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Mapping and Measuring the Channels of Oil Price Exposure in the Economy and the Role of Oil Derivatives in Reshaping Them

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Abstract. This paper provides a framework for understanding how the trade in oil derivatives relates to the physical production and use of oil in the economy. We use this framework to benchmark the scale of investment in exposure to oil prices made using futures, options and other derivatives. The paper reviews the available research on the valuation of oil reserves and on how companies use oil derivatives for hedging. We identify the inadequacy of the publicly available statistics on the OTC derivatives markets, and the limited research and statistics available on the financial channels of oil exposures.

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INTRODUCTION

This paper is motivated by the recent debates concerning the impact of financial investors on the price of oil and other commodities. The last two decades has seen a growing volume of investment dollars channeled into futures contracts on oil and other commodities. One popular vehicle for these investments are commodity index funds, which from their origin in 1991 are estimated to have grown to somewhere between \$200-\$300 billion. Hedge funds, too, have dramatically increased their involvement in commodity derivatives, as have other financial investors. In a paper issued earlier this year by the Federal Reserve Bank of St. Louis, Basu and Gavin (2011) reported that "The gross market value of commodity derivatives rose by a factor of 25 between June 2003 and June 2008—reaching \$2.13 trillion in June 2008." A broad array of market participants, elected officials, regulators and others have expressed concern that this flow of money disturbs the normal determination of price through the supply and demand of the physical product.

Although the debate touches on the markets for several different commodities, the oil market has often received the most focus. One reason is that the index funds allocate the largest share of their investments to oil—approximately 40%. This paper will focus exclusively on oil.

How large are these financial investments when placed in context with the scale of oil production and consumption? What about in comparison with the value of the physical reserves of oil? The Federal Reserve report cited above attempts a relative comparison for data on commodity derivatives as a whole:

> Figure 4 shows the outstanding notional amounts of commodity derivatives contracts (their face value): The amount tripled between June 1998 and June 2003 and then

> rose 19-fold in the next 5 years, peaking at $13 trillion in June 2008. … To provide some perspective on the size of derivative positions, consider that world GDP rose from $30 trillion in 1998 to $61.1 trillion in 2008. Commodity prices almost quadrupled over the decade before their peak in July 2008. Even at 2008 prices, the total output of commodities was less than half the notional value of outstanding commodity derivatives contracts (nearly $13 trillion). The ratio of the notional amount of commodity derivatives contracts in June 1998 to world GDP rose from 1.5 percent in 1998 to 21.6 percent in 2008.

Are these the correct points of comparison? Is the notional amount of contracts the right one to use in making this comparison? Earlier in the same report, the authors had cited the gross market value, which was less than $1/6^{th}$ the notional amount. Which should be used? And should the figure on financial investments be compared to annual output or to something else? What is the right way to aggregate figures in order to make a useful comparison?

In order to address these points, this paper attempts to place financial speculation with oil futures and related derivatives into their proper context in the broader economy. The oil futures market should be seen as one part of a larger capital market for oil related investments. Commodity index investors, hedge funds and other financial speculators in the oil futures market are seeking exposure to fluctuations in the price of oil. An investment in futures contracts is but one channel for obtaining that exposure. This paper is intended to place these investments in futures contracts into a broader context by exploring the full scale of the economy's exposure to fluctuations in the price of oil and the variety of channels through which that exposure flows to ultimate investors.

2. A FRAMEWORK

In this section we provide a framework for understanding how the trade in oil derivatives relates to the physical production and use of oil in the economy. This framework will help identify appropriate ways of benchmarking the scale of investment through derivatives and suggest the type of statistics needed to properly evaluate the dynamic between the financial and physical markets.

Figure 1 shows the classic diagram of the circular flow of economic activity that is at the heart of national income accounting. On the right-hand-side are households. On the left-hand-side are businesses. Households supply the various primary factors of production—labor, land and other natural resources including oil, capital and so on—shown by the gray arrows at the top of the diagram. Because of the special focus of this paper, I have drawn two arrows. One is the natural resource of oil in the ground. The other is for all other primary factors. Businesses take the primary factors to produce goods and services. A subset of these are final goods and services which flow to households as shown by the gray arrow at the bottom of the diagram. It is sometimes useful to think of the various final goods and services as embodying oil, with some containing more and some less. However, I have not itemized that separately, in order to emphasize the distinction between oil as a primary factor and the array of final goods and services made using the oil, whether directly or indirectly.

Inside the box labeled 'Businesses' are many complicated flows of intermediate goods and services between individual companies as the primary factors of production are transformed, first to the various intermediate goods, and ultimately to the final goods and services. In particular, crude oil is extracted, shipped, refined into various products and then marketed. Some of the product is used as fuel by other business—including airlines, shipping and trucking companies, as well as some manufacturers—some some as chemicals used by other businesses, and some is sold to consumers as fuel for personal transportation.

The dark black arrows flowing in the opposite direction represent the financial flows. Households pay businesses for the goods and services they receive, and business pay households for the primary factors of production supplied. Payment for primary factors of production includes payment for oil supplied, and in this diagram I have itemized that separately. While one can think of payments for the final goods and services as including payment for the embodied oil, I have not itemized that separately, but leave it as a part of the total payment.

Corresponding to the many complicated flows of intermediate goods and services inside the box labeled 'Businesses' are the many complicated payment flows between different businesses, including payment for the oil embodied in the intermediate products sold along the value chain.

The payment on Figure 1 labeled 'oil revenue' shown flowing from 'Businesses' to 'Households' is the net value paid for the primary factor of oil in the ground. This will equal the gross receipts for sale of produced crude oil less the cost of production, i.e., payment to other primary factors used in production. Figure 2 provides a more detailed analysis of this flow. It shows the gross oil revenue flow into an oil producing company and how this flow is then channeled to various payments that ultimately flow to households in different guises. Of the gross oil revenue flow into the company, a portion branches off to the left; these are other factor payments—i.e., costs of production such as labor costs, or costs paid to other companies. Another portion branches off to the right; these are more factor payments, such as returns to the company's own capital. These factor payments appear as income on corporate financial statements. The third portion of gross revenue is shown in the center of the diagram, and is marked 'A'. This is the net oil revenue. This flow is, in turn, portioned into pieces itself. Two portions are shown branching off to the left. These include including royalty and lease or bonus payments to the original owner of the mineral rights. This flow is marked ‘C’. These also include any excise and other taxes over and above the cost of government services used in the production process. This flow is marked ‘D’. Both of these flows are accounted for as a cost to the oil producing company, and so are not recorded as income to this company. The remaining portion of the net oil revenue flow to the company’s income statement; this is the portion shown in the figure as the flow out to the right with the circle marked ‘B’ next to it. The company’s income is then paid out to the liability holders and shareholders; these are shown as the two flows out at the bottom center. Since this flow into the company is linked to the price of oil, then at least some of the flows out of the company must also be linked to the price of oil. For ease of exposition, we will focus on the equity flow capturing the oil link. Although the equity cash flow contains the portion of the net oil revenue marked ‘B’, this is also mingled together with other factor payments entering the oil producing company.

Households’ are exposed to fluctuations in the price of oil through each of these different flows that is linked to the oil price. It is also possible that some of the other flows have some less direct link to the price of oil, as will be discussed more later.

Figure 2 makes clear that household’s claims on the net oil revenue is channeled through different sources. Some households may have direct ownership of mineral rights, and they obtain royalties from the oil producing company which operates the fields for them. The royalties to private owners are a portion of flow ‘C’. All households own mineral rights indirectly through the fact that their government owns mineral rights.

These are another portion of flow ‘C’. All households also benefit indirectly through the government’s excise and other taxes an amount greater than the cost of government services used in the production process, the flow marked ‘D’. Many households own oil indirectly as financial investors in companies that own the oil. They may receive stock dividends or debt repayments from these companies, or they may own partnership interests or royalty trust claims. This will be a portion of flow ‘E’. Where the oil producing company is state owned, households benefit indirectly from the government’s equity stake. This will be the other portion of flow ‘E’.[1]

The general structure shown in Figure 2 applies to a wide array of cases that will differ markedly in the specific values and proportions. In the U.S., the common structure is to set the oil royalties—flow ‘C’— equal to a fixed percentage of the gross revenue. In the U.S., the majority of oil producing companies are owned by private investors, although a small amount is operated by state owned corporations based in other countries. In some countries, all production is controlled by a state owned company that also is the owner of the mineral rights, so that all of the flow of gross revenue is through that company. The revenues from the state company flow into the government budget and so, indirectly, benefits households. In other cases, the state owned company contracts with an operating company which runs the production, and a production sharing agreement defines how the gross revenues are split. The state company passes its share on to the government, while the operating company passes its share along to the private owners of its equity. These different structures are important to understand, but not very well documented.

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[1] Technically, the oil producing company’s debt cash flow is also exposed to the oil price through the oil revenue flowing into the company. However, for ease of exposition, I have abstracted from that fact.

Figure 3 focuses the analysis further back along the chain of businesses that use the produced crude oil, a refiner and an airline. At the top of the figure we see the flow of ticket revenue into the airline. In some cases this revenue is payment for a final service to households, like that shown at the bottom of Figure 1. In other cases it represents payment for an intermediate good, which in Figure 1 occurs inside the box marked Businesses. The payment flow of ticket revenue is then divided at the airline into (i) payment of certain costs of doing businesses, which is the flow diverted out to the left on the diagram, (ii) payment for jet fuel, which is the flow diverted out on the left and then down as revenue to the refinery, and (iii) payment to debt and equity, which is shown in the bottom right hand side of the diagram, flowing to households.

The payment flow for jet fuel revenue going into the refinery is then divided at the refinery into (i) payment of certain costs of doing businesses, which is the flow diverted out to the left on the diagram, (ii) payment for crude oil, i.e., the gross oil revenue that appeared at the top of Figure 2 going into the oil producing company, and (iii) payment to debt and equity, which is shown in the bottom right hand side of the diagram, flowing to households.

Figure 4 focuses the analysis on the households themselves. At the top of the Figure we have the different payment flows into the households. Some of these will be 'oil-linked', such the oil royalty flow from Figure 2, or the equity flow from Figure 2. Some will not be. The Figure shows one oil-linked flow and one other cash flow on the left, and one other cash flow on the right. The Figure highlights two households, one labeled investor #1 and the other labeled investor #2. These could be private investors, or one of them might be a government. At the bottom of the diagram are the payments made by households for final goods and services. These correspond to the payments at the bottom of Figure 1. The Figure also shows the flow of final goods and services consumed by the households. These are shown as grey arrows pointed towards the households, and correspond to the flow of final goods and services shown in Figure 1. Insofar as the price paid for the final goods fluctuates with the price of oil, these flows may embody household's exposure to the oil price. This exposure will be less explicit than the factor payments.

Oil Derivatives and the Flow of Oil Payments

Oil futures contracts are another type of financial security channeling payments along the circular flow diagram in Figure 1, as are other oil derivatives. Figure 5 shows one of the many ways in which this can happen. It is identical to Figure 2, except that at the bottom of the figure, shown in red, we have added the flows on a futures contract between the oil company and an investor. These are marked 'F'. Presumably the company is hedging its exposure to the price of oil and is short the futures contract, while the investor is long the contract. We show the futures cash flow at the oil producing company with one arrow and the flow at the investor with a separate arrow because technically the two sides of the transaction do not need to directly trade with one another. The dotted circle between them represents the market where the trades take place: for example, the futures exchange. Figure 5 also differs from Figure 2 in the equity cash flow from the oil producing company to investors: it is now drawn in red and marked with an asterisk in order to call attention to the fact that it is a different cash flow than the one shown in Figure 2. The equity cash flow here will be net of the futures cash flows, and will exhibit less exposure to the price of oil than if the company did not hedge with futures.

A key fact that this figure makes clear is that the total net oil revenue payments channeled to investors is exactly the same across Figures 2 and 5; it is the amount flowing through the channel marked ‘B’. The addition of the futures contract shifts the cash flows between the futures and the equity, but the combined flow to investors is the same. The aggregate household net exposure is the same; it has just been rerouted from one financial claim to another.

Figure 5 also help make the point that from a financial investor’s perspective, being long futures contracts is comparable to ownership of the oil in the ground. Payment on the oil futures contract in Figure 5 flows from the net oil revenue stream that is also the source of royalty payments and equity payments to a holder of reserves. It is just a different form of claim on the net oil revenue stream that is compensation for the primary factor of oil in the ground. The futures contract sells this stream in monthly increments, so to replicate the ownership of a developed field would require a strip of monthly futures contracts with the quantity of each month’s contracts owned varying in parallel with the expected decline in production from the field.

A key question, then, is how large a fraction of the total cash flow on physical oil assets is channeled by trade in futures and other derivatives, and how does this interact with other elements of the payment flows on this diagram. This is a discussion about the market value of the physical oil assets, so we need to look beyond a simply summing up of the total oil in the ground measured in barrels, and consider instead the market value of that oil and how it is a function of the current spot price or the entire term structure.

Some commentators on futures markets make much of the fact that futures contracts are by definition always in zero net supply. For any investor 'long' a futures contract, there is another investor 'short'. The conclusion they would like to draw is that one can therefore abstract from the futures market, ignore it. The conclusion does not follow. The fact that futures are in zero net supply only means that trade in futures contracts does not directly impact or alter the flow of real goods or services charted along the grey lines in Figure 1 and Figure 2. This is true as far as it goes. The total flow marked 'A' in Figure 2 and 5 is unchanged between the two figures. But trade in futures can change the flow of payments charted along the black lines, potentially in dramatic ways. Whether the structure of payments has an indirect impact on the production and consumption of real goods and services is a much more difficult question to address and answer. Insofar as futures markets are a useful institutional innovation, it would seem that the presumptive answer is that there is an indirect impact. And if that is so, one can imagine that there are ways in which the institution can also malfunction. This paper does not pretend to address this question, except insofar as gaining the big picture may help shape future research on it.

As a starting point for the quantitative benchmark we seek in evaluating the scale of investment in oil futures and other derivatives, consider the total flow at 'B' into publicly traded oil companies and how that compares to the total volume of hedging at 'F', and then to the total volume of other trade in the futures market. If 'F' were to equal the portion of 'B' flowing into publicly traded companies, then it would capture 100% of the oil exposure flowing onto the income statement and into the liabilities of those companies. The equity will be completely immunized against exposure to the price of oil.

Futures contracts can re-channel flows related to net oil revenue at other points in Figure 1. Figure 6 shows a possible futures contracts bought by an airline that is hedging the cost of its jet fuel oil purchases. Figure 6 can be compared to Figure 3: the equity cash flow of the airline is changed due to the existence of the futures contract. Because the price of jet fuel is not perfectly correlated with the price of crude oil, buying a crude oil futures contract provides only an imperfect hedge of the jet fuel costs. However, because the crude oil futures market is much more liquid than the jet fuel derivatives market, this is a common strategy among airlines. This emphasizes a potential problem is attempting to circumscribe our analysis to a specific product, such as crude oil, without due regard for related products.

Figure 7 shows a futures contract between two investors, without any business involved in the open position. This can be a hedge for both investors if one of them is positively exposed to an oil linked cash flow, such as oil royalty payments or an equity stake in an oil producing company, and the other is not similarly exposed. It can also be a hedge for both if one of them is exposed to fluctuations in the price of oil affecting the price of the goods and services they would purchase and the other is not similarly exposed. On the other hand, the futures trade shown in Figure 7 may not be a hedge for one or both of the investors.

Figures 5, 6 and 7 each identify a pair of parties to a given futures contract, although each figure is drawn with the trades actually being intermediated by the futures market, identified by the red dashed circle. Because the trades are intermediated by the market, one can never specifically associate one investor or business on one side of the trade with a specific other investor or business on the other side of the trade. We did that in those figures purely for expository purposes. Figure 8 better illustrates the situation for the market as a whole. Different parties each maintain a position in futures contracts with the market as a whole. These positions may change the exposure of various businesses or of individual investors.

How large are the payment flows associated with oil futures contracts relative to the other elements of the diagram? How large are the natural oil price exposures of various businesses and households—those associated with the flow of real goods and services, measured in the direction of the grey lines—and what is the scale of hedging or speculating in oil futures relative to these natural exposures. These are the questions this paper seeks to address.

As we shall see, there is very little data on the size of these various flows and the scale on which oil futures and other derivatives re-channel exposure.

3. OIL DERIVATIVES: FUTURES, OPTIONS & SWAPS

There is relatively good data on aggregate quantities of exchange traded crude oil futures and options. Unfortunately, the data on quantities traded off exchanges, in the OTC swap market, is very poor. So we only have an incomplete picture of oil derivative contracts outstanding.

Table 1 shows the total futures and options open interest outstanding at the end of 2010 on the three contracts that account for most of the trade. The leading oil futures contract trades on the CME in its NYMEX . The underlying product is a light sweet crude oil also known as West Texas Intermediate (WTI) crude oil. Open interest is the total number of 'bets' in play at a given point of time, with someone being on the long side of the bet and someone else being on the short side of the bet. The total open interest in contracts of various maturities is publicly reported. At year-end 2010, the total open interest in crude oil futures across all maturity dates stood at 1.402 million contracts. A contract is for 1,000 barrels of oil, so this translates to contracts on 1.402 billion barrels. The exchange also hosts trade in crude oil options, which can be managed to yield a similar exposure to changes in the oil price as a futures position. For any given open interest in option contracts one can calculate the open interest in futures required to maintain an equivalent exposure. The U.S. Commodities Futures Trading Commission (CFTC) reports the combined open interest, summing together futures and options, for those contracts it supervises which include the NYMEX's WTI contracts. For the CME's WTI contract, recognizing the exposure created in the option markets adds open interest equal to 76% of the futures contract open interest, bringing the combined open interest to 2.465 billion barrels as shown in Table 1. Multiplying the open interest measured in barrels by a price of oil of $90 per barrel expresses the open interest in dollars of exposure which was $221.8.18 billion. This represented roughly 62% of the world's crude oil futures and options open interests.

The other major futures contracts for crude oil are offered by the Intercontinental Exchange (ICE). It runs a copycat contract that is pegged off the CME's WTI contract. The CFTC also reports combined futures and options open interest for this contract. At year-end 2010 this was 0.554 million contracts, which represents 554 million barrels or $49.8 billion. The ICE also offers its own futures contract on Brent crude, a type of oil from the North Sea and the main competitor to WTI as a benchmark for oil. At year-end 2010 the open interest in this futures contract was 0.883 million contracts. To get a combined futures and options open interest figure for year-end 2010 requires some estimation. The CFTC does not supervise this product, so its combined open interest reports do not include it, and until recently, the ICE did not report a combined figure. However, in June 2011 it began providing comparable information, and options accounted for 9% of the combined open interest. Assuming this ratio held true at year end 2010, we estimate a combined open interest on this contract for 0.967 million barrels, or $87.1 billion.

As Table 1 shows, the total open interest across all three contracts is 3.986 billion barrels or $358.7 billion. While there are a few other crude oil futures contracts, this represents the vast majority of global exchange traded crude oil futures.

A critical feature of trade in futures and options markets is the short maturity of the contracts traded. Figure 9 is a graph of the maturity profile of the combined futures and options open interest. Open interest is clearly concentrated in the contracts with delivery in the next couple of months: the first two months alone account for 40% of the total open interest. Contracts with maturity less than 1 year constitute more than 80% of the total open interest. At 2 years the total is 93%. Although contracts are offered monthly out to five years, open interest concentrates in just a few contracts, which improves liquidity. The December and June contracts attract the most positions, and so these are the contracts offered beyond five years. Although the share of open interest remains low at longer contract maturities, that share has been growing over the last decade. Combined with the total growth in open interest overall, this means that the liquidity at the long maturity contracts is notable, even if the liquidity remains relatively low—see Büyükşahin et al. (2008).

Figure 10 shows a breakdown of the open interest in oil futures and options by type of trader. We have chosen to show the breakdown for each side of the transaction separately. At the top we have the traders who are long oil futures, i.e., who have bought oil via a futures contract. Producers, processors, merchants and other commercial businesses—here labeled ‘Merchants’—make up 19% of the long positions. These are businesses that handle the physical commodity and use the futures market as a financial hedge of their exposure to fluctuations in the oil price. Swap dealers and managed money accounts, which includes hedge funds and other financial investors, 32% and 25% of the long positions, respectively, for a total share of 57%. This figure combines the long-only trades of these investors together with the long side of any spread positions. Other investors hold 24% of the long positions. On the short side, a larger fraction of the positions are held by ‘Merchants’, 32%. Swap dealers and managed money account for 33% and 13% of the short positions, respectively, for a total share of 46%. This figure combines the short-only trades of these investors together with the short side of any spread positions. Other investors hold 22% of the short positions.

In addition to the oil futures and options contracts sold on these exchanges, oil derivatives can be traded in the OTC market. The recent financial reforms imposes new trade reporting requirements on OTC derivatives markets, so that we are poised to learn much more about them. However, the reforms have not yet been implemented, and it remains the case that very little information on OTC trades is available. The largest portion of the OTC market is intermediated by the large banks that operate as swaps dealers. An OTC swap can replicate the payoff to an exchange-traded futures or options contract – or bundles of futures and/or option contracts. The open interest data for exchange traded futures and option reported above does not encompass these OTC trades, and therefore this data underestimates the true size of the open interest in crude oil. The Bank for International Settlements (BIS) publishes a pair of data series on the notional amounts outstanding and the gross market values of commodity derivative contracts traded OTC. At year-end 2010, the notional outstanding on all commodity derivatives was $2.922 trillion. The gross market value was $526 billion. This is the data referenced by Basu and Gavin (2011) in their report to the Federal Reserve Bank of St. Louis. However, neither the notional outstanding nor the gross market value exactly corresponds to open interest as reported on the exchanges. The notional outstanding is a 'gross' figure, cumulating many offsetting positions which, if sent to an exchange with central counterparty clearing, would cancel each other out and not contribute to open interest. It is therefore an exaggerated value. In addition to the failure to net offsetting exposures, the gross figure aggregates exposures of very different sorts, such as options and futures, without taking care to place them in equal terms. The gross market value represents an entirely different concept than open interest. Until the reporting mandated under Dodd-Frank is fully implemented, we do not have a complete picture of total exposures in the oil derivatives market.

For sake of completeness, Table 1 includes the notional amount outstanding figure for the OTC derivative market. This figure covers derivatives in all commodities. To have a sense of the magnitude for oil, we assume a 40% share, which means oil derivatives are estimated to have $1.168 trillion notional outstanding. This is more than 3 times the exchange traded open interest. Translated into number of barrels, OTC oil derivative notional is for 12.987 billion barrels.

4. PHYSICAL FLOWS AND STOCKS

Production

Table 2 shows estimates of annual oil production in the U.S. and globally. U.S. production is estimated at 5.5 million barrels of oil per day, or 2.0 billion barrels per year. In addition, the U.S. imports another 9.2 million barrels of oil per day, or 3.3 billion barrels per year. This yields a total U.S. supply of 5.3 billion barrels annually. Global production of crude oil in 2010 is estimated at approximately 74.1 million barrels of oil per day, or 27.0 billion barrels per year.

We can translate the U.S. production figure into a dollar value by multiplying the barrels produced by the net price, which is the difference between the average selling price of approximately $84 and the average lifting cost of $12/bbl.[2] This net price is $62/bbl. Multiplied by the volume of production, it gives us a value of $143.8 billion.

Reserves and Resources

Table 2 also shows recent assessments of the oil reserves and resources in the U.S. and globally. Total US proved oil reserves totaled 22.4 billion barrels in 2010. In addition, the table shows a forecast for growth in reserves from already discovered fields of 49.4 billion barrels. Although this 49.4 billion barrels has not yet been declared as proved reserves on these properties, it is anticipated that, due to additional drilling or to enhanced recovery efforts, this amount will at a later date become proved reserves and then ultimately produced. Finally, the table includes a forecast of 134.5 billion barrels of as yet undiscovered, but technically recoverable resources. The total U.S. resource is therefore 206.2 billion barrels.

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[2] Energy Information Administration, Performance Profiles of Major Energy Producers, 2009, Tables 10, 11 and 12, and Domestic Crude Oil First Purchase Prices. These values are for 2009.

Global reserves are estimated at 1.342 trillion barrels. In addition, the U.S. Geological Survey estimates that growth in existing discovered fields will yield another 661.4 billion barrels and that undiscovered, technically recoverable resources equals another 783.5 billion barrels. The total global resource is therefore 2.787 trillion barrels.

Valuing reserves

We can translate the physical values shown in Table 2 into economic values either by means of a valuation model that forecasts the schedule of production and a path of price and lifting costs, or by accumulating transaction data on the price at which companies have bought and sold old reserves. If the valuation model we use is correct, the results should match what we find in the transaction data.

Suppose we have a producing oil field with a well defined initial quantity of reserves, Q_0, to be produced according to a fixed schedule, q_t. For convenience of illustration, it is convenient to assume that the quantity produced at each point in time is proportional to the remaining reserves, Q_t, with $q_t = \gamma Q_t$. Then both the production schedule and the remaining reserves follow a simple exponential decline schedule:

$$Q_t = Q_0 e^{-\gamma t}, \text{ and} \tag{1}$$

$$q_t = \gamma Q_0 e^{-\gamma t}. \tag{2}$$

Suppose as well that we assume the forecasted price grows at an exponential rate,

$$p_t = p_0 e^{gt}, \tag{3}$$

as does the forecasted lifting cost,

$$c_t = c_0 e^{ht}, \tag{4}$$

where g and h are constants, with p_0>c_0 and $g \geq h$. The general cash flow valuation formula is,

$$V_0 = \int_0^\infty p_t \, q_t \, e^{-rt} \, dt \,, \tag{5}$$

and, under our assumptions this is,

$$V_0 = \int_0^\infty \left(p_0 \, e^{gt} - c_0 \, e^{ht} \right) \gamma \, Q_0 \, e^{-\gamma t} \, e^{-rt} \, dt \,, \tag{6}$$

which simplifies to

$$V_0 = \left(p_0 \frac{1}{r - g + \gamma} - c_0 \frac{1}{r - h + \gamma} \right) \gamma \, Q_0 \,. \tag{7}$$

The exposure on the reserves—known as the 'delta' w.r.t. the oil price— is:

$$Exposure = \Delta = \frac{dV_0}{dp_0} = \frac{1}{r - g + \gamma} \gamma \, Q_0 \,. \tag{8}$$

Or, expressing exposure in terms of the percent change, which is also known as the 'oil Beta',

$$oil\ Beta = \frac{\left(dV_0 / V_0 \right)}{\left(dp_0 / p_0 \right)} = \frac{p_0 \left(\dfrac{1}{r - g + \gamma} \right)}{p_0 \left(\dfrac{1}{r - g + \gamma} \right) - c_0 \left(\dfrac{1}{r - h + \gamma} \right)} \geq 1 \,. \tag{9}$$

The Hotelling Rule

Deploying a valuation model like equation (5) requires us to forecast the rate of production and the future path of prices and costs. The more specific version in equation (6) simply collapses this to an estimate of the average rate of production, γ, and growth rates in price and cost, g and h. Economists sometimes finesse this burden by appealing to the Hotelling (1931) model.

Hotelling analyzed the producer's choice of when to produce the oil from the reserve, i.e., the production schedule q_t. Changes in the forecasted path of prices in cost ought to result in changes to the production schedule. Conversely, the pattern of the forecasted prices and costs through time ought to respond to changes in the overall industry production schedule. The ability of the industry to shift production from today to tomorrow should constrain the shape of the term structure of forecasted prices and costs. That is to say, the term structure of net price will be an outcome of the intersection of supply and demand, including the intertemporal supply and demand profiles. Under certain assumptions, this logic yields the well known Hotelling Rule which states that the net price is forecasted to grow at the rate of interest:

$$p_t - c_t = \left(p_0 - c_0\right)e^{rt}. \qquad (10)$$

A consequence of the Hotelling Rule, again under certain assumptions, is what Miller and Upton (1985) call the Hotelling Valuation Principle:

$$V_0 = \left(p_0 - c_0\right)Q_0. \qquad (11)$$

That is, according to the Hotelling Valuation Principle, the value of a reserve equals the undiscounted cash flow at present net price. The consequent exposure formulas are:

$$Exposure = \frac{dV_0}{dp_0} = Q_0. \qquad (12)$$

Or, expressing exposure in terms of the percent change,

$$oil\ Beta = \frac{\left(dV_0/V_0\right)}{\left(dp_0/p_0\right)} = \frac{p_0}{p_0 - c_0} \geq 1. \qquad (13)$$

Equations (11)-(13) are a special case of equations (7)-(9) in which g=h=r, although there are also more general conditions under which (5) yields (11)-(13).

The Hotelling Valuation Principle, equation (11), is popular among economists attempting to incorporate the value of natural resource endowments into national statistics—see, for example, Boskin et al. (1985), Bureau of Economic Analysis (1994), World Bank (2006) and Arrow et al. (2010). Landefeld and Hines (1985) are circumspect about applying the Hotelling Valuation Principle, noting that the valuation resulting from the Hotelling Rule varies dramatically from (i) the valuation resulting from other price forecast rules, and (ii) the valuation derived from land prices. Unfortunately, application of the Hotelling Valuation Principle seems to be popular primarily because it simplifies the burdens on the analysis, and not because the results are empirically validated.

The earliest empirical work testing the Hotelling model focused on the Hotelling Rule, equation (10): does net price—or simply price—grow at the rate of interest? The results have generally not been good. See Barnett and Morse (1963), Smith (1979), Feige and Geweke (1979) and Smith (1981), as well as many others since then.

More recent empirical work has focused on the Hotelling Valuation Principle, equation (11). The main test is to compare data on directly or indirectly observed market valuations of reserves, V_0^i, against the values implied by equation (11). The regression equation used is some variation on:

$$\frac{V_0^i}{Q_0^i} = \hat{\alpha} + \left(p_0^i - c_0^i\right)\frac{\gamma^i}{\hat{\delta} + \gamma^i} + \varepsilon^i , \tag{14}$$

where $\hat{\alpha}$ and $\hat{\delta}$ are the coefficients to be estimated and ε^i are the error terms. The Hotelling Valuation Principle implies the coefficient estimate $\hat{\delta}$=0, or equivalently, $\delta/\left(\hat{\beta} + \delta\right)$=1. In contrast, the mass of the literature has found that $\hat{\delta}$>1, meaning net price grows at less than the interest rate.

Miller and Upton (1985a) examine the market value of reserves implied by the stock price and debt values of 39 U.S. oil and gas producing companies at fiscal year-ends falling between December 1979 and August 1981. The implied valuation involves backing out the value of non-reserve assets. Their regression results support the Hotelling Rule. Miller and Upton (1985b) continue their analysis looking at the later time period of August 1981-December 1983. The results this time are not supportive of the Hotelling Rule, yielding an estimated coefficient $\gamma/(\delta+\gamma)$=0.466, much less than 1. The authors find the results of their second sample unconvincing due to the lack of adequate variation in the oil price during the sample so that the data are not sufficiently informative relative to the data from the earlier paper. Miller and Upton (1985b) also look at a very small sample of data on oil and gas Royalty Trusts, which have the advantage of providing a cleaner estimate of the implied reserve value since they are free of other assets and corporate tax liability issues. According to the authors, the results from this small sample are supportive of the Hotelling Valuation Principle.

A number of other researchers have conducted similar tests with results that lead to rejecting the Hotelling Rule. Adelman (1990) cites data on the market value of developed reserves from Arps (1962) to illustrate that the value of reserves are generally a fraction of the undiscounted cash flow at present net price. Similar results are reported in Adelman, DeSilva and Koehn (1991), Adelman and Watkins (1997), Thompson (2001) and Adelman and Watkins (2005) using a set of market transactions of oil and gas reserves in the United States compiled by the petroleum consulting firm Scotia Group, Inc. and covering the years 1982-2003. Watkins (1992) and Adelman and Watkins (1995) repeat the tests using a set of market transactions of oil and gas reserves in Canada assembled by the petroleum consulting firm Coles Gilbert Associates Ltd. and covering the years 1989-1991, and confirm again the same result. Adelman, DeSilva and Koehn (1991) does the same again, using the J. S. Herold Company's estimated valuation of the value of in-ground oil and gas reserves for many individual producing companies from 1948-1986. Thompson (1991) uses a sample of the market value of reserves implied by the stock price and debt values of 53 U.S. oil and gas producing companies at fiscal year-ends falling between September 1991 and June 1992, finding the same thing, viz. the value of reserves are generally a fraction of the undiscounted cash flow at present net price.

Is the Hotelling model wrong? Hotelling's model has lasting significance in the economic theory literature primarily because it was a very early example of solving a classic type of dynamic optimization problem. The key insight about the relationship between the rate of growth in the flow variable—net price—and the discount rate has proven to be essential to a wide range of dynamic optimization problems. However, the model is most widely understood to be relevant to the particular problem of understanding the extraction of a non-renewable resource, and its relevance there depends crucially on the validity of a number of the associated assumptions, as we shall see. In particular, the Hotelling model assumes that the key constraint on the production profile, q_t, is the total amount of reserves in the field. The producer is assumed to be free to shift production across time, with modest assumptions required about how this shifting impacts costs. What analysts in the oil industry stress, however, are other, physical constraints on production—notably pressure. Creation of a reserve of oil involves not just discovery of the presence of oil, but investments in drilling which yield a batch of oil available for production under the given physical pressure conditions. Once the investment has been made in pressure, the optimal rate of production is set by a constraint and not by the optimal timing decision hypothesized by Hotelling. The owner of the reserve would like to move production sooner, if that were possible without making major expenditures in adding pressure, but taking the investments in pressure as given, the optimal production profile is set by the constraint of pressure. Consequently, a net price that increases at less than the rate of interest is perfectly consistent with the producer optimizing production under the constraint of the sunk investment in pressure. A mathematical presentation of this meta-optimization problem is presented in Cairns and Davis (2001).

Adelman (1990) and Adelman and Watkins (2005) provide additional evidence for this model by showing empirically that reserves with a higher rate of production have a higher value. Thompson (2001) uses his oil and gas company data to establish that production is constrained below the optimal rate and that the forecasted growth in net price is less than the rate of interest.

The bottom line is that the Hotelling Valuation Principle likely leads to an overvaluation of proven reserves and an overestimate of exposure on a reserve. Using transaction data on reserves leads to a value approximately half that implied by the Hotelling Valuation Principle. For example, using the net price of $62.00, the Hotelling Valuation Principle would yield a value of onshore reserves equal to $1.606 trillion. The more conservative value would be $802.8 billion, which is what we have entered in Table 2.

These results also imply a much lower measure of exposure for oil reserves. Instead of an exposure delta of 1, proven reserves would have an exposure delta of ½. As we shall see below, this difference grows when we move from proved reserves to the more speculative undiscovered resources. This is very important for assessing the scale of hedging using futures markets against the scale of physical reserves. The 'delta' measures the quantity of short maturity futures contracts needed to completely hedge the exposure on the proven reserve.

The oil Beta is the same for equation (9) without the Hotelling Valuation Principle, or for equation (13) with the Hotelling Valuation Principle. Given the estimated price and lifting cost, the oil Beta is 1.17.

The results presented here emphasize the value of data on reserve transactions. Currently this data is only produced irregularly by private parties and without the degree of consistency appropriate to provide a reliable answer. Therefore, maintaining a consistent dataset on the transaction prices for oil and gas reserves is a potentially valuable contribution that the EIA could make.

The literature on the Hotelling Valuation Principle has opened up the question of measuring the 'delta' on reserves, but has only made minimal progress. All of the focus to date has been on testing whether the delta is one or significantly less than one. There has been only modest analysis of how the delta may be conditioned by any number of variables. Both Adelman and Watkins (2005) and Thompson (2001) discuss the rate of production being one such variable. Thompson (2001) raises the possibility that the 'delta' is conditioned by the shape of the term structure of futures prices, but does not formally test this. Much more work could be done to develop a more thorough understanding of the market value of various reserves. At present, all we can do is use the data to determine roughly an average 'delta'.

Valuing unproved reserves and resources

Any aggregation like the one shown in Table 2 involves mixing together different things. For example, the 22.4 billion barrels of proved reserves include reserves of many different qualities. The oil itself is different, varying by sulfur content, API gravity, viscosity, and so on. And the conditions of production vary, too, with some fields being cheaper to operate and others more expensive. Consequently, the per barrel value of the reserves vary. Nevertheless, it is useful to add the different reserves together into one figure, speaking of the total quantity of reserves measured in barrels and of the per barrel price of reserves. The decision to create some sub-classifications—such as whether the oil is found on- or offshore, and whether the reserves are proved, forecasted as growth from already proved reserves, or forecasted to come from as yet undiscovered or unproved fields—reflects a recognition that certain dissimilarities in the quantity being measured may be especially relevant.

Although we accept the need to compromise with the enormous differentiation that exists among the quantities of oil described in Table 2, and therefore we willingly sum together oils of different qualities, we simultaneously accept the limit of such compromise and the necessity to preserve a few discrete categories. Recognizing the diversity characteristics of the barrels of oil summed together in Table 2 is critical to appreciating the economic complications involved in putting a number on the value of the nation's oil resources. In the previous section, we have discussed the valuation of proved reserves. The other categories of oil—forecasted growth from existing reserves, and undiscovered resources—are sufficiently different from proved reserves that it is impossible to value them similarly.

The problem goes beyond taking into account the incremental exploration and development costs. In addition, there is the greater risk and uncertainty associated with undiscovered resources—what will turn out to be the true cost of producing any given quantity, and when will economic circumstances make it worthwhile to produce any given quantity. Unfortunately, the dangers involved in attempting to extend the valuation of proved reserves to undiscovered resources are often overlooked. For example, Boskin et al. (1995) value the future Federal royalties from undiscovered resources exactly as they value the future Federal royalties from proven reserves. Their argument relies on extending the Hotelling Valuation Principle to all resources, treating a barrel of undiscovered resources the same as a barrel of proven reserves.

The more common analytic approach is to treat the undeveloped resource as an option on proved reserves. The option can be exercised by investing in exploration of properties and development where the resource is found. An illustrative derivation and calculation is given in the Appendix. The Appendix includes a figure graphing the value of the developed and undeveloped fields as a function of the oil price, and also figures graphing the delta and oil Beta for the developed and undeveloped fields.

Unfortunately, to my knowledge, there is no dataset available that maps the resource figures shown in Table 2 into market values, whether based on an option pricing methodology or some other technique. Nevertheless, it is clear that the economists' lazy recourse of leaning on the Hoteling Valuation Principal dangerously exaggerates the value of these resources and their relevance in benchmarking the financial market in oil.

The market value and the social value

The market value of reserves is net of royalties and taxes, i.e., after a portion of the total value has been shared with others. In our Figure 2, the market value of reserves captures the slice of the oil net revenue that flows onto the oil production company's balance sheet, slice 'B'. That is, the market value is not the full social value. To recover the full social value, it is necessary to add back the value of the stream of royalty payments, plus a portion of the taxes. In Figure 2, these are the other two slices out of the total net oil revenue which were marked 'C' and 'D'. The total is marked with an 'A'. That portion of taxes that covers the government's provision of real services necessary to the extraction of oil should not be added. Adelman and Watkins (1996) estimate that the ratio of social value to market value is probably about 1.27. That is, in Figure 2 the flow marked 'A' is 1.27 times the flow marked 'B'. We use that figure to complete Table 2. However, it should be obvious that this figure has a very weak foundation and there is room for valuable research to improve it.

Comparing the Scale of Derivative Claims to the Physical Asset

We can now make one comparison between Tables 1 and 2 in light of Figure 5. In Figure 5 we can see that futures contracts, marked 'F', channel a portion of the net oil revenue, marked 'A'. According to Table 2, the total volume of oil produced in the U.S. is 2 billion barrels per year or a value of approximately $183 billion. U.S. production plus imports is 5.3 billion barrels or $481 billion. How do these flows compare to the flow channeled through futures contracts? Since it is an annual flow we are charting here, we should examine just the next year's futures contracts, which account for 80% of the total open interest on the exchanges, or 3.2 billion barrels and $287 billion. This is markedly greater than U.S. production, although less than the total quantity of oil used in the U.S. economy.

Of course, the futures market is a global exchange used to hedge production and consumption in other countries. According to Table 2, the total volume of oil produced globally is 27 billion barrels per year which is about 8.5 times the open interest outstanding on the futures exchanges. It is, however, only 2 times the notional amount outstanding in the OTC market. This is astonishing. It is difficult to imagine that fully one half of the total exposure of the next year's oil production is channeled through the futures market, leaving only one half to be channeled through the publicly traded equity of oil producing companies, royalties and state-controlled claims. This is especially true since globally the state-controlled and non-tradeable claims are such a large fraction of the flow marked 'A'. Some of the state-controlled claims are occasionally hedged in the derivatives market, as Mexico has publicly done, but the majority are not. But we must remember that the notional amount outstanding of OTC derivatives is not comparable to open interest, containing as it does offsetting exposures. Nevertheless, the figure highlights the importance of gaining a more complete picture of the scale of this financial market, which hopefully will happen with the financial reform that is underway.

In comparing positions on the futures market with the scale of physical production of crude oil, we should also take care to appreciate that the crude oil market is a part of a larger liquids and energy complex. Financial trades in crude oil futures can be used to hedge exposure on products that are close substitutes for crude oil, which includes natural gas liquids and biofuel production. It is beyond the scope of this study to address this issue.

If we look beyond the first year of payment flow, the scale of derivative activity is much less—just 20% of the open interest on the futures market, or 800 million barrels. Assuming the same maturity structure in the OTC market, the notional amount outstanding that references payment flows past one year is 2.6 billion barrels. This figure is much smaller than U.S. proved reserves, and clearly dwarfed by global reserves. However, were the scales to ever become comparable, one would want to take more care in making a comparison, avoiding simply aggregating all barrels of oil derivative positions across all contract months and then comparing that to a simple aggregation of all barrels of physical production anticipated to be produced across all years. The need for a more sophisticated aggregation is illustrated by the fact that the calculated 'delta' exposure on a reserve is ½ of the aggregate reserves. A more complete calculation on both sides would require using a term structure model of oil futures prices. This would provide the necessary equivalence between exposures at different contract months. Extending this to unproven resources, however, would be very speculative.

5. CORPORATE EXPOSURE AND HEDGING

The CFTC's Commitment of Traders report provides some aggregate information about how companies hedge. A small bit of academic research has investigated bottom up sources of data on company exposures and their financial hedging. This is what we report on in this section. However, the research is very limited, and there is no systematic collection of data on this vital issue.

Measured Oil Betas on Oil Production Companies

There is a long string of studies estimating the sensitivity in the stock price of oil companies to fluctuations in the price of oil. This sensitivity is a company's oil Beta. This is distinct from the company's standard Beta which measures the sensitivity in the stock price of the company to fluctuations in a general market index. The oil Beta is measured using some variation on this equation:

$$R_{it} = \hat{\alpha}_i + \hat{\beta}_{im} R_{mt} + \hat{\beta}_{io} R_{ot} + \varepsilon_{it} , \qquad \text{(XX)}$$

where i indexes the oil company or portfolio of oil companies for which we are estimating the Betas, R_{it} is the observed stock return on company i in period t, R_{mt} is the observed return on the market portfolio in period t, R_{ot} is the observed change in the log oil price in period t, $\hat{\alpha}_i$ is a constant to be estimated, $\hat{\beta}_{im}$ is the traditional Beta for company i, which is to be estimated, $\hat{\beta}_{io}$ is the oil Beta for company i, which is to be estimated, and ε_{it} are the error terms. A number of the studies focus exclusively on pure E&P companies, while others include integrated companies that operate refineries and market refined products, or other oil-related companies such as oil services firms. Some studies focus on the US—which enables them to focus on pure E&P companies, while others include other countries. The results across the many studies are generally very consistent.

Manning (1991) calculates an oil Beta for portfolios of oil companies in the Financial Times index during the period 1986-1988. The E&P portfolio has an oil Beta of 0.24 while the integrated oil company portfolio's oil Beta is 0.10. Al-Mudhaf and Goodwin (1993) calculate oil Betas for 29 companies listed on the NYSE during the period 1970-1978, around the oil price shock of 1973. The median oil Beta is 0.11. Rajgopal (1999) calculates a median oil Beta of 0.30 using data on 52 U.S. oil and gas firms (SIC code 1311) over the period 1993-1996. Sadorsky (2001) estimates a Beta of 0.3 using data on a portfolio of Canadian oil and gas companies over a sample period of

1983-1999. Jin and Jorion calculate a median oil Beta of 0.28 using a sample of 119 U.S. oil and gas firms (SIC code 1311). Boyer and Fillion (2007) calculate a median oil Beta of 0.26 using data on 105 Canadian oil and gas firms, including 99 pure E&P companies and 6 integrated companies over the period 1995-2002. Cai et al. (2006) calculate an oil Beta of 0.15-0.27 for a global oil exploration and production industry portfolio sourced from Datastream covering the period from 1990 to 2005. The portfolio comprises 127 companies across 21 countries. They also analyze geographical sub-indexes, and the largest calculated oil Beta is 0.37 for the North American index. Nandha and Faff (2008) calculate an oil Beta of 0.15 for a global portfolio of oil and gas companies over a sample period 1983-2005. Mohanty and Nandha (2011) analyze a sample of 40 US companies in various parts of the oil and gas industry over a period from 1992-2008. Their median oil Beta estimate for the 14 E&P companies is 0.32. Bredin and Elder (2011) calculates an oil Beta of 0.22 for a broad oil industry portfolio over the period 1974-2009.

Although the specific value of the estimated oil Betas naturally vary across the many studies, most estimates lie around the range of 0.2-0.3. A beta of 0.2 means that for every 1% change in the price of oil, the stock price of the company changes by 0.2% in the same direction.

This is a very low value. In the earlier section on exposure in reserves and resources, we calculated an oil Beta on a developed reserve of 1.17 using equation (9) and data on actual prices and lifting costs. Following Tufano's (1998) practice in regard to gold Betas, we call this calculated exposure using equation (9) an analytic oil Beta. As can be seen in the figures in the Appendix, the exposure or oil Beta on undeveloped resources should be larger than the oil Beta on developed reserves, at least for oil prices that are not too low. Insofar as an oil company is primarily a bundle of oil reserves, developed and undeveloped, its measured oil Beta should be comparable to this other, analytic oil Beta—1.17 or larger. But what we see from these studies is that the measured oil Beta is much less than the analytic oil Beta.

Contractual and Financial Hedging

One potential explanation for the low measured oil Betas is that oil companies hedge their exposure to the oil price, either through the terms of their contracts governing the sales of physical oil or through the use of financial contracts such as futures and options.

There has only been a small amount of research carefully analyzing these contractual and financial hedges. However, the results are consistent across the studies, and they all suggest that there is too little hedging to explain the low value of company oil Betas. Haushalter (2000) examine a sample of 100 U.S. oil and gas producers (SIC code 1311) over the years 1992-1994. In roughly 50% of the firm years firms report no financial hedges at all. Conditional on hedging, the mean level of hedging is less than 30% of one year's production. The unconditional mean level is roughly 15%. Pincus and Rajgopal (2002) examine a sample of 139 U.S. oil and gas producers (SIC code 1311) over the years 1993-1996. In only 44% of the firm years do firms report using financial hedges at all. Conditional on hedging, the mean level of hedging is 66% of one year's production. Jin and Jorion (2006) examine a sample of 119 U.S. oil and gas producers (SIC code 1311) over the years 1998-2001. In fewer than 50% of the firm years do the firms report any financial hedging at all. Conditional on hedging, the mean level of hedging is 33% of one year's production, which is also 4% of the company's total oil reserves. Dan et al. (2005) study large Canadian oil and gas companies during the period 2000-2002, including 38 E&P companies and 8 integrated companies. Hedging at these Canadian firms is even less than at the US companies: the mean level of hedging is 15% of one year's production, which is less than 2% of the company's total oil reserves.

Jin and Jorion (2006) go one step further in their study and estimate the amount by which hedging adjusts the oil Beta. They find a statistically significant coefficient on the hedge variable, so financial hedging does materially reduce a company's oil Beta. But their result does not explain the low level of the typical oil Beta.

An alternative type of hedging is embedded within the normal commercial contracts of producing firms, as opposed to their financial hedges. The studies cited above take the quantity of a company's oil reserves as a fixed number, so that a company's initial 'delta' per barrel is 1. However, in some cases the quantity of a company's oil reserves is itself a function of price. This is true whenever the company's reserves are determined by a production sharing agreement. These agreements usually determine the fraction of sales assigned to the operating company based on priority cost recovery, on total quantity and on price. Typically, the lower the price, the higher the fraction of production captured by the operator, and the higher the price, the lower the fraction. Therefore, a company's starting 'delta' may be less than 1, and it may be a function of the price. Hampson et al. (1991) provide a case study of a production sharing contract which explains how the operator's exposure is contingent on the realized quantity produced as well as on the realized sales price. Kretzschmar et al. (2007) document the variability in realized reserve exposures of companies based on reserve locations and contingent on the level of the oil price.

This caveat most likely applies to reserves located outside the US, since the most common contractual arrangement in the US is said to be a straightforward royalty payment that is a constant percent of revenue. However, even when this has been the case, the percent has occasionally been adjusted ex post, e.g. in response to low oil prices and the need to give the operator a minimum level of revenue in order to incentivize production—see the U.S. GAO (2008). This means that the actual exposure of the operating company declines with price. The U.S. GAO (2008) had recommended exploring making this contingency an ex ante feature of the contract, specifying a sliding scale scheme in which the royalty percentage is contingent on the price level, and the Department of Interior recently stated it is actively considering this idea.[3]

Regardless of what happens going forward, it is clear that insufficient attention has been paid in the academic research on determining the actual contractual exposure of oil companies. Researchers have assumed that reported reserves are owned in their entirety and that the quantity is independent of the price, when that clearly is often not the case. There is no available data base reporting these contractual exposures.

Other Problems in Measuring Corporate Exposure

A number of other reasons may explain the discrepancy between the analytically calculated oil Betas and the measured oil Betas. Some of these were discussed by Tufano (1998) in regard to a comparable discrepancy for analytic and measured gold Betas.

Our analytic oil Beta of 1.17 is based on the assumption that oil prices follow a random walk, so that changes to the current spot price translate into changes in the expected price at all time horizons. However, the oil price exhibits a large amount of

[3] Petroleum Intelligence Weekly, June 20, 2011, US Considers Bold Changes in Royalty Rates.

mean reversion. Therefore, measured oil Betas calculated using changes in the spot price will be systematically biased below the true Beta. Better oil Beta estimates could be made by exploiting full information on the term structure. Although the academic literature contains excellent models of the oil price term structure, the literature on oil Betas has not taken full advantage of this. At best what has been done is to substitute a longer maturity future contract as the independent variable in the estimation. For example, we see in Cai et al. (2006) that the estimated oil Beta is higher when the 6 month futures contract price is used as the independent variable instead of the spot price.

A second possible misspecification of the analytic oil Beta formula comes in the assumption that the oil price is entirely independent of the cost of extraction. There will be many circumstances in which, for example, a rising oil price will also drive rising extraction costs even on fully developed reserves. Numerous oil company economists and financial officers have, in personal conversations over many years, expressed the belief that this is often true. In particular, during the years 2003 and 2008, when global economic activity grew tremendously, the prices of many commodities together with the cost of key inputs to major capital investments and engineering projects increased dramatically. In particular, in the Canadian oil sands territory, wages for labor of all types increased dramatically together with the increasing price of oil. Tufano (1998) documents this for his set of gold mining firms, as did Petersen and Thiagarajan (2000) for two mining firms.

The third, and probably most important problem is that oil companies are not just a bundle of mechanically operated reserves. They have many other assets. This is obvious for integrated oil companies which operate refineries and refined product marketing units.

When this is the case, the measured oil Beta, since it corresponds to the percent return, will be reduced according to the fraction of assets in these other lines of business. And, indeed, in those studies that separate out the integrated companies from those exclusively engaged in E&P, we see that the measured oil Beta on the integrated companies is less than for the E&P firms—see, for example, Al-Mudhaf and Goodwin (1993) and Boyer and Filion (2007).

Of course, the measured Betas of pure E&P companies is still very low. Here, too, though, it is important to understand the pure E&P company not as a bundle of reserves that it passively cashes in, but rather as an operator with specific human, organizational and intellectual capital that can be repeatedly applied to different reserves. The value of all of that capital is not the same thing as the value of the reserves on which it is applied.

To make this point in the starkest form, we can run a thought experiment leaning on a contract structure that is uncommon to the oil industry. Suppose the operator contracted with a resource owner to execute the drilling for a fee instead of a share of the output. Put to the side for the moment the incentive problems this contract structure would engender. The operator in this thought experiment would have an oil price Beta close to zero.[4] It would still be a valuable company, commanding a profit on its capital. The fact that incentive issues force the industry to compensate operators with an equity stake in the resource now means that the operator's oil Beta must be greater than 0. But there is no reason that the operator's oil Beta must be made equal to the oil Beta of the reserves.

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[4] Interestingly, Mohanty and Nandha (2011) find a high oil Beta for oil services firms, which is at odds with the thought experiment being constructed here.

This can also be seen in Figure 2. The oil Beta measures the percentage sensitivity of the cash flow marked 'E'. This is a combination of the oil Beta on the cash flow marked 'B' and the oil Beta on the other factor payments entering the company's income statement. Our analytic oil Beta calculated using equation (9) purports to measure the oil Beta on flow 'B', while assuming away the other flow. The market data shows that this other flow is the dominant source of risk in most publicly traded E&P companies.

Exposure and Hedging by Oil Consuming Businesses

What do we know about exposure and hedging by businesses that purchase oil products as an input to their operations? The answer is two things: (i) very little in total, but (ii) what we do know reinforces the evidence on oil producers that financial hedges are heavily weighted to the near term production and do not represent a large fraction of total exposure.

Among the oil consuming businesses, the one that has received the most study regarding oil hedging is the airline industry, and yet even here the available literature is small. Carter, Rogers and Simkins (2006) study hedging at US airlines over the period 1992-2003. They find a negative exposure or oil Beta of -0.11. There is significant diversity in hedging practices among airlines, with many airlines employing no financial hedge at all in many years, and with the notable other extreme of Southwest Airlines which at the end of their sample hedged 80% of the next year's fuel needs. The mean level of hedging when firms hedged was 29.4% of next year's fuel needs, and the unconditional mean was 10.9%. Related studies include Treanor et al. (2009) and Lin and Chang (2009) who study global firms as well, and these studies document similar results.

These studies all identify contractual structures that also reduce exposure to oil prices: fuel price pass-through agreements and commercial arrangements such as the structure of charter operations. While some information is produced about these, we currently know very little about these.

The literature does not contain any analytic models of airline exposure comparable to our valuation model of a proved oil reserve. The airline's exposure is likely to be very complicated. On the one hand, it purchases jet fuel and would appear on first blush to be exposed to an increase in the price of jet fuel. However, the price charged for the airline's services will also adjust to increases in the price of jet fuel, limiting the airline's exposure. How the two cash flows—revenue and fuel cost—adjust relative to one another over time is what determines the airline's total exposure. While there is a literature that analyzes the relationship between jet fuel and crude oil prices, there is little in the academic literature that unpacks how this, together with the pass through to ticket revenue, translate into the airline's net exposure.

Related statistical work by Bredin and Elder (2011) documents a negative oil Beta for the transport industry generally, without going into any greater detail. Gogineni (2010) documents a negative oil Beta for the air transport industry, and attempts to quantify separately cost-side dependence on on oil and demand-side dependence on oil, although this is just a start in the direction of properly measuring net exposure.

Another major purchaser of oil is the refinery industry. It, too, will see the price of both its inputs and its outputs fluctuate with the price of crude oil, although not necessarily in tandem. Rajgopal (2000) uses a sample of 25 oil refiners over the period to estimate an oil Beta of 0.09, which is very low. To my knowledge, there is no literature that attempts to generate an analytic oil Beta for a refinery business, nor any that assesses the extent of financial hedging. Processing industries, such as the oil refining industry, have historically been the premier users of futures exchanges, so the paucity of academic literature here is remarkable.

Benchmarking Hedging by Producers

Based on the research to date, 20% of the next year's production would seem to be an upper bound on the scale of hedging done by U.S. producing firms using oil derivatives. Assuming this figure applies to all U.S. production, U.S. producers should account for short open interest of no more than 400 million barrels. The CFTC's Commitment of Traders report assigns 32% of the short open interest to merchants, or 1.3 billion barrels. That leaves 900 billion barrels sold short by companies classified as merchants in the CFTC report. There are four things that may make up this 900 billion barrels. First, it may be attributable to producers from outside the U.S. hedging their production. Second, it may be attributable to non-producer merchants hedging their exposures. Third, the 20% figure for US producers may be an understatement, either due to the fact that times have changed or due to the samples generating that figure being unrepresentative. In particular, it excludes all of the U.S. supermajors, and they may hedge more than 20%. This seems an unlikely explanation, since we know, for example, that the lead supermajor, Exxon Mobil, doesn't hedge at all. Nevertheless, the point is that we do not keep any reliable database on this. Fourth, the CFTC's categorization may not be quite as it would seem so that a large volume of financial trades appear there which are not a hedging of production. This may happen because the CFTC allocates all trades by any company to a single category chosen for that company regardless of whether or not that company may be trading for different purposes. Suppose, for example, that Shell and BP are categorized as merchants, which they are in respect to some portion of their business. But another portion of their business is dealing in oil derivatives. That portion will be categorized as merchant regardless of the fact that it actually represents purely speculative financial trading by their customers. If that line of business were to move to a different company such as a major dealer bank, the same transactions would no longer be classified as merchant.

Once again, all of the comments above are based exclusively on looking at oil derivatives outstanding on the exchanges. The 900 billion barrels unaccounted for by hedging of U.S. firms is a low estimate as it omits the positions held on the OTC market.

The inability to triangulate what we know about oil company hedging from individual disclosures with what is reported at the exchanges and dealer banks helps to illustrate how little reliable information we have about the scale of hedging by oil companies and how it fits into the larger picture of the oil derivatives market.

CONCLUSIONS

This paper has provided a framework for understanding how the trade in oil derivatives relates to the physical production and use of oil in the economy. We can use this framework to benchmark the scale of investment in exposure to oil prices made using futures, options and other derivatives. The paper has also reviewed available statistics on the scale of trade in oil derivatives, the scale of production and of the asset of oil-in-the-ground, and on how companies use oil derivatives for hedging.

The most important observation to make from this exercise is the inadequate state of knowledge about the oil derivative market. A large portion of the market—OTC derivatives—remains opaque, although current regulatory reform may change that. The OTC market produces only the coursest of data, and not on the most relevant quantity such as open interest. In contrast, the futures exchanges produce data in a useful and transparent format, in some meaningful detail—such as open interest by contract month, and generating futures equivalent open interest from the options market. The CFTC Commitment of Traders report, which pertains to the futures exchange data, but not the OTC market, provides some information, but it, too, is very course and difficult to convincingly means what it says.

If a proper comparison is to be made between the investment in the physical asset of oil-in-the-ground and the financial asset of oil derivatives, then economists will have to give more careful attention to accurately measuring the value of the physical asset as a function of the price of oil. The crutch of relying on the Hotelling Valuation Principle produces a significantly exaggerated measure of value and exposure. Existing databases on the value of proved reserves are a useful starting point, but they have not been thoroughly scrutinized and have not been developed to the standards of the EIA's other databases. In particular, it will be important to disentangle the value of the already established proved reserves from the value of the likely growth in reserves from the same fields. There is virtually no work that has attempted to value undiscovered resources, beyond anecdotal examples.

Comprehensive data on corporate exposure is also very limited. The structure of commercial contracts, such a production sharing agreements, is a major determinant of the company's exposure before any trading in oil derivatives. While there is some academic literature alerting us to this, even that literature does not ultimately provide us with clear, quantitative assessments. And there has been no effort to assemble this information at any comprehensive scale. There has been a plentiful set of academic papers measuring the oil Beta of publicly traded companies. This is a reflection of the fact that the minimal data required is readily accessible, and the statistical programs are now well standardized and easy to execute. Where there is room for more research is in understanding exactly what to make of the number: why is the number so small? There has also been a small amount of research on hedging with derivatives by oil producers. But there has been no effort to systematically collect and aggregate this data. There has been only the smallest amount of research on hedging by oil processors and consumers of oil products.

In the financial markets for other asset claims, notably equities, research over the last couple of decades has highlighted the way that the structure of the financial asset market relative to the underlying cash flows can make a great deal of difference in whether prices are tightly ties to fundamentals. For example, Ofek and Richardson (2002) argue that the wide deviation of stock prices from fundamentals during the internet bubble from January 1998 to February 2000 was due in part from the fact that such a small fraction of the equity claims of the start-up companies was available for trading in the public market. In the oil market, it is also the case that a very small fraction of the underlying cash flow stream on oil as a primary factor of production is available for trade.[5] A large portion of production is handled by state-owned oil companies without

[5] Much of the work on the limits to arbitrage in equity markets, including the paper by Ofek and Richardson (2002), leans heavily on the institutional obstacles to shorting stock. The situation is very different in the oil market. In fact, the futures market would appear to be the ideal solution to the problem since it makes shorting oil easy to do even without controlling any physical product. However, that would be a superficial understanding of the obstacles to shorting and executing an arbitrage. Naked shorting requires credit, and credit is another thing that is often in short supply, especially for would be arbitrageurs—see Shleifer and Vishny (1997) for the classic statement of the problem.

publicly traded equity. A few other state-owned oil companies have a small fraction of their shares traded publicly. Even the equity of the large, publicly traded international oil companies, only captures a partial claim on the underlying oil resource cash flow. The remainder goes either to the state corporation hosting their operation as governed by the production sharing agreement, or to royalty holders. Few of these non-equity claims are available for sale to private investors. If investors seek exposure to oil, purchasing an stock in an oil producing company is a poor tool for capturing that exposure, since the equity contains so many other exposures that mute the expression of the oil exposure. Oil futures markets represent an alternative channel for private investors to capture that exposure to the oil cash flow. But futures markets only re-channel exposures that would otherwise be reflected in these other claims, whether state-owned, resource royalty or oil producer equity. It is entirely possible that far too much speculative pressure is placed on a financial tool that fundamentally cannot bear the burden placed on it, thus leading occasionally to strong divergence of oil prices from fundamentals. This paper only mentions this as a hypothetical possibility, and does not assert that it is the case. Understanding the true size of the different cash flows channels tied to oil as a primary factor of production is an important starting point for thinking about this problem. There is much to be done here.

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Appendix: Illustrative Option Valuation of an Undeveloped Field

For this illustration we will make the following assumptions. The lifting cost for a barrel of oil from a proved reserve is c=$12/bbl. The cost of developing a resource is k=$22/bbl. Once developed, the production profile declines exponentially at rate γ=10%. The discount rate is r=10%. The price of oil is forecasted to be constant, as are both the lifting cost and the development cost, i.e., with growth rate g=h=0%.

Denote the per barrel value of a developed reserve, if we ignored the option to close it down by X_A. The value of X_A is given by a version of equation (7):

$$X_A(p) = (p_0 - c_0)\frac{\gamma}{r - g + \gamma} = 0.5\, p_0 - 6. \tag{A1}$$

The value of the developed reserve will incorporate the option to abandon production if the price drops below the lifting cost or some trigger, p_B, below that. Denote the per barrel value of a developed reserve, including the option to close it down by X_B. Following Dixit and Pindyck (1994), the value of X_B is given by an equation of the form,

$$X_B(p) = B_2\, p^{\beta_2} + X_A(p), \tag{A2}$$

with,

$$\beta_2 = \tfrac{1}{2} - \left(\frac{r-g}{\sigma^2}\right) - \sqrt{\left[\left(\frac{r-g}{\sigma^2}\right) - \tfrac{1}{2}\right]^2 + \frac{2r}{\sigma^2}}\,. \tag{A3}$$

Equation (A2) must also satisfy the condition that the value on abandonment at p_B equals 0,

$$X_B(p_B) = 0, \tag{A4}$$

and the optimality condition defining p_B,

$$X_B'(p_B) = 0. \tag{A5}$$

This system gives us two equations, (A4) and (A5), in two unknowns, p_B and B_2. Solving for these we obtain p_B = \$8.05/bbl and B_2 = 137.5. Figure A1 graphs the value of a developed reserve with and without the option to abandon, X_A and X_B, as a function of the above-ground price of oil.

Denote the per barrel value of an undeveloped reserve by X_C. This value will reflect the firm's optimal choice of a price trigger, p_C, at which it will exercise its option to develop the reserve. Again following Dixit and Pindyck (1994), the value of X_C is given by an equation of the form:

$$X_C(p) = A_1 p^{\beta_1} . \tag{A6}$$

with,

$$\beta_1 = \tfrac{1}{2} - \left(\frac{r-g}{\sigma^2}\right) + \sqrt{\left[\left(\frac{r-g}{\sigma^2}\right) - \tfrac{1}{2}\right]^2 + \frac{2r}{\sigma^2}} . \tag{A7}$$

Equation (A6) must also satisfy the condition that the value on exercise of the option equals the value of the developed reserve less the cost of development,

$$X_C(p_C) = X_B(p_C) - k , \tag{A8}$$

and the optimality condition defining p_C,

$$X_C'(p_C) = X_B'(p_C). \tag{A9}$$

This system gives us two more equations, (A8) and (A9), in two unknowns, p_C and A_1. Solving for these we obtain p_C = \$148.45/bbl. The coefficient A_1 = 6.3 E-06. Figure A1 also graphs the value of an undeveloped reserve, X_C, as a function of the above-ground price of oil.

With these equations in hand, we can calculate the delta and beta corresponding to each value function. These are graphed in Figures A2 and A3.

Table 1: Oil Derivative Contracts Outstanding, 2010

Futures & Options Open Interest

		barrels (billions) [A]	$ (billions) [B]
[1]	CME/NYMEX WTI	2.5	221.8
[2]	ICE WTI	0.6	49.8
[3]	ICE Brent	1.0	87.1
[4]	Total	4.0	358.7

OTC Derivatives Notional Amount Outstanding

		barrels (billions) [A]	$ (billions) [B]
[5]	Commodity contracts		2,922.0
[6]	Oil @ 40% share	13.0	1,168.8

Sources:

[1] [A] CFTC Commitment of Traders Report, December 28, 2010.

[2] [A] CFTC Commitment of Traders Report, December 28, 2010.

[3] [A] The combined futures and option open interest is not available for year-end 2010, so I estimate it using the futures only open interest for year-end 2010, and the ratio of the combined futures and options open interest to the futures only open interest for June 28, 2011 when this is first available from ICE. Open Interest on Futures, December 28, 2010 = 0.882866. ICE Commitment of Traders Report for June 28, 2011 shows the combined futures + options equals 110% of the futures only position.

[4] [A] =[1][A]+[2][A]+[3][A].

[1] [B] =[1][A]*$90.

[2] [B] =[2][A]*$90.

[3] [B] =[3][A]*$90.

[4] [B] =[1][B]+[2][B]+[3][B].

[5] [B] BIS (2011).

[6] [A] =[6][B]/$90.

[6] [B] =[5][B]*40%.

Table 2: Oil Production, Reserves and Resources

	barrels (billions, annual) [A]	market value, $ (billions) [B]	social value, $ (billions) [c]
United States			
[1] Domestic Production	2.0	143.8	182.6
[2] Imports	3.3		
[3] Supply, Total	5.3		
Global			
[4] Production	27.0		

	barrels (billions) [A]	market value, $ (billions) [B]	social value, $ (billions) [c]
United States			
[5] Reserves	22.3	802.8	1,019.6
[6] Reserve Growth	49.4		
[7] Undiscovered Resources	134.5		
[8] Total	206.2		
Global			
[9] Reserves	1,341.6		
[10] Reserve Growth	661.4		
[11] Undiscovered Resources	783.5		
[12] Total	2,786.5		

Sources:

[1] [A] U.S. Energy Information Administration; Short-term Energy Outlook, Table 4a, Domestic Production 2010. Includes lease concentrate.

[2] [A] U.S. Energy Information Administration; Short-term Energy Outlook, Table 4a, Crude Oil Imports (net) 2010.

[3] [A] =[1] [A]+[2] [A]

[4] [A] U.S. Energy Information Administration, International Energy Statistics. Production, Crude oil and lease concentrate, 2010.

[5] [A] U.S. Energy Information Administration, International Energy Statistics. Proved Reserves of Crude Oil-Time Series, 2009 (Jan 1).

[6] [A] Combines separate onshore and offshore estimates. Onshore estimate is from the U.S. Departments of Interior, Energy, and Agriculture; "Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development;" Page 110, Table 2-8; 2008. Offshore estimate is from the U.S. Minerals Management Service, “Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation’s Outer Continental Shelf, 2006,” Page 5, Table 2; February 2006.

[7] [A] Combines separate onshore and offshore estimates. Onshore estimate is from the U.S. Geological Survey, "USGS National Assessment of Oil and Gas Resources Update," Page 3; December 2010. Offshore estimate is from the U.S. Minerals Management Service, “Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation’s Outer Continental Shelf, 2006,” Page 5, Table 2; February 2006.

[8] [A] =[6] [A]+[7] [A]+[8] [A]

[9] [A] U.S. Energy Information Administration, International Energy Statistics. Proved Reserves of Crude Oil-Time Series, 2009 (Jan 1).

[10] [A] U.S. Geological Survey, World Petroleum Assessment 2000. USGS estimate excludes US, which we have added back.

[11] [A] U.S. Geological Survey, World Petroleum Assessment 2000. USGS estimate excludes US, which we have added back.

[12] [A] =[9] [A]+[10] [A]+[11] [A]

Figure 1
The Circular Flow of Economic Activity

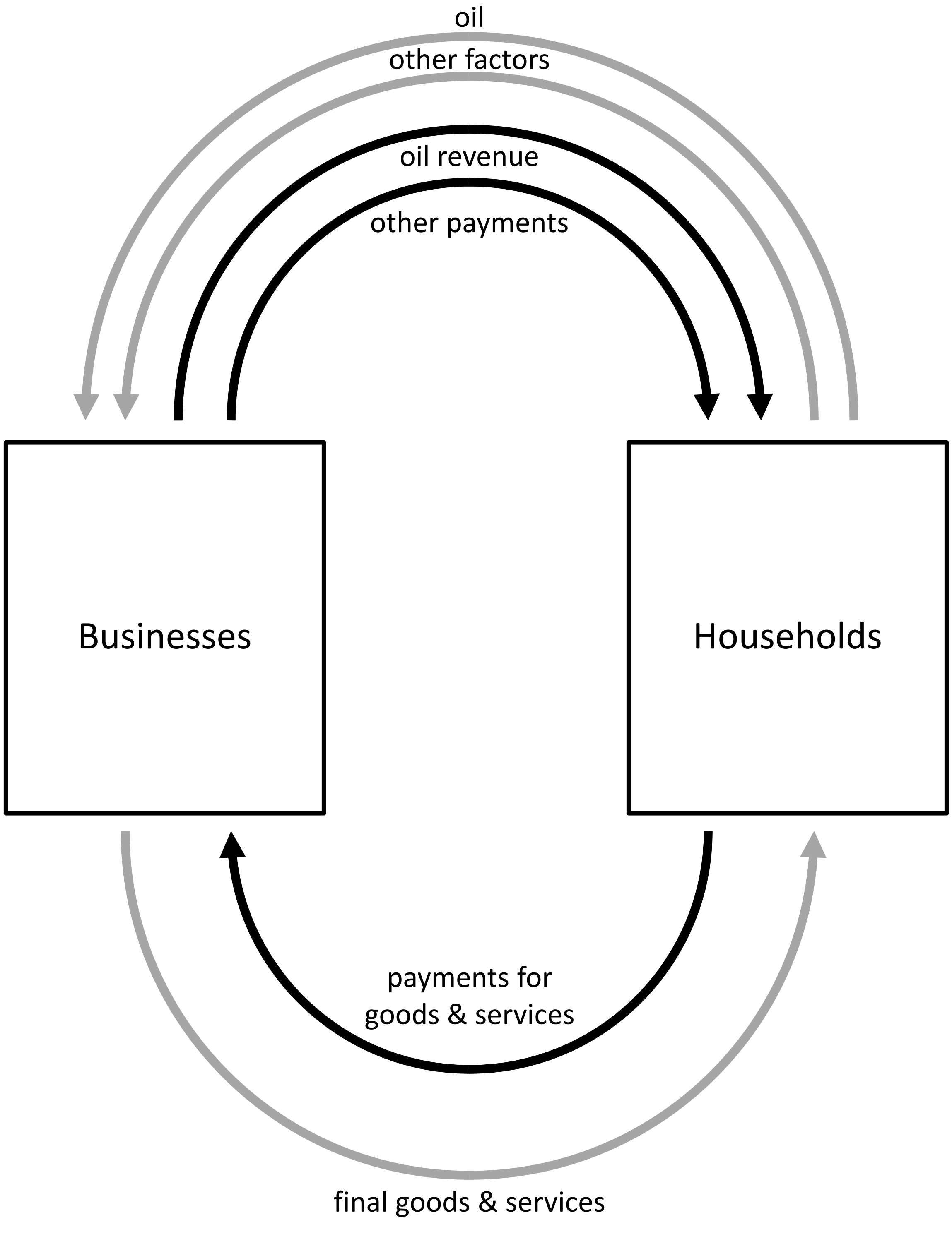


Figure 2
Factor Payment Flows from an Oil Company

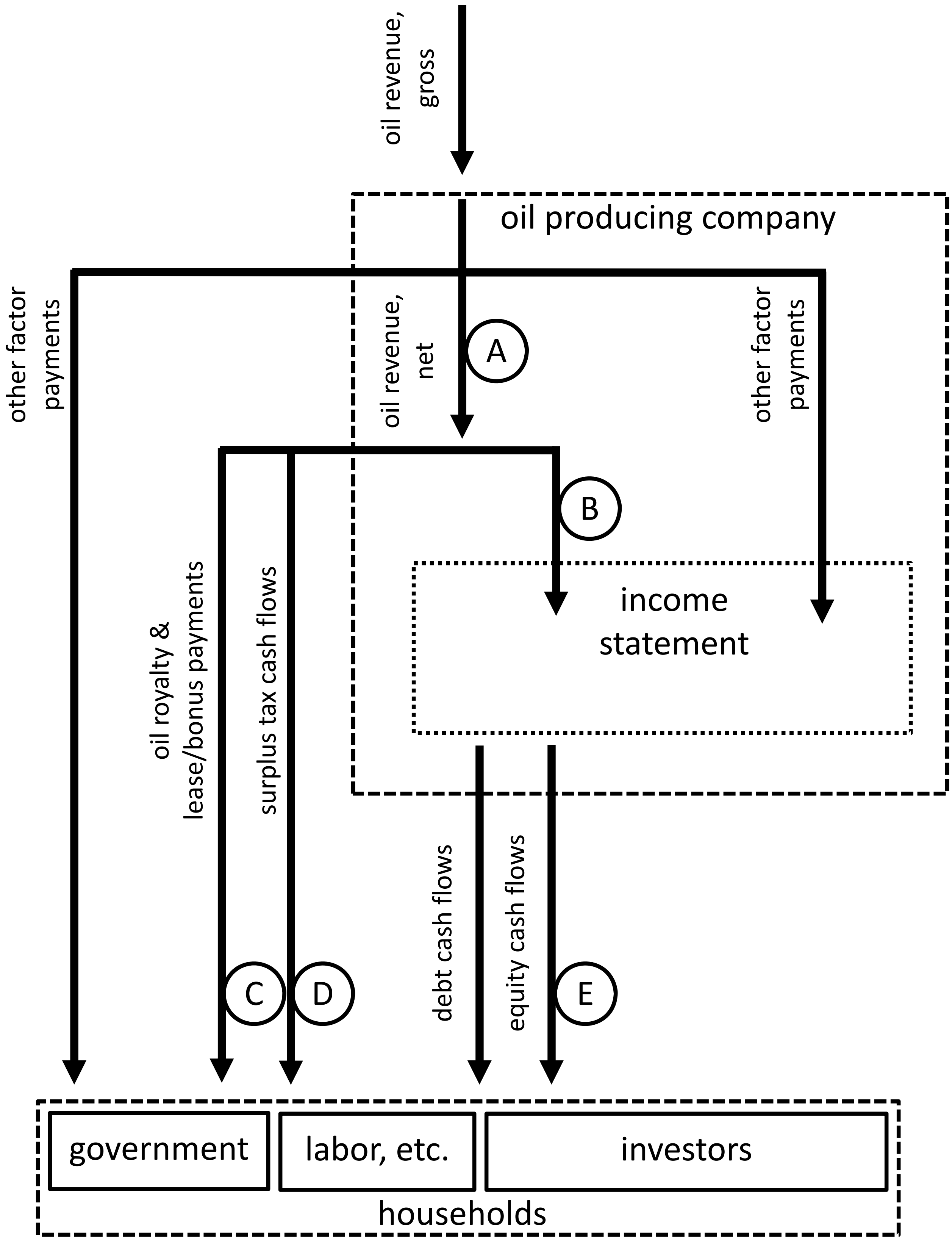


Figure 3
Payment Flows for a Refinery and an Airline

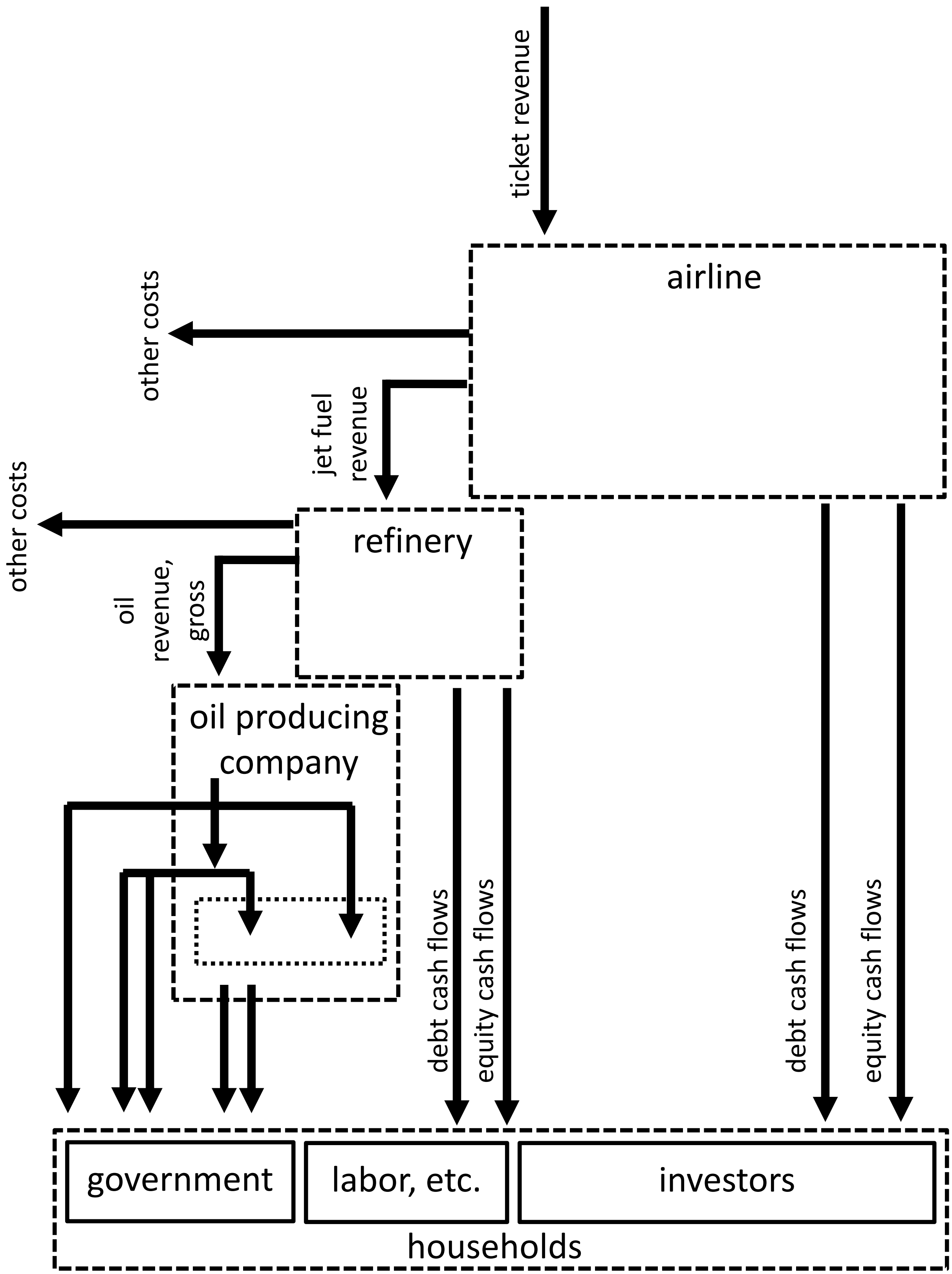


Figure 4
Payment Flows for Households

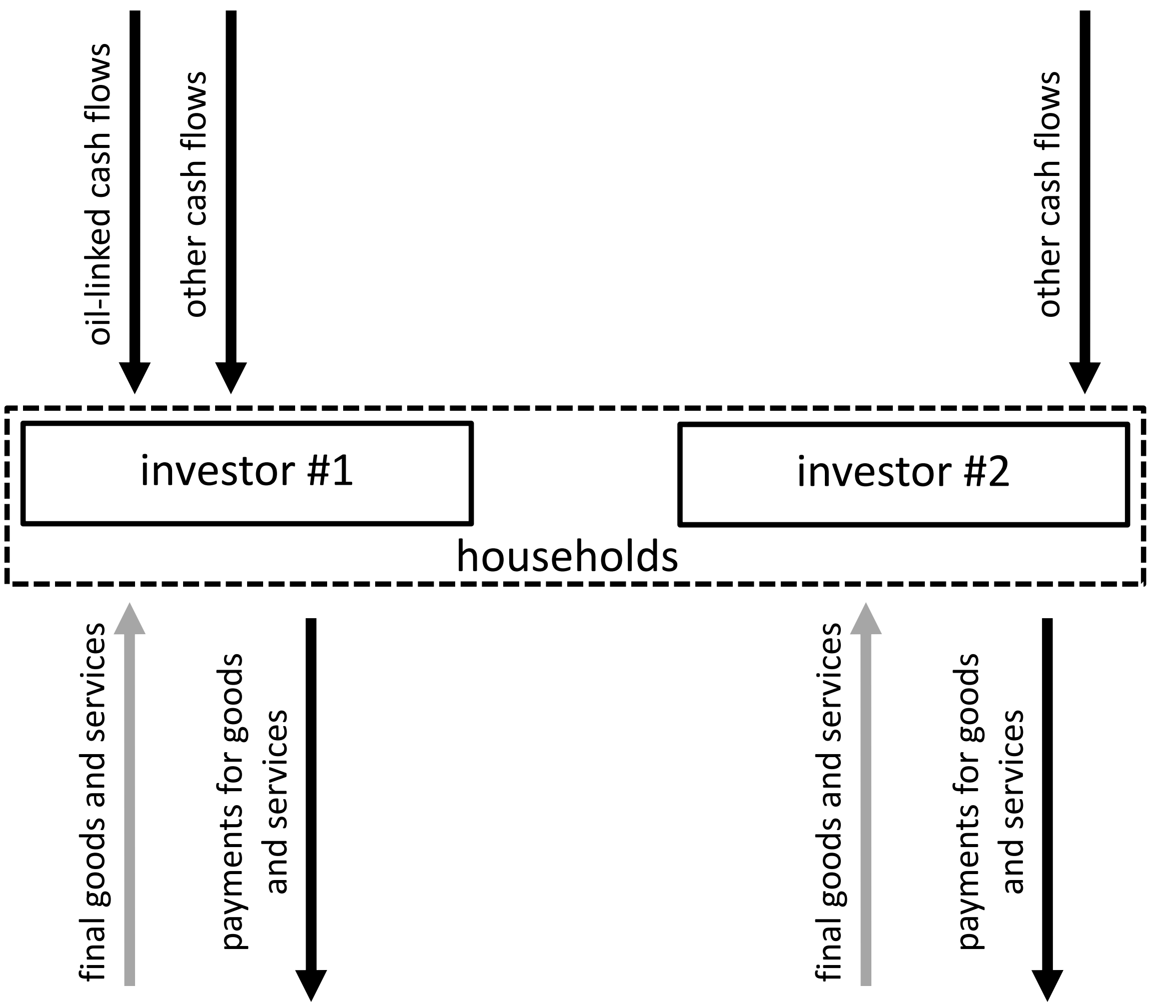


Figure 5
Effect of an Oil Company's Futures Contracts on Factor Payment Flows

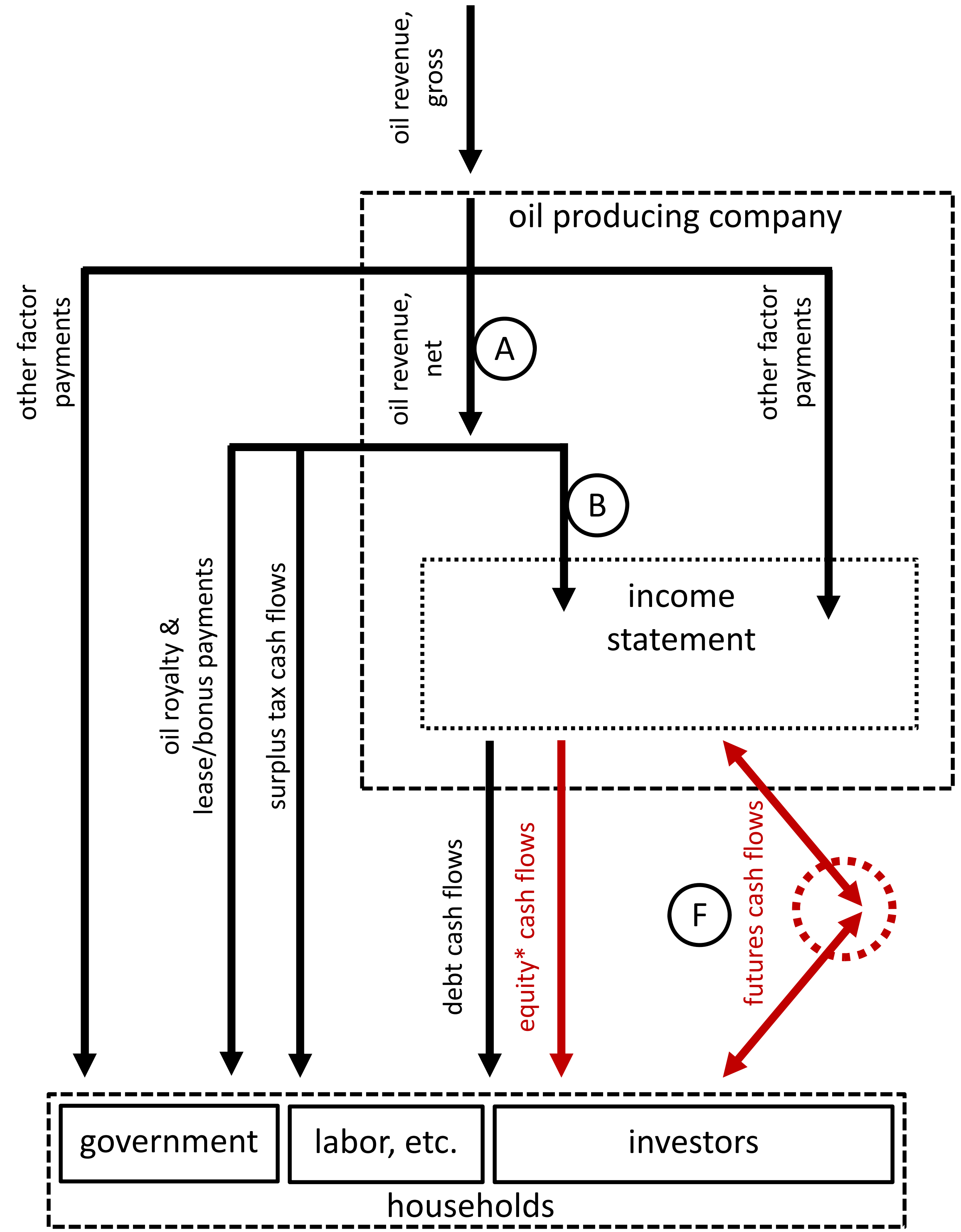


Figure 6
Effect of an Airline's Futures Contracts on Payment Flows

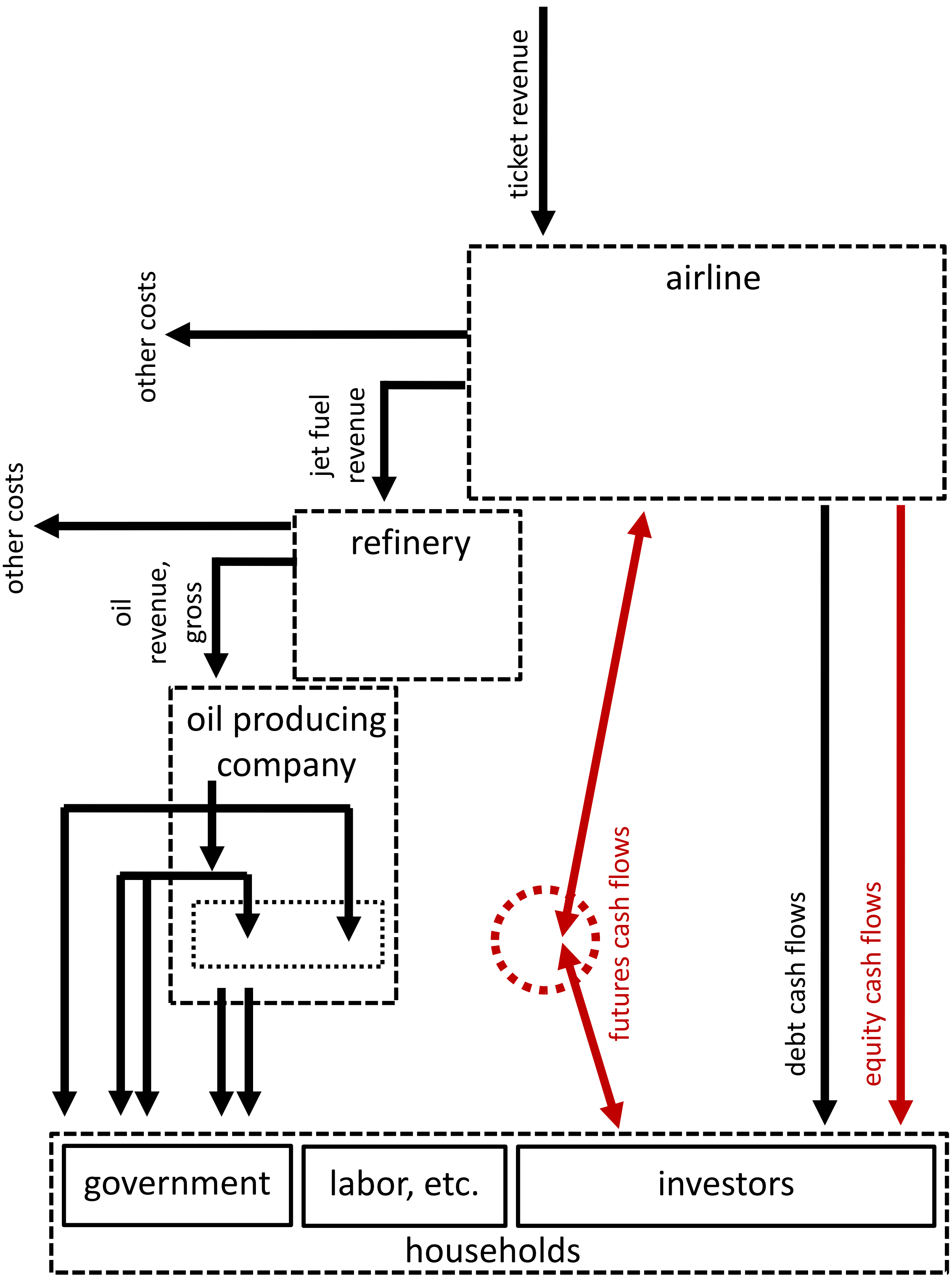


Figure 7
Effect of Households' Futures Contracts on Payment Flows

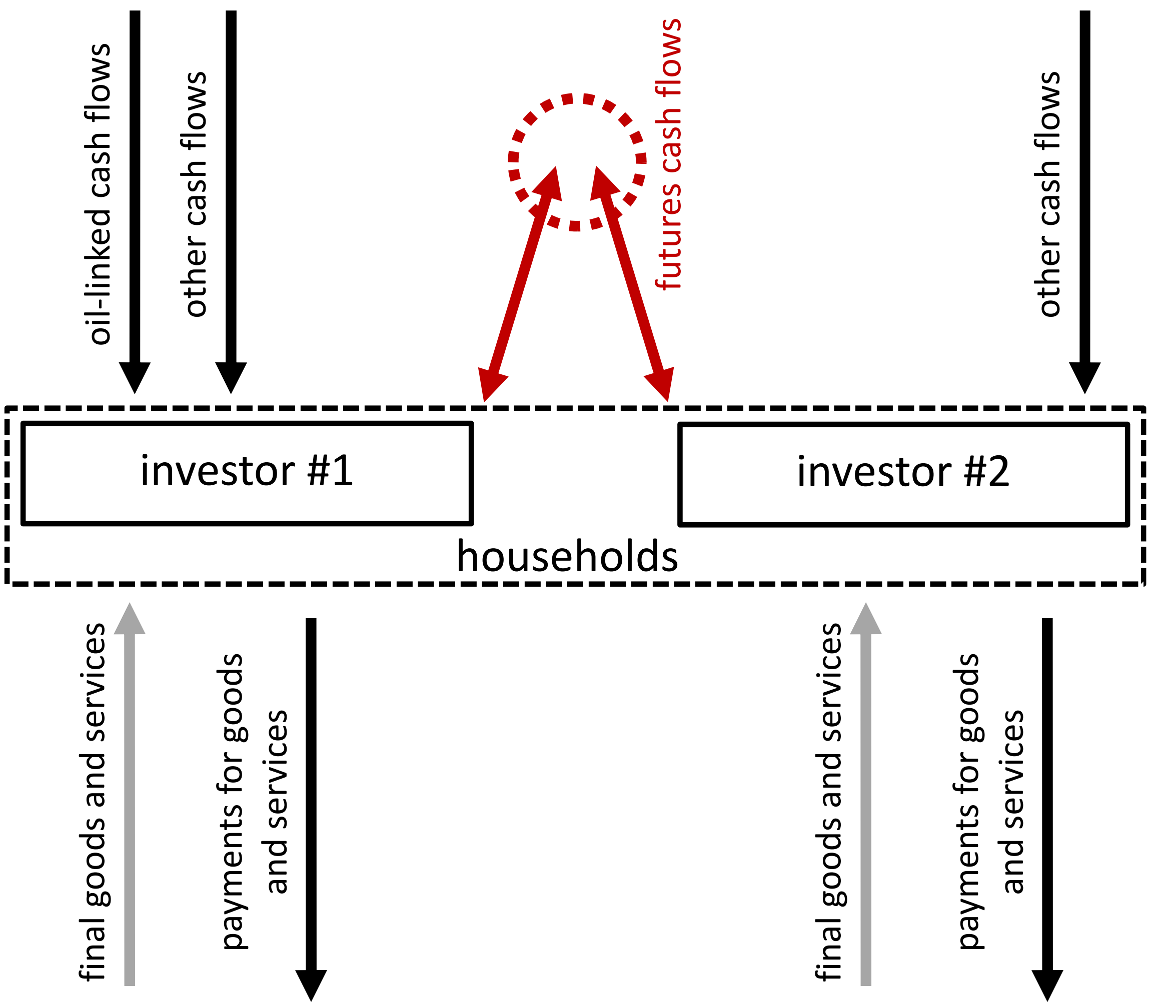
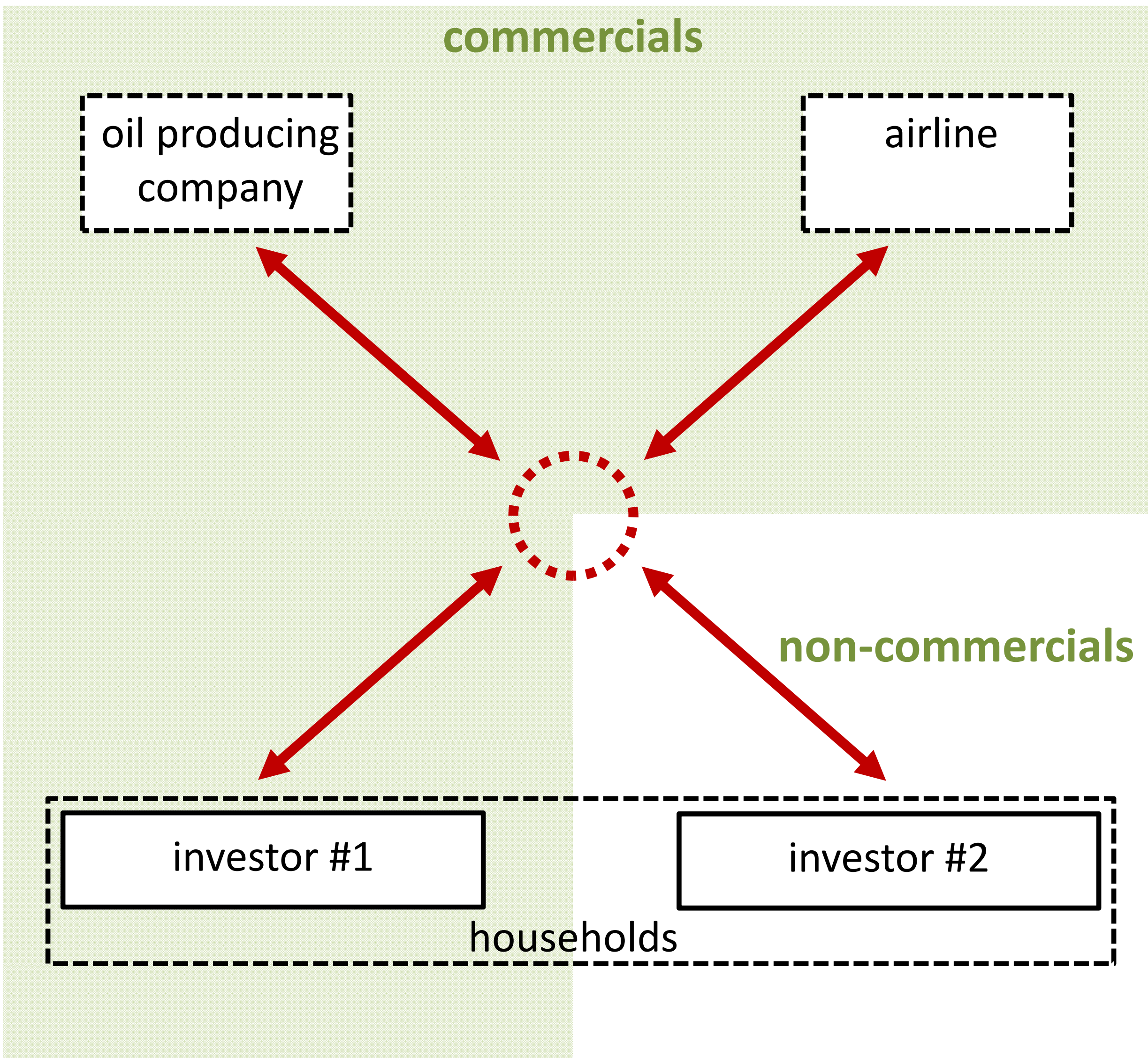
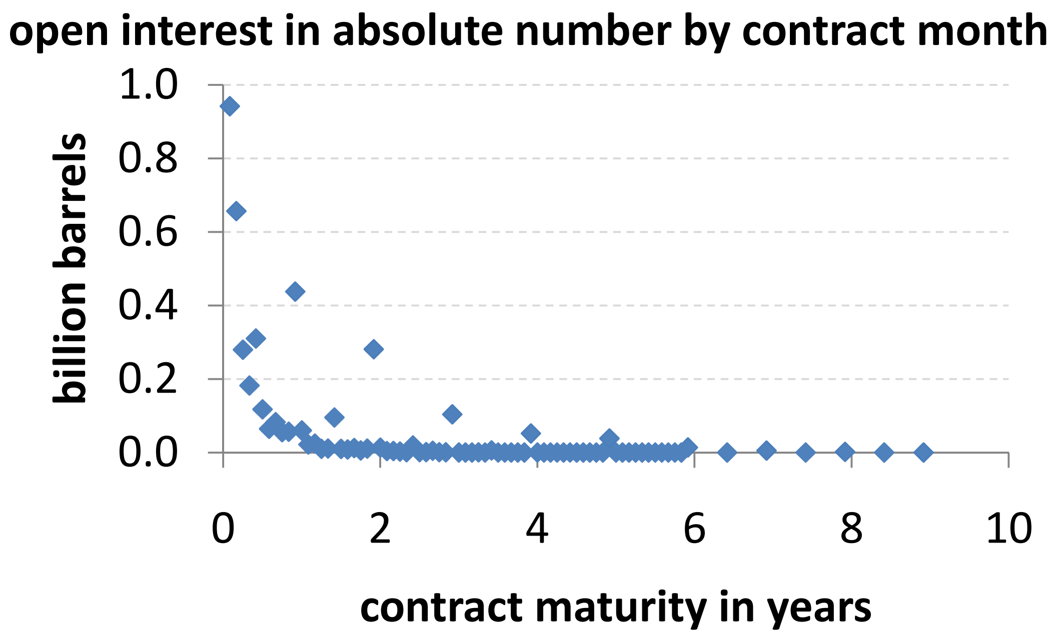


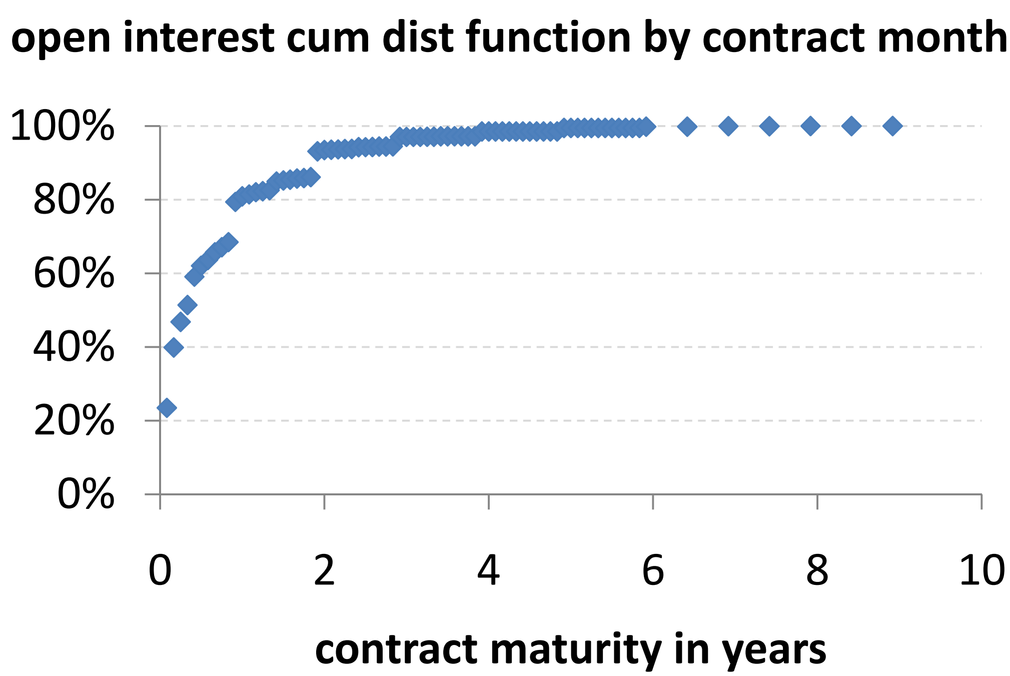
Figure 8
Commercial and Non-commercial Traders of Futures Contracts



Shading shows how different parties trading oil futures and options are categorized as Commercials or Non-commercials in the CFTC Commitment of Traders Report. The label Commercial encompasses Merchants, Producers, Processors and others with physical exposure to oil. This obviously includes airlines and oil producing companies. This also covers state-owned oil companies, although in our schematic their exposure is owned by households. Hence, we have extended the shaded area to partially cover the households box.

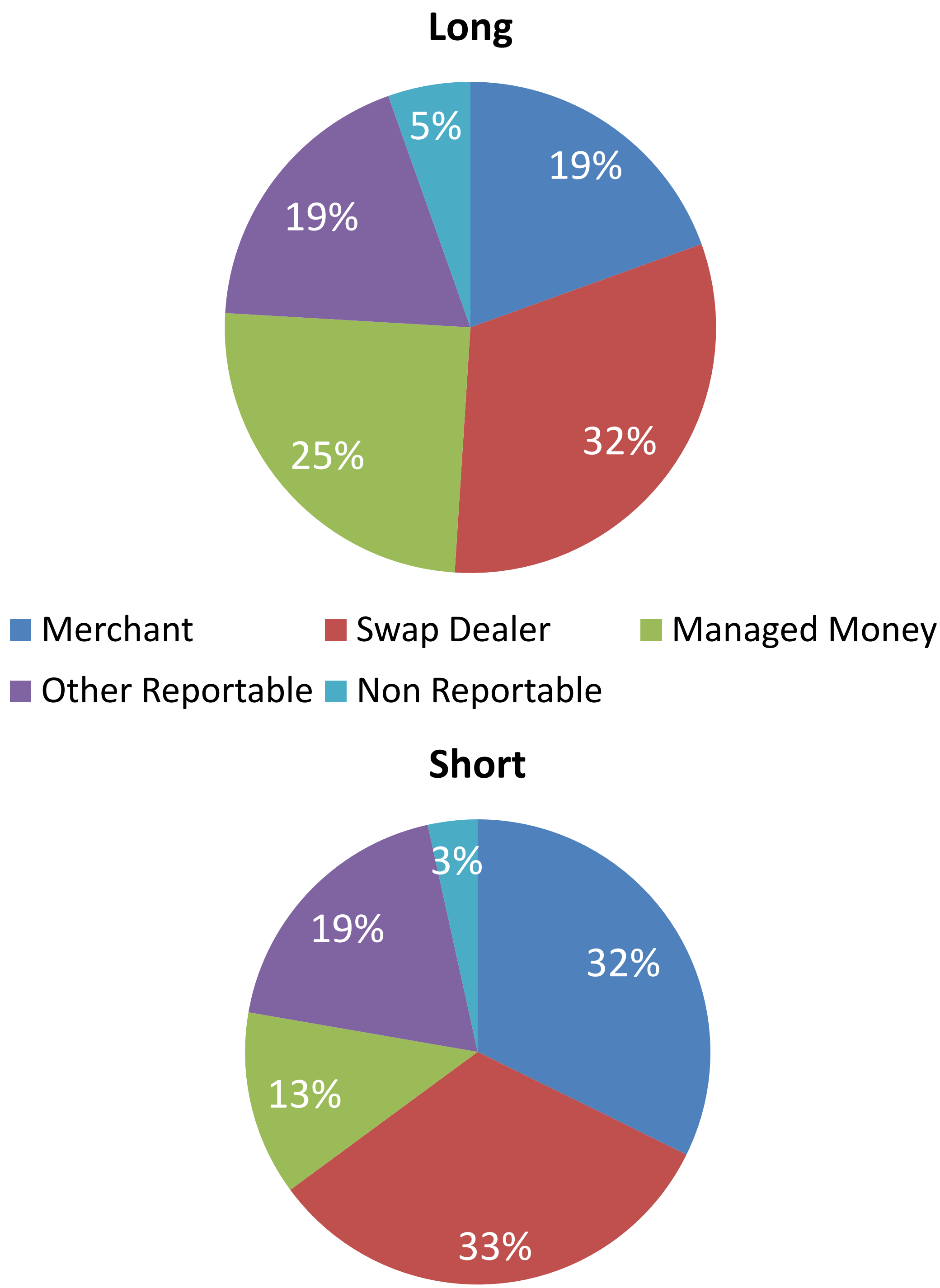
Figure 9
Maturity Profile of Open Interest in Oil Futures and Options





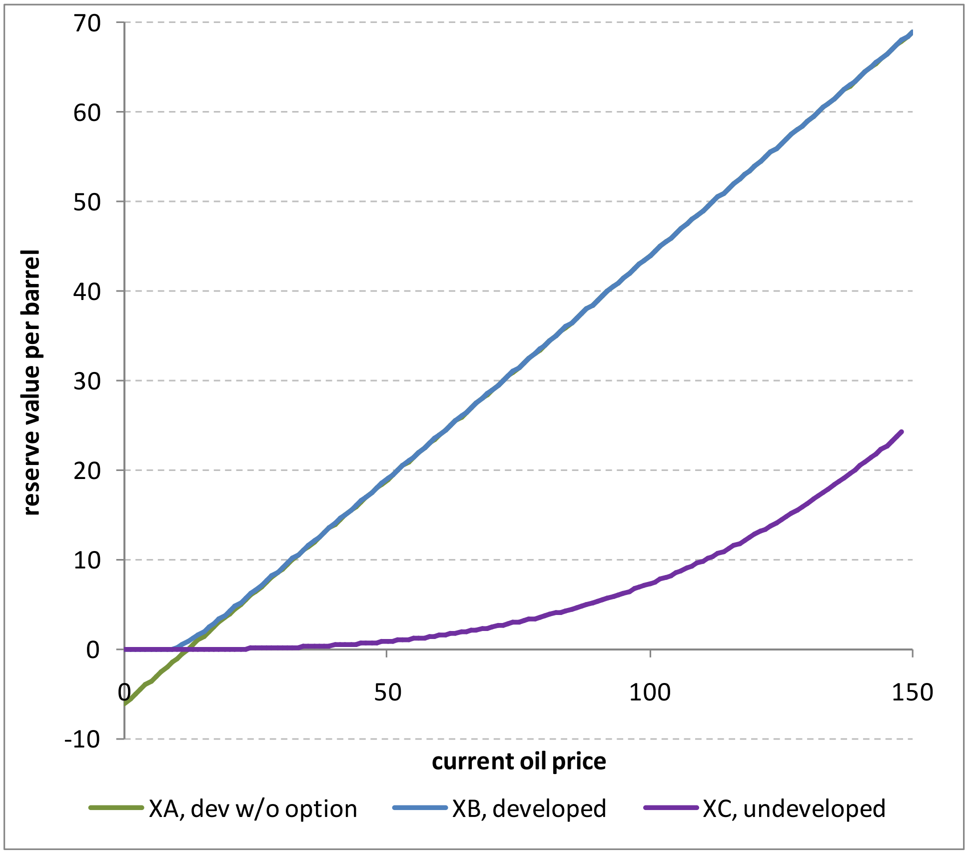
Source: Bloomberg. Data shows open interest in crude oil futures only, covering CME/Nymex WTI contract and the ICE WTI and Brent contracts.

Figure 10
Share of Open Interest by Type of Trader



Source: CFTC Commitment of Traders report, December 28, 2010, covering CME/Nymex WTI contract and the ICE WTI contract, combined futures and options data.

Figure A1
Option Valuation of an Undeveloped Field



This figure shows the value of a developed and undeveloped oil field as a function of the current price of oil. The lifting cost is $12/bbl, the exponential rate of decline of production is 10%, the discount rate is 10%, expected price and costs are assumed constant. The volatility in the price is 18%. The cost of development of the field is $22/bbl reserves.

The green line shows the value of the developed field ignoring the option to shutdown and abandon the field. When the oil price is below the lifting cost, this value is negative. The slope of the green line is ½. The blue line shows the value of the developed field taking into account the option to shut down and abandon the field. The optimal price below which the field is shutdown, is $8.05/bbl. The purple line is the value of the undeveloped field. The field is developed if the price rises to $137.49/bbl.

Figure A2
Delta of an Undeveloped Field

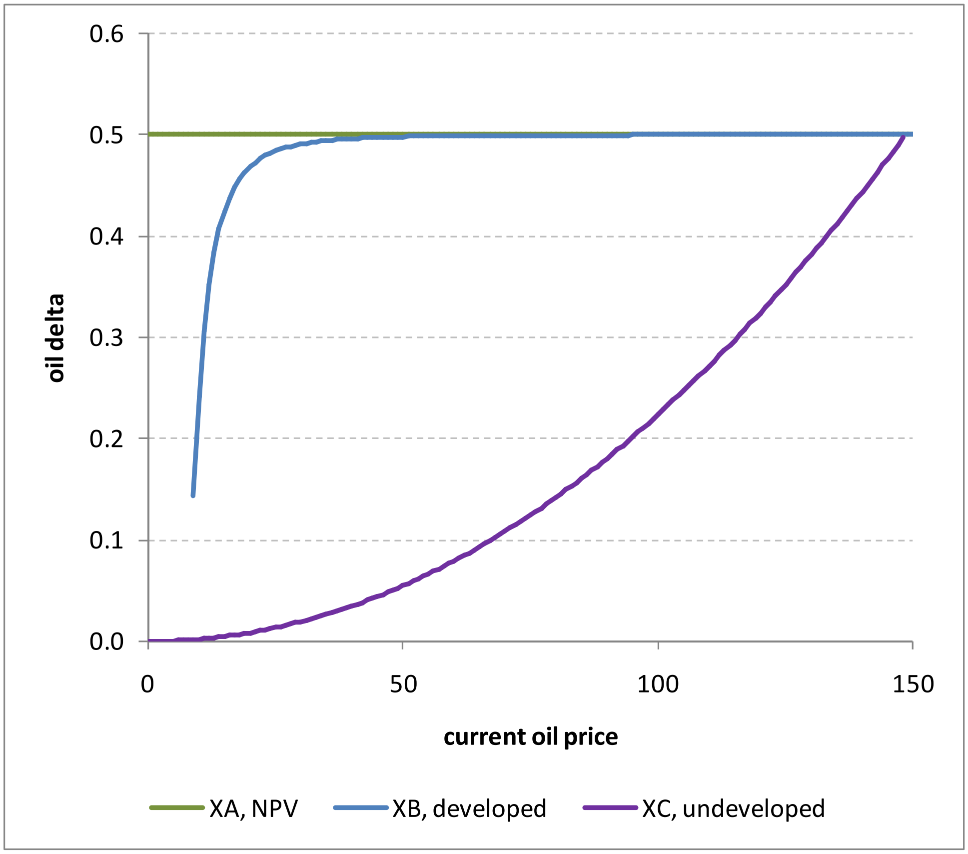


Figure A3
Oil Beta of an Undeveloped Field