Cooperate or Compete? Insights from Simulating a Global Oil Market with No Residual Supplier

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We investigate a transition to a competitive world oil market in which OPEC — led by Saudi Arabia — stops acting as the primary residual supplier within the world oil market starting in 2020. Our modeling results include the following highlights.

- In 2020, as OPEC ramps up production, Brent prices fall US$11.5/b below the World Energy Outlook (WEO) stated policies scenario of the International Energy Agency (IEA 2019).
- From 2020 to 2030, prices recover as a result of demand response combined with a need for sustained investment in new long-term conventional production.
- Only when capital approved for new conventional projects matches historic highs (present value of about US$125 billion per year) do prices remain below the WEO stated policies scenario through 2030.
- Crude prices recover faster and exhibit significantly higher variability when investment in shale oil production slows and output peaks at 12 million barrels per day (MMb/d) versus 16 MMb/d in 2025.
- A decline in short-term tight oil projects limits its role in balancing the market as a source of marginal production, compared to new conventional projects with longer lead times.
- Saudi Arabia benefits financially by continuing to act as the primary residual supplier only with strong cooperation from other producers in OPEC and the larger OPEC+ group.

Key Points
Summary

Structural changes in the global oil sector are disrupting conventional market dynamics and the roles played by competing and cooperating producers. Industry players are adjusting to the shale (or ‘tight’) oil revolution and the possibility of plateauing or peaking global oil demand. In particular, OPEC and Saudi Arabia, its top producer, are reshaping the organization’s role as the primary residual supplier to the world oil market. In recent years, OPEC has invited other major exporters, including Russia, to cooperate under the OPEC+ production agreement in an effort to stabilize prices.

Given these changes, what if OPEC, led by Saudi Arabia, decided to cease organizing residual production collectively, transitioning the world to a more competitive oil market? We investigate such a transformation by simulating the mid-term market from 2019 to 2030. We construct scenarios where OPEC, or OPEC members other than Saudi Arabia, start behaving as competitive price takers in 2020, and stop participating as part of a collective residual oil supplier. Our analysis employs an economic equilibrium model, and is calibrated to the World Energy Outlook (WEO) stated policies scenario of the International Energy Agency (IEA 2019) as a reference for expected real future oil prices, demand and income growth. In our alternative residual supplier scenarios OPEC, or Saudi Arabia alone, organize production targeting the WEO price levels.

In our competitive market scenario, prices drop in 2020 by around 12 United States (U.S.) dollars per barrel (US$/b) below the WEO reference of US$66/b (Brent), accelerating global oil demand growth. However, depending on upstream investment trends, we find significant variability in the mid-term price response. This includes approvals for long-term conventional oil developments, and shorter-term tight oil projects, in line with historic trends and analyst projections. Following the increase in production by OPEC members and initial price decline, prices do recover to WEO levels by the end of the decade in most scenarios.

In our simulations prices only remain well below the WEO outlook when the approval of new conventional projects increases significantly with respect to the slowdown observed in recent years. Given the initial lowering of prices when transitioning to a competitive market, one might expect a continued slowdown in investment. In addition, as existing conventional projects are depleted over the next decade supplies are expected to tighten, assuming demand growth does not reverse. In this case the additional capacity from OPEC is not sufficient to keep prices below the WEO.

In a scenario where investment in new tight oil projects drops by 50% and total shale oil output reaches a peak of 12 million barrels per day (MMb/d) in 2025 (instead of 17 MMb/d), prices recover quickly to WEO levels after 2020. However, they exhibit greater variability compared to more aggressive growth scenarios for global tight oil projects. Under this tight oil constraint, the standard deviation of the annual change in competitive prices increases by at least 200%. This holds even with accelerated investment in conventional projects. In this case the slower development of tight oil projects limits its availability as a source of marginal production to balance supply and demand in the short term.

From 2020 to 2030, our results show that average competitive market prices only remain below the WEO reference levels when the present value of capital committed to investment in new conventional projects exceeds US$125 billion per year on a present value basis. This level is similar to the average yearly investment from 2004 to 2014,
when project approvals reached a four-decade peak. However, when the present value of projects approved each year falls below US$100 billion, the recent 10-year average, the three-year moving average prices surpass the WEO reference by mid-decade.

Under the more aggressive growth scenario for tight oil (17 MMb/d peak in 2025), the decline in oil prices persists with Brent falling an average of US$10-14/b below the WEO reference, and demand exceeding the WEO scenario by at least 3 MMb/d. Only if annual conventional investments drop well below their 2004-2014 average, as might be expected given the decline in prices, do the competitive market prices fully recover or exceed the WEO outlook in the second half of the decade.

We compare the present value of profits generated by Saudi Arabia under the competitive market and the residual supplier scenarios. The latter assume that the residual supplier is able to stabilize the market in line with the price and demand levels from the WEO. We find that Saudi Arabia only benefits financially by serving as a residual supplier, rather than engaging in traditional competitive market behavior, with strong cooperation from OPEC. As a sole residual supplier, Saudi Arabia would have to withhold large amounts of production, compromising its relative market share, resulting in lower profits. Cooperation has become even more necessary since the emergence of U.S. shale oil has introduced structural uncertainties (such as the price responsiveness of non-OPEC oil supplies) into the market.

Expanding the role of the residual supplier to other producers (OPEC, OPEC+) reduces the sensitivity of Saudi Arabia’s market share and revenues to the growth in tight oil production within the expected range of the long-run price elasticity of global oil demand (between -0.2 and -0.4). Therefore, Saudi Arabia should seek greater support from the rest of OPEC as well as non-OPEC producers (such as Russia) to ensure that the Kingdom’s oil revenues exceed what could be earned in a market with no residual supplier at all. In other words, it is in Saudi Arabia’s interest either to abandon its role as primary residual supplier or to share this responsibility with a larger group.
1. Introduction

The oil market is undergoing profound structural changes due to the shale oil revolution and the prospect of plateauing or peaking oil demand. These developments could induce either more cooperation or more competition between oil-producing countries. In this paper, we simulate a global oil market without a residual supplier that organizes production levels in an attempt to manage the price of oil, as opposed to behaving as a competitive price taker.

We develop an equilibrium model of the global oil market through 2030 with a detailed representation of oil-producing assets throughout the world. Rather than apply a dominant firm model with a competitive fringe, as is standard in oil modeling (Plaut 1981; Rauscher 1988; Jones 1990; Behar and Ritz 2017; Golombek, Irarrazabal, and Ma 2018; Volkmar 2018), we test cases under a competitive market with no residual supplier scenario in which every oil-producing country behaves as a price taker. In this case, investment and production decisions depend only on how their marginal production cost compares to price. We analyze how market prices would potentially materialize in such a scenario and the corresponding revenues for Saudi Arabia as the largest residual supplier within OPEC.

We then compare the outcomes of the hypothesized competitive market to an alternative reference residual supplier scenario. We examine two cases within this scenario: in the first, OPEC members collectively operate as a residual supplier; in the second, Saudi Arabia acts as the only residual supplier, and other OPEC members join the fringe. In both instances, the residual supplier follows a price targeting strategy: it adds or subtracts oil from the market to achieve the desired global market price, based upon how much is being supplied by the fringe.

These two residual supplier cases reflect different perspectives within the research community. While some studies treat OPEC as the world’s dominant oil firm (Rauscher 1988; Jones 1990), others (Plaut 1981; Adelman 1995) argue that Saudi Arabia performs the role of the dominant firm within OPEC when its members fail to coordinate the organization’s output. For example, in preparation for expected oversupply in 2020, Saudi Arabia reportedly encouraged OPEC to increase cuts (Sheppard and Ravel 2019). In a review of the evolution of OPEC models, Fattouh and Mahadeva (2013) concluded that OPEC’s market power has varied over time and thus that no single model fits OPEC’s behavior. Behar and Ritz (2017) suggest that OPEC still operates as a dominant player but prioritizes market share over deterrence strategies.

Following the oil crisis of the 1970s, the literature on the strategies of oil-producers (especially OPEC) regarding pricing and production decisions has grown substantially (e.g., Powell 1990; Gately 1995). The geopolitical environment and oil market structure are much different today than in the 1980s-90s. First, the market has transformed due to increased shale oil production and reduced production costs, weakening OPEC’s market dominance and its ability to influence prices. Second, while non-OPEC oil supply continues to grow, global oil demand is slowing. Third, legislative attempts, such as the No Oil Producing and Exporting Cartels (NOPEC) Act, which was proposed by the United States (U.S.) Congress to allow the national oil companies that make up OPEC to be sued under U.S. antitrust law, may potentially make it difficult for OPEC to engage in coordinated cuts in world oil supply (NOPEC 2007; Rystad Energy 2018b; Reuters 2019). To our knowledge, no study exists that investigates the implications of these changes in an oil market without a residual supplier. We believe our analysis is timely and will
contribute to debates over the future of the global oil market and the significance of the residual supplier role currently filled by Saudi Arabia and OPEC.

The next section describes the representation of demand, the decision rules for producers, and other features of the model. Section 3 details scenarios that explore the consequences of structural changes in the world oil market, including to the role of the residual supplier, and different scenarios regarding investment in new oil production capacity. Section 4 discusses the results and their interpretation. Finally, Section 5 offers concluding remarks.
2. Model Description

We propose an aggregate model of the global oil market within an equilibrium framework in which price clears the market. The discussion below describes the supply and demand representations and provides a comparison to techniques used in other world oil market models. Appendix A provides the complete mathematical formulation with equations.

The model simulates the medium-term consequences of a market with and without a residual supplier. First, to calibrate our demand outlook, we establish a reference residual supplier scenario in which the residual supplier targets a given oil price by increasing or decreasing production in response to the total output of all other suppliers, treated as fringe competitors. Then we solve for the market equilibrium under the competitive scenarios where all producers behave as price takers (no residual supplier). The model is solved to find a new competitive price equilibrium in the midterm. It also estimates the financial consequences for different suppliers in terms of oil revenues.

The model is dynamic and captures the transitional adjustments that occur when an alternative market structure is assumed. The world oil market clears, period-by-period, with demand balancing supply on an annual basis, for all hydrocarbon liquids including crude oil, condensates, natural gas liquids (NGL), refinery gains and other liquids (biofuels and alcohols destined for the same market as petroleum products). We represent global demand and supply as a single node and do not account for regional crude flows.

2.1. Representation of global oil demand

The following equation specifies total world oil demand in each year \( t (D_t) \)

\[
D_t = A_t \bar{p}_t^e Y_t^\gamma 
\]  

(1)

where \( A_t \) is a scaling variable, or a variable capturing the effects of all other exogenous factors, and \( \bar{p}_t \) is the three-year moving average market price with \( \bar{p}_t \) representing the market-clearing price in year \( t \). We consider a single global oil price based on the Brent Crude oil marker. \( Y_t \) is the current global gross domestic product (GDP), \( e \) is the long-run price elasticity of oil demand, and \( \gamma \) is the long-run income elasticity of oil demand, or the impact of global GDP. The price elasticity of demand is applied to the three-year moving average price to reflect the lag on the impact of oil prices on demand (Hamilton 2003; Kilian 2008).

Current global GDP is given by

\[
Y_t = Y_{t-1} \left(1 + \bar{g}_t (\bar{p}_t/\bar{p}_t) ^\theta \right) 
\]  

(2)

where \( \bar{g}_t \) is a reference GDP growth rate. The ratio \( \bar{p}_t/\bar{p}_t \) in equation (2) represents the impact of prices on GDP growth, where \( \bar{p}_t \) is the three-year average reference price linked to the reference GDP growth. The parameter \( \theta \) can also be interpreted as the elasticity of real economic growth with respect to variations in the price of oil. For instance, if the moving average oil price (\( \bar{p}_t \)) is higher than that of the reference level (\( \bar{p}_t \)), then for \( \theta < 0 \) the economic growth from \( t-1 \) to \( t \) will be slower than the reference (\( \bar{g}_t \)), and vice versa.\(^1\)

A straightforward way to specify equations (1) and (2) is to use elasticity estimates available in the

\(^1\) James L. Smith suggested this demand-side representation and has our gratitude.
2. Model Description

literature. Then, $A_t$ can be calibrated based on projections for a desired reference case (i.e., using the expected oil demand $\bar{D}_t$, the moving average oil price $\bar{p}_t$, and global GDP $\bar{Y}_t$). However, the exact value of $\theta$ cannot be estimated based on available data. We show in Appendix A.1 that an approximate value of $\theta$ can be obtained by formulating a time series equation that relates the growth rate of global GDP to that of oil prices.

2.2. Calibrating the world oil demand

We calibrate the demand curve to replicate a reference scenario that projects annual world demand, average oil price and global GDP growth. We investigate the period from 2019 to 2030, using the 2019 World Energy Outlook (WEO) from the International Energy Agency (IEA 2019).

The scaling coefficient $A_t$ from equation (1) is set as follows:

$$A_t = \frac{\bar{D}_t}{\bar{p}_t^{\varepsilon} \bar{Y}_t^\gamma}$$

In other words, $A_t$ guarantees that the price and GDP outlook replicate the global oil demand projected in the reference scenario.

$$D_t = \bar{D}_t \left( \frac{\bar{p}_t}{\bar{p}_t^\varepsilon Y_t^\gamma} \right)^\varepsilon \left( \frac{\bar{Y}_t}{\bar{Y}_t^\gamma} \right)^\gamma = A_t \bar{p}_t^{\varepsilon} Y_t^\gamma$$

Regarding the price and income elasticities of oil demand, the relevant literature offers no consensus. The estimates range widely, from -0.01 to -0.58 for price elasticity ($\varepsilon$) and 0.24 to 1.32 for income elasticity ($\gamma$) (Javan and Zahran 2015). For the simulations in this paper, we select -0.25 as the long-run price elasticity of oil demand and 0.75 for the long-run income elasticity. We also run sensitivity analyses by calibrating the model across a range of price elasticities from -0.1 to -0.6.

We source world oil prices for the years 2017 and 2018 from Reuters to construct the three-year moving average prices during the first two years of the study period. All prices are adjusted to 2019 real terms.

WEO publishes several outlooks for the global oil market. We focus on the organization’s stated policies scenario, which accounts for new environmental measures that target a gradual reduction in oil demand growth. Under this scenario, annual demand growth slows to an average of 0.8% as global demand rises from 98.8 MMB/d in 2019 to 107.7 MMB/d in 2030. This scenario assumes Brent prices steadily increase from 61 U.S. dollars per barrel (US$/b) in 2019 to US$88/b in 2025, and US$96/b in 2030. Over this period GDP growth averages 3.6%, and oil demand does not peak.

As part of our sensitivity analysis, discussed in Section 4.3, we also calibrate our model to the International Energy Outlook (IEO) of the Energy Information Administration (EIA 2019). The IEO projects weaker average price and demand growth, with Brent hitting a maximum of US$76.9/b and global demand reaching 105.8 MMB/d in 2030, reflecting annual growth of 0.5%; GDP also expands more slowly at an average of 3.3%. Table A.2 in Appendix A.1 presents the values from WEO and IEO.

2.3. Global oil supply model

In each period, suppliers organize to maximize their profits in two ways: selling oil produced from existing projects at the market price and investing in new ones. The model assumes fringe suppliers behave competitively, selling oil at the market price that clears demand, corrected to account for crude quality and regional price markers (e.g., Brent versus WTI). Appendix A.2 provides a detailed
2. Model Description

mathematical formulation of the supplier's problem.

To explicitly model supply decisions at the asset level, we use a set of linear activities built using a detailed database of production cost and capacity projects, as described in Section 2.4. Supplies are differentiated by quality, field type, location, and ownership, providing a detailed representation of different supply categories. As we represent oil demand at the global level, we do not explicitly model regional transportation.

An alternative approach would be to employ a reduced-form supply curve. For example, Huppmann and Holz (2012) develop a model to investigate market power in the global oil market. Each node in their model represents a single continuous non-linear Golombek supply curve (Golombek, Gjelsvik, and Rosendahl 1995). However, their model only considers a single year and neglects investment decisions and depletion.

One can also design a structural equation based on the price elasticity of supply rather than using a supply curve. This provides a more aggregate representation of production and investment decisions and can be useful for investigating longer-term trends and time horizons, and when detailed supply data may not be available. The dominant firm-competitive fringe model developed by Golombek, Irarrazabal, and Ma (2018) employs this technique to investigate the exercise of market power by OPEC from 1986 to 2016, and drivers of long-run oil price trends, including GDP and supply depletion.

Our model includes investments as additional linear activities and categorizes them as either short-term (shale, or 'tight,' oil projects) or long-term (all other developments, including conventional oil, oil sands, heavy oil, NGL, and condensates). U.S. shale oil projects are generally characterized by fast decline rates, and short development lead times and production cycles; the majority of a single well's total production occurs within a year (Kleinberg et al. 2016). Other developments, such as conventional onshore and offshore, and oil sands, generally have multi-year investment lags and production profiles.

For tight oil, we assume that on an annual scale, the time between project approval and start of production is negligible. Therefore, producers effectively make only one decision: to develop new capacity if the total unit production cost (operating and development) is lower than the current price at the time. We then embed capital development costs within the marginal production cost, defined as the breakeven cost of the shale project. The model decides whether to make investments in tight oil projects based on the current equilibrium price and assumes they will be available for production within the same year that the investment decision was made.

For longer-term investments, producers make two decisions based on different cost curves: the first for production from existing capacity, when the price exceeds the variable operating cost, and the second for capacity expansion. As detailed in Appendix A.2, the model initiates conventional investments if the forecasted present value (PV) of oil revenues for all future production exceeds the PV of the total capital commitment of the project. All PVs are calculated using a discount rate of 10%, a standard value applied in the oil industry and the related literature (e.g., Powell 1991; Gately 1995).

We calculate future oil revenues for production beyond the model horizon by extrapolating forward oil prices. We fix prices to the level output by the model at the end of the horizon, and production to the expected annual output reported by Rystad.
The model can be solved using either myopic or forward-looking supplier behavior. In the latter we solve the model as a single problem, assuming suppliers have perfect foresight over the model horizon. The myopic approach uses a rolling horizon that provides suppliers with limited or imperfect information on current and future market conditions. In this case, we solve the model using the recursive method described in Appendix A.5.

A myopic supplier does not factor in the longer-term exhaustibility of reserves. However, work by Hart and Spiro (2011) finds that scarcity or Hotelling rents that would result from resource depletion have historically been marginal or absent in oil markets, and that other factors play a stronger role in shaping oil prices.

### 2.4. Supply calibration

To calibrate oil supplies, we employ Rystad Energy’s UCube upstream oil and gas database, which represents each OPEC member, including Saudi Arabia, on a stand-alone basis. This allows us to capture country-level supply changes and disruptions, including the attack on Saudi Arabia’s oil production in September 2019. For each country, the database provides distinct resource endowments, cost structures, and financial, technical and geopolitical constraints. Rystad production data extracted for existing projects include projected annual output, marginal costs, capital development cost, and breakeven oil prices (for tight oil). All costs are reported in real 2019 terms.

We also extract data on crude quality ranked by the American Petroleum Institute (API) gravity scale, sulfur content, and regional price differentials, such as Brent-WTI spread. These values are used to adjust the price paid for different grades of oil in different regions. Table 1 displays a summary of the quality indices and examples of regional Brent/WTI spreads, providing an overview of the indices evaluated at the asset level. First prices for a given crude type are determined by dividing the projected annual revenues of each asset by the production. The prices are then compared to Rystad’s Brent outlook to determine a price index that reflects crude quality, regional logistics, and other factors.

We calibrate OPEC production data to reflect the total sustainable production capacity of each member country, defined as the capacity that can be put into production within 90 days, based on data from IEA’s monthly oil market report (IEA 2019). The model defines spare capacity as total sustainable capacity minus annual production for each member country. Our analysis excludes some OPEC members (Ecuador, Congo, Gabon, Equatorial Guinea, Nigeria, and Venezuela) because of discrepancies between projected production in the IEA’s monthly oil market and self-reported production levels, noting that they do not hold significant spare capacity.

Appendix A.5 provides additional descriptions of the supply data, including the characterization of tight oil fields, gas condensates, and other liquids. We also describe data aggregation methods used to reduce the number of supply activities in the model and improve model performance, without severely compromising the model resolution.

### 2.5. Calibrating investments

We utilize Rystad UCube data on new oil projects planned between 2020 and 2050, including the projected approval year, production start year, and annual capital development costs. We initially calibrate the model so that all projects can be approved in any year within the horizon, if they are profitable, with cost and production profiles.
2. Model Description

adjusted to the year selected by the model. However, under this assumption, the total capital committed in a given year can greatly exceed the range of values observed in the oil market.

Table 1. Examples of quality and regional price markers used in the model.

<table>
<thead>
<tr>
<th>(a) Price correction by product quality</th>
<th>Markdown</th>
</tr>
</thead>
<tbody>
<tr>
<td>Light Crude</td>
<td>1</td>
</tr>
<tr>
<td>Regular Crude</td>
<td>0.993</td>
</tr>
<tr>
<td>Condensate</td>
<td>0.99</td>
</tr>
<tr>
<td>Heavy Oil (API 20 – 23)</td>
<td>0.957</td>
</tr>
<tr>
<td>Sour Crude</td>
<td>0.936</td>
</tr>
<tr>
<td>Synthetic Crude</td>
<td>0.908</td>
</tr>
<tr>
<td>Heavy Oil (API 15 – 19)</td>
<td>0.907</td>
</tr>
<tr>
<td>Extra Heavy Oil</td>
<td>0.901</td>
</tr>
<tr>
<td>Bitumen</td>
<td>0.624</td>
</tr>
<tr>
<td>NGL, refinery gains, and other liquids</td>
<td>0.512</td>
</tr>
</tbody>
</table>

(b) Brent-WTI price spread

<table>
<thead>
<tr>
<th>Year</th>
<th>Brent/WTI</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>1.15</td>
</tr>
<tr>
<td>2020</td>
<td>1.15</td>
</tr>
<tr>
<td>2021</td>
<td>1.18</td>
</tr>
<tr>
<td>2022</td>
<td>1.12</td>
</tr>
<tr>
<td>2023</td>
<td>1.08</td>
</tr>
<tr>
<td>2024</td>
<td>1.08</td>
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<tr>
<td>2025</td>
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<td>2026</td>
<td>1.08</td>
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<tr>
<td>2027</td>
<td>1.07</td>
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<tr>
<td>2028</td>
<td>1.07</td>
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<tr>
<td>2029</td>
<td>1.07</td>
</tr>
<tr>
<td>2030</td>
<td>1.07</td>
</tr>
</tbody>
</table>

Sources: KAPSARC analysis, Rystad.

Although many projects may be profitable within an expected price range, numerous factors exogenous to our basic optimization problem constrain potential investments. The amount of capital available globally for the development of new oil projects is limited and can be influenced by social and political factors. Investors may react to environmental concerns related to oil projects, choosing to allocate funds to other markets.

To address this, we introduce annual investment constraints shared by all suppliers, as detailed in the following scenario design section. Within our equilibrium framework, they introduce an additional cost to the development of oil projects that are profitable but exceed the investment cap. Appendix A.2 presents the mathematical formulation of the constraints.

Figure 1a plots the PV of capital (in real 2019 dollars) approved annually for new long-term projects between 1980 and 2030, calculated using reported and projected development costs for all global oil projects included in the UCube Database through 2100. The values vary significantly during this period, averaging US$46 billion during the 1980s and 1990s and US$145 billion from 2004 to 2014, before the mid-decade crash in oil prices. Based on Rystad’s outlook, capital commitments are expected to reach similar levels after 2020.

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2 This representation allows us to simulate the oil price for a given level of investment in the upstream sector. The model assumes a scarcity premium on the investment cost and applies this for all producers. Investment happens in countries that have the lowest production costs.
2. Model Description

Figure 1a. Aggregate PV of capital committed to new long-term oil projects globally.

Figure 1b. Total annual capital expenditures on short-term tight oil projects.

Note: Values beyond 2018 (patterned area) based on projections from Rystad.
Sources: Rystad UCube, KAPSARC Analysis
2. Model Description

Figure 1b shows the annual capital expenditures on tight oil investments from 1980 to 2030, rather than the discounted lifetime project costs, reflecting the short-term nature of these projects, and the extensive funds required to keep them running. The rapid expansion beginning around the year 2000 reflects the U.S. tight oil boom and the expected future capital required to continue growth based on Rystad’s projections.

Compared to other industry research firms, Rystad predicts more aggressive growth for tight oil. It forecasts that U.S. tight oil output will more than double from an average output of 6.4 MMb/d in 2018 to a peak of about 17 MMb/d in 2025. The outlook is based on Rystad’s assessment of commercially viable projects, at a WTI price in the range of US$55/b to US$70/b. The 2017 World Oil Outlook (OPEC 2017), and the WEO stated policies scenario (IEA 2019) both project slower growth in tight oil production, with global output reaching 12 MMb/d in 2025. Reducing the annual capital invested in tight oil projects to 50% of the levels projected by Rystad generated similar production levels.

Using our detailed supply representation, one could apply different assumptions at the country or firm level, based on past performance or current geopolitical constraints, for example. Technical and logistical bottlenecks can be included by constraining new capacity to a fraction of the capacity existing in the previous period. A maximum expansion rate could be assigned to different producer groups based on historical and projected expansion rates. Investment behavior could also be adjusted by altering the discount rate or using different techniques to extrapolate future oil prices.
3. Scenario Design

We design scenarios to assess the medium-term consequences (2019 to 2030) for the world oil market. This includes the competitive scenarios assuming all oil producers behave as price takers (no residual supplier), and reference scenarios where OPEC, or Saudi Arabia alone, continues operating as a residual supplier.

The competitive market model is calibrated to the WEO stated policies scenario (IEA 2019). The model is run first with no investment constraints, and then under different constraints on capital available for new long-term conventional and short-term tight oil projects. These scenarios are used to analyze how development of these different types of production impact the dynamics of the competitive scenarios. We also compare Saudi Arabia’s market share and revenues in the competitive and residual supplier scenarios under identical investment constraints.

Under the residual supplier scenario, a select group of producers (e.g. OPEC) implicitly target a world oil price by adding or removing capacity. We use the price, and corresponding global demand, from WEO as the target for the residual supplier; however, alternate targets could also be tested. Appendix A.3 describes how we solve our equilibrium model under the residual supplier scenario. The model determines production and investment decisions of all countries, except the residual supplier, by assuming they behave as competitive price takers. The residual supplier then sets its production in order to clear the market.

First, we assume that the group of OPEC members with production quotas in 2018 (Algeria, Angola, Iran, Iraq, Kuwait, Libya, Saudi Arabia, and the United Arab Emirates) collectively serve as the residual supplier, and that they coordinate production in proportion to their total capacity. Given the history of oil markets and that Saudi Arabia is the largest oil exporter and maintains most of the world’s spare capacity, we run an alternative case in which Saudi Arabia acts as a residual supplier without support from OPEC. In this situation, OPEC members are assumed to stop negotiating production quotas, which could happen under international pressure, such as the U.S. NOPEC bill. (We note that our analysis is purely hypothetical and does not reflect policies of Saudi Arabia’s government.)

3.1. Financial constraints for new long-term projects and tight oil

For long-term projects we simulate various investment constraints within the range of historic values reported in Figure 1a. Between 2020 and 2030, the Rystad data projects that the average annual capital committed to new projects is US$132 billion in present value terms. In our Rystad investment plan scenario the model can invest in new projects on or after their projected approval year.

Next, we simulate alternative scenarios in which new projects can be developed up to an annual cap on the present value of approved capital. Instead of following the project approval years from Rystad, any project approved between 2020 and 2050 can be built. The constraints and corresponding scenario labels are US$75 billion, US$100 billion, US$125 billion, and US$150 billion cap. These differ from the standard Rystad plan because we assume suppliers can prioritize projects according to profitability. This provides a straightforward approach to simulate a range of constraints, while allowing flexibility in project plans, including accelerated development of new profitable projects by OPEC members.
3. Scenario Design

Short-term tight oil production and investment decisions are based on the commercial outlook provided by Rystad, reaching a peak of about 17 MMb/d in 2025. We assume suppliers can develop any tight oil field, up to the maximum production level, as long as prices exceed the break-even point. To restrict tight oil production to near 12 MMb/d we implement a tight oil cap scenario limiting annual investments to 50% of the Rystad projections.
4. Model Analysis and Results

In this section, we will analyze the market equilibrium in the competitive market scenario with different investment constraints, and conduct a sensitivity analysis with respect to the model demand parameters. We also examine the impact of these scenarios on the production and revenue of the primary residual supplier (i.e., Saudi Arabia) with and without support from other OPEC members.

4.1. Oil price and demand dynamics: cap on long-term investments.

Figure 2 compares oil price (2a) and demand (2b) trajectories from the models of perfect competition (no residual supplier scenario) with the reference WEO levels used to construct the residual supplier scenario. We include results for the competitive market model with no investment constraints under both the forward-looking and myopic supplier assumptions. We then simulate the competitive market under the different investment constraints described in section 3.1; the Rystad investment plan and the three average investment caps (US$75 billion, US$100 billion, US$125 billion and US$150 billion). We apply the forward-looking supplier assumption in these cases; however, given binding investment constraints in these scenarios, the results do not differ significantly with myopic suppliers.

Under the competitive market scenarios with unconstrained investments (forward-looking and myopic in Figure 2), the present value of capital approved for new projects exceeds US$1.6 trillion in 2020. This surpasses historic investment levels reported in Figure 1 and drives prices below US$55/b after 2023 with a rapid acceleration in demand growth. It is very unlikely that such aggressive investments would materialize on the basis of profitability alone. These two scenarios illustrate the impact of applying myopic versus forward-looking supplier behavior without binding investment constraints. In the latter, producers expect a downward trend in prices, withholding approval for projects that become unprofitable below about US$45/b.

Under the constrained scenarios, the difference between the myopic (not shown) and forward-looking assumptions become much less pronounced because the investment constraints are binding in both cases, resulting in nearly identical sets of approved projects and available capacity.

The level of the constraint does alter the resulting equilibria significantly after 2024 as new capacity ramps up and replaces declining production from existing projects. Under the Rystad investment plan and the US$150 billion cap, prices between 2020 and 2025 average US$11/b, or 14%, below the WEO reference prices. However, if the current slow-down in long-term project approvals persists (below US$100 billion), prices could exceed the WEO reference.

4.2. Oil price and demand dynamics: tight oil investments

In Figure 3 we show price (3a) and demand (3b) for scenarios where tight oil investments are capped at 50% of the levels projected by Rystad. Figure 4 depicts global tight oil production levels before and after applying the US$150 billion investment constraint.
4. Model Analysis and Results

Figure 2a. World oil price, IEA WEO versus ‘no residual supplier’ scenario.

Figure 2b. World oil demand, IEA WEO versus ‘no residual supplier’ scenario.

Sources: IEA World Energy Outlook, KAPSARC analysis.
4. Model Analysis and Results

**Figure 3a.** World oil prices: residual supplier (WEO stated policies) versus the competitive scenarios, assuming a 50% reduction in annual capital expenditures on short-term tight oil projects.

**Figure 3b.** World oil demand: residual supplier (WEO stated policies) versus the competitive scenarios, assuming a 50% reduction in annual capital expenditures on short-term tight oil projects.

Sources: IEA World Energy Outlook, KAPSARC analysis.
4. Model Analysis and Results

In Figure 3a, the slowdown in the growth of tight oil production causes both average prices and price variation to increase. The standard deviation of the annual rate of change in competitive market prices increases by at least 120% in the presented scenarios. This holds even when assuming stronger investments in conventional long-term production. What we observe is that a decline in the capacity of short-term tight oil projects restricts its ability to balance the market as a source of marginal production, compared to new conventional projects with longer lead times.3

Under the range of investment assumptions considered, prices recover much faster than in Figure 2. As a result, the market could experience a ramp-up in investment in long-term projects, in response to increasing prices. Only under the accelerated approval of new long-term projects (i.e., the US$150 billion cap), do the competitive prices remain below the WEO reference after 2025.

In Figure 3b total demand drops well below the reference scenario after 2024, when the average annual capital committed to long-term projects is capped below levels projected by the Rystad investment plan (i.e. US$75 billion and US$100 billion). We observe peak oil demand in both these scenarios, as well as under the Rystad investment plan.

Note that under the residual and no residual supplier scenarios we apply the same constraints on investments in new projects, and find them to be binding in both cases. Under the lower investment constraints (e.g. US$75 billion and US$100 billion) the total sustainable production (demand) in the competitive scenarios is less than the demand in WEO. In this case the residual supplier would have to produce above its sustainable production levels at additional capital cost, to balance the market at the price and demand projections of the WEO. Under these capital constraints it appears that the WEO market equilibrium would not be sustainable.

Finally, Figure 4 displays the global tight oil production in different scenarios, with and without investment caps. The black dotted and dashed lines illustrate how tight oil production responds to the increased production from conventional projects and decline in prices. The dashed line (competitive w/o investment cap) represents the scenario with myopic suppliers and no investment caps. It shows the sensitivity of tight oil production as prices dip below US$60/b after 2022. Below US$45/b production drops rapidly, with output in 2026 falling to pre-2018 levels but recovering as price recover to US$ 55/b by the end of the decade. The other scenarios in Figure 4 are for the Rystad investment plan. In this case the smaller reduction in prices in the competitive results in a smaller reduction in tight oil production, between 1 and 2 MMb/d.

4.3. Sensitivity analysis: demand parameters

The price elasticity of demand plays a central role in calibrating how consumers respond to a change in the supply structure. To investigate the sensitivity of our model to our assumptions, we run several scenarios calibrated across a range of elasticities. We also investigate sensitivity with respect to income elasticity, but find that for the range of values of interest the price elasticity of demand has a much stronger impact on the equilibria.

---

3 A Rystad study (2018) finds amplified short-term price volatility when U.S. tight oil capacity increases. However, the methodology and data frequency differ from those employed in this study.
4. Model Analysis and Results

Figure 4. Global tight oil production in the residual and the competitive scenarios under the Rystad investment plan (dashed line is without constraints on conventional and unconventional projects).

The price and demand results under three different price elasticity assumptions (-0.1, -0.25, and -0.5) are presented in Appendix B, figures B.1 and B.2. As expected, with consumers more (less) responsive to the change in price in the competitive market, demand and prices recover faster (slower).

Figure 5 plots the average prices from the competitive scenario (solid lines) from 2020 to 2030 across a range of demand elasticities: the US$150 billion cap (5a), US$125 billion cap (5c), and US$100 billion cap (5e), and cases including the 50% cap on tight oil (5b), (5d) and (5f), respectively. Dotted lines show the maximum and minimum values, and the dashed lines the average prices from WEO.

In the scenarios with more relaxed investment constraints (US$150 billion cap) average prices respond more to changes in the absolute price elasticities, or demand response. As the price elasticity increases, demand reacts stronger to lower prices created by additional OPEC production, leading to higher equilibrium prices. As the investment constraints, and supplies, are tightened average prices flatten out across different elasticities, but exhibit larger variability (maximum and minimum price spread) as observed in Figures 2 and 3. Here the results reflect the calibration, with average prices converging towards the WEO reference, while oscillating with greater amplitude due to the higher scarcity premiums on investments.

The trend of flattening of average prices reverses as the investment constraints are increased further, Figure (5f) US$100 billion and tight oil cap. In this case unresponsive demand does not catch up with tighter supplies, causing more frequent price spikes (see Appendix B Figure B.2) and higher average prices for lower elasticities.

In Appendix B, we present additional scenarios calibrated to the reference demand and price projections of IEO (EIA 2019).
Compared to WEO, calibrating the model to IEO data produces reduced prices and price variability, due to the slower price and demand growth projections.

**Figure 5.** Average prices (solid lines) from the competitive scenarios between 2020 and 2030 across a range of long-run price elasticities of demand. Dotted lines represent maximum and minimum prices in the competitive scenario, dashed lines the average price from the WEO reference (2019).

Sources: KAPSARC analysis.
4.4. Supply dynamics of the residual supplier

Figure 6 plots the annual liquids production for Saudi Arabia (a) and OPEC (b) under the competitive market scenarios with different investment constraints. These scenarios illustrate the growth in Saudi Arabia and OPEC’s total production, as well as available capacity assuming accelerated approval of new projects based on their profitability relative to other producers. Note that under the Rystad plan many projects organized by OPEC members are scheduled for approval after 2030.

The lines in Figure 6 reflect total production assuming OPEC coordinates residual production under the Rystad investment plan, with dashed lines including the cap on tight oil. See Appendix B (Figure B.4) for the residual supplier’s production under different investment constraints.

Saudi Arabia’s production falls to 11.4 MMb/d, about 2 MMb/d below its capacity, coinciding with tight oil production peaks in 2025. In this case OPEC production falls to 35.3 MMb/d, with participating members contributing an amount of residual production proportional to their total capacity. Historically, Saudi Arabia has shouldered the largest share of production cuts compared to other members. If Saudi Arabia were to organize the majority of withheld production (about 6.4 MMb/d), with limited to no support from OPEC, it would face a significant reduction in market share.

Under the 50% reduction in the amount of capital invested in tight oil projects market share of the residual supplier increases significantly, exceeding 40 MMb/d after 2020. In this case Saudi Arabia may be better positioned to operate as a residual without support from OPEC. Also under this tight oil constraint, the residual supplier’s production exceeds OPEC capacity under the Rystad investment plan by 2.2 MMb/d. This would require members to produce above sustainable production levels, or accelerate project approvals, such as under the US$75 billion cap investment cap.

In a world with strong tight oil growth, clearly Saudi Arabia would require stronger support from other producers to maintain production above 10 MMb/d at the stated price target. This might include countries outside OPEC, such as Russia and other producers participating in the OPEC+ group (Gnana 2019). The idea that OPEC may require support from other countries outside of the organization has been explored in the study titled “Is OPEC Dead Without Russia?” by Volkmar (2018).

4.5. Economics of the residual supplier

In light of the findings above, we investigate whether serving as a residual supplier can increase Saudi Arabia’s oil revenues relative to a purely competitive market behavior, assuming the kingdom can independently maintain its market share as the primary residual supplier, or do so with support from OPEC (and other partners).

To answer this question, we estimate the relative value of Saudi Arabia’s oil profits, defined as net revenues less annual capital expenditures, under the competitive and residual supplier scenarios. We calculate the difference between the annual profits in the residual supplier and the competitive scenarios in two cases: OPEC jointly acting as residual supplier and Saudi Arabia acting alone.

---

4 We assume that the residual supplier targets the same reference price regardless of whether all OPEC or only Saudi Arabia serves as residual supplier. Although Saudi Arabia might revise (reduce) the price target to preserve its market share if operating solo, we do not include such an adjustment in our estimates of the relative value of the different markets.
Then we calculate the net present value (NPV) of the difference from 2020 to 2030 using a discount rate of 4%, as opposed to the 10% rate used to evaluate upstream investment decisions. This reflects the lower discount rates typically applied by governments, and is within the range of risk premiums derived by Pierru and Matar (2014) for the evaluation of oil-related public investment projects in Saudi Arabia.

Our NPV calculation provides an estimate of the profits gained (or lost) by Saudi Arabia when transitioning to the competitive market structure. However, one should be careful in interpreting this as a measure of the additional market value that can be achieved by the residual supplier. First matching the price and demand equilibrium from the WEO stated policies assumes perfect coordination of residual production by different producers (e.g. OPEC). This may not be feasible. In addition, the residual supplier could adopt a different production target that does not reflect the WEO levels. Our analysis is simply used to identify a directional shift in profits of the competitive scenario compared to the WEO reference case.

Figure 7a and 7b plot the difference in Saudi Arabia’s profits for different price elasticities of demand, for scenarios without and with the 50% cap on tight oil, respectively. This illustrates how the consumer response to a change in price can impact the relative value of transitioning to a more competitive market structure. Solid lines represent cases where Saudi Arabia coordinates production with OPEC as the residual supplier and dashed lines with Saudi Arabia acting alone.

As shown in Figure 5 when consumers are less price responsive (lower absolute elasticity) average prices tend to decrease in the competitive market, resulting in lower overall profits. This trend is reflected in Figure 7a. Under these scenarios when Saudi Arabia coordinates production cuts with OPEC, the NPV of its profits are greater than the competitive scenarios for price elasticities of demand below 0.35 (in absolute terms), depending on the investment constraints applied. When acting as a residual supplier without support from OPEC, Saudi Arabia’s profits are always lower than the competitive scenarios (> US$300 billion) due to a significantly lower market share.

When applying the tight oil cap in Figure 7b the market share of the residual supplier increases. This increases the profits of the residual supplier, and under the US$150 billion cap this pushes the NPV curve to the right, crossing at a higher price elasticity. However, the supply constraints also result in higher average prices in the competitive market that balance the increased production by the residual supplier.

As the investment cap on new conventional projects drops to US$100 billion the slope of the NPV curve changes. Under this scenario average competitive prices decrease as the elasticity increases (Figure 5e). Despite the declining prices in the competitive market they are still on average higher than the WEO reference, and the profits made by a residual supplier. We exclude results where Saudi Arabia acts as the only residual supplier, because, in this scenario Saudi Arabia produces well above its sustainable production capacity after 2024 (see Appendix B Figure B.4a).
Figure 6a. Liquids production by Saudi Arabia in the competitive scenarios (shaded areas) and OPEC as the residual supplier (lines). Dashed lines are for the 50% cap on tight oil investments.

Figure 6b. Same as Figure 6a but for Liquids production by OPEC.

Sources: Rystad, KAPSARC analysis.
4. Model Analysis and Results

Figure 7a. NPV of Saudi Arabia’s profits (residual supplier minus competitive scenarios) versus the price elasticity of demand. Residual supplier as OPEC (solid lines) or only Saudi Arabia (dashed lines).

Figure 7b. NPV curves as described in 7a including the 50% cap on tight oil investments.

Source: KAPSARC analysis.
This study introduces a competitive market model for the supply-demand equilibrium of the global oil market, based on a novel approach that analyzes mid-term oil market dynamics with and without a residual supplier. The model uses detailed linear supply activities and explicit financial investment constraints, and differentiates supplies and investment as either long-term conventional or short-term tight oil projects, and can further categorize them based on political, geographic, product quality and other factors.

We calibrate the model to a given reference outlook relating oil prices, global demand and GDP growth from 2019 to 2030, including global price elasticity of demand and income elasticity assumptions. The reference represents an idealized view of the current market structure with Saudi Arabia, supported by OPEC, operating as the primary residual supplier.

This study presents several scenarios across a range of investment assumptions for long-term and tight oil projects, solved from the year 2019 to 2030. Our competitive scenarios demonstrate how prices and demand could respond, relative to the reference scenario, in a market with no residual supplier. Under our standard demand elasticity assumption ($c=-0.25$) prices decline significantly under the Rystad investment plan and the US$150 billion cap for long-term investments, average US$14/b less than the reference WEO prices from 2020 to 2025.

Our analysis indicates that prices under our competitive market scenarios have a high sensitivity to growth in tight oil production. Price variability, measured as the annual change in prices, increases substantially (by at least 200%) when capping tight oil investments to 50% of the levels projected by Rystad. In this case the ability of new short-term tight oil projects to balance the market as a source of marginal production is reduced compared to conventional projects that involve longer lead times.

The study finds that Saudi Arabia only benefits financially by serving as a residual supplier (following the WEO reference demand and prices) with strong coordination from other OPEC and possible assistance from OPEC+ members. Also, this only holds when the long-run price elasticity of demand is low, less than about 0.35 in absolute terms.

The results suggest that cooperation between Saudi Arabia and other producers can reduce the sensitivity of the Kingdom's oil revenues to tight oil production growth. Given that the long-run price elasticity of global demand is likely to be close to the values mentioned above, this finding supports the view that collectively enlarging the function of the residual supplier to other non-OPEC producers (like Russia) may be necessary for Saudi Arabia to maintain higher oil revenues than it could in a market without a residual producer.

The emergence of U.S. shale oil has introduced structural market uncertainties (such as the price responsiveness of non-OPEC oil supplies), making cooperation even more necessary. Even in cases where tight oil production growth slows, Saudi Arabia's does not clearly benefit from acting alone as a residual supplier. Therefore, it is in Saudi Arabia's interest either to abandon the role of residual supplier, or to jointly perform this function as part of a larger — and more fully cooperative — group.

5. Conclusion
References


Appendix A. Model Formulation

Table A.1. List of indices, variables and parameters used in the model.

<table>
<thead>
<tr>
<th>Indices</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$i$</td>
<td>All projects existing and new</td>
</tr>
<tr>
<td>$j$</td>
<td>All projects with existing production capacity</td>
</tr>
<tr>
<td>$k$</td>
<td>All new projects that can be built</td>
</tr>
<tr>
<td>$k_l$</td>
<td>All new projects with long-term production cycles (no tight oil)</td>
</tr>
<tr>
<td>$i_s$</td>
<td>Projects of the residual supplier, existing and new</td>
</tr>
<tr>
<td>$i_s'$</td>
<td>All short-term tight oil projects existing ($j_s$) and new ($k_s$)</td>
</tr>
<tr>
<td>$t, t'$</td>
<td>Years in the model ($t_s, t_s+1, ..., t_N$) where $t_s$ is the start year and $t_N$ the last year modeled (horizon). $t'$ indexes years when new projects are built.</td>
</tr>
<tr>
<td>$\tau$</td>
<td>All years for projects operating beyond the model horizon ($t_s, ..., t_\infty$)</td>
</tr>
<tr>
<td>$\Delta t$</td>
<td>Shift in the projected production profiles for new projects $k$, $\Delta t'=t_s-t'$. As a convention the approval years of all new projects $k$ are set to $t_s$.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Coefficients</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{i,\tau}$</td>
<td>Production cost profiles projected for all projects in USD/bbl</td>
</tr>
<tr>
<td>$E_{i,\tau}$</td>
<td>Projected production profiles for existing projects in MMbbl</td>
</tr>
<tr>
<td>$F_{i,\tau}$</td>
<td>Projected production profiles for new projects in MMbbl</td>
</tr>
<tr>
<td>$K_{i,\tau}$</td>
<td>Annual projected capital development cost for each project $i$ and year $\tau$ in million USD</td>
</tr>
<tr>
<td>$\hat{K}_i$</td>
<td>Cap on the total discounted capital committed to all new long-term projects in year $i$</td>
</tr>
<tr>
<td>$\hat{t}_i$</td>
<td>Cap on the total capital expenditures on all short-term tight oil projects in year $i$</td>
</tr>
<tr>
<td>$r$</td>
<td>Interest rate used to discount future cash flows</td>
</tr>
<tr>
<td>$M_{i,\tau}$</td>
<td>Index to correct the global market price (calibrated to Brent) for each asset based on quality and regional markers</td>
</tr>
<tr>
<td>$T_h$</td>
<td>Minimum year when investment decision for new asset $h$ can be made</td>
</tr>
</tbody>
</table>

**Demand Curve**

| $\hat{g}_i$ | Reference GDP growth rate projected for all future years |
| $\hat{d}_i$ | Reference oil demand for each year in MMbbl |
| $\hat{p}_t$ | Moving average reference oil price projected for all future years in USD/bbl |
| $\hat{Y}_i$ | Reference world GDP for the model start year in million USD |

<table>
<thead>
<tr>
<th>Variables</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$b_{k',\tau}$</td>
<td>New project $k$ built in year $\tau$' (scaled by the projected production profile)</td>
</tr>
<tr>
<td>$q_{j,\tau}$</td>
<td>Quantity produced from existing asset $j$ in year $\tau$ in MMbbl</td>
</tr>
<tr>
<td>$x_{k',\tau}$</td>
<td>Quantity produced in year $\tau$ from new project $k$ built in year $\tau'$ in MMbbl</td>
</tr>
</tbody>
</table>
Appendix A. Model Formulation

<table>
<thead>
<tr>
<th>Dual</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$p_t$</td>
<td>Market clearing price, the marginal value of oil demand in USD/bbl</td>
</tr>
<tr>
<td>$y_t$</td>
<td>Marginal value on the constraint on investment in new projects $i'$ (A3.1)</td>
</tr>
<tr>
<td>$\lambda_{jt}$</td>
<td>Marginal value on the supply constraint for existing projects $i$ used in $t$ (A3.2)</td>
</tr>
<tr>
<td>$\mu_{k't'}$</td>
<td>Marginal value on the supply constraint for new projects $i'$ built in $i'$ and used in $t$ (A3.3)</td>
</tr>
</tbody>
</table>

**Dependent variable**

| $D_t$                         | Demand for oil as a function of the oil price, world GDP and GDP growth rate in MMbbl |
| $y_t$                         | World GDP per year in million USD |
| $\bar{p}_t$                  | Moving average of the market clearing price in USD/bbl |

Here we complete the mathematical formulation of the demand and supply models used to construct an equilibrium model of the global oil market formulated as a mixed complementarity problem (MCP). All indices, variables and parameters used in the model are shown in Table A.1.

$$\sum_j q_{jt} + \sum_{k't'} x_{k't'} \geq D_t \quad \perp p_t \geq 0 \quad \forall i \quad t \quad (A.1)$$

First we introduce the independent demand constraint in equation (A.1), complemented by the market-clearing price $p_t$. It sets the demand equations from equation (1) as the lower bound on the total supplies from existing and new projects, $q_{jt}$ and $x_{k't'}$, respectively. The index $j$ represents all existing oil projects, and $k$ all new oil projects, while $t$ is the production year, and $t'$ the build approval year for new projects.

### A.1 Estimation of $\theta$ and calibration of $A_t$ in the demand equation

To estimate an approximate value of $\theta$ in Eq. (2) we consider the following equation:

$$\ln \frac{g_t}{g_{t-1}} = \theta \ln \frac{p_t}{p_{t-1}} + u_t \quad (A.1)$$

where $u_t$ is an error term. To get Eq. (A.1) we consider the growth equation given in Eq. (2) (i.e. $g_t = \frac{\Delta y_t}{y_t}$), take the natural logarithm of both sides and replace $\tilde{g}_t$ and $\tilde{p}_t$ by $g_{t-1}$ and $p_{t-1}$, respectively. To avoid spurious regression, we test for stationarity of the variables in Eq. (A.1) using the augmented Dickey-Fuller (Dickey and Fuller 1981) and the Phillips and Perron (1988) unit root tests. As expected, both series are found to be stationary, which allows us to estimate Eq. (A.1) by means of ordinary least squares (OLS). The estimated value for $\theta$ from the OLS regression is -0.2, which will thus be used in the following simulations to replace $\theta$ in Eq. (A1.1). For the sake of completeness, the sensitivity of the results are evaluated against a range of plausible values for $\theta$ (such as -0.5 and -0.8). The results of the sensitivity analysis (unreported here) show that our simulation results are robust to different values of $\theta$.

---

1 In both ADF and PP tests the Akaike information criterion (AIC) is used to choose the lag length. The OLS regression includes time dummies for the years 2009 and 2010 to control for the effects of the global financial crisis. While time dummies are significant, the parameter $\theta$ is found to be insignificant at conventional levels. To ensure the goodness of fit of the model, a series of diagnostic and stability tests are also conducted. To conserve space, we do not report the econometric results here. All unreported results are available from the authors upon request.
Appendix A. Model Formulation

The reference prices, demand, and GDP from the WEO state policies scenario (IEA 2019) and IEO reference scenario (EIA 2019) used to calibrate the scaling coefficient $A_i$ with a price elasticity of -0.25 and income elasticity of 0.75 are provided in Table A.2. Notice that the slower average demand and price growth in the IEO results in reduced scaling coefficients, $A_i$.

**Table A.2.** IEA WEO 2019 oil demand, oil price (Brent) GDP, and corresponding calibration coefficients $A_i$.

<table>
<thead>
<tr>
<th>Year</th>
<th>Oil Demand, $\tilde{D}_i$ (Mmbbl/d)</th>
<th>Oil Price, $\tilde{p}_i$ ($/bbl$)</th>
<th>GDP PPP Growth (%)</th>
<th>$A_i$, $\varepsilon=-0.25$, $\gamma=0.75$</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>96.60</td>
<td>54.16</td>
<td>3.7</td>
<td>0.0390</td>
</tr>
<tr>
<td>2018</td>
<td>99.20</td>
<td>70.81</td>
<td>3.7</td>
<td>0.0391</td>
</tr>
<tr>
<td>2019</td>
<td>98.75</td>
<td>61.04</td>
<td>3.6</td>
<td>0.0390</td>
</tr>
<tr>
<td>2020</td>
<td>99.83</td>
<td>65.53</td>
<td>3.6</td>
<td>0.0391</td>
</tr>
<tr>
<td>2021</td>
<td>100.90</td>
<td>70.03</td>
<td>3.6</td>
<td>0.0385</td>
</tr>
<tr>
<td>2022</td>
<td>101.98</td>
<td>74.52</td>
<td>3.6</td>
<td>0.0386</td>
</tr>
<tr>
<td>2023</td>
<td>103.05</td>
<td>79.01</td>
<td>3.6</td>
<td>0.0386</td>
</tr>
<tr>
<td>2024</td>
<td>104.13</td>
<td>83.51</td>
<td>3.6</td>
<td>0.0386</td>
</tr>
<tr>
<td>2025</td>
<td>105.20</td>
<td>88.00</td>
<td>3.6</td>
<td>0.0385</td>
</tr>
<tr>
<td>2026</td>
<td>105.70</td>
<td>89.60</td>
<td>3.6</td>
<td>0.0382</td>
</tr>
<tr>
<td>2027</td>
<td>106.20</td>
<td>91.20</td>
<td>3.6</td>
<td>0.0377</td>
</tr>
<tr>
<td>2028</td>
<td>106.70</td>
<td>92.80</td>
<td>3.6</td>
<td>0.0371</td>
</tr>
<tr>
<td>2029</td>
<td>107.20</td>
<td>94.40</td>
<td>3.6</td>
<td>0.0365</td>
</tr>
<tr>
<td>2030</td>
<td>107.70</td>
<td>96.00</td>
<td>3.6</td>
<td>0.0359</td>
</tr>
</tbody>
</table>

### A.2 The supplier’s optimization problem

\[
\max \pi = \frac{1}{(1 + r)(t - t_0)} \sum_{j} q_{jt} (p_{jt} M_{jt} - C_{jt}) \\
\quad + \sum_{t' \geq t} \frac{1}{(1 + r)(t' - t_0)} \sum_{k} x_{kt} p_{k,t'} (p_{k,t'} M_{k,t'} - C_{k,t'}^*) \\
\quad + \sum_{t' \geq t_i} \sum_{k} \sum_{t=t_i+1}^{\infty} p_{t'N,N,t} M_{k,t'} - C_{k,t'}^* b_{k,t'} F_{k,t'} \Delta t' \\
\quad - \sum_{t' \geq t} \sum_{t=t_0}^{\infty} K_{k,t'} b_{k,t'} \frac{F_{k,t'}^*}{(1 + r)(t' - t_0)}
\]  

(A3)
Appendix A. Model Formulation

\begin{align*}
\text{s.t.} \quad & b_{kt}, q_{jt}, x_{kt} t' \geq 0 \\
& \sum_{t'} E_{jt} \geq q_{jt} \\
& (b_{kt} F_{kt} + \Delta t') \geq x_{kt} t'
\end{align*}

\text{(A3.1)}

The supplier’s optimization problem is represented in equation block (A3). Oil producers make two decisions for conventional oil, based on two cost curves:

I. A cost curve for production \( q_{jt} \), from existing projects \( j \) over the period \( t \) constrained by the existing capacity \( E_{jt} \).

II. A cost curve for production \( x_{kt} t' \), from the development of new projects \( b_{kt} \) in year \( t' \), with projected production capacity \( F_{kt} \).

Over the simulation period, defined by the index \( t \), suppliers maximize profits \( \pi \) of selling production from existing and new projects. Net revenues are calculated as the market price, \( p_{t'} \), corrected by the marker index \( M_{jt} \), less marginal production costs, \( C_{jt} \). All revenues are discounted using the interest rate, \( r \), compounded for every year beyond the start year of the simulation, \( t' \). In the second revenue term for new projects, we shift the projected production cost profile \( C_{kt} \), by \( \Delta t' = t' - t \). By design we assume the projected profiles of all new projects start in the first year being modeled, year \( t' \), such that \( \Delta t' \) is the same for all projects built in \( t' \). Note that the profiles of new projects include the approval year and development lead times ahead of the production start.

In the third term we calculate the net revenues from the production of new long-term projects \( k \) (excluding tight oil) beyond the model solve period, \( r > t' \). Here we calculate the future revenues assuming the oil price equals the equilibrium price from the last year solved by the model, \( P_{t'} \). In the last term we subtract out the corresponding total discounted capital development cost \( K_{kt} \) of new long-term project. The suppliers use this term to select the projects that are economically viable; the discounted net revenues exceed the discounted capital costs over the lifetime of the project.

The investment variable \( b_{kt} \) is defined as a unit-less non-negative number, approximating investment decisions as a continuous variable. In Eq. (A3.1) the upper bound on \( b_{kt} \) is set to 1. This allows the model to partially develop a new project in a given year when it is the marginal supply unit, rather than solving a more complex problem where \( b_{kt} \) is a binary decision equal to 0 or 1. Note that new investments are limited to \( t' \geq T_{jt} \), where \( T_{jt} \) represents the minimum year when a new project \( k \) can be approved for development, restricting the start date of new projects.

The supply from existing and new projects are constrained in (A3.2) and (A3.3), respectively. Recall production and cost curves of new projects are adjusted by the shift parameter, \( \Delta t' \), to account for delays in the decision to approve new projects.
Appendix A. Model Formulation

To capture the short investment and production cycles of new tight oil projects the model considers that the producers make one decision only: to develop new capacity if the full cost (operating and development) are lower than the current price, for this reason the capital development costs are embedded in the cost parameter \( C^c \), defined as the breakeven price for the tight oil play. Therefore, we do not have explicit capital development costs for tight oil projects in the objective function. Finally, the approval year of these projects is assumed to coincide with the first year of production.

However, in some of the scenarios described in Section 3 we do apply financial constraints on the total capital development costs for all tight oil projects. This constraint is defined in equations (A3.4), where \( \hat{h} \) is the capital on total annual tight oil capex. The two terms on the right-hand side include the capex spent on the development of new projects, and the capex spent on extracting tight oil from existing projects, respectively.

Equation (A3.5) adds a cap on the total discounted capital that can be committed to all new long-term oil projects in a given year, defined by the coefficient \( \hat{K} \).

### A.3 Optimality conditions of the supplier’s problem

\[
\begin{align*}
E_{jt} & \geq q_{jt} \quad \forall j, t \\
\left( b_{kt’} F_{kt+\Delta t} \right) |_{T_k \leq t’} & \geq x_{kt,t’} \\
\sum_{T_k \leq t’} b_{kt’} & \leq 1 \\
\hat{F}_{jt} & \geq \sum_{k} K_{ist+\Delta t} b_{ist} + \sum_{j} K_{jst} \frac{q_{jst}}{E_{jst}} \\
\hat{R}_{jt} & \geq \sum_{T_k \geq t} \sum_{k} K_{ist+\Delta t} d_{kt} (1 + r)^{t-i} \\
C_{jt} + \lambda_{jt} + \phi_{jt} K_{jt} & \left( \frac{1}{(1+r)^{t-i}} + \frac{\sigma_{t}}{(1+r)^{t-i}} \right) \geq p_t M_{jt} \quad \forall j, t \quad (A4.6)
\end{align*}
\]

\[
\begin{align*}
\sum_{t \geq \Delta t} K_{k,t+\Delta t} & \left( \frac{1}{(1+r)^{t-i}} + \frac{\sigma_{t}}{(1+r)^{t-i}} \right) \geq \sum_{t > T_k} \left( p_t M_{kt+t+\Delta t} (1+r)^{(t-i)} \right) + \sum_{t \geq \Delta t} \left( (p_t M_{kt+t+\Delta t} (1+r)^{(t-i)})^F_{kt+t+\Delta t} \right) \quad \forall k, t’ \geq T_k \quad (A4.9)
\end{align*}
\]
In order to solve the supply and demand problems simultaneously we formulate an equilibrium model consisting of the demand function (A1) and demand constraint (A2) with the optimality conditions of the supplier’s problem defined in (A4). Equations (A4.6), (A4.7), (A4.8) and (A4.9) represent the optimality conditions for the primal variables \( q_{jt}, x_{kt}, t, \) and \( b_{kt}, \) respectively. They are expressed in terms of the coefficients of the objective function and the dual variables \( \lambda_{jt}, \mu_{kt}, \gamma_{kt}, \phi_{t}, \) and \( \sigma_{t} \) from the original primal constraints, (A4.1), (A4.2), (A4.3), (A4.4) and (A4.5), respectively.

When the capital constraints (A4.4) and (A4.5) are binding the dual variables \( \phi_{t} \) and \( \sigma_{t} \) represent the additional cost of tight oil projects, and new long-term investments, respectively. On the left-hand side of optimality condition (A4.8) \( \sigma_{t} \) is added to the discounted cost of capital, representing an adjustment to the profitability of projects when the capital constraint is reached. Similarly, \( \phi_{t} \) is added to the production cost of exiting tight oil projects for existing projects in (A4.6) and development cost of new projects in (A4.9).

When solving the residual supplier scenario we use complementary slackness to incorporate price ceiling (A4.10) and floor (A4.11) constraints into the optimality conditions of the supplier’s problem. These constraints signal the residual supplier to add or remove capacity, \( r_{-t} \) and \( r_{+t} \), in response to the production from the competitive fringe to achieve the desired ceiling or floor, represented by the coefficients \( \tilde{P}_{t} \) and \( \tilde{P}_{t}^{-} \), respectively.

\[
\begin{align*}
\hat{P}_{t} & \geq p_{t} \quad \perp r_{+t}^{+} \geq 0 \quad \forall \ t \\
\check{P}_{t} & \leq p_{t} \quad \perp r_{-t}^{-} \geq 0 \quad \forall \ t
\end{align*}
\]

The variables \( r_{-t} \) and \( r_{+t} \) are defined as duals on the price constraint, and are used to adjust the total production required from the residual suppliers assets. For example, \( r_{-t} \) represents the aggregate spare capacity that can be distributed across the supplier’s assets in several ways. For example, withhold the most expensive assets (revenue maximization), or by distributing it relative to the share of capacity by each asset. The optimal strategy will depend on various technical characteristics and operational requirements of the supplier not accounted for in our model. We choose a strategy to distribute spare capacity across all assets, reflecting the average production cost of the residual supplier.

Given that the price target is fixed, the fringe and residual supplier’s production level can also be evaluated using a pure accounting approach. However, we leverage the competitive market model to evaluate production and investment decisions, including constraints, to avoid developing additional accounting logic. This approach also allows for flexibility in how the residual supplier targets the market price, for example only setting a price floor.

A.4 The recursive problem

The full MCP consisting of (A1), (A2) and (A4) over the time period \( t = \{t_{s}, t_{s+1}, \ldots, t_{N}\} \) can either be solved as a single problem, or recursively for several smaller time periods \( t' \) of size \( n \), \( t' = \{t_{s}, t_{s+1}, \ldots, t_{s+N}\} \). All \( t \) and \( t' \) are replaced by \( t' \) and \( t'' \), with \( n < N \) and \( s \) denoting the start year in each recursive step. After solving the equilibrium model for the first period we perform the recursive operations outlined in (A5) to update the model coefficients, move forward the start year, \( s = s+1 \), and repeat until we reach the last period covered by the model, \( s+n = N \).
Appendix A. Model Formulation

The number of years solved during each step defines the horizon over which suppliers make decisions, and can be adjusted to represent myopic or forward-looking supplier behavior. Under a myopic approach suppliers incorporate a limited amount of information or expectations about demand and production in future years. In the extreme case, suppliers only consider decisions made in the current start years, \( s = n \).

\[
j = j \cup k; \quad \text{if } b_{kt} > 0 \tag{A5.1}
\]

\[
C_{kt} = (\bar{C}_{kt} + b_{kt}^{f}F_{k,t} + E_{kt}C_{kt}) / \tag{A5.2}
\]

\[
(b_{kt}^{f}F_{k,t} + E_{kt}) \quad \forall \ kt \geq t_s
\]

\[
E_{kt} = E_{kt} + b_{kt}^{f}F_{k,t} \quad \forall \ kt \geq t_s \tag{A5.3}
\]

\[
B_k = B_k + b_{kt}^{f} \quad \forall \ k \tag{A5.4}
\]

\[
k = \text{false}; \quad \text{if } B_k = 1 \tag{A5.5}
\]

\[
s = s + 1 \tag{A5.6}
\]

In (A5.1) we include all new projects \( i' \) that are built in the current start period \( b_{i't} > 0 \) to the set of existing projects. In (A5.2) the projected cost profiles for new projects built in \( i' \) are adjusted based on the shift parameter \( \Delta t' = t - t' \). We define \( \bar{C}_{i'} \) as a copy of the original \( C_{i'} \) to track cost profiles of new projects partially built in different years. Notice the updated cost parameter is a weighted average of the production profile corresponding to the current build \( b_{i't}F_{k,t}^{f} \) of a new project and the existing production resulting from the partial build of the same project in past years, where \( E_{it} \) is initially 0. In (A5.3) we add the production profiles for new projects built in the current start year to the existing capacity parameter \( E_{i'} \), again accounting for the shift parameter \( \Delta t' \).

in Eq. (A5.4) we introduce the unitless coefficient \( B_k \) that keeps track of all new build decisions from previous start years, initialized to 0. Any new project built to completion \( (B_k = 1) \) are removed from the subset \( k \) in (A5.5). Under the recursive solution approach we add \( B_k \) to the left-hand side of (A4.3) since we are solving the model over the reduced time period \( t \) that excludes past start years. Finally, we move forward to the next start year, solve the equilibrium problem, and repeat.

A.5 The supply data (Rystad UCube)

The Rystad UCube upstream database is constructed using a bottom-up approach based on private sector and government reporting and calibrated using various other sources for country-level production. It includes more than 21,000 individual assets, with historical data starting from the year 1900 and projected data up to year 2100, including production profiles, operating costs, and investment plans. It also includes lead times between approval year (first year of development) and start-up (first year of production).

For each asset, the approval year shows which year the asset was, or is expected to be, sanctioned for development in UCube. OPEX values were extracted in USD/bbl. At the beginning and end of the projected production profile, OPEX values were abnormally high due to dividing costs by expected low production in early and late production years. These outliers were replaced with average OPEX for each asset using statistical analysis.
Gas condensate fields

All hydrocarbon liquids are extracted from UCube, including crude oil, condensate, NGLs, refinery gains, and other liquids. Liquids produced from gas-condensate fields (gas fields with condensate-to-gas-ratio exceeding 1 bbl/MMcf) are assumed to be a byproduct with no additional costs in our model. In reality, processing the liquids from gas fields will have some operating cost and perhaps some capital expenditure; however, as a simplifying assumption, we disregard these costs.

Tight oil fields

Tight oil field costs are treated separately in the model. Tight oil fields represent an aggregation of many wells drilled at a projected schedule depending on the forecasted oil price. As such, each new well can be treated as having its own break-even price and as a new investment. Due to the inability to disaggregate profiles for individual wells from the extracted UCube data, we chose to use the full-cycle break-even prices. Break-even prices are calculated on an asset level by estimating the oil prices that give an NPV of zero based on future free cash flow. Cash flows incorporate all production costs (CAPEX and OPEX) as well as any government taxes. A discount rate of 10% is applied to calculate the NPV. Decommissioning and abandonment costs are not included in break-even calculations (see Rystad).

We use the Rystad data to calculate a price correction term for all hydrocarbon liquids at the project level based on the API, other discount elements (sulfur content, etc.), and regional price markers. The term is calibrated with respect to Brent prices used to calibrate the demand curve used in our model. Condensate, NGL and gas prices are estimated within UCube based on defined links to oil prices.

Liquids production (condensate, NGLs, refinery gains, and other liquids) are also based on UCube projections for existing producing fields developed prior to 2018.
Appendix B. Sensitivity Analysis: Price Elasticity of Demand

The detailed results from the equilibrium problem solved in the competitive scenario under the Rystad investment plan are listed in Table B.1, alongside the reference values from IEA’s stated policies scenarios.

Table B.1. Scenario results for demand, price and GDP in the competitive market scenarios under the Rystad investment plan.

<table>
<thead>
<tr>
<th>Demand (MMbbl/d)</th>
<th>Oil price ($/bbl)</th>
<th>GDP Growth (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>IEA</td>
<td>WEO</td>
</tr>
<tr>
<td>Year</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>99.2</td>
<td>70.81</td>
</tr>
<tr>
<td>2019</td>
<td>98.8</td>
<td>98.9</td>
</tr>
<tr>
<td>2020</td>
<td>99.8</td>
<td>100.8</td>
</tr>
<tr>
<td>2021</td>
<td>100.9</td>
<td>102.8</td>
</tr>
<tr>
<td>2022</td>
<td>102.0</td>
<td>104.5</td>
</tr>
<tr>
<td>2023</td>
<td>103.1</td>
<td>105.8</td>
</tr>
<tr>
<td>2024</td>
<td>104.1</td>
<td>107.5</td>
</tr>
<tr>
<td>2025</td>
<td>105.2</td>
<td>109.2</td>
</tr>
<tr>
<td>2026</td>
<td>105.7</td>
<td>109.7</td>
</tr>
<tr>
<td>2027</td>
<td>106.2</td>
<td>110.0</td>
</tr>
<tr>
<td>2028</td>
<td>106.7</td>
<td>109.9</td>
</tr>
<tr>
<td>2029</td>
<td>107.2</td>
<td>109.8</td>
</tr>
<tr>
<td>2030</td>
<td>107.7</td>
<td>109.2</td>
</tr>
</tbody>
</table>

In Figure B.1 we present the results for total oil demand and price under different assumptions for the price elasticity of demand with no residual supplier. As expected, we find a much faster price recovery in the no residual supplier scenario when the absolute value of the elasticity is higher and consumers are more responsive to the shift in OPEC supplies. Notice that when consumers are less responsive to the structural change, over time the equilibrium price grows at a rapid rate and surpasses reference. This occurs as a result of the slow price recovery delaying the approval of new projects as scheduled under the Rystad investment plan, and therefore available capacity towards the end of the decade.

Figure B.2 shows the same set of scenarios as Figure B.1 after applying the 50% cap on investments in tight oil projects. Notice that the price volatility increases as the absolute value of the elasticity is reduced. Since supplies are tighter in these scenarios, reduction in consumer price response and associated changes in production decisions have a more pronounced impact on the market equilibira over a shorter time period (e.g. three years). Also, the total demand converges in each case as a result of the elevated price levels and nearly identical investment decisions.
Appendix B. Sensitivity Analysis: Price Elasticity of Demand

**Figure B.1.** World oil price and demand for the competitive scenario under the Rystad investment plan for different price elasticity assumptions.

To assess the sensitivity of our model to the reference case (IEA NPS) we also calibrate the demand curve to the EIA’s IEO. We compare the results with the original IEA calibration in Figure B.3, when applying the US$150 billion cap on long-term investments and the tight oil cap.

**Figure B.2.** World oil price and demand for the no residual supplier scenario under the Rystad investment plan with the 50% tight oil investment cap for different price elasticity assumptions.

Clearly the EIA adopts a more moderate growth trajectory overall with prices consistently below WEO. Following accelerated demand growth in the year 2020, it is consistently slower over the next 10 years, with total demand falling to 2 MMbbl/d below WEO in 2030.
Appendix B. Sensitivity Analysis: Price Elasticity of Demand

Overall, the IEO calibration produces both lower and slightly more stable oil prices. A contributor to the lower price volatility is that demand is slightly lower under the IEO calibration, and therefore supplies are less tight. Keep in mind this is assuming that investors spend on average US$150 billion per year in both scenarios.

Figure B.3. World oil price (a) and demand (b): Comparing results under the IEA NPS and EIA IEO reference calibration. All scenarios apply the US$150 billion cap on new long-term investment and the 50% cap on short-term tight oil. Sources: IEA World Energy Outlook, KAPSARC analysis.

Figure B.4 depicts Saudi Arabia’s liquids production under different investment constraints. Notice that under the US$100 billion investment cap (Figure 4a) with the tight oil cap (hollow dashed line), by the end of the decade Saudi Arabia’s production exceeds the total sustainable production in the competitive scenario. As a lone residual supplier, Saudi Arabia would have to expand its existing production capacity to meet the demand (and price) outlook of the WEO. A more realistic expectation is that the residual supplier would produce at the sustainable production levels, and a different price equilibrium would be reached.
Figure B.4. Total liquids production by Saudi Arabia in the residual supplier scenarios, under different investment constraints. Dashed lines depict production by Saudi Arabia when it is the residual supplier without support from OPEC. Shaded areas show total production in the competitive scenarios.
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Bertrand is a senior research associate focusing on the impact of market regulation and liberalization in energy markets. An experienced energy systems model developer (linear optimization and mixed complementary problems), he is working on developing the KAPSARC Energy Model (KEM) as a decision support tool for analyzing price regulation in energy economies. Bertrand has contributed to the development of KEM Saudi Arabia and is the lead developer of KEM China, studying the impact of government regulation in the coal, power and natural gas markets. He was previously employed as a research assistant at the Canadian Space Agency.

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Cooperate or Compete? Insights from Simulating a Global Oil Market with No Residual Supplier

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Colin Ward
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About the Project
This project investigates a world oil market where there is no residual supplier, such as OPEC, that adjusts its production to influence prices. A partial equilibrium model is used to simulate oil supply and demand dynamics assuming perfect competition among all producers. The model provides a detailed representation of supplies, characterized as longer-term conventional and shorter-term tight oil production, that can be used to construct a variety of production and investment scenarios. It is also used to compare the financial implications of transitioning to a competitive oil market for the current residual supplier, OPEC, and Saudi Arabia as its largest contributor.