Regression analysis of historic oil prices: A basis for future mean reversion price scenarios

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\section*{ARTICLE INFO}

\textbf{JEL classifications:}
Q11
Q31
Q47

\textbf{Keywords:}
Oil spot price
Mean reversion price
Demand elasticity
Supply elasticity
Price scenarios

\section*{ABSTRACT}

We propose price forecasting algorithms based on regression analysis of historic oil prices over 150 years (1861–2012). From 1986 onward daily market prices allow more detailed analyses of the principal crude oil benchmarks (West Texas Intermediate [WTI] and Brent). The mean reversion price for a given time period corresponds to the marginal cost of supply. When supply and demand are out of equilibrium, spot prices move in a bandwidth bound at the bottom by cash cost of supply and at the top by the concurrent price of demand destruction. Short-term elasticity of demand is 0.015 (highly inelastic), and long-term elasticity of supply changed from 0.99 (highly elastic) during 1965–1983 to 0.39 (less elastic) during 1984–2012. We derive functions for the long-term equilibrium price and expand them into scalable equilibrium price functions for forecasting future price scenarios if “business-as-usual” is assumed. We also consider how two hypothetical black swan events (“unknown unknowns”) may affect the mean equilibrium price.

\section*{1. Introduction}

The past decade included two unanticipated, steep oil price falls: one in late 2008 and early 2009, and a second that started in August 2014 and seemed to bottom out several times during 2015 but reached a new low in February 2016 to slowly rebound to about $50 per barrel at the end of 2016. Such price shocks tend to take oil and gas companies by surprise, impairing their business performance. As we document below, petroleum companies taking final investment decisions on mega-projects became accustomed to a decline in oil price volatility until mid-2014, and many assumed they could count on sustained high oil prices of $100+/bbl well into the future.

For industry, the increased volatility of crude oil spot prices raises concerns and uncertainty about the appropriate reference price to use in approving new field development projects. Steeper commodity price swings lower the reference price, so that fewer of the screened projects will pass the corporate hurdle rate test. Commodity price shocks may affect the business planning and operations of petroleum companies in various ways:

\begin{itemize}
  \item Past and current increases in the volatility of commodity prices increase uncertainty about what oil price should be used in estimations of net present value and internal rate of return to validate new investment decisions on long-term field development.
  \item Upward price shocks may convert contingent resources (hitherto uneconomic) into “proved reserves ready for future extraction,” merely in compliance with requirements to report reserves.
  \item Similarly but in the reverse direction, rapid price falls may decrease the nominal value of proved reserves in obligatory
\end{itemize}
operational and financial reporting (e.g., to the SEC), affecting the company's balance sheet. Such decreases may even trigger bank borrowing base redeterminations and recall of revolving credit, leading to bankruptcy due to debt restructuring under Chapter 11 (and reemergence after restructuring, as has frequently occurred in the U.S. market over the past few years; see references in Section 5.1).

- Increased volatility in concurrent oil and gas prices increases the uncertainty range in fair-value assessments of oil and gas properties, making M&A price offers more dependent on forecasts of commodity prices.
- When spot price volatility decreases, projections of oil prices (and oil-indexed natural gas prices) stay in a narrower price deck, which tends to reduce concerns about future price volatility in corporate investment decisions.
- Oil and gas price movements are also relevant for hedging decisions of petroleum companies that use derivatives to mitigate adverse trends in future delivery prices.

The recent volatility of oil prices not only increases uncertainty about corporate earnings and project evaluations for companies, but also erodes tax revenue for governments (Weijermars, 2015). A better understanding of oil pricing mechanisms (micro-economics) is critical for anticipating their effects on the global economy (macro-economics) for as long as oil remains a major fuel in the world's pool of primary energy resources (Kumhof & Muir, 2012, 2014; Roeger, 2005). About 45% of 2015 global oil production is used to feed refineries that produce a range of transportation fuels (kerosene, diesel, gasoline, etc.). And, of course, oil is also used as fuel for electricity generation in power plants, as industrial feedstock, and as home heating fuel.

The steep 2014–2016 decline in oil spot prices has renewed industry awareness of the need to hedge the business against future oil price volatility. Oil price models provide essential support for decision-making in the upstream hydrocarbon industry. Numerous studies of oil price dynamics are available (Al-Qahtani, 2008; Alquist & Guénette, 2014; Alquist, Kilian, & Vigfusson, 2011; Baumeister & Kilian, 2012; Benes et al., 2012; Manescu & Robays, 2014; Miltersen, 2002; Pagano & Pisani, 2009). The idea of mean reversion of the oil price to a (varying) trendline has been discussed at length by Pindyck (1999). However, since that ground-breaking work, > 15 years of additional market dynamics have become available to be captured in time series. Our study provides equations for the mean reversion price (and restoration to the mean reversion price), including the recent period when major market agents caused short-term price shocks owing to supply-demand disequilibrium. The mean reversion price formulas established in our regression analysis of historic prices also update Slade's (1982) oil price regression. Our analysis accounts for the emergent share of unconventional resources (such as shale) in the global petroleum supply system, and for the general upward drift in the marginal cost of supply since the 1990s as extraction technology has become more costly. The regression analysis of historic oil prices over 150 years in our study places the development of the long-term mean reversion oil price in perspective. We derive equations for the time-dependent equilibrium supply rate by including the rising cost of marginal supply based on detailed price data available from 1986 onward.

Pindyck (1999, 2001) has emphasized that structural models of supply and demand can be linked to mean-reverting price trend-lines only when the long-term marginal cost of supply is taken into account. Although many factors may affect marginal cost of supply, it rises when a resource gets scarcer and extraction technology innovations are slow in catching up. In spite of technology innovations, the cost of petroleum exploration and production gradually increases (Weijermars, Clint, & Pyle, 2014), because the bulk of conventional hydrocarbon resources remaining in the twenty-first century are located in physically and politically more hostile environments, and technology innovations that significantly reduce resource development cost occur relatively slowly. For example, deep-water and Arctic projects require expensive advanced technology. Increased political risk commonly means that a higher hurdle rate is adopted for project approval, so that only the larger deposits are extracted.

The current (2014–2017) low oil price regime is due to the oversupply policy of the dominant market firm (Saudi Aramco, backed up by its government owner and OPEC) in response to U.S. technology innovations during the past decade (i.e., fracking and horizontal drilling of shale formations; Weijermars et al., 2017; Weijermars, Sorek, Seng, & Ayers, 2017), which have added a significant new oil supply stream to the global market. How that development will play out and affect the future mean reversion price of oil can be further modeled from our analysis and the equations we derive.

This study is organized as follows. Section 2 details a comprehensive series of regression analyses (long-term, short-term) for the primary global oil price benchmarks (Brent and WTI). Certain subsections highlight decadal variations in price volatility and provide a basis for the updated mean reversion price trend-line for oil. The stark contrast between long-term and short-term price elasticity is highlighted here for the first time (Section 2.6). The long-term cost escalation is further analyzed in Section 3 and captured in our updated model for the mean reversion price. Section 4 provides examples of how our price model can be applied in price projections, using certain specific assumptions. Section 5 offers a discussion, and Section 6 formulates brief conclusions.

2. Analysis of historic oil prices

We analyze past realizations of crude oil prices in the commodity market, applying regressions, probability density functions, kernel smoothing, and volatility to quantify the dynamics of oil prices for various periods. Price volatility was modest in the 1980s and 1990s, but increased in later decades. Past price volatility helps to construct models for possible future price scenarios to aid decision-making, but any such prediction involves assumptions about constraints on future market dynamics (see Section 6).

Our price data sources are as follows. For historic world oil prices (1861–present) we use annual production data (BP, 2015; OPEC, 2015). From 1986 onward daily time-series of WTI and Brent spot prices are readily available. WTI remains the benchmark price for North American operators, and we analyze in detail daily WTI spot prices (1986–present) and monthly domestic production data (1986–present; EIA data sets; WTI, 2015). The prices of WTI futures (trading on NYMEX since 1983; see WTI Futures, 2015) and
Brent futures (trading on ICE since 1988; see Quandl, 2015) allow us to compare spot prices with contract prices of front month oil futures. We analyze Brent prices separately, as they increasingly constitute the global oil price benchmark. The lead role of Brent is confirmed by our observation that Brent futures went into contango trading three months before WTI in fall 2014 (see Fig. A2 in Appendix A.2 for details), when Saudi Arabia abandoned its earlier policy to balance the market by reducing supply whenever demand was lagging (Appendix A.3). For completeness, Appendix A.1 includes a summary of the role of price reporting agencies in spot pricing, and other information pertinent to the market dynamics of crude oil prices.

2.1. The long-term U-shape of equilibrium oil prices (1860–2012)

Fig. 1 graphs the real price of crude oil, annually averaged over a 150-year period (1861–2012). The historic data fit a second-order polynomial regression curve:

\[ P(t) = P_0 + \alpha t + \beta t^2 \]  

(1)

the reference price \( P_0 = $58.57/\text{bbl} \) is for crude oil in 1861 (\( t = 0 \)), and the linear term factor \( \alpha \) is \(-1.25/\text{bbl/year}\), with the quadratic term factor \( \beta \) equaling \(0.0089/\text{bbl/year}^2\). The U-shaped price profile outlined by the regression curve is typical for commodities with a finite resource base, as has been highlighted in earlier studies (Slade, 1982; Stürmer, 2013). Prices commonly drop after the early development of the nonrenewable natural resource when extraction technology and efficiency improve (governed by the linear term \( \alpha t \) with the negative gradient in Eq. (1)). Over a longer time, the finite resource remains only in reservoirs and locations where production is more difficult and costlier, leading to an increase in the marginal cost of supply and a corresponding increase in the equilibrium price (accounted for by the quadratic term \( \beta t^2 \) in Eq. (1)). The \( R^2 \)-squared of 0.43 is due to the diffuse spread around the regression curve.

2.2. Late-life upward trend in the WTI equilibrium price (1986–2015)

The more recent part of the life cycle of crude oil, characterized by an upward trend in the oil price, is separately graphed in Fig. 2. The plot for the period 1986–2015 is based on average daily real spot prices of WTI crude oil, representing > 7300 trading days between 1986 and 2015. Spot market price changes are fairly reliable indicators of shifts in the balance of supply and demand. The long-term trend of the mean reversion (equilibrium) price is indicated by a regression curve, which fits a second-order polynomial similar to that described in Eq. (1), using for WTI oil a reference price \( P_0 = $20.64/\text{bbl} \) in starting year 1986 (\( t = 0 \)), a linear term factor \( \alpha = -$0.0067/\text{bbl/year} \), and a quadratic term factor \( \beta = $0.000003/\text{bbl/year} \). The \( R^2 \)-squared of 0.83 suggests that the regression curve is a reasonable fit for the price data. We also investigated regression with a higher-order polynomial, but such curves contain multiple terms that turn either extremely negative or positive when used to project prices forward in time. One must also be cautious in evaluating trend lines using Excel regression functions, which must be set to maximum accuracy (30 decimals), else the trend lines become highly unreliable.

The mean reversion price indicated by the regression curve (solid red) in Fig. 2 closely corresponds to the marginal cost of supply estimated by industry analysts (dashed curve; see Appendix A.2, Fig. A4). Episodes with actual spot prices (blue curve) departing from the mean reversion price (red curve) can commonly be explained by specific events or market agents that triggered higher price volatility. For example, the positive price shock of 2007 (point A in Fig. 2) was the climax of a commodity supercycle (Canuto, 2014; Erten & Ocampo, 2012; Heap, 2005). Such commodity supercycles typically are 20-year boom periods characterized by strong demand, historically associated with moments of rapid industrialization and urbanization (as for the United States in the 1890s and China in the 2000s). The negative price shocks of 2008–2009 (point B in Fig. 2) and 2014–2016 (point C in Fig. 2) correspond to slow
adjustments on the supply side to lagging demand due to global slowdowns in economic growth. The empirical data of Figs. 1 and 2 contain a number of economic truths. The regression curves reveal a long-term price drift that can be ascribed to increasing marginal cost of production as oil gets scarcer and extraction costs rise.

2.3. Price volatility WTI

To better understand the recent volatility in oil prices, we assess the historic volatility of both WTI (this section) and Brent (next section). If we assume that the random walk model for crude oil price applies, the commodity price is.

\[ \epsilon(t) = P_t - P_{t-1} \]

that is, any difference between the commodity price in past times \( P_t \) and present times \( P_{t-1} \) is unpredictable, and consequently fully described by a Brownian motion or a Wiener process \( \epsilon(t) \). However, there is a long-term trend in the historic volatility of oil prices.

Fig. 3a–e analyze daily WTI oil prices from 1986 onwards. Fig. 3a is a 3D plot of WTI spot prices with corresponding frequencies. The daily data (7511 samples) between January 2, 1986, and May 18, 2015, are grouped into monthly bins in order to establish a price frequency for each month, and slices of each frequency for different months together form this 3D graph. The “frequency” here actually is the relative frequency, meaning the probability of falling into a specific interval. The relative frequency is computed from

\[ \text{frequency of Month on Unit} = \frac{\text{number of data points from Month in Unit}}{\text{sample size of Month}} \]

2.3.1. Stable price period

From the plot of Fig. 3a we conclude that WTI spot prices were relatively stable in the 1980s and 1990s, moving within a narrower range with higher frequencies than in later decades. From 1986 to 1996 oil traded between $10/bbl and $25/bbl (Fig. 3b). Fig. 3b shows the period January 2, 1986–December 31, 1996, using 2822 daily samples, following the same procedure as for Fig. 3a, and can be regarded as a partial 2D top view of the 3D Fig. 3a. In Fig. 3b the frequencies are represented by different colors: green and blue indicate low frequencies (lows in Fig. 3a), and red is for higher frequencies (peaks in Fig. 3a).

2.3.2. Rising prices

From 1997 onward the price spread significantly increased, ranging between $10 and $125/bbl (Fig. 3c). Fig. 3c uses 7511 daily averages of WTI real spot prices ($/bbl) for the period January 2, 1986–May 18, 2015, green and blue indicate high frequencies and red is for lower frequencies. From about 2000 onward the spot price increased faster and the range for each month is larger, causing lower frequencies.

2.3.3. Price frequency curves

Fig. 3d and e plot the density functions for each subset of Fig. 3b and c by kernel density estimation using statistical software. The curves are smoothed by the kernel smoothing method and the bandwidths are chosen automatically by the software for compatibility. Medians and means are marked on the plots. Fig. 3d and e plot the likelihood of any particular price occurring at any one time. The price range of $10–$25/bbl in the period 1986–1996 (Fig. 3d) appears with higher frequencies than the price range of $10–$125/bbl in the period 1987–2015 (Fig. 3e). That is, price forecasting involves greater uncertainty as we move forward in time.
2.4. Price volatility Brent

To analyze volatility in the Brent oil price benchmark, we use a variable sample window. The annual oil price volatility is defined here as the ratio of the standard deviation (std) to the mean (avg) of the daily oil price for that particular year:

$$\text{volatility} = \frac{\text{Sd of daily price}}{\text{avg of daily price}} \times 100\%$$

(4)

Fig. 3. a–e. WTI prices in Period 1 are confined to a narrow price deck with higher frequency of a particular price than in Period 2, which has a much larger price spread with a significantly lower frequency. Time series plotted using Excel. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)
Volatility is always measured in terms of the standard deviation of the price, so that modest price spikes in periods of relatively stable oil prices (1986–1996) produce high volatility scores (e.g., 1990). When we use annual sample windows (Fig. 4a and b), the period of escalating oil prices (1997–2015) shows volatility (~30%) for 2008 to be about equal to volatility for 1998 and 1990. However, much higher volatility values result for 2008 when we use 5-year and 10-year sample windows (38% and 59% respectively; see Fig. 4c and d). By all the measures used in Figs. a–d, price volatility peaked in 2008. However, according to the daily price variations for annual volatility (Fig. 4a), the price fall of 2014 heralded a new period of high price volatility.

2.5. Mean reversion oil spot price (1986–2015)

The increase in price volatility since 1986 has made it more difficult to predict future oil price development. In order to find a long-term price trend, we refocus on the mean reversion price analyzed in Sections 2.1 and 2.2. We deepen our analysis by not just looking at time series of price changes, but plotting historic prices versus production volumes. A regression fit will smooth disequilibrium prices and must be close to the long-term equilibrium price, which changes with the cost of production as larger volumes need to be supplied from costlier oil fields (see details in Appendix A.2).

Fig. 5a and b show the production rate against the price of the day and the real price of crude oil, respectively. The prices used are based on the leading global benchmark for each period, which are respectively Arabian Light (1965–1983) and Brent (1984–2012). The regression curve for the equilibrium price fits an exponential relationship:

\[ P_E(Q_e) = y e^{\gamma Q_e} \]  

(5)

For Fig. 5a, the regression curve fits Eq. (5) for \( \gamma = 0.12/\text{bbl}, n = 0.0762 \text{ day/MMbbl} \). For a given equilibrium production rate, \( Q_e \), the equilibrium cost of production equals the long-term equilibrium sales price, \( P_E \). The R-squared of 0.76 suggests that the regression curve is an accurate fit for the price data. For comparison, Fig. 5b shows the real price relationship, for which the regression curve fits Eq. (5) for \( \gamma = 4.45/\text{bbl}, n = 0.033 \text{ day/MMbbl} \), with R-squared of 0.41. The random walk function of Eq. (2) can explain the volatility about the mean reversion price; the long-term drift of the equilibrium price (= reversion price) is given by Eq. (5), applied to the empirical data. Evidently production cost has risen while the production rate has increased, in contrast with a manufacturing model, where cost per unit normally comes down when the output rate increases. Obviously, the manufacturing model does not apply to natural resource development in general nor to oil production in particular.
2.6. Long-term versus short-term price elasticity

Although it takes years for new oil fields to develop, the industry has historically been able to anticipate a certain long-term trend in the growth of demand and ensure that new fields begin producing in time. The results shown in Fig. 5b, with the real oil price plotted against the supply rate, can be used to quantify elasticity of supply for certain periods. The exponential growth of the mean reversion price implies that long-term elasticity of supply decreases as we move forward in time. For example, for the period 1965–1983, when demand nearly doubled from 30 to 58 MMbls/day (BP, 2015), equilibrium prices increased from $18/bbl to $32/bbl—an almost perfectly elastic response (long-term price elasticity of supply, $ED = 0.99$). For the later period of 1984–2012, demand increased further from 58 to 78 MMbls/day (BP, 2015), and equilibrium prices rose from $32/bbl to $78/bbl, a less elastic response ($ED = 0.39$). The basic principles of price elasticity are briefly reviewed in Appendix B.

The short-term demand rate function for oil is rather inelastic: a rapid price fall is not cushioned by increased demand. If global oversupply persists, prices remain depressed. Short-term price elasticity of demand using the midpoint rule is defined as:

$$PED_{SHORT} = \frac{\Delta Q}{\Delta P} \cdot \frac{0.5(Q_1 + Q_2)}{0.5(P_1 + P_2)}$$

(6)

The extreme price falls of 2008–2009 and 2014–2016, in response to oversupply caused by sudden lapses in demand due to global recessions, can each be used to determine supply-side impacts in terms of the short-term price elasticity of demand. Using the $100/bbl price fall of 2008–2009 due to 1.5 MMbbl/day oversupply (OPEC, 2015) and the $60/bbl price fall of 2014–2015 due to 1 MMbbl/day oversupply (OPEC, 2015), we find $ED = 0.015$. This confirms that short-term oil demand is fairly inelastic (see Appendix B.1, Fig. B2). A percentile increase in supply causes a major price fall (and vice versa). We contend that short-term oil supply is largely a policy-inspired quantity, which may react differently to short-term price changes at different times. When the leading supply firm decides to balance demand, short-term supply can be fairly elastic in the sense that production cuts or increases take only months to materialize, as Saudi Aramco, U.S. shale producers, and/or Canadian oil sand producers ramp up or idle spare capacity. However, when the dominant market firm(s) respond to market disequilibrium by deliberately maintaining oversupply, short-term demand will be inelastic.

3. Long-term price trends

3.1. Long-term trend in the equilibrium supply rate

The regression curves in Fig. 5a and b are long-term equilibrium price curves (since 1965). The plotted curves are assumed to represent a continuous series of pairs of equilibrium production rates and costs/prices, which averages out any nonequilibrium data from periods when the market was off-balance. To link long-term equilibrium prices to changes in supply, Fig. 6 plots the equilibrium production rates versus time in order to obtain a regression curve for $Q_E$. The regression curve (R-square 0.9) is a second-order polynomial that gives a suitable forward trend (beyond the data inputs):

$$\dot{Q}_E(t) = \dot{Q}_0 + at + bt^2$$

(7)
the reference rate $\dot{Q}_0 = 39.93 \text{MMbbl/day}$ is for 1965 ($t = 0$, expressed in integer years), and the linear term factor $\alpha = 1.18915125202113 \text{MMbbl/day/year}$, with quadratic term factor $\beta = -0.0056938813614952 \text{MMbbl/day/year}^2$. The fractional terms may seem overly complex but are needed to provide the polynomial fit shown in Fig. 6. Below, we propose simplifications for practical use.

### 3.2. Long-term equilibrium price linked to equilibrium supply rate (1965 forward)

Combining Eqs. (5) and (7) yields an equilibrium price function for the mean reversion price (money of the day) that accounts for shifts in the equilibrium supply rate:

$$P_{E}(t) = \gamma e^{n(Q_{0}+\dot{Q}_{0}+\beta t)}$$

(8)

We now have an expression for the drift of the mean reversion price (money of the day) as a function of time (with 1965 as the starting date/reference year) and accounting for the historic growth in the supply rate. Input parameters are fixed using the empirical data as specified above: $\gamma = $0.12/bbl, $n = 0.0762 \text{day/MMbbl}$, $\alpha = 1.18915125202113 \text{MMbbl/day/year}$, with quadratic term factor $\beta = -0.0056938813614952 \text{MMbbl/day/year}^2$ and the reference rate $\dot{Q}_0 = 39.93 \text{MMbbl/day}$ starting from 1965 ($t = 0$, expressed in integer years). Again, fractional terms are specified for maximum accuracy, but can be simplified (see Section 3.4).

### 3.3. Comparison of cost escalation adjustments

Expression (8) accounts for changes in the equilibrium supply rate as time moves forward and gives the equilibrium spot prices that satisfy both the supply and the demand functions. Fig. 7a plots Eq. (8) as Curve 1. When used for forward extrapolation of the future mean reversion oil price, the last known price for 2012 is real but equals money of the day. The forward extrapolation may need to be inflation adjusted from 2012 onward with inflation rate $\iota$:

$$P_{E\iota}(t) = \gamma e^{n(Q_{0}+\dot{Q}_{0}+\beta t)}(1 + \iota)^{t_0}$$

(9)

de the time $t_0$ is counted from 1965 (for which $t_0 = 0$, using the parameters specified in Section 3.2), while time $t_1$ is applied to adjust for future monetary inflation using reference year 2012 as a starting point (for which $t_1 = 0$). Expression (9) with inflation rate 2.5% is included in Fig. 7a as Curve 2.

#### 3.4. Simplification

Fig. 7a includes a comparison with simple exponential price functions starting from the mean reversion price $P_0$ for 1965 and applying various inflation rates ($i = 2.5\%, 5\%, 10\%$; Fig. 7a, Curves 3–5), using.

$$P_{E}(t) = P_0(1 + i)^t$$

(10)

The 1965 reference price used is $P_0 = $2.52/bbl. It appears that the mean reversion price curve of Expression (8) (Fig. 7a, Curve 1) lies between the exponential curves (using Eq. (10)) for inflation rates of 5 and 10% (Fig. 7a, Curves 4 and 5). The mean reversion price according to Eq. (9) (Fig. 7a, Curve 2) can be represented by an approximation using a simple exponential function (Eq. (10)) starting from 1965 with an inflation rate of 6.84842% (Fig. 7a, Curve 6). This exponent was determined using a least square
optimization rule for the 86-year period between 1965 and 2050:

\[ f(r) = \sum_{t=0}^{86} \left[ P_E(t) - P_E(0)(1 + r)^t \right]^2 \]  

(11a)

The above objective function has a minimum when the first derivative is zero:

\[ f'(r) = -2P_E(0)(1 + r)^t \frac{t}{1 + r} \sum_{t=0}^{86} \left[ P_E(t) - P_E(0)(1 + r)^t \right] \]  

(11b)

A closed form solution is hard to obtain, which is why we use Newton’s method by updating \( r \) from iteration \( k \) to iteration \( k + 1 \):

\[ r(k+1) = r(k) - \frac{f(r(k))}{f'(r(k))} \]  

(11c)

The solution is obtained when at the \( (k+1) \)th iteration convergence occurs: \( |f(r(k+1)) - f(r(k))| \leq 10^{-10} \), which gives \( r = r(k+1) = 0.0684842 \).

For practical use, we suggest that Eq. (9) captures the historic mean reversion price that can be used for forward projections of the mean reversion price. Assuming that any future inflation beyond the fitted curve will be countered by a corresponding cost reduction due to technology innovation \( (i = 0) \), Curve 1 (Fig. 7a) provides the most likely extrapolation. However, if such efficiencies do not develop fast enough, the higher price scenario shown in Curve 2 (Fig. 7a) is possible. Note that the likelihood of any future price trend is an extrapolation choice (or scenario) rather than a quantifiable factual value. The critical choice is the likely future inflation of the mean reversion price; the distribution of spread around the mean is set by the development of the historic price range and kurtosis.

Fig. 7b plots the preferred solution of Eq. (8), Curve 1 with 99% confidence band extrapolated until 2050. Time series plotted using Excel.

4. Price projections

We undertook this study to help operators set price scenarios for the future. The historic trends documented in Section 2 and the long-term equilibrium price trends documented in Section 3 may temporarily give way to short-term disequilibrium in the market. Although Curve 1 in Fig. 7b captures the long-term price trend in a business-as-usual price scenario, short-term price developments need to be accounted for when operators plan field acquisitions, field development, and work-over. This section provides examples of
how such price scenarios may be used.

4.1. Short-term price scenarios

The 2014–2016 oil price depression appears to have bottomed out in February 2016. We have used the market low to tie monthly oil prices from January 2014 through February 2016 (26 months) to possible price recovery trends. Fig. 8 shows those WTI prices together with five price recovery scenarios up until 2020. The $30.32/bbl WTI monthly average price of February 2016 is fitted with the simple inflation function of Eq. (10) to reach 2020 target prices given in Table 1. The long-term mean reversion price according to Eq. (8) is $100/bbl in 2020 (Curve 1, Fig. 7b). Scenario 3 reaches exactly that price, which is the mean reversion price, in 2020. However, because of the lagging investments in field development due to the profit falls and consequent budget cuts of all operators (see Appendix A.5), which deepened in the period 2014–2016, oil prices may overshoot the mean reversion price in 2020. If that happens, price recovery scenarios 4 and 5 will apply (Fig. 8). At the endpoint of our study (December 2016), WTI had recovered to $50/bbl, which fits the more aggressive price recovery scenario 5 (Fig. 8).

4.2. Nested inflation/deflation of the price equilibrium function

The equilibrium price function of Eq. (9) is formulated here in a more generic form:

$$P(t) = P_0\left(1 + i_1\right)^t\left(1 + i_2\right)^t\left(1 + i_3\right)^t\ldots\left(1 + i_n\right)^n$$

(12)

The mean reversion price may either deflate or inflate over any future period $t_1$ to $t_2$, $t_2$ to $t_3$, ..., $t_n$ to $t_{n+1}$, each period having its own inflation/deflation rate $i_n$. The price projection with confidence bands in Fig. 7b is a “business as usual” trend-based scenario that uses both the mean equilibrium price and historic volatility to project prices and estimate uncertainty. Such future price scenarios are inevitably based on a set of assumptions concerning market dynamics and the behavior of principal agents (Bentham, 2014). Different scenarios cannot be excluded, as market uncertainty (unlike uncertainty in geological subsurface parameters) remains essentially unconstrained because of unknown unknowns, as is illustrated by the following black swan price scenarios (McCredie & Weijermars, 2014, 2015).

4.3. Black swan scenarios

An unlimited number of price scenarios for the future can be generated using Eq. (12). We have shown in Section 4.2 how adopting a business-as-usual constraint allows us to construct future price trend lines with an uncertainty range based on the forward

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
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<td>2020 Target Price WTI ($)</td>
<td>50</td>
<td>75</td>
<td>100</td>
<td>125</td>
<td>150</td>
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Table 1

Target prices for 2020 in five oil price recovery scenarios.
projection of past uncertainty ranges. The business-as-usual assumption captures past market dynamics, such as enhanced oil recovery, deep-water technology, and response to important supply-side changes by OPEC. Although some observers believe that changes in the structural mechanism of market dynamics are so frequent that the analysis of past price movements is useless, we disagree. Past price volatility provides a baseline for future price trends. We know that technology innovations can slow down the rise in marginal cost of supply of a finite fossil resource. Fracking technology and horizontal drilling in onshore shale formations provide prime examples (Weijermars, 2014a, 2014b). However, there may also be other, unexpected changes in the market, due to so-called black swan events. Here, we consider two black swan price shock scenarios to illustrate the principal use of Eq. (12) when large demand-supply disruptions occur.

Black swan price scenario 1 assumes a steep drop in global oil demand (Fig. 9) due to decimation of the world population by an untamed global epidemic raging over the period 2018–2025. Price pressure becomes a long-term effect and leads the mean reversion price to contract toward the 50th percentile cash cost of supply at $35/bbl (Appendix A.2), after which supply-side adjustments will restore the long-term price trend to the expected marginal cost of supply (cf. Figs. A3a and A4). The smooth curve for this scenario in Fig. 9 was generated by choosing appropriate inflation factors for Eq. (12).

Black swan price scenario 2 assumes that major producers in the Middle East (Saudi Arabia, Kuwait, Iraq) are all overrun by fundamentalists in 2018 (Fig. 9), leading to sanctions and import bans on 15% of the current global oil supply. The upward price shock develops in the short term (fall 2018), but import bans may last for decades, causing the mean reversion price to climb to the estimated price of demand destruction at $150/bbl, after which supply-side adjustments will restore the long-term price trend to the expected marginal cost of supply (Appendix A, Figs. A3a and A4).

5. Discussion

5.1. Price of equilibrium supply

Commodity price forecasting has been described by two complementary expressions: “imaginative eyeballing” (Frankel & Rose, 2010) and “narrative evidence” (Stürmer, 2013). In contrast, our analysis of historic time series of spot prices (WTI and Brent) establishes formulas that connect the historic trend of the mean reversion price with the expectation of future supply-demand balance due to predominant market agents. Such an approach provides reproducible insight into possible long-term price development and short-term price volatility.

Our analysis provides an empirical basis for the long-term equilibrium price. A daily price spread plot of WTI for the period 2005–2008 shows that real-time oil spot prices tend to move within a certain price deck (Fig. 3a–c). In the time-averaged, historic WTI spot-price deck of Fig. 3a–c, the long-term drift of the equilibrium price ranged between two streaks of high-frequency spot prices. Relatively short-term volatility occurs within the bandwidth averaged out by the kernel smoothing. The real-time spread of spot oil prices over the past two decades shows a bimodal distribution (Fig. 3e). The skew of oil spot prices toward the lower end of the oil price deck in the 1990s (Fig. 3d) reflects a structural tendency of the dominant firm to slightly oversupply the market.

The industry uses price projections in cash flow calculations to estimate the operating income from existing projects and to validate the business case for potential new projects. Adopting an overly optimistic price scenario increases the risk of illiquidity. For
example, the 2014–2016 period of low oil prices has resulted in bankruptcy filing (including Chapters 7, 11, and 15 and Canadian filings) for 114 North American E&P companies in the period from January 2015 through December 2016, involving a total debt of $74.2 billion (Haynes & Boone, 2016a). Separately, 110 oilfield service companies filed for bankruptcy in the same period with an aggregate debt of $18.8 billion (Haynes & Boone, 2016b). Companies with the lowest credit rating, highest cost of capital, and lowest cash flow from operations were most likely to go bankrupt (Bocardo & Weijermars, 2016; Cirilo Agostinho and Weijermars, 2017).

5.2. Increase in marginal cost of supply

To support our contention that the marginal cost of future oil production is likely to rise exponentially (as Eq. (8) and Fig. 7b suggest), Fig. 10a presents a globally averaged marginal cost curve for estimated remaining worldwide oil resources (after McGlade, 2013). The graph includes conventional plus unconventional oil resources, using IEA 2010 estimates of field development cost (opex and capex, discounted for the cost of capital at the wellhead [no transportation cost included] before taxation).

The low-cost resources near the origin of the plot mostly are the legacy fields in the Middle East, which should continue to produce at low marginal cost well into the future (Fig. 10b). However, as such fields eventually are depleted, production growth needs to come from more expensive sources (Fig. 10b). Clearly, barring technology breakthroughs, the development and extraction of oil from new fields is progressively more expensive than production from less complex fields that were discovered first (McGlade, 2012; Weijermars et al., 2014). Past breakthroughs have enabled the production of oil from new plays hitherto beyond technical reach (e.g. ultra-deep water, shale, etc.), but are not rapidly reducing costs. An exception is onshore oil shale plays in North America, but currently those resources account for only about 8% of global oil supply. Consequently, the marginal cost of supply develops according to the cost structure of the combined pool of producers, an example of which is given in Appendix A.2 (Fig. A3a).

Throughout the 1990s OPEC deliberately chose to counter any prolongation of high prices that would have accelerated the development of previously uneconomic high-cost fields and would have eroded OPEC market share once the new oil came to market. The low-oil-price business environment in the 1990s was tough for the oil majors, leading to numerous megamergers at the end of that decade (Exxon-Mobil, BP-Amoco, Chevron-Texaco, Total-Fina-Elf, etc.). OPEC, led by the dominant market firm’s owner (Saudia Arabia), then continued its market-balancing policy by using production cuts to counter any price falls due to demand-side recession—until 2014 (see Appendix A.3). That policy was abandoned to protect OPEC’s market share against the rapid expansion of new oil supply from unconventional fields in North America. Sustained oversupply between 2014 and 2016 caused a temporary departure from the mean reversion oil price. Possible price recovery scenarios have been given in Fig. 8 (Section 4.1).

5.3. Price forecast methods

The regression-assisted price forecasts advocated in our study account for past changes in market fundamentals. Such fundamentals are detailed in Appendices A and B and include (1) historic changes on the supply side due to finite resource depletion and technology innovations, and policy actions by dominant market agents; (2) changes on the demand side related to global economic cycles; and (3) an evolving mismatch between supply and demand, leading to either upward or downward price shocks. The process of devising price forecasting methods may include derivatives such as contango and backwardation spreads in oil and gas futures (WTI, Brent), which are notoriously inaccurate if the historic price strip is matched against actual spot prices realized (this can be readily demonstrated, and is the subject of work in progress by the senior author of the present study). Cortazar, Millard, Ortega, and...
Schwartz (2016), among others, have asserted that commodity price models would be successful in fitting the term structure and dynamics of the prices. Our opinion is that prices of oil and gas futures are an extremely poor indication of future oil spot prices. The pricing of future price contracts reflects an erratic mixture of physical market agents’ hedge positions and purely speculative market players taking either long or short positions invariably aimed at short-term gains.

For traders in oil futures, regression-based trend analysis and forward projections provide merely one input among many. We contend that past mean reversion price trends can be projected forward with quantified confidence or probabilistic certainty, assuming that the past pace of technology change and its role in offsetting resource depletion continue unabated in the future. An alternative view (Jafarizadeh & Bratvold, 2012) is that a mean reverting price model, when including short-term geometric Brownian departures from the mean reversion price trend, may lead to significant overestimations of uncertainty in future cash flows. As a result, net present value estimations will exhibit a similar change in uncertainty spread, but future mean prices will be overestimated (Fig. 11, Curve 1) as compared to a forward mean reversion curve determined as the fiftieth percentile (P50) value of a narrower uncertainty spread obtained by applying a Ornstein-Uhlenbeck mean-reverting price process (Fig. 11, Curve 2). In both models uncertainty about the future is the main input to any future commodity valuation. The main difference with the historic trend line given in our study (Figs. 7–9) is that the predicted uncertainty range may or may not be related to uncertainty ranges quantified and extrapolated forward from historic data. Accepting this unavoidable limitation of uncertainty forecasting, the best one can do is to adopt a consistent set of assumptions before setting out any price forecasting as a basis for evaluating a project.

Here, we adopt as a baseline for future spot prices the historic trend of the mean reversion price and consider various choices for future volatility: (1) business as usual, (2) negative price shocks and a downward pull on the mean reversion price as the lower boundary of the uncertainty range drops, and (3) positive price shocks leading to an increase of the mean reversion price as the upper boundary of the uncertainty range rises. To avoid overoptimistic, monotonically increasing price profiles, other researchers have proposed the so-called inverted hockey stick (IHS) method (Akilu, McVay, & Lee, 2006; Olsen, McVay, & Lee, 2005), using only three price realizations based on a bootstrapping process to quantify uncertainty. The high and low cases were designed to better capture the range of possible future price paths. One drawback of the IHS method may be that the choices made in the procedure (such as subtracting for each forward month 70% of the maximum historic price in the previous month) leads to overly conservative price forecasts that may miss viable project opportunities.

6. Conclusions

The mean reversion pricing formulas derived in our study may support both the quantitative scenario planning of oil companies and fiscal earnings estimates of petroleum-exporting nations. Figs. 7, 8, and 9 show several possible future oil price scenarios based on the mean reversion price formulas with adjustable inflation. Such scenarios are inevitably based on specific assumptions about the principal market agents. Long-term regression analysis shows a rising trend over the past 50 years (1965–2012), but oil spot prices have seen short-term price shocks in 2008–2009 and 2014–2016, in both periods moving well below the mean reversion price based on the historic spot price range and kurtosis.

Assuming that the long-term mean reversion price will prevail when market supply and demand are in equilibrium, we have proposed formulas for predicting future prices. For example, when business-as-usual resumes, oil prices will converge on the long-term mean reversion price, with the inflation rate canceled out by cost reductions due to technological innovation (Fig. 7b). Any superposed short-term price volatility can be constrained by a probability spread, if no major deviations from the equilibrium trend occur (Fig. 7b). However, spectacular technology innovation would cause oil prices to decline. Although unconventional resources like onshore shale oil and oil sands are relatively easy to mine, the recovery efficiency is relatively low for both. Operating costs for shale oil recovery have come down because of faster drilling and other workflow improvements, which may dampen any future rise
in field development cost and therefore in oil prices. In the long run, reserve replacement likely will become more challenging due to the remaining oil resources being more complex to extract in more hostile environments (Fig. 10a and b), and technology innovations at best may slow down the imminent rise in oil prices.

Although the mean reversion price follows a stable path if business-as-usual resumes (Fig. 7b), using the trend of historic mean reversion prices to predict future price development remains a scenario choice rather than a narrowly quantifiable probability. The future cannot be known, as our two black swan scenarios indicate (Fig. 9). Events that disrupt global oil supply will generally increase oil prices, and events that suppress GDP growth will generally decrease oil spot prices (Sorrell & Speirs, 2014). A holistic framework that optimizes decision-making at every step in the global energy system may be needed (GEA, 2012) but is not currently in place. Instead, the global energy system is led primarily by market dynamics that motivate business decisions to privatize profits and socialize the cost to the environment (see Energy Strategy Research Charter in Weijermars et al., 2012; Weijermars, 2011).

Acknowledgements

This study was funded by start-up funds to the senior author from the Texas A&M Engineering Experiment Station (TEES). Thanks are due to Prof. Suojin Wang, Department of Statistics at Texas A&M University, for discussions and providing support for our study.

Appendix A. Oil price making

A.1. Oil price reporting mechanisms

Crude oil spot prices transacted in physical oil markets are reported by privately owned publishers (Platts, Argus Media, Asia Petroleum Price Index [APPI], and ICIS London Oil Report), which are commonly referred to as price reporting agencies (PRAs). Oil is traded in numerous regions, but WTI is the principal benchmark in the United States, Brent in Europe, Arab Light in the Middle East, Ural in Russia, and Maya in South and Central America. Other crude oils like Bakken and Louisiana Light may trade at either a discount or a premium depending on the American Petroleum Institute (API) value and sulfur content. Such crude oil prices are then adjusted to reflect how suitable the particular oil is to feed petrochemical plants and refineries. Price differentials may develop because of additional cost of cracking and/or any transportation bottlenecks. Particularly, crude oil may trade at a discount in booming production regions when refinery capacity is limited and distant, so that transportation infrastructure needs to be expanded to handle the regional influx. For example, in North America since the emergence of production from shale oil plays, WTI has traded at a significant discount with respect to Brent because of transportation bottlenecks (mostly insufficient pipeline capacity and overstrained railway capacity). Crude oil produced from the remotely located Bakken shale has suffered even larger discounts at the wellhead (Fig. A1).

![Fig. A1. Bakken crude oil and WTI frequently trade at a discount compared to Brent crude. The price spread fluctuates and depends on the severity of crude oil transportation bottlenecks. These regional price discounts occur because of limited capacity of pipelines. Crude is also evacuated by oil trucks and trains, all of which are strained by the increasing production from North American shale formations. Courtesy: Energy Information Administration.](image-url)

The G20, the EC, the U.S. Federal Trade Commission, and Russia have launched repeated critical inquiries into the role of PRAs and traders in fixing spot prices. For example, the U.S. FTC investigated alleged anticompetitive reporting practices by British Gas and Statoil. EU officials raided the offices of BP, Shell, and Statoil in May 2013, and an investigation by the EU lingered on for years. Platts’s market-on-close (MOC) method has been questioned (IOSCO, 2011, 2012; Platts, 2012, 2014a, 2014b). Price fixing of oil goes back as far as 1928, when CEOs of the oil majors (Teagle, Exxon; Deterding, Shell; and Cadman, BP) met in Achnacarry Castle in Scotland and agreed on a price-fixing scheme. The pact lasted until 1950, when the U.S. FTC stopped the practice (FTC, 1952).

Oil spot prices may differ from crude oil front month future prices quoted in the derivatives markets, which include three regulated exchanges: ICE Europe ("ICE") for Brent futures contracts, CME NYMEX ("NYMEX") for WTI futures contracts, and Dubai
Mercantile Exchange ("DME") for Arab Light Futures contracts. Concerns have been raised by regulators and policy makers that trading in the futures market by non–commodity owners for speculative purposes could inflate oil prices in both the spot and futures markets (U.S. Senate Staff Report, 2008).

Our analysis shows that the price of the front month oil future contract always closely tracks the spot market price (Fig. A2). Far-out contracts trade in either backwardation or contango, as the price difference between future contracts and current spot prices is positive or negative (Schwartz, 1997). The futures market was in normal backwardation in 2014 until August (Fig. A2), when larger contango price spreads began to develop in response to the steep decline of oil spot prices in the second half of 2014. Brent is the leading indicator, and its futures went into contango three months before WTI futures (Fig. A2). Over longer time periods, crude oil futures switch back and forth between backwardation and contango in response to the process of reversion to equilibrium spot prices based on physical trading contracts. During the reversion to equilibrium, the crude oil futures market shows major price shifts in future contracts other than the front month contract.

![Fig. A2. Delay in the switch from backwardation to contango of WTI futures (M1–M12) as compared to Brent futures (M1–M12) during fall 2014 drop in crude oil prices. Adapated using basic data from EIA (2015). Vertical scale shows price differential M1–M12, which is different for WTI and Brent futures from Jan 2014 onward.](image)

The world has invested heavily in oil contango storage and stockpiling (Ye, Zyren, & Shore, 2002). In addition to the statutory strategic stockpiling, commercial storage occurs when oil prices are low, especially during periods of contango trading. For example, North America can curtail supply to the market by using commercial storage in salt dome caverns at about a tenth of the cost of storage in surface tanks. Such storage facilities give real teeth to U.S. oil producers, enabling them to assume a swing producer role. The commercial storage capacity is normally large enough to avoid underpriced oil sales for extended periods (Sieminski, 2015). For example, U.S. commercial crude oil inventories stood at 407 million barrels as of January 23, 2015, 49 million barrels higher than the preceding year. In the months following November 2014, commercial inventory in Cushing, Oklahoma, accumulated at an average rate of 1.5 million barrels per week (EIA's Weekly Petroleum Status Reports). Stockpiled inventories help to provide a price floor equal to the cash cost of supply plus the cost of storage and normally reduce the duration of any contango spread. When spot prices begin to recover as supply and demand rebalance, the futures market quickly reverts to normal backwardation trading.

### A.2. Oil price deck components

Long-term oil spot prices remain fundamentally driven by the marginal cost (technical cost) of production (see below), which is why the average marginal cost of supply is the aggregate result of the global extraction activities of the world’s combined petroleum firms. In the long run, firms produce oil at market equilibrium price for marginal cost (including time value of money and cost of capital). Fig. A3a and b give comprehensive estimations of the concurrent variation of the industry’s marginal cost of production and its concurrent cash cost of production. In 2013, non-OPEC marginal cost ranged between $75 and a 90th-percentile marginal cost of oil at US$107/bbl, the latter being the ineffective production performance of PEMEX (Fig. A3a) that led the Mexican government to reform its energy laws (Weijermars & Zhai, 2016).
Fig. A3. a. Marginal cost of production for the 50 largest non-OPEC oil and gas producing companies globally (excluding FSU). Companies are identified by their NYSE ticker symbols.
b. Cash Cost of production, which indicates the price level below which operational cost for existing wells becomes subeconomic and thus leads to production shut-ins. Source: Bernstein Research June 10, 2014.

The cash cost of supply ranges between $10/bbl for TOTAL to $55/bbl for ONGC (90th percentile) and then rapidly goes up for remaining operators (Fig. A3b). Cash cost of supply refers to the minimum price at which existing oil extraction installations can still be operated without losing money. The prices shown in Fig. A3a for marginal and cash cost are based on 2013 data for the 50 largest oil and gas companies.

Normally, the wholesale prices of energy and mineral commodities all move within a price deck determined by marginal cost of supply, cash cost of supply, and price of demand destruction. Fig. A4 gives the long-term price deck for Brent oil based on leading industry analyst data. When supply and demand of primary fuels are in equilibrium, the price of oil converges on the marginal cost of supply curve. Oil prices are unlikely to drop below the cash cost curve far or long, because companies would shut-in wells if oil prices lingered below cash cost of supply. When supply is short and demand high, oil prices may rise until demand destruction occurs in overpriced markets. Ordinarily, end users will switch fuel only for factors such as price, convenience, safety of use, and security of supply.
Fig. A4. Oil price deck for Brent oil. Cash cost (lower bound of price deck) is the average operating expenditure required just to maintain production from existing wells, treating development expenditure as sunk cost. Marginal cost (central curve in price deck) is calculated using company's estimated average cost of production, including E&P majors and a sampling from small and microcap producers. Marginal cost will grow 3% year-over-year. The estimated curve of demand destruction (DD, upper bound of price deck) is the oil price at which demand is negatively affected by high prices, which occurs, for example, when consumers stop driving because of high pump prices. Source: Bernstein Research.

Some producers can actually sell oil below cash cost of supply when their hedges compensate for the difference between the actual stock price and cash cost of supply. For example, U.S. producers had hedged 22% of their 2015 oil output (Barclays, 2015). These hedges helped soften the blow of the 2015 oil price drops and delayed the imperative to cut production. Shale oil production kept rising until the second half of 2015, despite low oil prices, partly because of hedging. However, any price differential between cash cost of supply and actual spot price is sustainable only for a few producers and for brief periods, as hedges tend to mature and can be renewed only when prices are high enough to lock in another period with safe hedging margins. U.S. oil production started to decline in August 2015 (EIA, 2015).

A.3. Saudi swing role

The principal driver for long-term equilibrium in oil demand/supply, in our opinion, is currently residing on the supply side. As Fig. A5 shows, under normal circumstances the dominant market firm (Saudi Aramco) ensures that the global oil market remains more or less balanced (see also Brackett et al., 2015; Santis, 2003). Back in 2008–2009, OPEC helped to restore oil prices rapidly by steep production cuts in response to lagging oil demand due to the global recession. As suppliers tailor production rate to demand, oil supply needs to be tight for a prolonged period in order for higher oil prices to prevail and for more new fields to come on stream. When this happens, the dominant firm (Saudi Aramco) runs an increased risk of losing market share, because high commodity prices may bring higher cost producers (e.g., U.S. shale oil companies) into the market. This was indeed the case between 2009 and 2014, when high-cost producers developed offshore (ultra) deepwater fields in the Gulf of Mexico and onshore unconventional assets such as Alberta oil sands and U.S. shale oil.

Fig. A5. Saudi Arabia cut back production in 2009 to relieve price drop of crude, which was effective.
Saudi Arabia started the 2014–2016 price war with the stated aim to prevent further erosion of OPEC market share. U.S. shale oil producers had rapidly expanded their production since the start of the shale oil boom in late 2010 and by the end of 2014 added 4 MMbbl daily to global oil supply (Fig. A6a); and Canada increased its output from heavy oil sands to 3.7 MMbbl/day at the end of 2014, up from 1.1 MMbbl/day in 2008 (Sieminski, 2015). The glut pushed down oil spot prices at a time of weak demand (2014–2015), so that prices fell far below the marginal production cost. Growth in non-OPEC supply had captured almost all of the demand growth over the past decade, without any net growth for OPEC producers (Fig. A6b). Instead, OPEC supply tended to swing in order to restore short-term equilibrium of supply and demand (Fig. A5). The 2014–2016 oil price plunge was a turning point in OPEC’s oil price support policy: a deliberate decision to continue to oversupply the market by > 1 million barrels per day in order to prolong the depression of global oil prices, so that new entrants and marginal cost producers could no longer gain market share and might even need to cede part of their share.

![Fig. A6](image)

b. OPEC production (green curve) usually balances the market, while non-OPEC supply (blue curve) fills in demand growth. Source: Bernstein Research. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Normally, the dominant market firm with swing production capacity tries to keep supply either in balance or slightly exceeding demand (as in the 1990s). Oversupply is possible because the marginal cost of production for producers from legacy fields such as those in Saudi Arabia is much lower than for the newer complex fields owned by oil majors. Saudi Aramco’s marginal cost of production in 2014 is estimated at $35/bbl, about half that of the oil majors (Clint, Beveridge, Brackett, & Green, 2015). Saudi Arabia owns a centrally controlled oil company with the appropriate infrastructure (and favorable reservoir conditions) to change its contemporary production at a rate of about 1 million bbls per month. Although demand for crude oil products may shift daily, the crude oil supply chain can thus adapt over a matter of months even to major price shocks. And once production is ramped up, Saudi Arabia can keep flooding the market with “under-priced” crude oil for as long as it wants to, alleviating any government budget shortfall by monetary injections from its sovereign wealth fund, which could fully cover the government’s annual budget for nearly a decade (IMF, 2015a, 2015b).
A.4. Price shocks

Major price shocks such as those in 2008–2009 and 2014–2016 are superimposed on the mean reversion price. The equilibrium price for oil in the long term always reverts to the marginal cost of supply and can be inferred from the time series of historic prices (Fig. 2, main text). The result has been checked against both cash cost of production and marginal cost of field development (Fig. A4). The equilibrium points in all oil supply curves can be obtained by plotting price against production for a continuous time series (Fig. 5a and b, main text). In all cases, short-term oil supply can be assumed to be rather inelastic, which explains why small mismatches between supply and demand lead to steep volatility in crude oil prices. In the short term there is no readily available substitute for crude oil as a fuel or feedstock, so the demand curve at any time has a steep slope. Oil prices rise fast when supply is tight, but may drop just as fast when supply is ample.

Price shocks remain largely confined between the upper and lower boundaries of the price deck, defined by concurrent cash cost of supply and estimated price of demand destruction; short-term price volatility can be explained by specific agents afflicting market balance. Price shocks that are superposed on the long-term moving average of the oil equilibrium price commonly evolve during episodes of “sudden” (either intended or unintended) mismatch of supply with demand. For example, unintended mismatches took all producers by surprise when energy markets suddenly contracted in the aftermath of the 2008 banking crisis, which triggered a global recession. In such cases, when suppliers react late to limit excess supply, oil prices may drop toward the cash cost curve (Fig. A4). Commonly some time lag is involved before the development of an unbalanced market causes short-term deviations from the long-term mean reversion value of the oil spot price (Fig. A2). Such deviations are reflected in the valuation of crude oil futures contracts (Baum & Zerilli, 2014; Jafarizadeh & Bratvold, 2012).

A.5. Profitability decline and major market players

Oil and gas price volatility remains an ongoing concern in investment decisions by the global oil and gas industry (Mitchell & Mitchell, 2014). As long as the market pays equilibrium prices, produced oil can cover the marginal cost of supply (or cost plus a small market premium), and oil can keep flowing. From 1997 to 2002, the growth of corporate profitability correlated positively with peaking oil spot price trends (Osmundsen, Asche, Misund, & Mohn, 2006). For the period 2003 to 2007, petroleum industry returns on capital employed (ROCEs) averaged 23%, peaking in 2005 (Weijermars, 2010). However, during the third ROCE cycle (2009–2014) profitability fell below 10% (Fig. A7); and throughout 2015 and the first half of 2017, cash cost of supply price levels prevailed. For the majority of oil and gas companies, since 2012 ROCE has dipped below the weighted average cost of capital (WACC). For 18 representative U.S. operators, the 2015 WACC (before income tax) was 13.46% (Hegar, 2015). The widening gap between ROCEs (< 10%) and WACCs (~13.46%) means that corporate debt is on the rise, and bankruptcies or forced mergers and acquisitions follow for those companies that are already highly leveraged (Rodriques and Weijermars, 2016).

To restore profitability, the petroleum industry must adjust to volatile commodity prices. The largest uncertainty in budgetary decisions for all parties concerned with the oil value chain, including consumers, is dictated no longer by geology but now by current and future market dynamics. Earlier this decade, price shocks in the North American natural gas market reduced the profitability of domestic shale gas projects, which led to a massive shift to producing liquids, rather than gas alone, from shale plays (see Weijermars, 2014a, and references therein). The principal effects of depressed oil prices on companies are declining revenues, declining profits, higher debt, increased cost of capital, lower value of oil and gas properties, loss of market capitalization (investor response), and postponement of new E&P projects. (For detailed analyses of company performance over the past decade, including the effects of the more recent oil price shocks, see Bocardo & Weijermars, 2016; Cirilo Agostinho & Weijermars, 2017; Weijermars & Bocardo, 2016).
Appendix B. Price elasticity

B.1. Elasticity of oil price in response to supply changes

To support the long-term equilibrium price curves for oil (Section 3), it may be useful to briefly review the basic concept of price elasticity (as it is easily misinterpreted when discussing oil markets). We consider price elasticity of supply (PES):

\[ PES = \left| \frac{\text{%Change in Quantity Supplied}}{\text{%Change in Price}} \right| \]  

(B1)

Fig. B1 captures the fundamental aspects of price elasticity (PE) that apply to both supply (S) and demand (D) (although for each case, the curves for supply and demand will have different slopes):

- **PE = 0**, price is perfectly inelastic: price changes do not lead to sales increases or decreases. Think of a drug that saves the lives of a fixed number of disease victims, assuming they all can afford any price.
- **0 < PE < 1**, product quantity in market is price inelastic: market growth is not driven primarily by price incentives. However, product price netted will be very sensitive to changes in product supply. Slight oversupply may lead to huge price falls.
- **PE = 1**, product supply quantity is unitarily elastic, and price drops are inversely proportional to any oversupply.
- **1 < PE < \infty**, product quantity in market is price elastic: actual quantity used/supplied is sensitive to price changes, but a small change in supply leads to only minor price change (e.g., any price fall will be slowed because new clients will adopt the product).
- **PE = \infty**, perfectly elastic: price is not influenced at all by actual quantity used/ordered. For example, your tailor will make one or ten suits for the same price each, as the amount of work is not reduced for 10 suits if all labor is manual.

The actual price paid for crude oil can be determined from the demand-supply curve, with three distinctive cases (Fig. B2a–c):

- When supply and demand rates are in perfect equilibrium (\( \dot{Q}_S = \dot{Q}_D = \dot{Q}_E \)), the price received by producers will be equal to the mean marginal supply cost (\( P_S = P_D = P_E \); Fig. B2a).
- When the actual supply rate is larger than the demand rate (\( \dot{Q}_S > \dot{Q}_D \)), the price received by producers will be below the mean marginal supply cost (\( P_S < P_E \); Fig. B2b). In this case, producers with the highest marginal cost (Fig. A3a) will be hardest hit.
- When the actual supply rate is smaller than the demand rate (\( \dot{Q}_S < \dot{Q}_D \)), the price received by producers will be above the mean marginal supply cost (\( P_S > P_E \); Fig. B2c).

Fig. B1. Elasticity type curves.
B.2. Elasticity of oil demand

Adopting a simple equilibrium model for oil and gas prices, we conclude that short supply of oil and/or gas will lead to spot price increases. As is explained above, Saudi Arabia can ramp up additional production to balance the market. But if it chooses not to do so, prices will fall because of increased supply and/or lagging/unchanged demand. Price elasticity of demand (PED) is defined as follows:

\[
PED = \left| \frac{\text{%Change in Quantity Demanded}}{\text{%Change in Price}} \right| \quad (B2)
\]

The short-term demand rate function for oil is rather inelastic: a rapid price fall is not cushioned by increased demand. If global oversupply persists, prices remain depressed. Short-term price elasticity of demand using the mid-point rule is defined as

\[
PED_{\text{short}} = \frac{\Delta Q/[0.5(Q_1 + Q_2)]}{\Delta P/[0.5(P_1 + P_2)]} \quad (B3)
\]

The extreme price falls of 2008–2009 and 2014–2016 in response to global recessions can each be used to determine the short-term price elasticity of demand. Using the $100/bbl price fall of 2008–2009 due to 1.5 MMbbl/day oversupply and the $60/bbl price fall of 2014–2016 due to 1 MMbbl/day oversupply, we find \( E_D = 0.015 \). This confirms that short-term oil demand is fairly inelastic (Fig. B2). A percentile increase in supply causes a major price fall (and vice versa).

B.3. U.S. gas supply and demand elasticity

Fig. B3 a–d show how a lowering of the natural gas price (due to oversupply in a closed market region) has substantially increased U.S. natural gas consumption. When the price of natural gas dipped below that of the calorific equivalent quantity of coal (from fall 2008 onward), U.S. power stations switched to using more natural gas instead of coal.
Demand Response to Commodity Price Changes

a) Movement Along the Demand Curve

Lowering of price increases demand

b) Higher price will lower demand

c) US natural gas price drop induced demand growth

Natural Gas Spot Prices – Henry Hub
(DOE EIA data)

d) Demand by sector

Fig. B3. a–d. Lower commodity prices stimulate demand (a), whereas higher prices reduce demand (b). Example: (c) Natural gas price decline in North America. (d) Associated increase in demand; data courtesy EIA.
The supply side usually responds to structural oversupply by several contingency measures: cost-cutting, delay or cancellations of ongoing field development projects, and shifts to fields with better economic outlook. For example, when natural gas prices started to slide from 2009 onward, North American producers of shale gas shifted to producing oil, for which prices were exceptionally high from 2009 to July 2014. Fig. B4 shows that declining U.S. natural gas prices rendered the peripheral parts of the Haynesville shale gas field subeconomič (cf. Weijermars & Linden, 2012), and forced shale producers to cut costs and diversify their portfolios to include more liquids.

References


