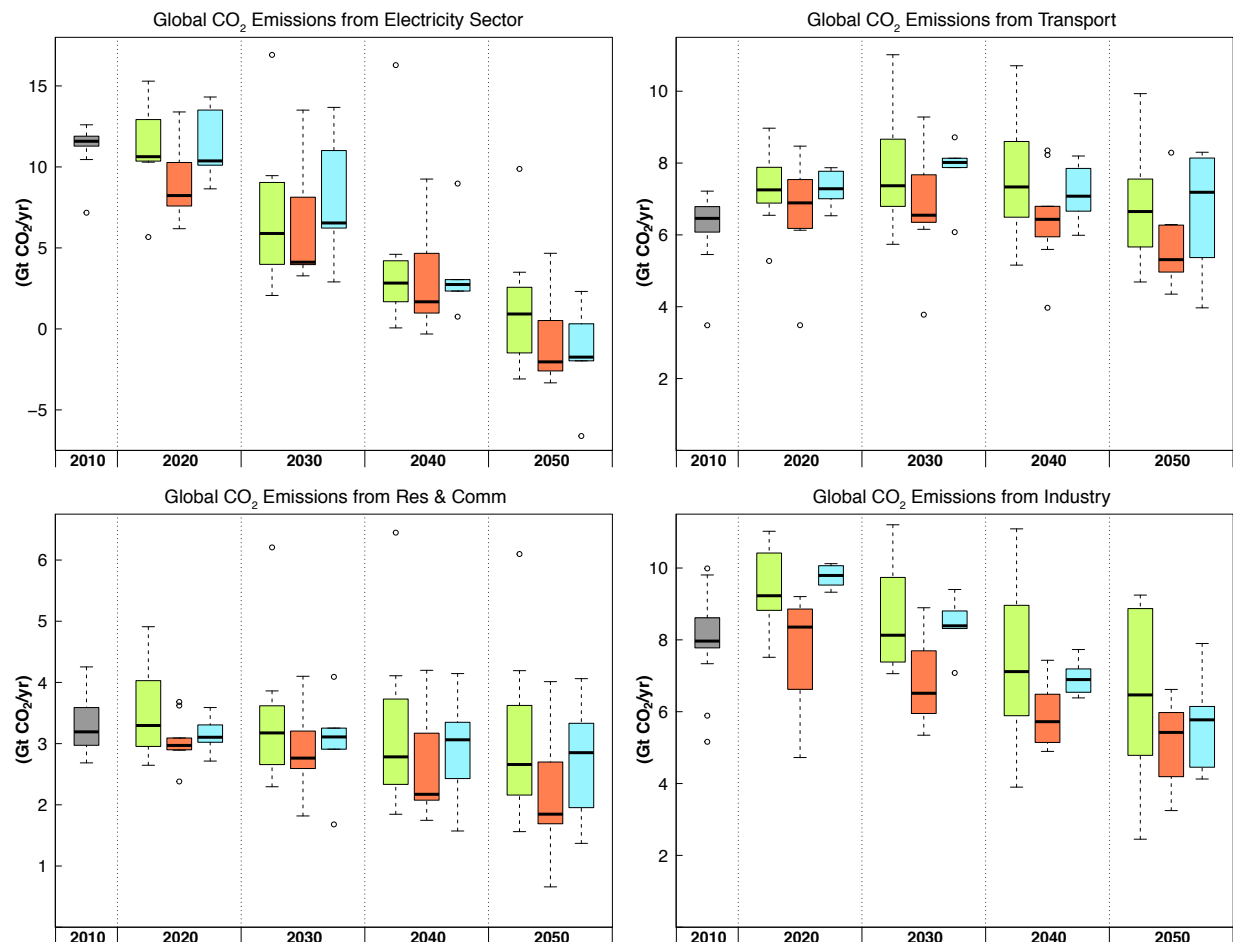
Note: Boxplots are for electricity generation *(top left)*, transportation *(top right)*, industry *(bottom right)* and the residential and commercial energy end-use sector *(bottom left)*. Boxes show emissions at outliers *(open dots)*, lower and upper extremes, 25th percentile, median *(black center line)*, and 75th percentile as forecasted by models in the AMPERE study *(green)*, EMF27 study *(orange)*, and LIMITS study *(blue)*. Grey boxplot is 2010 emissions for all three modeling studies. Only models that reported emissions in electricity and major end-use sectors at AR5 Scenario Database are included in boxplots sample (see Appendix A for list).

Emissions from industry differ more widely within the modeling studies and the decline in emissions from the residential and commercial sector is minimal. EMF27 industry emissions range from 4.7 Gt CO₂ to 9.2 Gt CO₂ in 2020 (the first year in which most models begin global carbon pricing) and AMPERE industry emissions range from 3.9 Gt CO₂ to as high as 11.1 Gt CO₂ in 2040. However, the average decline in industry emissions from 2010 to 2050 for the medians of these three model comparison studies is 2.2 Gt CO₂. Median emissions from residential and commercial energy end-use, which includes building space heating and air conditioning, are only about 3.2 Gt of CO₂ in 2010, but do decline in response to 2 C climate policy to reach 2.7 Gt for AMPERE, 1.8 Gt for EMF27, and 2.9 Gt for LIMITS by 2050.

Primary Energy Changes

To meet global energy demand with a 2 C constraint on GHG emissions, the models suggest the amount of primary energy supplied by lower emission energy sources will increase as fossil fuel energy decreases. Figure 4.3-2 is a set of pie charts showing the average global primary energy mixes in 2 C climate policy scenarios from the three model comparison studies for 2030 and 2050. Fossil fuels lose their current 82% dominance of the global primary energy supply mix, but the application of CCS to coal and natural gas point source emissions keeps fossil fuels at 54-62% of total energy in 2050. To achieve deep emission reductions, the burning of coal without CCS is roughly cut in half by 2030 and drops to 30 EJ in 2050 according to the mean results from the EMF27 450-FullTech scenario. Less primary energy comes from oil too. LIMITS shows oil declining by 23% (a decline of approximately 20 mb/d to reach 65 mb/d in 2050) and the mean decrease for EMF27 is about 25%. Natural gas is the only fossil fuel source that increases in supply to 2050; the mean gas projection results from LIMITS suggest an increase of 31% from 2012 levels and AMPERE of 40%. Importantly, 26% of total natural gas consumption in EMF27 has CCS by 2050.

Supplying 1% of global energy in 2012, the contribution from new renewables (primarily wind and solar) increases about tenfold for all of the modeling studies. The modeling studies also suggest biomass will increase in the electricity sector along a cost-effective 2 C pathway to represent 24-27% of global energy in 2050. Of this electricity generated through the burning of biomass, almost half is equipped with CCS to produce negative emissions according to the average EMF27 results. Nuclear does not represent more than 6% of energy consumption in any of the mean results, but because the global energy system grows, nuclear sees an absolute increase of approximately 30% by 2050 from 2012 levels.

Figure 4.3-2: Pie graphs of current and 2 C scenario global primary energy mix.
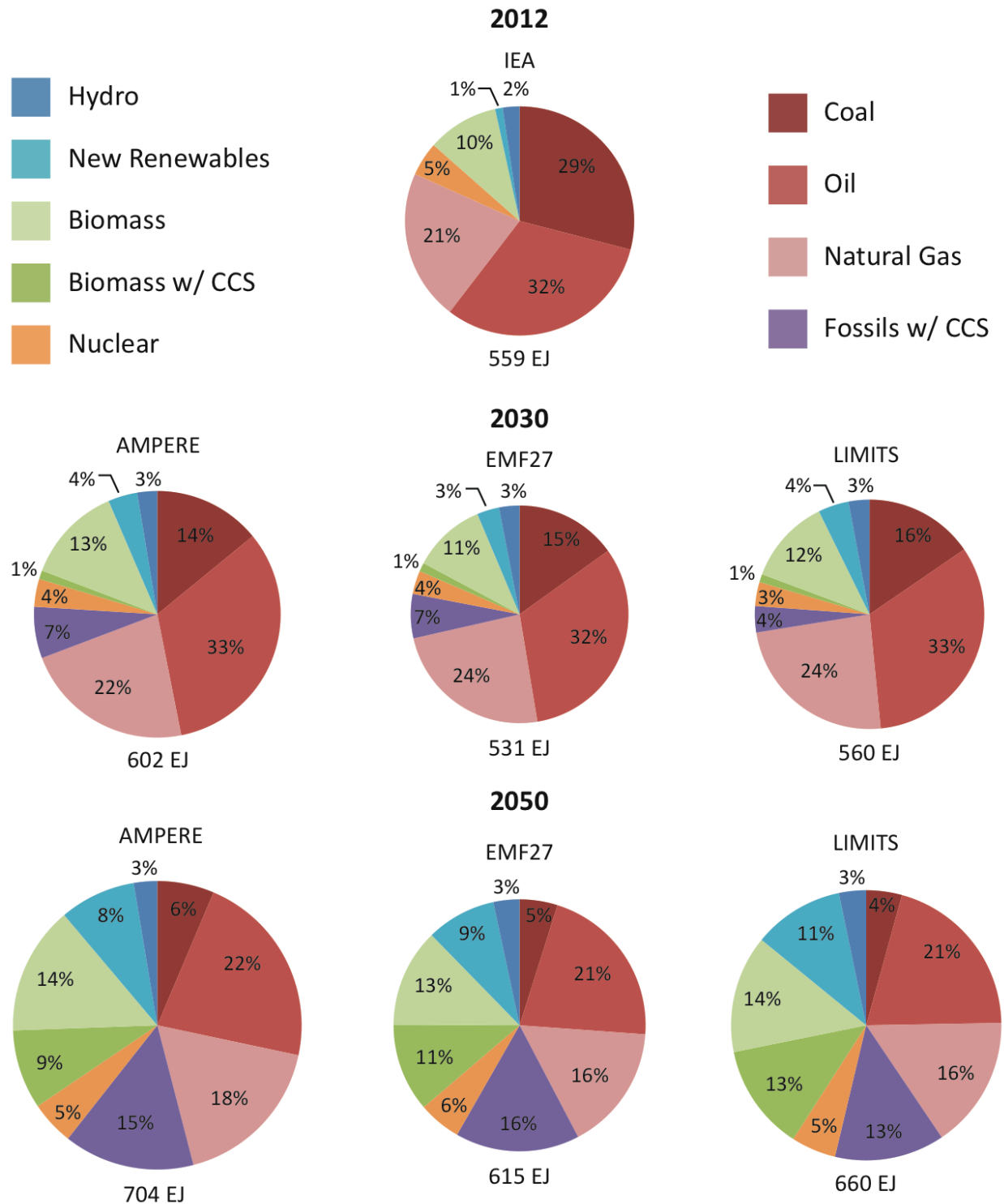
Note: 2012 data from IEA (2014) and 2 C scenario averages from AMPERE, EMF27, and LIMITS modeling studies for 2030 and 2050. Size of pies is relative to total global energy in each projection *(value beneath each pie)*.

Global Oil Supply

The average global oil supply results for six scenarios from EMF27 are shown in Figure 4.3-3. As is apparent, the 450-ppm scenarios have lower oil supply than the less stringent 550-ppm climate policy and Baseline scenarios. As well, modifying the technology assumptions of the models for the 450-ppm scenario results in less oil supply than if all technologies are assumed to be available. The most drastic impact on oil supply from the sample of technology modification scenarios shown is the elimination of CCS as an option in electricity generation and other sectors (450-NoCCS) as average oil supply is 21.9 mb/d less in 2040 than the 450-FullTech (with CCS enabled) scenario. Both limiting the amount of biomass supply (450-LimBio) to a fixed amount per year as well as constraining the proportion of electricity generated from solar and wind (450-LimSW) requires marginally greater reduction of oil consumption. With fewer emission-minimizing technologies available and less energy from renewables, humanity must reduce global emissions through reducing oil demand. The difficulty in matching energy demand with a limited number of energy technology alternatives is demonstrated by the fact that many of the models in EMF27 were unable to meet the 450-ppm target if there were critical technology constraints, simply because it became infeasible for the model to solve or the carbon price rose to unrealistically high levels (only six of the eighteen participating models reported primary energy supply levels for 450-NoCCS).

Figure 4.3-3: Mean global oil consumption mean results from EMF27.
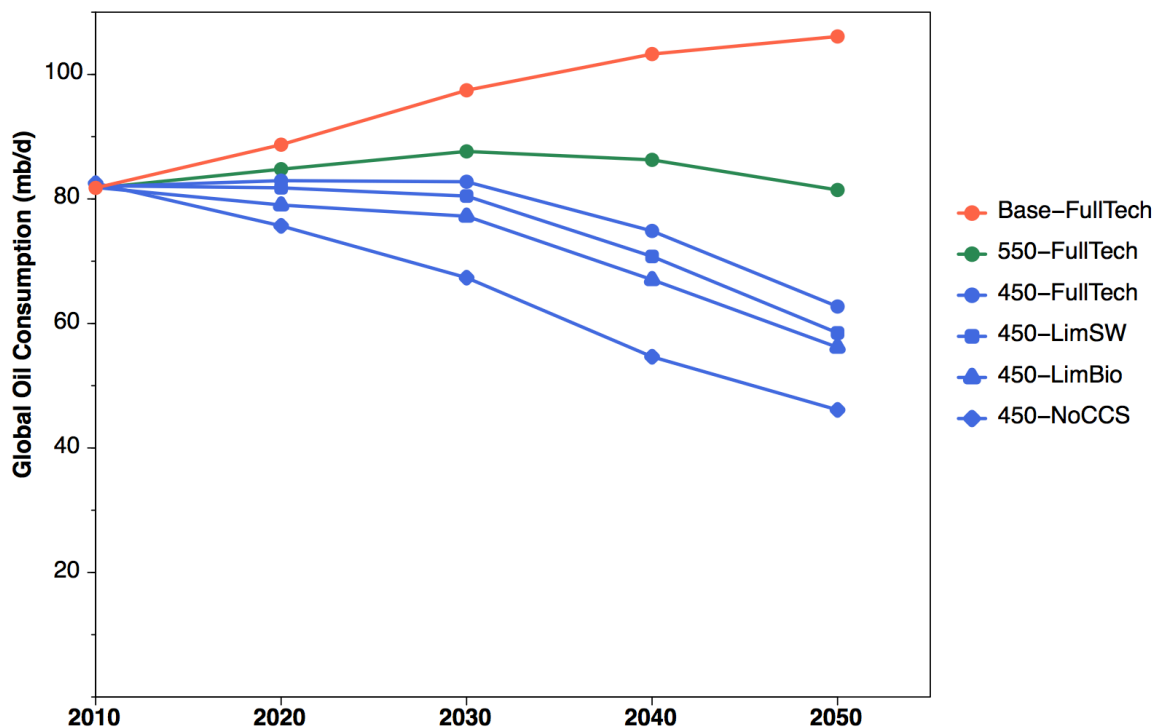
The mean results from the 13 EMF27 models that reported primary oil consumption for the 450-FullTech scenario forms the basis for future oil demand in this research project. Figure 4.3-4 shows the spread and skewness of the data through boxplots for each future model period. The median and lower quartile (25th percentile) results show the pace of the decline in global oil demand from 2030 to 2050. The upper quartile (75th percentile) and maximum oil demand values peak in 2030 at 96.7 mb/d and 107.2 mb/d respectively before declining. These high near-term oil demand forecasts are possible because the models with the three highest average oil demand projections from 2020 to 2050 (WITCH, ReMIND, and GCAM) each forecast emissions from the electricity sector being negative by 2060, which would offset a portion of the higher emissions from oil consumption to stay within the 2 C carbon budget. Two mild outlier values exist in the 2050 oil demand data, which are 23.6 mb/d (2.0 SD below mean) and 98.7 mb/d (1.8 SD above mean). Since the EMF27 450-FullTech data does not appear to be skewed, the mean values for each period are the most appropriate measure of central tendency and therefore are used to inform the rate of future oil demand in the 2 C scenario for this research project.

Figure 4.3-4: Range in modeled oil consumption for EMF27 450-Fulltech scenario.
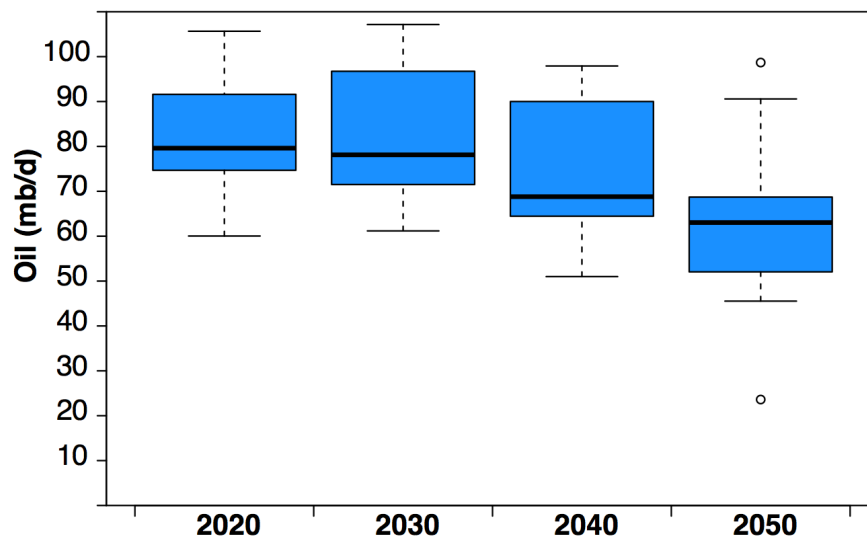
However, because oil production in 2013 was 86.8 mb/d, which is 4.9 mb/d above the EMF27 450-FullTech mean for 2010 (the base year for many of the models) and 3.9 mb/d above the 2020 mean, some adjustment was necessary to more accurately represent how the supply side of the oil market would respond to 2 C climate policy. For example, simply taking the 450-ppm FullTech mean value for the year 2020 would produce an unreasonable oil demand projection because that would imply oil demand already peaked between 2014 and 2020 and started to decline before the first year of carbon pricing in 2020. To better integrate higher recent oil production information with the model projections, oil demand between

2013 and 2020 in my 2 C scenario grows at the same annual rate as forecast by the models for the period 2010-2020.[14] This causes oil demand to still peak in 2020, but as is displayed in the comparison Table 4.3-1, oil use then declines more rapidly to match the 450-FullTech mean in 2030. Oil demand in 2040 and 2050 in this project's 2 C scenario is equal to the 450-FullTech mean values as well.[15]

Table 4.3-1: Oil demand comparison (mb/d).

	2010	**2013**	**2020**	**2030**	**2040**	**2050**
450-FullTech mean	81.9	-	82.9	82.8	74.9	62.7
2 C scenario for supply curves	-	86.8	87.5	82.8	74.9	62.7

Carbon Pricing

In the EMF27 study, the 450-ppm carbon price levels are calculated in an idealized scenario of global emissions pricing. As apparent from Figure 4.3-5, there is a substantial variation across the models in the level of carbon pricing necessary to achieve economy-wide emission reductions consistent with the 2 C target.

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[14] Strictly speaking, it may be necessary to compensate for higher recent and near-term oil consumption through deeper emission reductions from other sources, or even lower oil consumption post-peak, in order to stay within the 2 C carbon budget. Nonetheless, the oil demand forecast used in this analysis remains consistent with the EMF27 450-FullTech model projections while incorporating the most recent global oil production estimates.
[15] In its latest 450 scenario, the IEA (2014) shows a similar world oil demand projection. The IEA projects demand in 2020 being 93.4 mb/d, but its oil demand in 2040 is 3 mb/d lower than my 2 C scenario.

Figure 4.3-5: 450-FullTech carbon prices as modeled by 13 EMF27 models.
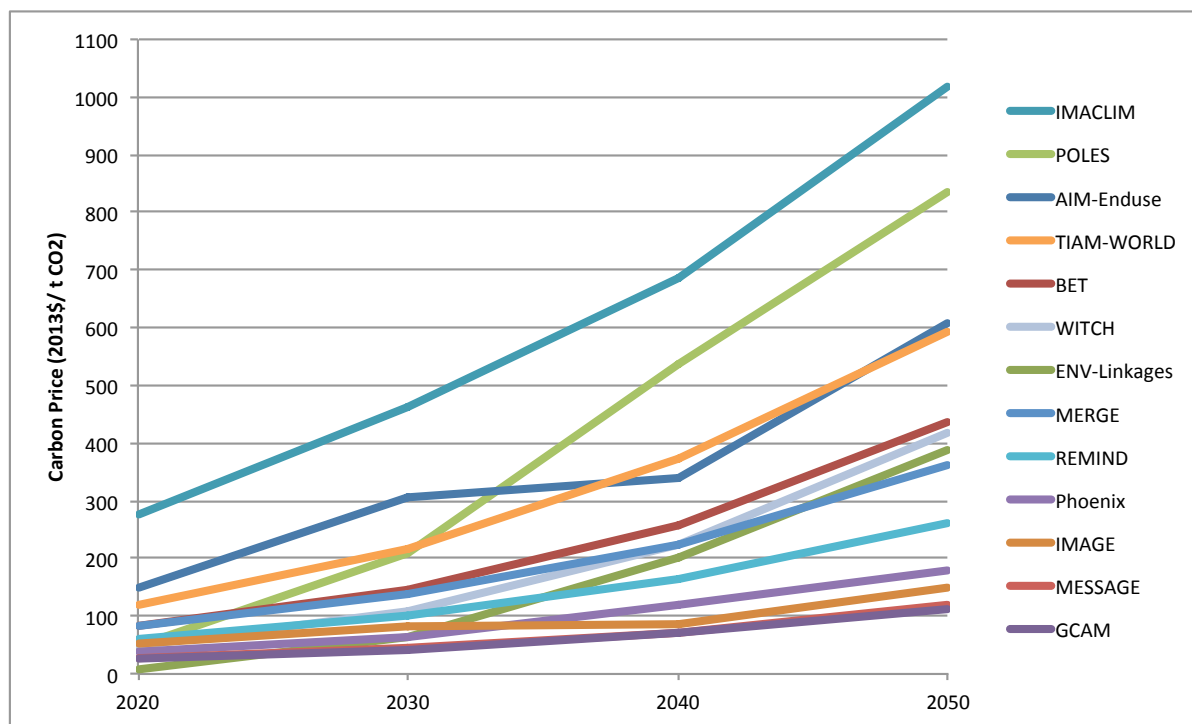
The difference in carbon pricing is a result of differences in model structure and assumptions, particularly those relating to the flexibility of decarbonizing energy use through technological change and emission mitigation costs for fossil fuel energy use. IMACLIM, POLES, AIM-Enduse, and TIAM-World each show 2 C carbon pricing above \$500/ t CO_2 in 2050. The need for this level of carbon pricing to achieve 2 C is indicative of these models' restricted portfolio of low-carbon technological and fuel options as well as imperfect foresight. My earlier analysis of the POLES model and its apparent lack of a backstop technology provides an example of the kind of model assumptions that can lead to such a price disparity. The majority of models expect emissions reductions consistent with 2 C could be achieved at significantly lower economic costs due to low- and zero-carbon alternatives becoming viable in most sectors and economy-wide feedbacks reducing fossil fuel demand. To ensure the very high carbon prices do not skew my analysis of the effect of carbon pricing on supply and operating costs upward, the median carbon price values (shown in Table 4.3-2) are adopted for this project as part of estimating the viability of individual oil resources in a 2 C scenario.

Table 4.3-2: Carbon price consistent with 2 C climate policy for graphics technique.

Carbon Price (\$/ t CO2)	2020	2030	2040	2050
450-FullTech median	52	109	224	388

Oil Supply Curves and Operating Costs

I present two oil supply cost curves below to express the logic behind my 2 C oil price projection. The first shows total resource availability and contrasts this with the amount humanity is likely to consume to 2100. The second oil supply curve represents how the oil market is currently structured in terms of daily production volume. The information contained within these graphs is used in the future-period supply curves included in the results chapter, which form the basis for my assessment of the viability of individual oil resources under 2 C climate policy.

Figure 4.3-6 is a traditional oil supply cost curve that I created to assess the overall availability of individual oil resource categories. Based on recoverable quantity and cost estimates from Aguilera (2014), IEA (2013d), and BP (2014) this oil supply curve illustrates the supply costs for a number of oil resource categories. By situating the mean oil cumulative consumption for the EMF27 450-FullTech and Baseline scenarios as vertical lines, it shows that the amount of resources available far exceeds the estimated cumulative amount of oil to be consumed from 2010 to 2100. The resource-to-production ratio for each resource category is simply the amount of remaining oil estimated to be technically recoverable divided by the amount produced per year. These indicate that at current production levels, the resource base for every resource type included is likely to be sufficient well past 2050. Even continuing to produce conventional oil at a constant rate of 75 mb/d would not deplete its resource base until 2112, assuming the entire resource is accessible and economically viable. Oil resources are plentiful.

Figure 4.3-6: Traditional oil supply curve.
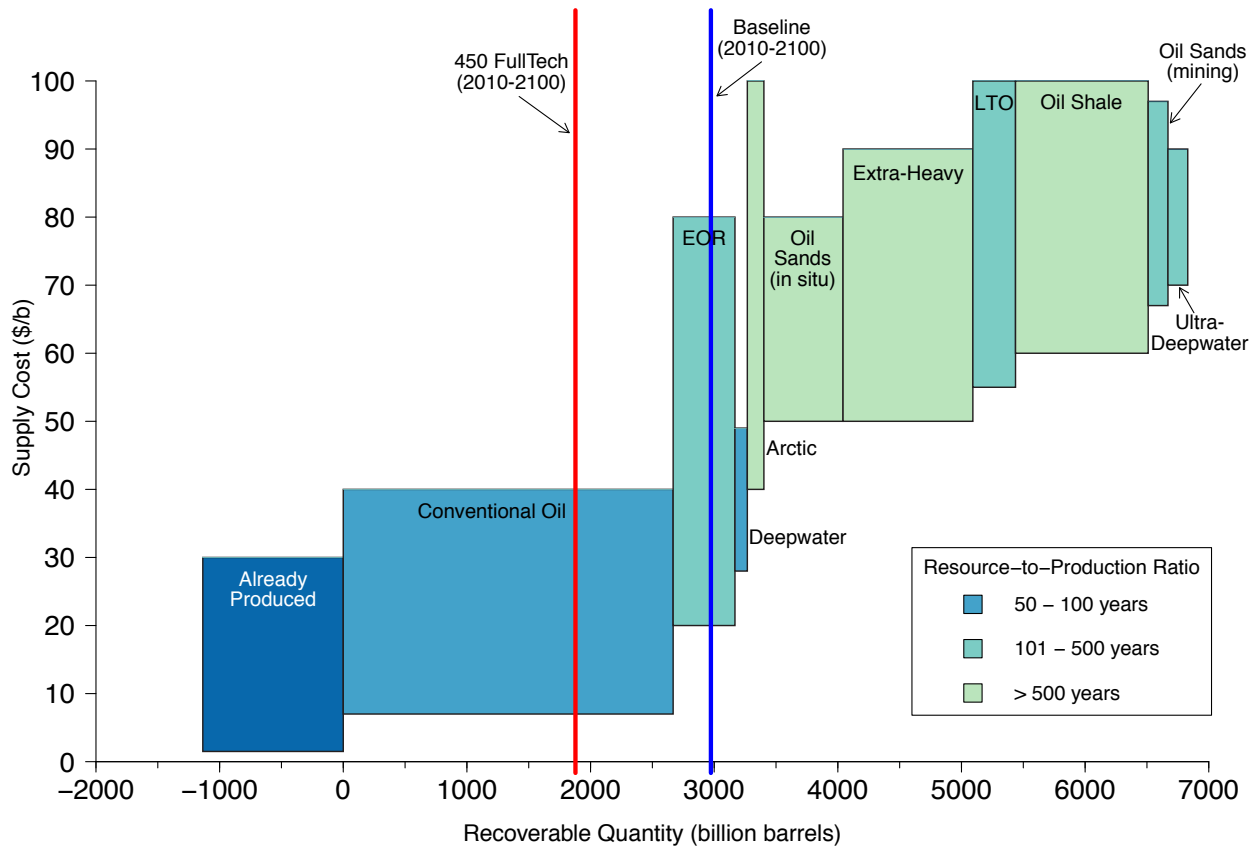
Note: Oil supply cost curve includes EMF27 mean cumulative oil use estimates in Baseline scenario *(blue vertical line)* and 450-FullTech scenario *(red vertical line)*. Resource-to-production ratio (in years) for these resources is shown according to ordinal legend.

Traditional oil supply curves, like Figure 4.3-6, are too much of an abstraction from the real-world oil market to estimate future oil prices— humanity's consumption of oil resources does not follow a perfect sequential time path from cheapest to more expensive. Rather, a mix of oil resources are exploited simultaneously to determine the world price. This complexity makes it difficult to identify which oil resource category in the market is truly marginal since supply costs can be comparable between different oil resources and costs often vary even between projects producing oil from the same type of resource.

To anticipate the changes to the oil market resulting from 2 C carbon pricing, I created another oil supply curve that features daily production volume rather than total resource availability. As shown in Figure 3.4-7, it provides a 'snapshot' of the daily global oil supply curve based on estimated 2013 costs and production levels of major conventional and unconventional oil resources. Production from these resources adds up to a total of 86.8 mb/d. This total oil demand is equal to the 2013 oil production

estimate from industry and is represented by the vertical black line (BP, 2014). The height of the bars represents the range in long-run supply costs for each oil resource category, which includes capital and operating costs as well as a return on investment to the producer. The horizontal dashed line at the top of the oil supply curve represents the average oil price in 2013 ($109/b), which notably, was above the estimated supply costs of the most expensive unconventional oil resources in production in 2013. This is not a traditional supply curve that shows total potential supply availability (Figure 4.3-6), because the width of the bars indicates current daily production levels at each level of price– hence the term 'daily snapshot oil supply curve'. Through a representation of the oil market, daily snapshot oil supply curves aid my analysis in communicating prices under falling demand.

Figure 4.3-7: Daily snapshot oil supply curve (2013).
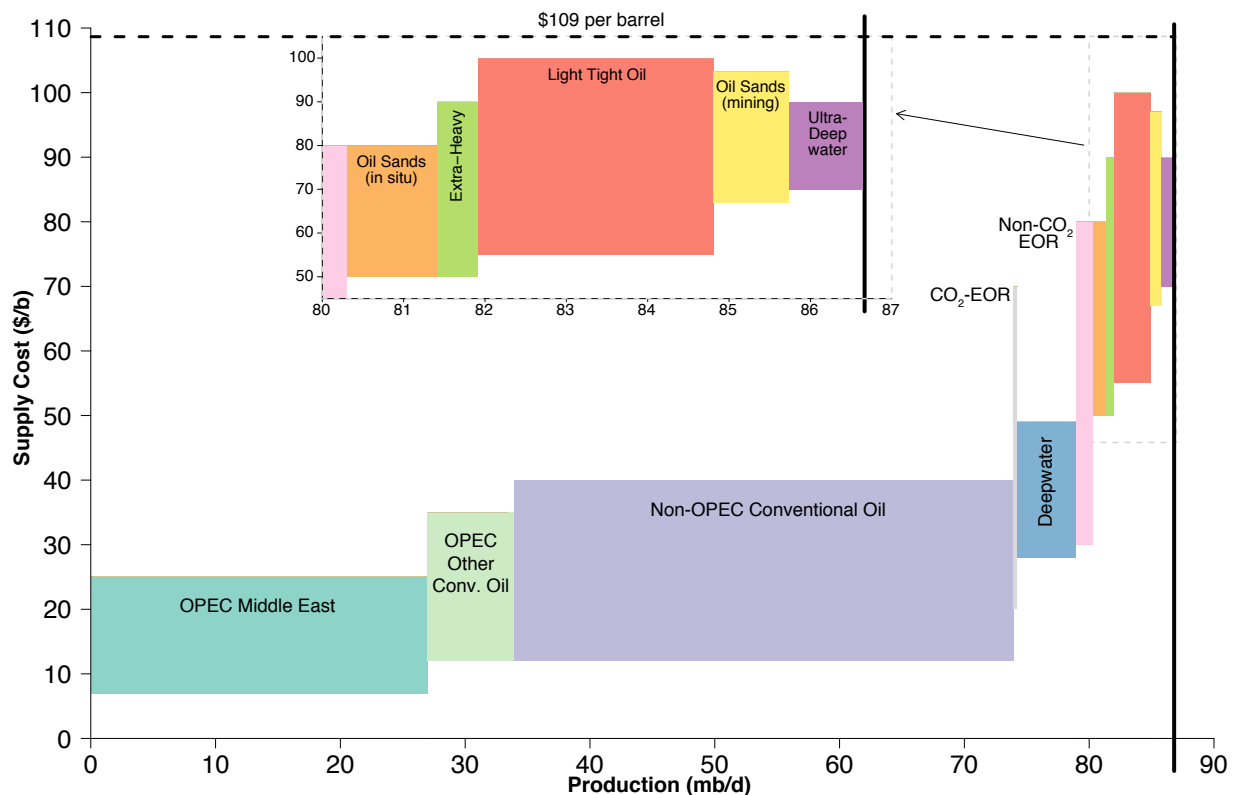
Notes: Costs based on estimates in IEA (2013b), IEA (2013d), Aguilera (2014), and CERI (2014). Conventional oil production is based on BP (2014). Unconventional production estimates from IEA (2013b), IEA (2013d), IEA (2013e), IEA (2014), EIA (2014b), and CAPP (2014).

Conventional oil production is separated into several categories. Conventional oil production in OPEC countries in the Middle East are the least costly source of oil and amounted to approximately 27 mb/d in 2013. Conventional oil from other OPEC countries in Africa and South America are the next least costly source of oil and are estimated to have produced 7 mb/d in 2013. Production of conventional

oil from non-OPEC countries accounts for 40 mb/d with supply costs in the range of $12-$40/b. Deepwater oil is oil in production from depths greater than 400 m and the highest cost resource in production, ultra-deepwater, is oil extracted at depths greater than 1500 m.

The costs of enhanced oil recovery (EOR) techniques for extracting crude oil using CO_2 and thermal EOR (e.g. steam injection) or chemical EOR vary more than other resource categories because feasibility is field site-specific. In total, EOR is estimated to have enabled the extraction of 1.7 mb/d in 2013 with EOR-CO_2 techniques, which are concentrated in North America, producing only 0.3 mb/d.

The daily snapshot supply curve in Figure 4.3-7 includes a magnified view of the higher-cost oil resources. This shows, by rising order of cost, the unconventional oil suppliers who are effectively responsible for about 6.5 mb/d of total global oil production. Oil sands and extra-heavy oil production is about 2.6 mb/d. Oil sands supply costs from in situ extraction methods range from $50-$80/b while the cost range for oil sands mining is estimated to be $17/b higher. Supply costs for extra-heavy oil in Venezuela are assumed to be comparable to oil sands. Light tight oil (LTO) requires advanced technologies to recover this oil lying within low-permeability formations, but has reached 2.9 mb/d in the United States. LTO production is estimated to be slightly more costly than oil sands ($55-$100/b).

A number of oil resource categories and potential substitutes for oil are excluded. Arctic and kerogen oil (also known as oil shale) are not part of this analysis because each currently produce less than 10,000 b/d globally. However, with sea ice melt, technological advances, and high oil prices these two sources could become significant liquid sources as the Arctic is estimated to possess 134 billion barrels of oil and natural gas liquids and oil shale is abundant globally (1,070 billion barrels). Potential substitutes for oil through the production of biofuels and synthetic diesel and gasoline from coal or natural gas are also not included.[16]

Figure 4.3-8 is the estimated range in operating costs for each oil resource included in the daily snapshot oil supply curve. Operating costs include all expenses incurred during day-to-day production operations that are not part of capital investment. In general, conventional oil resources have lower operating costs than unconventional resources. OPEC countries have the lowest operating costs at $2-$7/b whereas costs to operate extra-heavy oil and oil sands mining projects are estimated to be $27-$38/b. LTO operating costs are comparative to conventional oil operating costs at $8-$18/b.

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[16] Global gas-to-liquids production is concentrated in Qatar and Nigeria and amounted to about 0.2 mb/d in 2013. The transformation of coal into liquid hydrocarbons was approximately 0.2 mb/d in 2013 as this process accounts for a significant portion of transport fuel in South Africa and is beginning to displace demand for oil as a feedstock in China (IEA, 2013b). United States and Brazil are the primary producers of biofuels with current production of 0.9 mb/d and 0.5 mb/d, respectively.

Figure 4.3-8: Range in operating costs for oil resource categories.
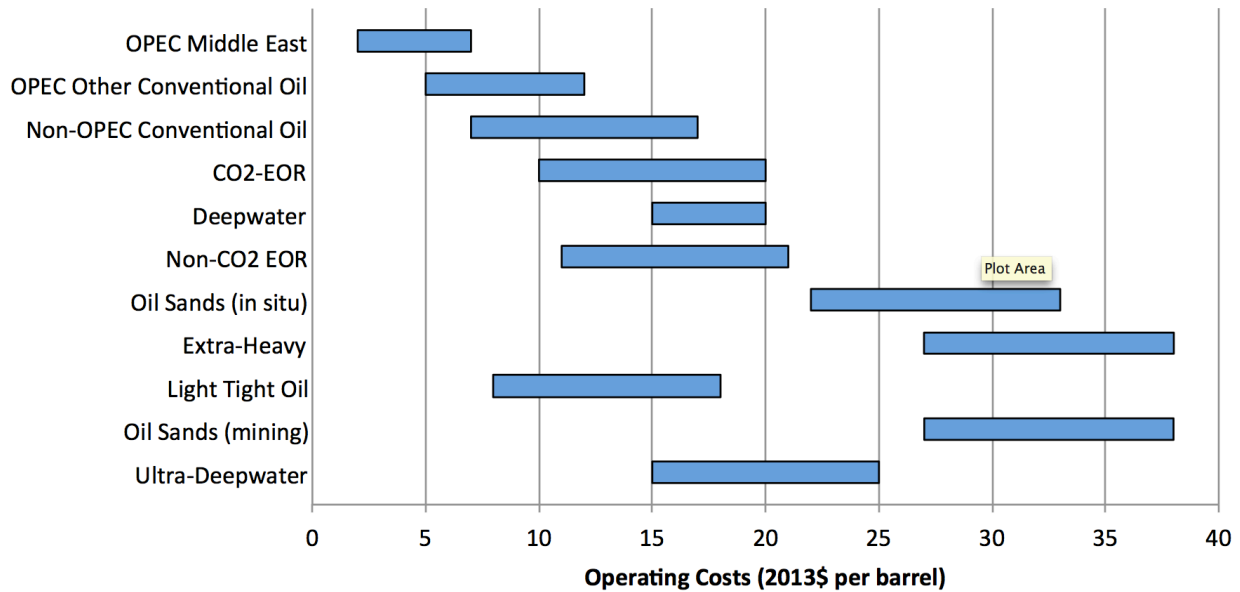
Estimates are based on values in IEA (2010), IEA (2012), and IEA (2013d).

Emission Intensities and CCS

Emission intensity estimates of oil resources were gathered from the IEA (2013d) and independent lifecycle GHG assessments to evaluate how relative production and operating costs are likely to change with 2 C carbon pricing in the period to 2050. Shown in Figure 4.3-9, the well-to-tank emissions assessments include emissions from production, refining, and distribution. The emissions from the combustion of the finished product are not included because the cost of these emissions would be borne by the consumer of the refined petroleum product (RPP). There are more emissions released during unconventional oil production than conventional oil production because more energy is required to extract, upgrade, and refine these resources for final use as RPPs. As the stringency of climate policy rises to reflect the tightening of the 2 C carbon budget, the well-to-tank emission intensity estimates are used to gauge the degree to which supply costs for each oil resource category will change.

Figure 4.3-9: Well-to-tank emissions intensities.
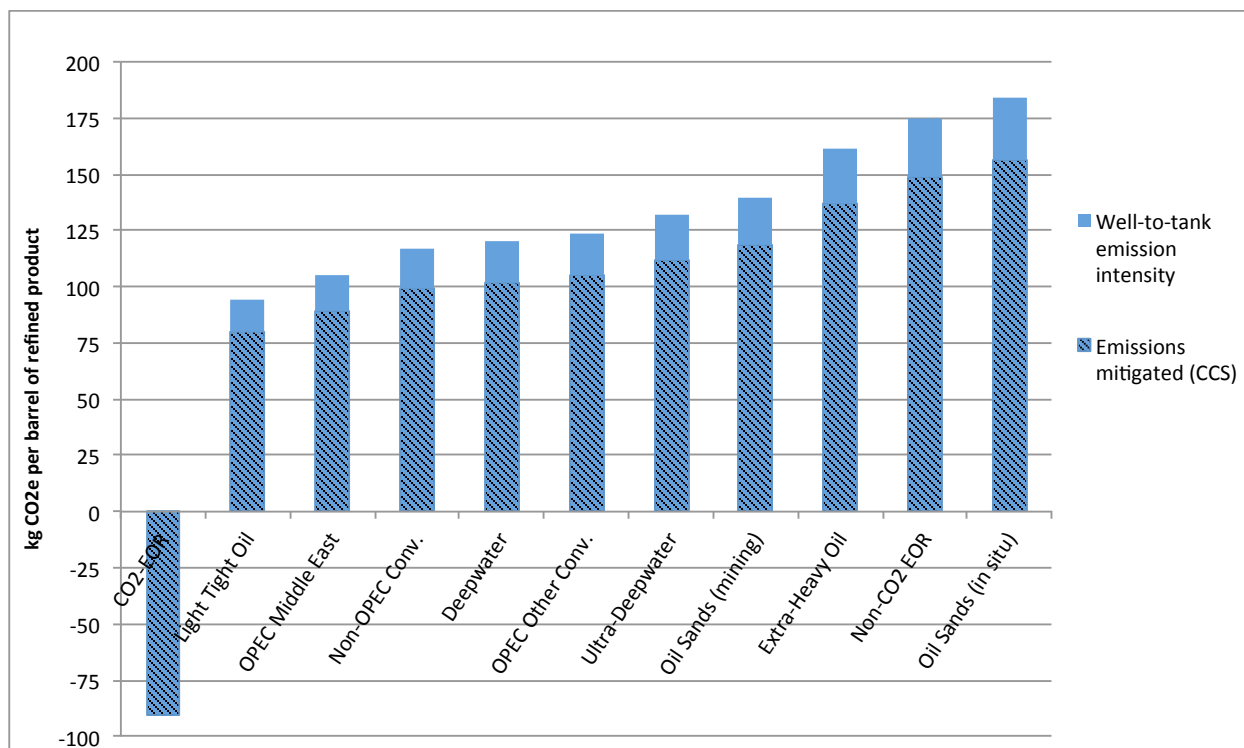
Notes: Well-to-tank emission intensity estimates from IEA (2013b), IHS Energy (2014), and Lattanzio (2013) shown in light blue. Amount of well-to-tank emissions potentially mitigated through the adoption of CCS technology represented by diagonal black lines.

In addition to being applied to emissions from the electricity sector, CCS for certain oil production processes could be an important technological option to mitigate associated GHG emissions in a 2 C climate policy scenario. The costs of oil production will increase with the rising 2 C carbon price, giving producers an incentive to reduce emissions. Although other emission mitigation options exist and if less costly, would be adopted first, I focus on CCS because the technology possesses the greatest potential for emissions abatement through permanent storage in saline aquifers and depleted oil reservoirs. As represented in Figure 4.3-9, I assume CCS can mitigate 85% of well-to-tank emissions to reflect CCS inefficiencies and the technology being applicable only to the concentrated emission sources (production, upgrading, and refining) associated with production. Following detailed analyses by the Integrated CO_2 Network (ICO$_2$N) (2009) and Kilpatrick et al. (2014), CCS costs in my analysis start at $100/t CO_2 captured and stored and decline by 10% per decade to mimic the effect learning rates have on decreasing overall costs (shown in Table 4.3-3). Producers implement CCS beginning when its costs are less than paying the rising carbon price on their emissions.

Table 4.3-3: Declining carbon capture and storage (CCS) costs.

Costs of capture and storage ($/ t CO2)	2020	2030	2040	2050
2 C scenario	100	90	81	73

2 C Producer Oil Prices

I have developed a novel method to forecast 2 C oil prices. Since estimates of total availability of oil resources far exceed the amount consumed in a 2 C scenario, speculation of oil scarcity is unlikely in the timeframe to 2050 and even beyond. The key determinant of oil prices will likely be the decline in oil demand as humanity reduces its GHG emissions in part through reductions in oil consumption. I therefore focus on the supply costs of the highest cost producers in the market as an indication of the price producers would receive for their oil. I formalize this approach through a function that samples the supply costs from a set of these marginal producers and weighs their influence on the oil price according to their relative daily production levels. This 'weighted average marginal price' is:

Weighted average marginal price = [Sum of (Medium estimate of range in supply costs for high cost resources that account for 10% of market) * (Daily production of corresponding high cost resources equal to 10% of market)] / (Daily production for 10% of market)

From the weighted average marginal price, the costs of supply for a sample of the highest cost producers in each future period determine my 2 C producer oil price trajectory. This change in prices that producers would receive for their oil is shown in Table 4.3-4 and calculation tables are provided in Appendix B. The primary reason for declining producer oil prices in a 2 C scenario, despite rising costs of production due to carbon pricing, is falling demand. As higher cost oil resources become uneconomic and unnecessary to meet demand, their supply costs no longer factor into the producer oil price. This dynamic is apparent from the daily snapshot oil supply curves in the following chapter.

Table 4.3-4: Producer oil price from weighted average marginal price function.

Producer Oil Price ($/b)	2020	2030	2040	2050
2 C scenario	76	63	38	39

The culmination of this research on the history of the oil market, oil demand projections in a 2 C scenario, and resource costs and emission intensities is presented through future-period global daily

snapshot oil supply curves. I have created these graphs for 2020, 2030, 2040 and 2050 to show the expected change in the producer oil price and viability of individual oil resources as the carbon price consistent with 2 C rises and global oil demand declines. The representation of supply costs in these graphs allows for visual estimation of the oil price level in a 2 C scenario and judgment of which oil resources will still be in demand. In these graphs, production rates for conventional oil resources remain unchanged from current levels to 2050, which would require investment in technologies to mitigate production declines from existing oil fields as well as development of new fields. Still, I assume these investments to offset oil field depletion would be made because they are likely to be a less costly oil supply option compared to developing unconventional resources located towards the upper end of the global oil supply cost curve. The value of this set of graphics is the high-level, probabilistic representation of the change in the oil supply market if governments succeed in limiting the global rise in temperatures to 2° C.

5. Results and Discussion

The 2 C climate policy constraint has a strong downward effect on the oil price received by producers. As the amount of CO_2 being emitted by the global energy system peaks and then decreases due to 2 C climate policy, oil producers will no longer earn scarcity rent because the prospect of near-term resource unavailability diminishes (Kalkuhl & Brecha, 2013). It becomes a buyer's market and, as the period 1986-2002 suggests, there is little incentive for low-cost oil producers to reduce production and lose market share in order to try to sustain prices. As a result, the oil price falls to levels that approach the supply costs of the marginal oil resources in production. This is shown in Figure 5-1.

Figure 5-1: Daily snapshot oil supply curves with carbon price, producer oil price, and demand in 2 C scenario (2020-2050).
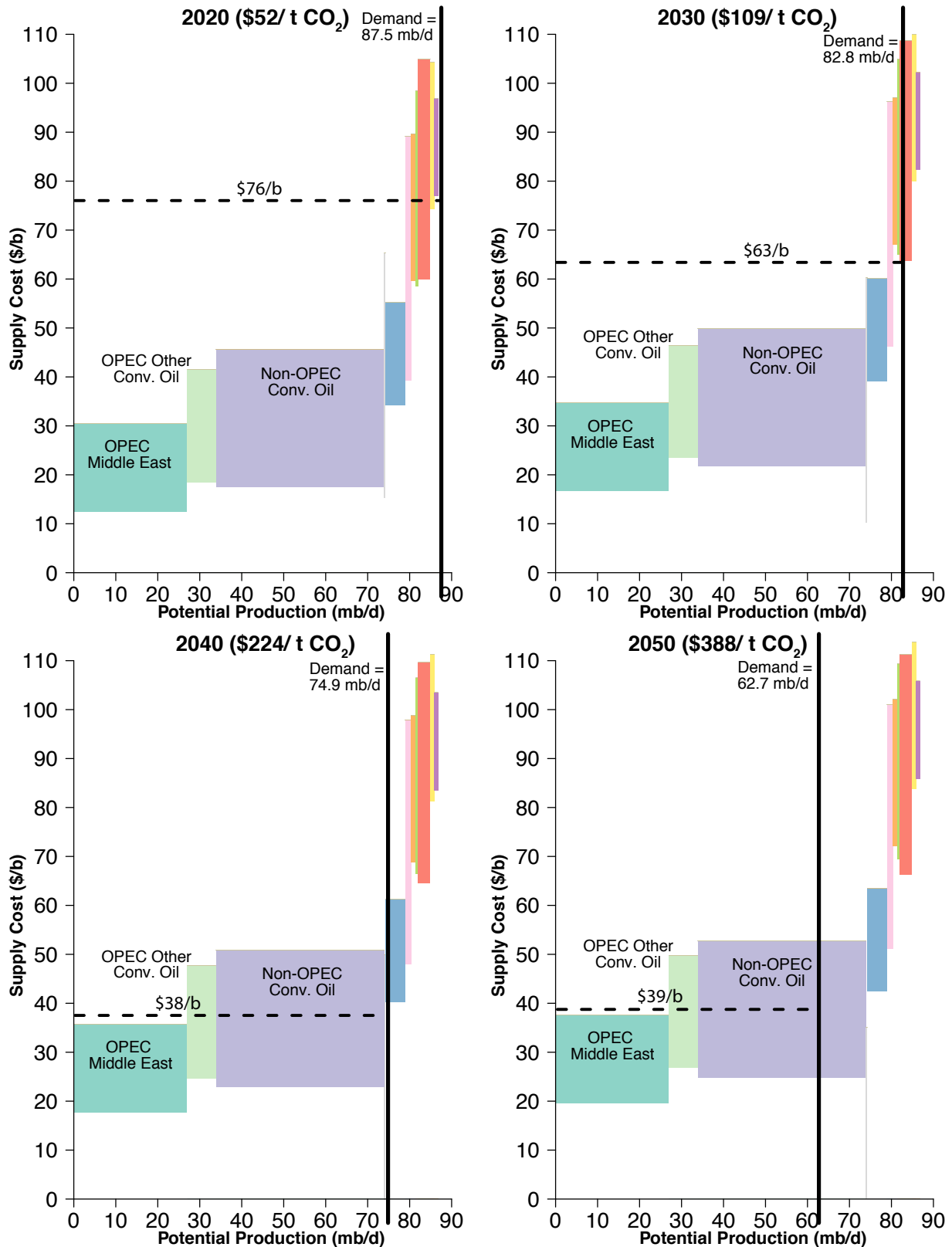
The daily snapshot oil supply curves in Figure 5-1 illustrate several dynamics, including the expected change in the producer oil price. These daily snapshot oil supply curves show the range in long-run supply costs of major oil resources through the vertical extent of each colored block. The horizontal distance of each oil resource category corresponds to its current rate of production in millions of barrels per day (mb/d). The black vertical line superimposed on the snapshot supply curves is global oil demand in each period and is derived from the EEE modeling results of the EMF27 450-FullTech scenario. Global oil demand declines from 88 mb/d in 2020 to 83 mb/d in 2030. In 2040, total oil demand is 10% lower than in 2030 and continues its fall to be 63 mb/d in 2050.

To cause this fall in oil demand, the carbon price rises quickly. The level of 2 C carbon pricing in each daily snapshot oil supply curve is also obtained from the 450-FullTech scenario and increases the supply costs of each oil resource category over the forecast. The carbon price starts at $52/ t CO_2 in 2020 and rapidly increases over the forecast to $388/ t in 2050. Producers are assumed to adopt CCS technology to mitigate 85% of their associated emissions when the costs of doing so are lower than paying the carbon price for all of their emissions. This occurs in 2030 for all resource producers when the cost of CCS technology is $90/ t CO_2 captured and stored and the carbon price reaches $109/ t. Due to CCS being economical from 2030 onward, producer oil supply costs are less than they would be in the absence of CCS.

The price producers would receive for their oil is shown through the dashed horizontal line that intersects the vertical demand line. Without scarcity rent, I forecast the oil price falling from an average of $109/b in 2013 to the weighted average marginal price for supply. This is a function that weighs the supply costs of the most costly resources in production that account for 10% of the market according to their current daily rates of production.[17] Using the weighted average marginal price function, I estimate the producer oil price to be $76/b in 2020 as the supply costs of deepwater, non-CO_2 EOR, extra-heavy, LTO, oil sands, and ultra-deepwater are around this level. In 2030, the ultra-deepwater and oil sands (mining) are on the right side of the demand line and therefore no longer factor into the producer oil price, causing the price to fall to $63/b. In 2040 and 2050, the producer oil price is below $40/b, even with a high carbon price, because of the adoption of CCS. The price in 2050 is about $1/b higher than in 2040 because the $164/ t CO_2 increase in the carbon price applied to the emissions not sequestered through CCS slightly increases the weighted average marginal price. To clearly depict the situation for non-conventional oil resources, I have constructed Figure 5-2, which is an enlargement of the non-conventional oil resources positioned on the right side of the daily snapshot supply curves in Figure 5-1.

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[17] Appendix B includes data tables for calculation of the weighted average marginal price for each future period year.

Figure 5-2: Magnified view of higher cost oil resources represented in Figure 5-1.
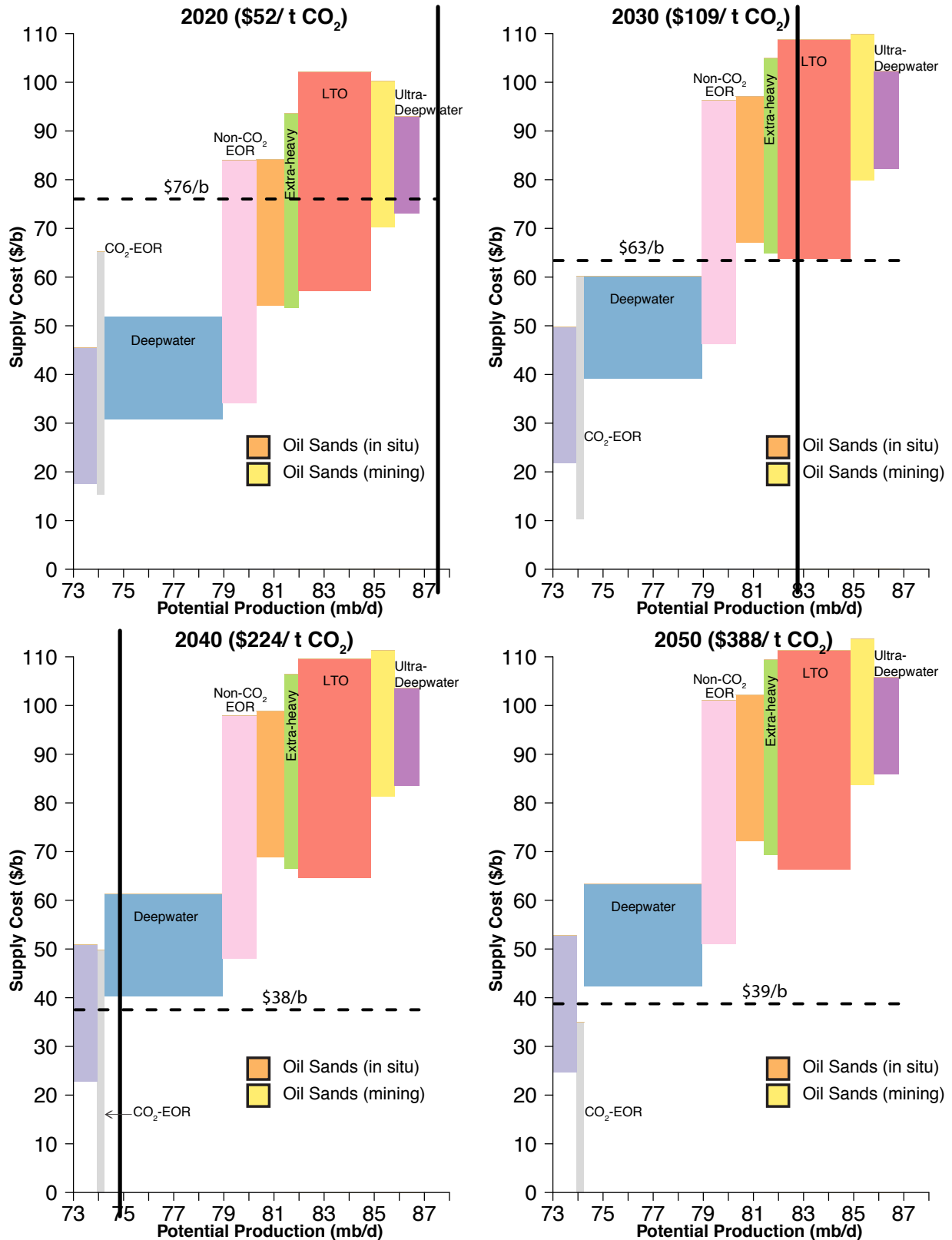
Note: The vertical black demand line does not appear on the 2050 snapshot since global oil demand is projected to be less than 73 mb/d by that time.

The market could be supplied entirely by conventional oil resources if current production rates are maintained. Oil demand of 63 mb/d in 2050 – a level roughly consistent with production in 1988 – occurs because consumers would be facing high and rising carbon charges on the price paid for gasoline and diesel derived from oil, whether because of carbon taxes, carbon permit prices or carbon fuel standards. These escalating prices would motivate consumers to reduce their demand for these fuels, through a combination of conservation and adoption of energy efficient and low-emission vehicles and fuel substitutes, causing global demand for oil to fall accordingly.

Supply costs for unconventional oil resources rise far above the producer oil price over the forecast. Table 5-1 summarizes this finding by showing the difference between the best-case costs for new unconventional oil supply and my 2 C producer oil price trajectory. By 2030, all unconventional oil resource category supply costs are higher than the price producers would receive for their oil. Moreover, producers would be well aware of this falling trend even from 2020, so it would affect their investment decisions if they exercise foresight.

Table 5-1: Amount above producer oil price of lowest estimate of supply costs ($/b).

Unconventional Oil Resource Category	2020	2030	2040	2050
Oil sands (in situ)	-16	4	31	33
Extra-heavy	-18	2	29	31
LTO	-16	0	27	28
Oil sands (mining)	-2	17	44	45
Ultra-deepwater	1	19	46	47

According to my analysis, sustained growth in unconventional oil production capacity is unlikely in a 2 C scenario. In 2020, supply costs for new oil sands production using in situ methods are estimated to be $16/b below to $14/b above the producer oil price. Even with a majority of related emissions mitigated through CCS in 2030, oil sands in situ production is uncompetitive due to the falling producer oil price. As oil demand declines to 2040 under a rising carbon price, the viability of new oil sands in situ production further erodes with supply costs estimated to be $31-$61/b above the producer oil price. Although mining is a less emission-intensive extraction method for oil sands production, its supply costs are $80/b-$110/b in 2030 in an oil market with producer prices of $63/b. In 2050, the medium estimate of supply costs for both oil sands production techniques are more than double the producer oil price. The other unconventional oil resource categories follow a similar path of decreasing competitiveness. Since decisions to develop oil resources are based on the expectation of long-term future production and

profitability to recoup massive upfront capital expenditures, unconventional resources are likely to be too expensive to attract investment in a 2 C scenario. Significant growth from current production levels would be unlikely.

Producing oil using EOR technologies by CO_2 injection could become less costly with 2 C carbon pricing when considering the net balance of CO_2. If the CO_2 emissions associated with production and refining can be stored underground long-term, the emissions associated with EOR-CO_2 are estimated to be -90 kg/b. Therefore, assuming EOR-CO_2 producers obtain compensation for emissions storage, their costs could decline as the price of carbon pollution rises. Starting in 2040, the value of CO_2 storage could offset all EOR-CO_2 supply costs, which suggests the application of EOR-CO_2 to oilfields may quite quickly become a common practice in a 2 C future. However, since this capacity is limited, future CCS would increasingly be in saline aquifers, with correspondingly higher costs (IEA, 2013d).

Through the adoption of CCS, some unconventional oil resources already in production may be able to remain profitable. As long as the operating costs of existing oil resource projects are lower than the price received, they will likely keep operating. Table 5-2 is the difference between the producer oil price and the medium value of the estimated range in operating costs for each unconventional oil resource category. A positive value suggests producers would be able to cover operating costs of existing operations, and thus continue producing, in a 2 C scenario.

Table 5-2: Amount below oil price of operating costs for unconventional oil resources ($/b).

Unconventional Oil Resource Category	2020	2030	2040	2050
Oil sands (in situ)	39	19	-9	-11
Extra-heavy	35	16	-11	-13
LTO	58	42	15	14
Oil sands (mining)	36	18	-9	-11
Ultra-deepwater	49	31	4	3

It is probable that existing in situ oil sands production will remain viable to 2040 because operating costs are below the projected producer oil price. This may also be the case for oil sands mining, although projects with higher-than-average operating costs may be in trouble earlier. The oil price decline to $38/b in 2040 might also result in production from existing extra-heavy oil deposits becoming unprofitable. The relatively low emission intensity and operating costs for LTO combined with the application of CCS in 2030 make production from fields with capital already in place likely to continue until reservoir depletion. Lastly, the difference between the operating costs of ultra-deepwater oil

facilities and the producer oil price points to sustained production being economical, though injection and storage of associated emissions would likely be required for these developments to avoid being retired before the end of their planned operational lifetime.

In the daily snapshot oil supply curves, the producer price for oil falls to the supply costs of the marginal resources, but if the global 2 C climate policy regime is perceived as legitimate and enduring, prices could fall even lower. This is because in a prolonged buyer's market, operating costs may set the oil price for many years. Then, the price can fall much lower and stay there, as was witnessed during the period 1986-2002. In 2030, when oil demand begins to decline rapidly, operating costs for some unconventional oil resources are in the range of $17-$27/b and so prices approaching this level in a 2 C scenario are possible. If this is the case, the prospects of higher rates of oil sands production would further deteriorate and existing projects could be at risk of being forced to shut down before 2040. As such, my 2 C analysis is optimistic in its assessment of the economic viability of the existing oil sands operations since producer oil prices could decline much lower than I have shown graphically.[18] But, as has been shown, even with this favourable condition, I find the combination of low oil prices and increasing production costs for oil sands, because of the high carbon price, would render uneconomic new investment to expand production.

Of course there are additional factors that may lead to a different real-world price outcome under rising carbon prices and falling oil demand than I have presented. For one, oil demand could be higher or lower than has been applied on the daily snapshot supply curves. If oil demand in a 2 C scenario were higher than the average of the EMF27 models, the prospects for unconventional oil expansion could improve since oil prices for producers would likely be higher. A 2 C scenario with high oil demand means that other major emission reduction options would be in large-scale use, especially biomass generated electricity with CCS. As the variety of EMF27 450-ppm scenarios indicate, (shown in Figure 4.3-3), if CCS is unavailable and renewables less attractive, then more emission reductions must come from lower oil use to stay within the 2 C budget. Oil demand could also be lower than shown if the transportation sector proves to be less costly to shift away from oil as a primary energy source than estimated by the models. In particular, with low to zero emission electricity, the prospects of the shift to low-carbon mobility might improve (Williams et al., 2012). Plug-in hybrid and electric vehicles are emerging as viable alternatives to conventional vehicles due to significant energy cost savings (Wu, Dong, & Lin, 2014). Considering the relatively short turnover rate of the global vehicle fleet, this transition could occur

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[18] Another favorable assumption for oil sands used in this study is that the North American price available to oil sands is likely to be lower than is shown as WTI is normally traded at a discount to Brent crude, which the projected 2 C future producer prices are approximated to.

quite quickly, potentially meaning less oil consumption, weaker prices, and even lower demand for expensive oil than I have depicted.

Changes in production rates for conventional oil resources are another development that could alter the future-period supply cost curves causing producer oil prices to be higher or lower than estimated. After disappearing upon the introduction of 2 C climate policy, scarcity rent could return over the following decades due to uncertainty of the amount of conventional oil that can be recovered. Though global conventional oil reserves can satisfy oil demand over the forecast period,[19] depletion of conventional oil fields means that production from fields either awaiting development or yet to be discovered will be required for rates from these low-cost sources to be sustained. If supply costs of this untapped conventional oil prove to be higher than oil market researchers and industry presume, then the supply cost curves would start at a position higher up than has been presented— potentially improving prospects for unconventional oil supply.

On the other hand, the price-collapse effect following a global climate agreement could be more rapid and profound than in my exercise. I assume a relatively gradual market adjustment to the rising carbon price due to unchanging production rates. In reality, the expectation of oil assets being stranded because of insufficient demand could motivate market producers to try to sell as much of their oil as possible as fast as possible. Provided that this response is prevalent among market players, it could exacerbate oil price declines as countries with spare production capacity increase production rates despite 2 C carbon pricing and falling demand. If, in this situation, prices fall quickly below $20/b and stay at this level, production from existing oil sands facilities might come to a fairly abrupt halt.

Or, for energy security reasons, some governments may undertake market interventions (i.e. subsidies, trade restrictions) to ensure a certain degree of supply diversity. For example, major importing countries like the United States and China may decide to pursue policies aimed at lessening the concentration of oil supply from historically turbulent regions. OPEC countries gain market share in my 2 C scenario because most of its oil production is low cost and thus, as high cost producers become uncompetitive, OPEC accounts for a greater percentage of a shrinking oil market. Shown in Figure 5-3, 46% of global oil production in 2040 would originate from OPEC member countries. OPEC oil increases to 54% of global oil production by the end of my 2 C forecast, which is about 3% higher than in 1972. To simulate the potential for governments to pursue policies aimed at avoiding such a concentration of

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[19] World oil reserves according to BP (2014) are equal to 1,688 billion barrels of which 388 billion barrels are Canadian oil sands and the Venezuelan Orinoco Belt. Estimated oil production over the forecast period (2014-2050) is 1,069 billion barrels. As shown in the traditional supply curve (Figure 4.3-6), resource estimates are much larger.

production, I have conducted an alternative 2 C oil market scenario in which OPEC's share of global oil production is restricted to a 45% threshold— a level that was last exceeded in 1979. However, this adjustment changes my oil price forecast only by a negligible amount due to the most costly resources in production that determine future producer oil prices in this study being mostly unchanged.[20] So even if certain countries interfere to restrict OPEC's share of global production to a share commensurate with modern times, this does not bring about future oil prices that justify expanding oil resources that are becoming uneconomic in a 2 C world. Moreover, since oil consumption will continue to decline past 2050 in a 2 C scenario, reducing the risk of an oil shock related to geopolitical tensions probably becomes less and less a concern for governments whose economies are decarbonizing.

Figure 5-3: Percentage of global oil produced by OPEC.
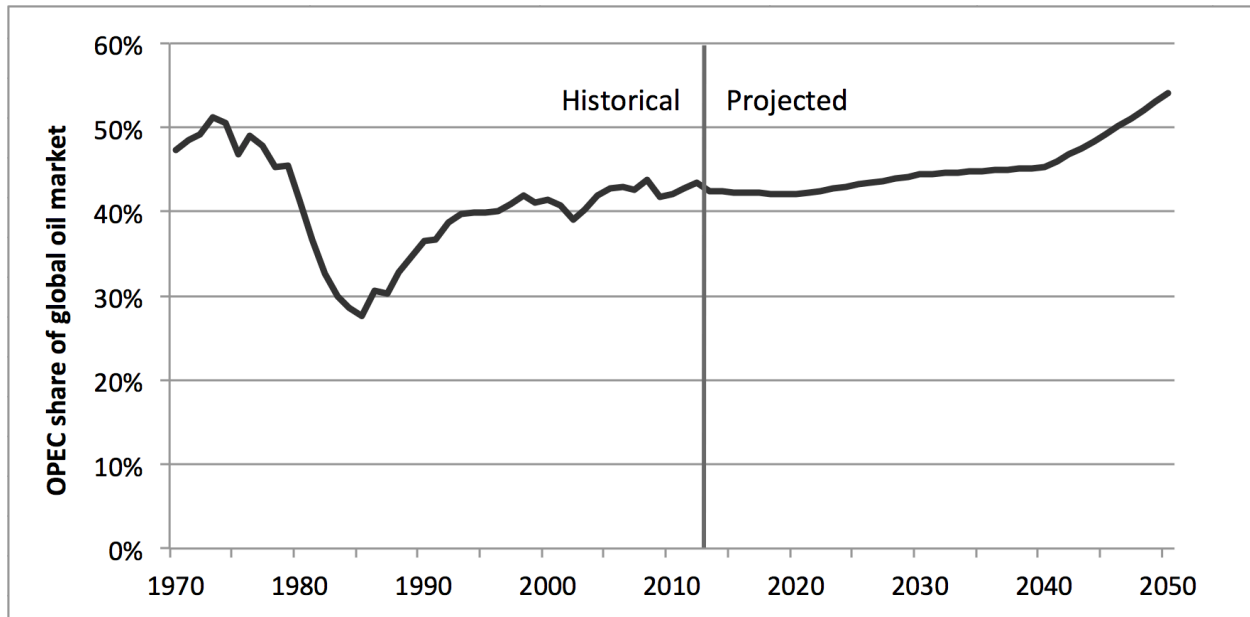
In summary, the main factors that determine, in concert, the evolution of the price of oil under 2 C climate policy are: (1) cost of replacing depleted reserves, (2) ability with innovation and investment to develop backstop technologies, (3) reduction in demand because of a rising carbon price, (4) declining marginal cost of production as oil demand shifts to the left of the global oil supply curve, and (5) willingness of consumers to pay a premium for oil from politically-stable suppliers. Figure 5-4 provides a simple representation of what happens to the price of oil received by producers and the effective cost of oil paid by consumers under the 2 C commitment and contrasts this with the historical evolution of the price of oil.

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[20] See Appendix C for sensitivity analysis of weighted average marginal price for 45% limitations on OPEC market share.

Figure 5-4: Historical and 2 C forecast oil prices.
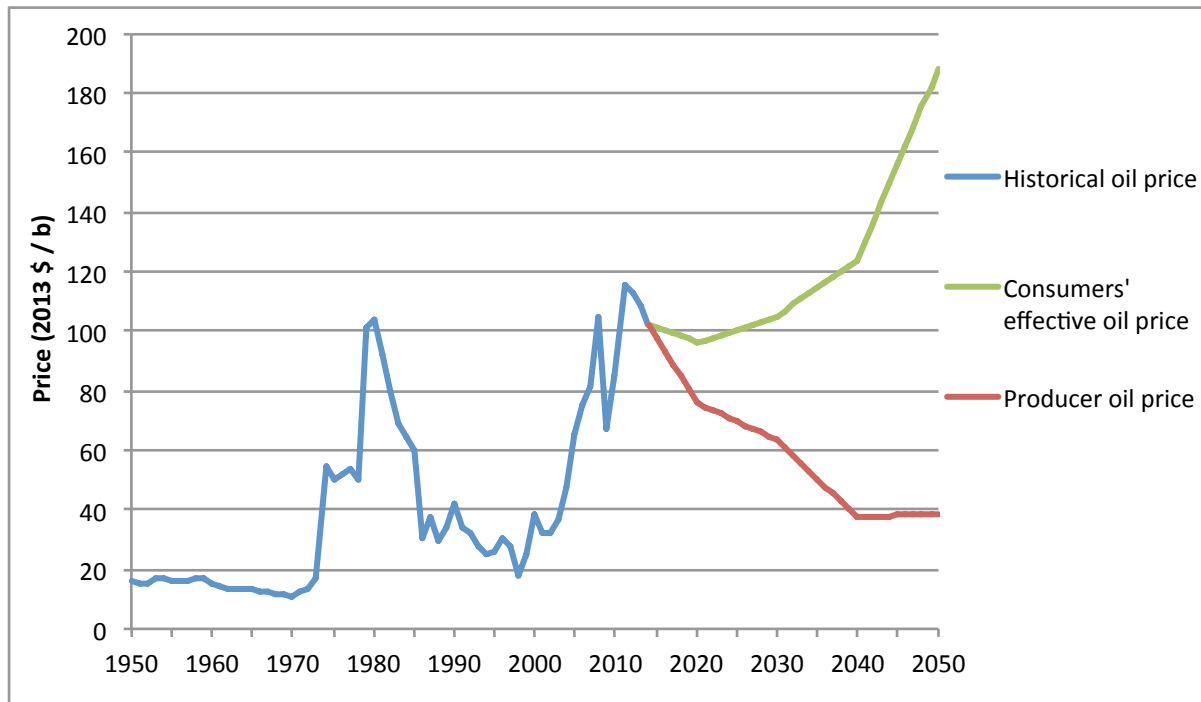
A carbon charge (or equivalent) drives a wedge between the prices consumers pay for RPPs ('consumers' effective oil price') and the price producers receive for their oil. The price of oil for producers falls because price competition for a declining demand forces higher cost producers out of the market. At the same time, the price of RPPs rises along with the rising carbon charge on emissions associated with their combustion. In Figure 5-4, this is the consumers' effective oil price, which I estimate to reach $188/b in 2050 when global oil demand is forecast to be about 24 mb/d lower than in 2013.

6. Conclusion

I find through this exploratory research project that global oil demand, oil producer prices, and unconventional oil production would all decline in a future where governments commit to their stated goal of not allowing temperatures to rise above 2° C. The transformation of the global energy system to low-carbon energy sources and technologies would be unprecedented, but the low price received by oil producers would not be. Sub-$40/b oil prices were the norm for more than a decade and a half following a global slowdown in demand and the prudent decision in 1986 by low-cost OPEC producers to let the price fall to levels that deterred further erosion of their market share. During this time, speculation on oil resource scarcity, and therefore scarcity rent, was virtually non-existent. Since oil availability estimates far exceed the amount to be used in the next 35 years if governments commit to their collective 2 C pledge, scarcity rent is likely to vanish again. The reason is that with a 2 C carbon budget, the atmosphere's capacity to absorb excess GHG emissions becomes the scarce resource rather than the long-run supply of oil. Consumers are then confronted with the cost of emitting carbon pollution through increasing prices for processed forms of fossil fuels, leading to a shift in demand away from oil towards alternatives and reduced consumption.

Through 2 C oil demand and pricing information generated by advanced EEE models and the creation of a series of graphs that represent potential future global oil production rates and supply costs, I have conducted a probabilistic assessment to identify those types of oil resources that would likely sustain production with 2 C carbon charges on the emissions associated with production and the higher-cost and higher-emission resources likely to become uncompetitive in a 2 C oil market. Global demand for oil declines to the extent that oil sands expansion, and therefore associated new pipelines, would likely not occur. Operating costs are estimated to be marginally below the producer price for oil to 2040, which indicates that oil sands projects already in production or close to completion when 2 C climate policy is established may be able to stay in the market if equipped with CCS. But, even with full adoption of CCS technology, my analysis suggests the economic rationale for new oil sands supply is questionable if the 2 C carbon budget is respected. The compatibility of oil sands with the 2 C target ultimately depends on relative costs, and with the costs of supply for oil sands producers expected to be above the producer price in the near future, expanded oil sands production appears unviable. Thus, demand for the oil-related products expected to flow through the many new pipelines proposed to traverse North America quickly dissolves in a world with a 2 C constraint.

Extensions of this research and improvements in EEE models could provide further insights into the economic viability of individual fossil fuel resources in a world with stringent climate policies.

Applying a similar framework as has been developed in this project to natural gas may yield policy-relevant results that highlight the exposure of the supply-side of the gas market to climate policy. As well, improving the fossil fuel pricing mechanisms of the models and increasing the level of detail in how fossil fuel resources are represented could provide researchers and decision-makers with a more precise forecast in terms of the number of barrels supplied by individual resources in a climate policy scenario. In the interim of these enhanced modeling developments, and in the midst of inadequate 2 C climate policy at a national and a multi-national scale, this research project serves as a guide for policy-makers and citizens to discern if the fossil fuel infrastructure projects being proposed in their communities and countries are part of a future in which climate change is minimized.

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Appendices

Appendix A- AR5 Scenario Database Models

Table A-1: Model versions that participated in model comparison studies and made sectoral emissions output data consistent with 2 C target available in AR5 Scenario Database.

Sectoral Emissions Data				
Model	**Version**	**AMPERE**	**LIMITS**	**EMF27**
AIM-Enduse	[Backcast] 1.0		✓	
	12.1			✓
BET	1.5			✓
ENV-Linkages	WEO2012			✓
DNE21	V.12	✓		
GCAM	3.0	✓		✓
	3.1		✓	
GEM	E3-ICCS	✓		
IMACLIM	V1.1	✓		✓
IMAGE	2.4	✓	✓	✓
MERGE	ETL_2011	✓		
	EMF27			✓
MESSAGE	V.4	✓	✓	✓
POLES	*study-specific*	✓		✓
Phoenix	2012.4			✓
REMIND	1.5	✓		✓
TIAM	ECN		✓	
	WORLD 2012.2			✓
WITCH	*study-specific*	✓		✓
WorldScan	2	✓		

Note: * denotes models with versions specific to model comparison study in which it participated.

Table A-2: Model versions that participated in model comparison studies and made primary energy output data available in AR5 Scenario Database.

Sectoral Emissions Data									
Model	**Version**	**AMPERE**	**LIMITS**	**EMF27**					
		450	**StrPol-450**	**Base-FullTech**	**550-FullTech**	**450-FullTech**	**450-LimBio**	**450-LimSW**	**450-NoCSS**
AIM-Enduse	[Backcast] 1.0		✓						
	12.1			✓	✓	✓	✓	✓	✓
BET	1.5			✓	✓	✓	✓	✓	
DNE21	V.12	✓							
EC-IAM	2012			✓	✓				
ENV-Linkages	WEO2012 calibration			✓	✓	✓	✓	✓	
FARM	3.0			✓	✓				
GCAM	3.0	✓		✓	✓	✓	✓		✓
	3.1		✓						
GEM	E3-ICCS	✓							
GRAPE	ver2011			✓	✓				
IMACLIM	V1.1	✓		✓	✓	✓	✓	✓	
IMAGE	2.4	✓	✓	✓	✓	✓		✓	
MERGE	ETL_2011	✓							
	EMF27			✓	✓	✓	✓	✓	
MESSAGE	V.4	✓	✓	✓	✓	✓	✓	✓	
POLES	*study-specific	✓		✓	✓	✓	✓	✓	✓
Phoenix	2012.4			✓	✓	✓	✓	✓	✓
REMIND	1.4								
	1.5	✓	✓	✓	✓	✓	✓	✓	✓
TIAM	ECN		✓						
	WORLD 2012.2			✓	✓	✓	✓	✓	✓
WITCH	*study-specific	✓	✓	✓	✓	✓	✓	✓	
WorldScan	2	✓							

Note: * denotes models with versions specific to model comparison study in which it participated.

Appendix B- Weighted Average Marginal Price Calculation Tables

Table B-1: Calculation of weighted average marginal price in 2020.

Marginal Resource	Production (mb/d)	Percent of Global Demand	Medium Supply Cost Estimate ($/b)	Production * Medium Supply Cost Estimate
Deepwater	0.82*	0.94%	44.80	36.64
Non-CO_2 EOR	1.36	1.57%	64.19	87.42
Oil sands (in situ)	1.10	1.27%	74.66	82.50
Extra-heavy	0.57	0.66%	78.45	44.72
Light tight oil	2.90	3.34%	82.44	239.06
Oil sands (mining)	0.93	1.07%	89.32	82.71
Ultra-deepwater	1.00	1.15%	86.93	86.93
SUM	**8.68**	10%	N/A	**659.98**
Producer Oil Price ($/b)	659.98 / 8.68 = **76.03**			

Note: *Share of deepwater production that is highest cost supply (10%).

Table B-2: Calculation of weighted average marginal price in 2030.

Marginal Resource	Production (mb/d)	Percent of Global Demand	Medium Supply Cost Estimate ($/b)	Production * Medium Supply Cost Estimate
Deepwater	4.46*	5.39%	49.63	221.34
Non-CO_2 EOR	1.36	1.65%	71.24	97.03
Oil sands (in situ)	1.10	1.34%	82.07	90.69
Extra-heavy	0.57	0.69%	84.94	48.42
Light tight oil	0.78**	0.94%	86.22	67.25
SUM	**8.28**	10%	N/A	**524.71**
Producer Oil Price ($/b)	524.71 / 8.28 = **63.40**			

Notes: *Share of deeepwater production that is highest cost supply (10%).
    **Share of light tight oil production to the left of global oil demand line.

Table B-3: Calculation of weighted average marginal price in 2040.

Marginal Resource	Production (mb/d)	Percent of Global Demand	Medium Supply Cost Estimate ($/b)	Production * Medium Supply Cost Estimate
Non-OPEC conventional oil	6.58*	8.78%	36.86	242.36
CO_2-EOR	0.30	0.40%	24.84	7.45
Deepwater	0.61**	0.82%	50.79	31.01
SUM	**7.49**	10%	N/A	280.82
Producer Oil Price ($/b)	280.82 / 7.49 = **37.52**			

Notes: *Share of non-OPEC conventional oil production that is highest cost supply (10%).
    **Share of deepwater production to the left of global oil demand line.

Table B-4: Calculation of weighted average marginal price in 2050.

Marginal Resource	Production (mb/d)	Percent of Global Demand	Medium Supply Cost Estimate ($/b)	Production * Medium Supply Cost Estimate
Non-OPEC conventional oil	6.27*	10%	38.75	243.00
Producer Oil Price ($/b)	243.00 / 6.27 = **38.75**			

Note: *Non-OPEC conventional oil accounts for all 10% of highest cost supply in market (left of demand line).

Appendix C- OPEC Market Share Sensitivity Analysis Calculations

It was not necessary to limit OPEC share to 45% of global production for future period years 2020 and 2030 since its market share is below this level in my standard 2 C forecast (42% and 44% respectively).

Table C-1: Calculation of weighted average marginal price in 2040 with 45% OPEC share of global oil market.

	Production (mb/d)	Percent of Global Demand	Medium Supply Cost Estimate ($/b)	Production * Medium Supply Cost Estimate
OPEC oil	33.69	45%	-	-
Marginal Resource				
Non-OPEC conventional oil	6.37*	8.51%	36.86	234.86
CO_2-EOR	0.30	0.40%	24.84	7.45
Deepwater	0.81**	1.09%	50.79	41.34
SUM	**7.49**	10%	N/A	283.66
Producer Oil Price ($/b)	283.66/ 7.49 = **37.89**			

Notes: *Share of non-OPEC conventional oil production that is highest cost supply (10%).
**Share of deepwater production to the left of global oil demand line.

Table C-2: Calculation of weighted average marginal price in 2050 with 45% OPEC share of global oil market.

	Production (mb/d)	Percent of Global Demand	Medium Supply Cost Estimate ($/b)	Production * Medium Supply Cost Estimate
OPEC oil	28.22	45%	-	-
Marginal Resource				
Non-OPEC conventional oil	6.27*	10%	38.75	243.00
Producer Oil Price ($/b)	243.00 / 6.27 = **38.75**			

Note: *Non-OPEC conventional oil accounts for all 10% of highest cost supply in market (left of demand line).