Global Hydrocarbon Model
Upstream Module Design Considerations

Prepared by

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List of Acronyms

AAPG	American Association of Petroleum Geologists
ADB	Asian Development Bank
CAPEX	Capital Expenditures
CBM	Coal Bed Methane
CBTL	Coal-Bed-to-Liquids
CNG	Compressed Natural Gas
CPC	Caspian Pipeline Consortium
CTL	Coal-to-Liquids
D&C	Drilling and Completion
DDA	Depreciation, Depletion, Amortization
DH	District Heating
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, Construction
EUR	Estimated Ultimate Recovery

EV	Electric Vehicle
FEED	Front End Engineering and Design
FID	Final Investment Decision
F&D	Finding and Development
GDP	Gross Domestic Product
GOR	Gas-to-Oil Ratio
GTL	Gas-to-Liquids
IDB	Inter-American Development Bank
IEA	International Energy Agency
IGU	International Gas Union
IIP	Initial in Place
IMF	International Monetary Fund
INGM	International Natural Gas Model
IOC	Integrated Oil Company
IRR	Internal Rate of Return
JODI	Joint Organisations Data Initiative
LLS	Louisiana Light Sweet
LNG	Liquefied natural gas
LPG	Liquefied Petroleum Gas
MTG	Methanol-to-Gasoline
NCF	Net Cash Flow
NEMS	National Energy Modeling System
NGV	Natural Gas Vehicle
NOC	National Oil Company
NPV	Net Present Value
O&M	Operating and Maintenance
OECD	Organization for Economic Cooperation and Development
OLADE	Latin American Energy Organization
OLOGSS	Onshore Lower 48 Oil and Gas Supply Submodule
OPEC	Organization of Petroleum Exporting Countries
OPEX	Operating Expenses
OTC	Over-the-Counter
PGC	Potential Gas Committee
PRMS	Petroleum Resources Management System
PWI	Present Worth Index
PWP	Present Worth Payout
R&D	Research and Development
RUR	Remaining Ultimate Recovery
SPE	Society of Petroleum Engineers
STEO	Short Term Energy Outlook
TIAM	Times Integrated Assessment Model
UAE	United Arab Emirates
USGS	United States Geologic Survey

WACC	Weighted Average Cost of Capital
WTI	West Texas Intermediate

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Executive Summary

The Energy Information Administration (EIA) desires to improve its capabilities to model global hydrocarbon markets in order to better understand and track resource development and changing trade dynamics for crude oil, refined products, natural gas and other liquids. This desire is based primarily on following observations:

- With the rapid growth of emerging economies led by China and India, the world oil market dynamics have been changing since the early 2000s.
- The same growth along with the increased availability of natural gas from an increasing number of sources and more globally via liquefied natural gas (LNG) is expected to render natural gas a more globally traded fuel and to change portfolio of fuels in favor of natural gas, especially in power generation.
- The unconventional oil and gas resource revolution in the U.S. since the mid-2000s has led to the realization that these resources are available across the globe. In addition to the possibility of oil and gas exports from the U.S., development of these resources elsewhere, especially in non-traditional resource production regions, will change the trade dynamics. But there are challenges.

In this document, suggestions on the details of the upstream module are offered in addition to discussion of many midstream and downstream issues since they inform the upstream given the highly integrated nature of the oil and gas value chains. Ways to improve the verisimilitude of the model are considered to the extent data and human resources are available. Many of the recommendations are confirmations of observations or preferences discussed in the requirements document or in the April 2014 workshop by the EIA staff and various experts but hopefully they are structured as a cohesive whole and add value. Other recommendations are possibly more unique and are meant to push the limits of traditional thinking about resource potential and oil and gas value chains in order to come up with a model that is more representative of investment and market cycles. The following represent most important suggestions.

- A mathematical model is needed to keep track of interactions in an increasingly complex global hydrocarbon market. However, such a model can only be useful as long as it is coupled with a deep understanding of reserves, potential resources, fiscal regimes, infrastructure needs, technology development and implementation, investment behavior of different types of players and cycles, and regulations among other factors.

- This depth of knowledge requires access to as much accurate data as possible. A database of upstream projects at the field level should be developed and tracked. A spreadsheet exemplifying this database is provided with the report. Fields on production, those approved for development, and those that are highly likely to reach their economic limit should be "hardwired" into the model.
    - The data need to be historical, current and forward looking. Both quantitative and qualitative data are required. All data should be subjected to continuous fact-checking and updating with the help of as many experts as possible.
        - Local expertise from regions of countries of interest should be sought but subjected to due diligence. Expert reports on different regions, countries and plays should be a key ingredient of the database contrasted against and supplemented with data from U.S. Geological Survey (USGS), the International Energy Agency (IEA), Joint Organisations Data Initiative (JODI), local government and private data sources. Numerous data sources are suggested in the report.
        - Qualitative data from local knowledge base should be particularly important for short-term analysis (e.g., six months to two years).
- If necessary to justify resource development, the cost of midstream and perhaps some downstream investments should be captured in upstream cost structure. This is especially important for natural gas resources, marketability of which often depends on construction of new pipelines and/or liquefaction trains.
- Most companies invest in upstream to maximize returns but there are differences across Integrated Oil Companies (IOCs), independents and national oil companies (NOCs) in terms of their hurdle rates, risk tolerances, capabilities and competencies, and interests. These should be captured.
- The Petroleum Resources Management System (PRMS) definitions and methodologies for classifying reserves and resources should be the basis of the database and modeling effort.
- Calibration of the model to ensure that it is capable of duplicating historical periods, especially cycles, is highly desirable.
- Relevant scenarios should be developed based on major trends observed, again with expert input, and analyzed by the model, results of which should again be subjected to qualitative proofing.
- Subsidies along the oil and gas value chain, although much more relevant for the demand side of the market, should be well understood and captured in the model. In the upstream, they can take the form of tax exemptions and intangible upstream cost deductions among others. Midstream projects can be provided with tax breaks and land rights; state companies can cover at least some of the cost.

In any modeling effort, there is always a balancing act between developing a model that is simple and computationally efficient yet cogent, and a model that is as much "real-life" as possible, which often renders the model too cumbersome to manage and computationally time consuming although the latter concern should be eased with today's high computing power. Developing and maintaining a projects database could be expensive and labor-intensive but it is absolutely necessary to capture the industry activity, which is lumpy and has inertia and cannot always react to price signals "rationally" or "quickly." More importantly, many of these investment decisions are not taken based on commercial reasoning but rather for strategic reasons and often financed by state funds.

It is necessary to capture as much detail as possible from field level resources and costs to individual refinery and liquefaction plant to markets for individual fuels at different regions. To be clear, I do not suggest capturing minutiae of operating costs at a field (e.g., water treatment) or details of production sharing agreements (e.g., local content and work commitments) via equations in the model. But a better understanding of such cost drivers at different fields will allow an improved aggregation of costs to manageable levels in a model. This can be considered background research and/or modeling.

Any model that yields straight line projections for supplies and/or prices over horizons longer than five years should be considered fundamentally flawed since we know that such trends are inconsistent with the history of the oil and gas industry, which is defined by cyclicality. Boom-bust cycles occur because by the time the industry develops and delivers the resources signaled by increased demand / price, demand might not materialize as expected and/or too many companies investing in resource development, leading to excess supply as most recently experienced with shale gas in the U.S.

Drivers for a new model

The global hydrocarbon model is needed to develop a more accurate representation of production, trading and delivery of oil, gas and related products across the world. This need arose from the following observations, possibly among others:

- The world oil market has been changing since the early 2000s with the rapid growth of emerging economies led by China and India. The associated growth in demand for oil products not only put pressure on the market and pushed prices higher but also induced new investments along the value chain, much of which have been carried out by NOCs from China among others.
- The same economic growth raised demand for natural gas as well. This increase was facilitated by the increased availability of natural gas from an increasing number of sources and more globally via LNG. There has been significant expansion in gas pipeline capacity, both transportation and distribution, as well. Natural gas is becoming the fuel of choice in many countries not necessarily because it is cheaper than competing fuels but rather it provides a faster and lower capital cost alternative to building coal-fired or other base load generation plants. Some are also attracted to its lower emissions. But, demand for gas in the electricity sector can grow less than what is commonly believed. For example, Xu (2014) expects lower electricity sector gas consumption in China than most outlooks. Renewables, energy efficiency and conservation, and a renaissance of nuclear industry might reduce the anticipated role of natural gas.
- The possibility of oil demand peaking might seem remote in mid-2010s but we might already be seeing some early indicators such as increased use of hybrid and alternative fuel cars (NGVs, EVs, biofuels) and increased efficiency of internal combustion engines or public transportation in increasingly urbanized population centers.[1]
- Demand for oil and gas can also be lower if economic growth slows down. Mature economies of Japan and Western Europe have been struggling for a long time and China and other emerging economies of the 2000s are faltering.[2] There are significant sociopolitical developments that pose hazards for economic growth. Global communication is becoming more seamless, and easier access to information is making people aware of the problems in their societies versus what is available elsewhere: income inequality, corruption, individual freedoms and other socioeconomic factors. So far, political reforms did not match the public uprising caused by such trends (e.g., Arab Spring, Rose Revolution in Georgia, or Orange Revolution in Ukraine); statism has been gaining favor in many places; religious extremism is also taking advantage of income inequality and lack of education.

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[1] In addition to Citi, IHS (2014) also has oil demand peaking in the period between 2035 and 2040. This timing of the peak is less aggressive than the Citi's peak oil demand scenario (early 2020s) but points to increasing attention being paid to the possibility of slower oil demand growth and eventual stabilization.

[2] For example, according to IHS (2014), China accounted for 52% of total oil demand growth between 2000 and 2013 but going forward expectation is much slower growth—2% per year between 2014 and 2040 as compared to 6.8% per year between 1990 and 2013.

- The unconventional oil and gas resources are available across the globe. It is expected that at least some of these resources will be developed given the example of the U.S. and the ongoing drilling activity in Latin America, Eastern Europe and Asia. But, the supply chain logistics are constrained in most locations. In addition, environmental and local community concerns can delay development. For example, methane leakage can be targeted across the world to fight against climate change.
- Although unconventional resources have been attracting a lot of attention, there are conventional resource developments under way including large projects such as sub-salt oil in Brazil, and gas discoveries in East Africa and Eastern Mediterranean. The ExxonMobil-Rosneft deal in Russia and, in general, major deals and bidding rounds should be tracked as they are early indicators of potential large resource development. Finally, although it might seem like a remote possibility at this time, the development of Arctic resources and possibly methane hydrates within a modelling timeframe of 30-40 years is worth investigating.
- Oil and gas trade patterns, which have already changed significantly since the early 2000s, might change further if these resources are developed globally. The possibility of LNG exports from the U.S. and Canada are already having an impact on contract negotiations and possibly leading to some discounts for Japan and other large importers. These pricing dynamics can impact the investment decisions for some upstream and midstream projects around the world. The recent Russia-China pipeline deal is also relevant from a long-term planning perspective as it can impact China's demand for LNG imports as well as investment in domestic unconventional resource development.

With these drivers, the model should be designed to analyze various scenarios that can help answer questions regarding possible paths for demand evolution (e.g., the implications of slowing down of emerging economies, led by China), sources of supply to serve the demand (i.e., existing and new basins / plays to be developed), conventional-unconventional balance, and onshore-offshore balance.

If the model is also intended to shed light on shorter term volatility in prices (such as those experienced in the mid-2000s, especially in 2007 and 2008), following factors need to be incorporated: financial markets (trading of energy derivatives in organized exchanges versus over-the-counter, or OTC, markets), types of market players (hedgers, speculators or "investors"), and relations between macroeconomic policies and financial markets (interest rates, other assets).[3]

Overview of considerations for a global hydrocarbon model

Global oil market is a complex, dynamic system but the oil price (adjusted for quality differences and transportation bottlenecks and costs) has mostly been determined globally since oil is mostly a fungible commodity. Still, deviations from long-term correlation among different crude prices can be informative. The empirical evidence for Adelman's (1984) "one great pool" hypothesis has been strong over the years, albeit with some qualifications. For example, Gülen (1997, 1999) and Fattouh (2010c) conclude that oil markets are not integrated in all time periods primarily because of difficulty of switching feedstock at refineries, cutting back consumption and/or increasing supplies during times of market

[3] Filimonov et al (2014), Hamilton and Wu (2014) can be provide some insights.

tightness that might be caused by demand and/or supply shocks. As Fattouh (2010c) puts it, "arbitrage is not costless or risk-free." Kaufmann and Banerjee (forthcoming) underlie some factors that could cause diversion from the long-term cointegrating relationship of prices for different crude oils, including country risk for the supplier, distance between supply ports and OPEC membership. The recent divergence of two global benchmark prices, West Texas Intermediate, or WTI, and Brent, indicate some other factors that might cause "one great pool" consensus to weaken at least from time to time.[4] Increasing supplies in North America from non-traditional areas such as Bakken and Eagle Ford not finding its way to international markets due to infrastructure bottlenecks and export ban are two of these factors. Refinery preferences for different types of crudes driven by their technologies and markets also play a role. A global hydrocarbon model needs to allow for such deviations; but for exploration and production investment decision making, long-term expectations of wellhead prices (or netback values) are what matter.

In general, drivers of the price include macroeconomic developments such as rapidly increasing demand from the emerging economies of China, India and others putting pressure on the supplies starting in the early 2000s and the composition of products in consumer portfolios, which is often reflected in refinery specifications. Consumer portfolios can be heavily impacted by price subsidies provided by governments. The most recent estimate by the International Energy Agency (IEA) puts consumer subsidies for fossil fuels at more than half a trillion dollars in 2012.[5] Subsidies make calculation of demand price elasticities more challenging since it is not always clear how much of the global price changes are reflected on retail prices paid by consumers. Black market activities such as smuggling and adulteration, encouraged by subsidy policies, introduce additional complexities. There are signals that governments are finally trying to eliminate at least some of the subsidies,[6] partially because of losing their net resource exporter status (e.g., Indonesia) or, more commonly, due to burden put on government budgets being felt more heavily during tough economic times such as the Asian financial crisis in the late 1990s and the global financial-economic crisis in 2008-2009 (e.g., Malaysia).[7] Many fear that removal of subsidies will have a negative impact on the economy because of lower personal consumption and business investment[8] but IMF (2013) points to significant gains for economic growth and the environment if subsidies were to be eliminated.

Presumably, the elimination of subsidies will lead to rationalization of consumer response and reduction in demand, especially if subsidies are eliminated in large markets such as China and India. Of course, if the economy slows down due to more expensive fuels as many fear, demand for fuels can further decline but clearly this additional impact will depend on how the reform is implemented. If, for example, the government compensates the lower income groups via alternative means, there might not be any decline in demand. ***From a modeling perspective, though, the bottom line is that prediction of demand***

[4] It is also common to report the gap between Brent and Louisiana Light Sweet, or LLS. There have been divergences between WTI and LLS as well.
[5] http://www.worldenergyoutlook.org/resources/energysubsidies/, last accessed August 23, 2014.
[6] In September 2009, G-20 countries agreed to phase energy subsidies out over mid-term.
[7] The Global Subsidies Initiative offers several case studies as well as guidelines for successful reduction or elimination of fossil fuel subsidies.
[8] For example, according to Bridel and Lontoh (2014), Credit Suisse lowered its GDP forecast for Malaysia after the government decided to raise the price of diesel and some other fuels by reducing some of the subsidies. Lin and Ouyang (2014) conclude that removing fuel subsidies in China will impact not only economic growth and employment but also emissions negatively.

for oil products, natural gas and electricity, which has an indirect but significant impact on global gas trade, in many countries is difficult and need to consider subsidy policies. These factors will impact expectations for the upstream products.

Resource triangle

The debate regarding the impact of subsidies aside, global demand for oil and gas is expected to grow. This growing demand has to be met from new supply sources, which might be more challenging and expensive to develop and deliver to the market. The resource triangle of Holditch (2006) implies that geology dictates the move from conventional to unconventional resources to require improved technology and be more expensive (Figure 1).

***Figure 1*. Resource triangle**

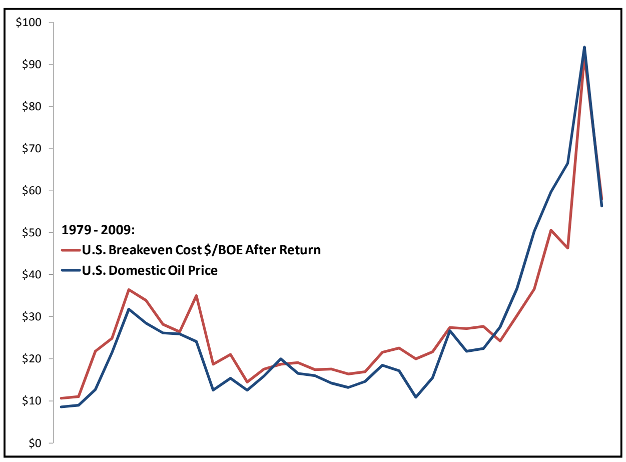
However, it would be wrong to conclude that the world has run out of high-medium quality conventional resources based on the increased unconventional production in the U.S. There are non-geologic considerations. For example, some conventional reservoirs are in deep waters, or simply distant from markets or in landlocked countries with low local demand, or environmental regulations prevent their development. Technology and economic development have been addressing such challenges although initially development of these resources might also cost higher than resources that are close to markets.

More importantly, policies and associated fiscal regimes put in place by governments as well as geopolitical considerations may render easier to develop and deliver resources inaccessible, at least for a period of time until the fiscal regime or policies change. For example, the recent reforms in Mexico are expected to lead to development of oil and gas resources with the help of integrated oil companies (IOCs) and independents that PEMEX has not been able to develop either because the company was not able to keep as much capital for reinvestment as necessary or the company did not have the expertise to develop deepwater or unconventional resources. If successful, these reforms can lead to a “shift” in the global oil supply curve. ***As such, even the most basic assumption of oil price increasing over time as demand increases should be questioned.***

Finding the data, let alone high quality data, for many of the fields around the world is the most important challenge. Resources and even reserves already have a range of geologic uncertainty associated with them. Unless reported by companies, whose shares are listed in public exchanges, reserves reporting is suspect: political considerations, gamesmanship within OPEC, promotion of resource development in emerging resource countries can all drive towards inflated volumes. Given that the great majority of world's reserves and resources are controlled by governments, often via their agents, national oil companies, or NOCs; the data is opaque. Even publicly traded companies had to make adjustments in recent years after regulatory scrutiny. Still these numbers that mostly follow the Petroleum Resources Management System (PRMS), or some classification that can be mapped to it, are more trustworthy. Increased exposure of NOCs to world markets is leading to some of them listing their shares in international exchanges and hence having to follow same rules as the integrated oil companies, or IOCs, which should increase confidence in their reserves numbers. But, resource estimates remain a concern. Despite best efforts, the U.S. Geological Survey estimates of at least some of the resources around the world, for which there is limited log, core, seismic or any other high quality geologic data will by definition have a large range of uncertainty. The problem could be particularly acute for unconventional resources. However, with due diligence and literature review supported by expert input, researchers should be able to procure sufficient data. The development of this database and quality control is a continuous process.

Data at the field level

Overall, a field-level model with relevant details on cost of production, fiscal terms and market access on each field should be able to incorporate all these factors into a "supply curve" to reflect the total cost of exploring and developing resources. Such a model is discussed later in this report and a list of suggested variables for the required database is provided in an accompanying spreadsheet.



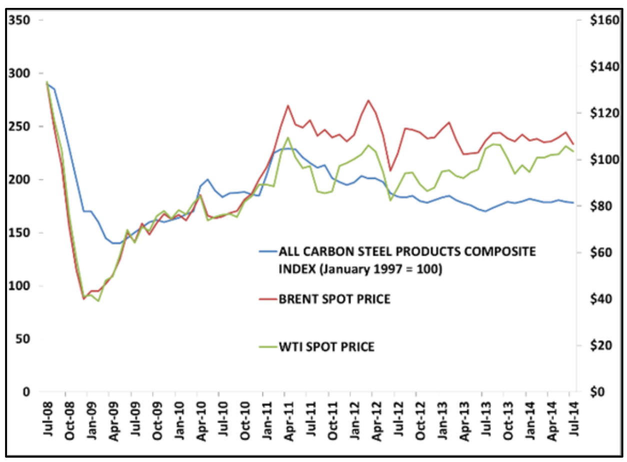


***Figure 2*. Correlation between oil price & cost and correlation between oil prices & cost of steel**

With respect to cost trends, Lynch (2014) makes the point that "high costs do not guarantee high prices." Underlying this statement is the belief that fundamental costs have not changed as much as the price increases in the 2000s would imply and that cyclical factors were at play. There is correlation between the price of oil and finding and development (F&D) costs (Figure 2, left panel). One can also observe correlation between the F&D cost and material prices such as steel, albeit indirectly via oil prices (Figure 2, right panel). It is not surprising that increasing demand for oil induces increased drilling activity that puts pressure on costs of oil field services. However, there has been a change in these relationships since the early 2011: the correlation between steel prices and oil prices fell from 0.74-0.77 range before January 2011 to 0.57 for Brent and 0.27 for WTI since then. The correlation between Brent and WTI fell from 0.99 to 0.6 for the same time periods. This change in relationship could be a partial evidence that there are drivers other than fundamental, or at least traditional, items such as steel.

Accordingly, deciphering the factors contributing to cost trends remains to be a challenge: how much is due to a shift to “lower quality” resources, which would presumably constitute an increase in fundamental costs, versus cyclical factors. Also, it is not clear what portion of cyclical factors remain cyclical for perpetuity and what portion represents a secular change. For example, do we expect front-end engineering and design (FEED) and/or engineering, procurement and construction (EPC) costs to come back down to the levels of the late 1990s or early 2000s? At the least, this is a question worth investigating for the time frame of the modeling exercise (see below for more on upstream cost trends).

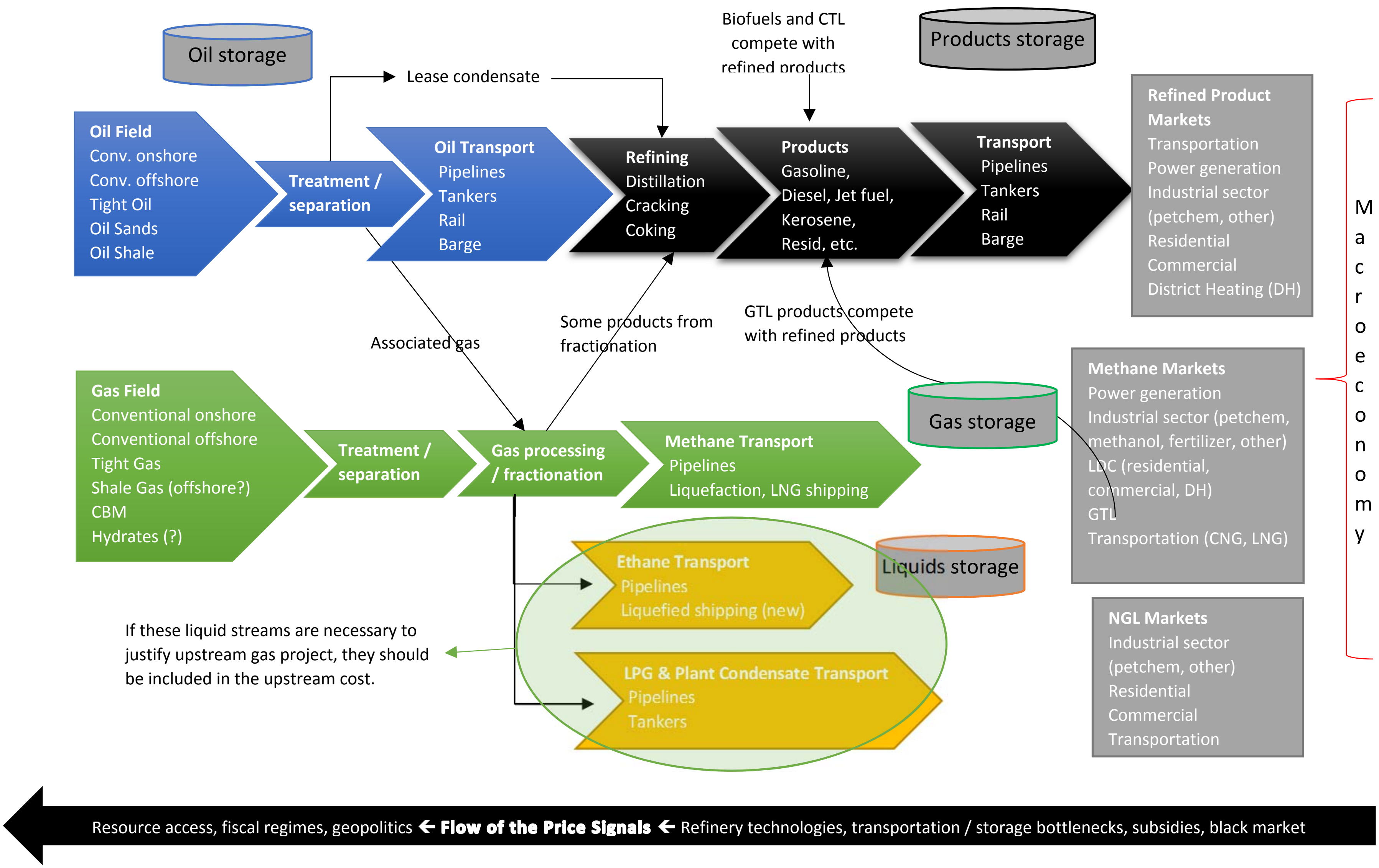
Technological developments can benefit the oil and gas companies by allowing them to access new resources but they can also be more mundane and improve estimated ultimate recovery, or EUR, from existing wells or plays; or, combined with operational practices, they can reduce the cost of operations. Commonly, technological improvement is modeled by annual improvement rates; but, this might not be the norm in the oil and gas industry. Unconventional resources have always been known to geologists, and the technologies of fracturing and horizontal drilling were used elsewhere before they were combined in an innovative way to cause a significant jump first in natural gas and then in oil production in the U.S. It might be necessary to distinguish between “routine” improvements and “revolutionary” ones based on a detailed analysis of historical data from the industry. It is also important to counterbalance technological improvements with the general cost inflation trend (see the Role of Technology section below for more discussion).

Oil versus natural gas

Figure 3 provides a depiction of oil and gas value chains and how they should be grouped for modeling purposes, albeit in a simplified manner. Natural gas resources become stranded for two main reasons: lack of nearby markets and lack of access to exports. In landlocked countries such as Bolivia, most of the gas remains stranded beyond the immediate needs of a small market. The Bolivia-to-Brazil (B2B) pipeline was developed to address the problem by allowing exports to a market that was expected to grow on the basis of increased gas-fired generation. Similarly, a pipeline was developed to bring Camisea gas to Lima for domestic market but also to a new liquefaction facility. Pipelines from Turkmenistan and Azerbaijan are other examples as are the current plans to build pipelines and liquefaction facilities in British Columbia to monetize the shale gas resources in Montney and Horn River. Many LNG projects were developed to monetize stranded assets: Trinidad & Tobago, Qatar, Nigeria, and Angola. It would hardly be realistic to model resources in Tanzania and Mozambique at the cost of developing the fields, which would not happen unless LNG projects are attached to them.

Private entities can be involved in the construction of such projects and trading of the product but their part being commercially attractive does not necessarily imply that the whole undertaking is assessed as a pure commercial enterprise. For example, the B2B pipeline was developed with the involvement of Shell and Enron but it would not have happened if Petrobras and Brazil did not provide certain guarantees. In short, an independent midstream industry making commercial decisions à la the North American market is often not the case. The model should capture this reality.

Figure 3. **Simplified oil and gas value chains**



Accordingly, the cost of such midstream assets should be considered as part of the resource development cost. Naturally, by the same logic, the cost of gas processing and fractionation, if necessary, to extract the valuable natural gas liquids should also be considered as part of the cost of monetizing stranded gas resources. ***The inclusion of these costs are necessary to calculate an accurate supply curve for deliverable natural gas.***

Another advantage of this way of grouping segments of the value chain is to credit producers with the value of wet gas resources properly. For instance, drilling in the Barnett play continued after the collapse of natural gas prices as most operators, who could, switched to wet parts of the play to take advantage of the additional revenues associated with natural gas liquids, especially high-priced ethane at the time. Qatar generates large revenues from liquids, which allows methane to be a cheap feedstock for its LNG exports as well as the world's largest gas-to-liquids (GTL) facility.

Note that resources that are near existing markets and infrastructure (processing, pipelines, liquefaction) would not be burdened by the capital cost of these midstream assets. They would pay the usage fees, which can also be reflected in netback pricing to the wellhead. This happens naturally in liquid markets such as that of the U.S. where basis differentials inform the producers regarding bottlenecks and midstream investment needs: they can then either be satisfied with discounted wellhead prices if their assets are behind bottlenecks or decide to invest in those midstream assets themselves if the higher netback pricing allows them fast recovery of that investment. We have seen examples of this in recent shale gas revolution in the U.S.

Other midstream projects should be based on arbitrage opportunities subject to geopolitical constraints. A decision analysis approach could be pursued to decide across options. For example, the options for delivering gas to markets from a particular field might include onshore and offshore pipelines, and LNG. Prices at different markets and costs of these options will allow modeler to develop a hierarchy of choices, which can then be subjected to geopolitical and geographic constraints. The Bakken oil deliveries via pipeline, rail and truck provide a good example for oil. These midstream transactions could be handled in a separate logistics module.

Given the maturity of the industry and the liquid nature of their product, the oil producers have not had the stranded resource problem as severely as the natural gas producers in recent history but there are still examples such as the Chad-Cameroon pipeline, in the absence of which the significant resources in landlocked Chad, with little regional market, would not have been developed. The Caspian Pipeline Consortium (CPC) pipeline is another recent example that allowed the development of the giant Tengiz field in Kazakhstan.

Contrary to conventional wisdom, the world oil market might become more regionalized as more countries become producers, more countries grow as consumers and develop their own downstream sectors with differing fuel mixes, including biofuels. Energy security policies can also impact global pricing; for example, Lee (2014) reports the Brent-LLS gap to increase from $10 per barrel in the fourth quarter of 2014 to $30 in 2018 if the U.S. export ban stays in place through 2015.

The natural gas, on the other hand, might be becoming more globalized with the increasing LNG trade from an increasing number of producer countries to an increasing number of consuming countries. In the early 1990s, there were a handful exporting countries with Indonesia, Malaysia and Algeria accounting for 70% of the LNG supply as compared to more than 15 exporters now with Qatar, which did not export a single molecule of gas until 1997, as the leading exporter with more than 30% of the market. Indonesia and Malaysia are reducing their exports as their internal demand for gas has been increasing and reserves have been diminishing. New supplies from existing exporters such as Australia and new exporters from East Africa, Eastern Mediterranean and North America will continue to change the make-up of the exporters club in the next decade and beyond. Similarly, there were a handful of major importers in the early 1990s with Japan dominating the market. Today, there are 29 countries with regasification capacity of various sizes according to IGU (2014); this number is likely to increase.

Still, there are two basins with distinct pricing levels. This difference is primarily due to oil-indexed pricing still being dominant in the Pacific Basin, which is mainly due to energy security concerns of major importing countries in that region. The Atlantic Basin has been creating more gas-on-gas competition (and exports of LNG from the U.S. could expedite this process) but oil-indexed pricing is still significant and probably necessary to build large, capital-intensive projects such as liquefaction plants and the rest of the LNG value chain as well as long-distance pipelines.

The INGM makes the assumption of competitive markets, which is difficult to justify (see Model Rationale on p. 12 in EIA, 2013b). LNG value chains and major pipelines, remain expensive and dependent on long-term contracting. The document offers "short-term market prices" as reflective of marginal supply and demand decisions. Further, the model assumes that long-term trends will be towards more flexible markets. Such a future is certainly possible but should not be taken as the foundation of the modeling exercise. For years, there was an expectation of increasing share of spot LNG trading. Indeed, some liquefaction plants were built without signing long-term contracts for 100% of their capacity and the share of spot trading has gone up for a while but started to stagnate, albeit with seasonal fluctuations or swings due to extreme events such as the Fukushima accident.

However, the LNG value chain remains expensive and energy security concerns still dominate many importers' strategies, especially in the Pacific Basin. Hence, it is also possible that spot trading in the LNG market has reached its limit and long-term agreements will continue to dominate. The trend of rising capital costs provide more reason to think that lenders for these expensive value chain projects as well as the sponsors would be more dependent on long-term contracts.[9] In any case, prices in the range of $15 to $20 paid by Japan and others in the Pacific Basin after the Fukushima disaster should not be treated as the main driver of LNG investments in a long-term modeling exercise. It is important to note that facilities might get built but not utilized much.

The North American natural gas market is the most mature, competitive gas market in the world with regional differences. For example, gas prices in parts of the Northeast started to diverge from their historical relationship to Henry Hub after the Marcellus development.[10] These changing basis dynamics have to be captured and possibly imply a more granular regional approach to natural gas than oil.[11] It is also important to have the flexibility in the model for other regions to experience a similar dynamism if they pursue a more open market for natural gas (e.g., Western Europe).

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[9] Hence, the statement "the model does not account for contractual flows or pricing" on page 12 of EIA (2013b) is troubling. Also of concern is the assumption of not allowing Saudi Arabia to export gas to reflect the domestic use policy. In a long-term analysis, one should allow for the change of this policy if Saudis produce enough gas.

[10] For an overview, see Foss (2012).

[11] For example, AURORAxmp, a commercial software for economic dispatch of electricity, can be run for individual reliability regions or independent system operators or any combination of them. Similarly, REMI, a dynamic computable general equilibrium model used for economic impact analysis, allows one to run the model at the county, state, regional or national level.

Some observations on demand

There seems to be a fundamental relationship between economic growth and demand for energy. Typically, energy intensity increases as countries transition from an agricultural economy to an industrialized one, then declines as the economy shifts towards services.[12] It is possible for some countries to transition faster than others or even to bypass energy-intensive industries. The demand module should capture this fundamental relationship between energy use and economic growth, and deviations from it; and even try to predict transition eras at the necessary regional level to represent the state of economic development. The World Bank, ADB, IDB, IMF are probably the best sources for such information but due diligence might be necessary via domestic sources in certain countries if there is too much discrepancy between estimates and/or expectations.

Demand from various types of customers for different products should drive the modeling process as it is currently done in the WEPS+ and other modeling efforts. Hence, it is important to capture fuels competing in each market segment and emerging trends in this competition. Some examples follow.

- Natural gas has been pushing oil out of the power generation sector; this will likely continue but deeper investigation of select regions might be necessary. There are many factors, all of which pose a threat to increased use of natural gas in power generation.[13]
- Natural gas has also increased its penetration in residential and commercial sector, mostly replacing liquid fuels for heating and cooking. Countries where distribution networks develop rapidly should be identified for similar switching. One scenario involves natural gas pushing LPG out of these markets, which could render LPG even more attractive as vehicle fuel.
- Oil products (gasoline, diesel, bunker fuel and jet fuel) dominated the transportation sector for a long time but there might be increasing competition from natural gas in the form of CNG in passenger vehicles and small trucks and in the form of LNG in heavy trucks, ships and even rail. LPG has a much larger market share as a transportation fuel outside the U.S. in general but especially in Asia and the Middle East. GTL, methanol-to-gasoline (MTG) and biofuels could challenge refined products more directly. Increased production of wet gas around the world could induce more LPG, GTL and MTG production.
- The petrochemicals sector use a lot of refinery products such as naphtha for ethylene production but increasing competition from ethane crackers should be watched, especially if liquefied ethane shipping grows and wet gas development expands beyond the U.S.

Connections between upstream submodule and other submodules

For an iterative approach, the model sequence used in WEPS+ is consistent with the recommendation of having macroeconomics drive demand. Figure 4 is the modified version of the WEPS+ structure (EIA, 2011a) to emphasize the importance of the refining sector, and the new oil and gas supply module

[12] See Medlock and Soligo (2001) and other literature on resource dematerialization.

[13] The role of nuclear energy and renewables are important supply side considerations whereas energy efficiency and conservation (via demand side response—smart meters and appliances, time-of-use pricing, remote control of appliances via smart phone apps) are equally relevant on the demand side. Electricity storage is a wild card technology that can change the fuel portfolio mix in power markets significantly, albeit probably not in the next decade.

replacing the WEPS+ Supply Models. The need for having a separate module for transformation (electricity generation and district heating) is not clear; electricity generation and district heating demand for fuels should be developed within the Demand Models.[14]

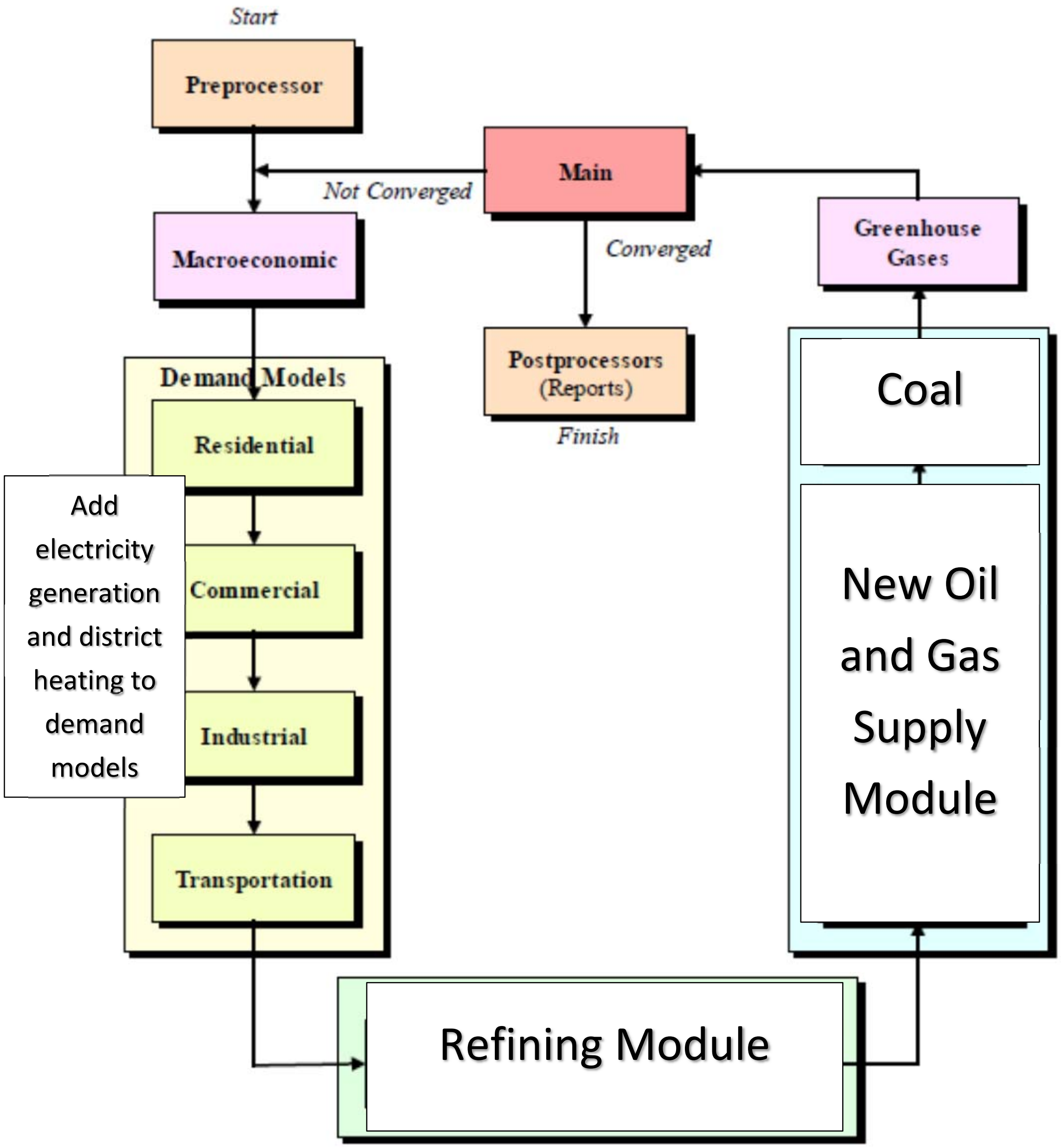

***Figure 4*. Potential global oil and gas model structure for an iterative approach.**

The demand will drive what refineries should produce and how much gas should be processed. Then the downstream model would translate products demand into the amount and quality of crude feedstock needed.[15] The downstream model should communicate this information to the upstream model, which

[14] WEPS+ is used in this section to depict the general model flow. In the Appendix, some observations are offered on other existing modeling structures that can be adapted for the purposes of the new hydrocarbon model.
[15] NEMS already has a detailed representation of refineries for the U.S. and can form the basis for modeling the global refining industry. But, if improvements are desired, industry modeling practices could be useful. Aspentech,

then tries to match that demand from the “supply curve” subject to logistical considerations (e.g., pipeline bottlenecks, refinery technologies, amount in storage).

Different grades are needed to match refinery technologies and market demand at different regions. The refining experts should be consulted to capture most recent regional trends but at the least the model should distinguish across light sweet, light sour, heavy sweet, and heavy sour via several API degree cut-offs as it has been done in other EIA models. The methane stream should be identified separately from natural gas liquids. In recent years, keeping track of ethane, propane, butane and lease condensate has been necessary to understand the upstream shale operations’ economics. With increasing exports of LPG and possible ethane exports in the near future from the U.S., and potential development of wet gas (conventional or unconventional) around the world, these products might become even more important.

The refining and local market experts should be consulted to capture most recent regional trends but at the least following products from refineries and those that compete with refined products should be tracked: gasoline (different types such as reformulated), diesel (ULSD, biodiesel), jet fuel, kerosene, fuel oil (different types), residual oil, pet coke, LPG and biofuels. In WEPS+ there are 13 mid and downstream products; aggregation of 20 product types from NEMS to 13 in WEPS+ might be desirable to simplify modeling while maintaining the plausibility of the model. Troner (2013) can provide useful knowledge on global significance of LPG and condensate.

The link between the refining module and the supply module is temporally complex.

1. The immediate and short-term needs of the refineries have to be met from producing fields and storage or some substitution would have to take place on the demand side.
2. Long-term investment decisions of upstream companies will be influenced by expectations for growth in demand for various products, their geographic locations and existing and planned refining technologies. These expectations are boiled down to internal price decks used in project evaluation within companies.

The oil and gas industry is cyclical (Figure 5). The boom-bust cycles depicted occur because, as Slaughter (2014) observed, “oil and gas prices depend on disequilibrium between demand growth and supply growth and are not supply-driven.” The time to develop sufficient supply chain capacity to produce and deliver products to consumers is long and can be made longer by economic and environmental regulations, local community opposition and geopolitics. Within this period, business cycles can disrupt demand for energy products. Increasing cost of delivering new supplies can contribute to these business cycles. In fact, some research into the “structure” of cycles could be useful.[16] Given that most projects

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Honeywell, Haverly and other companies serve the industry with optimization and other analytical tools for matching a variety of crude feedstock with the products demanded at a refinery’s market to maximize revenues in this very low profit-margin segment of the oil value chain. Although it is called “linear programming” the problem space is in fact non-linear. However, companies also use simpler programs to aggregate refineries in certain regions to model more immediate market circumstances. More sophisticated individual refinery modeling could still be relevant for individual refineries in the case of a new large refinery coming online or a major change in fuel specifications, or a change in quality of crude in a particular market. These companies might be approached to improve the EIA model’s verisimilitude. In addition to OGJ data services and IHS / Purvin & Gertz, GlobalData is an emerging data provider that could be useful for keeping track of new refining capacity.

[16] For example, referring mostly to geopolitical events, Paul Sankey mentioned the tendency for a major disruption to occur every seven years or so at the July 15 workshop. Of course, there is also a large literature on business cycles, the understanding of which can be complicated by geopolitics.

along the oil and gas value chain are capital-intensive projects with several years of preparatory work (e.g., regulatory filing, front end engineering and design, permitting) and their construction can take up to 7-8 years, a timeframe less than 10-15 years is not likely to be very informative.

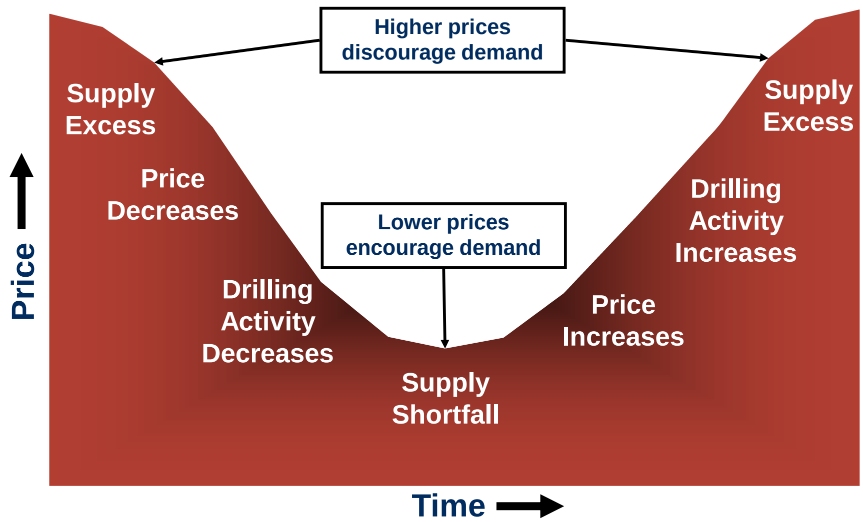

Figure 5. **A stylized representation of boom-bust cycles in oil & gas markets (by Michelle Michot Foss).**

Supply model design considerations

There are two important aspects of hydrocarbon supply that need to be captured: supplier behavior and resource characteristics, each of which come with numerous considerations.

1- Supplier behavior can depend on several factors.

a. The investment decisions of IOCs are different than those by NOCs, which might have at least two groups: partially privatized NOCs that compete in the international arena and NOCs that represent state interests primarily in domestic blocks but potentially with an increasing global presence. Independent upstream companies offer another group that is worth to distinguish; these companies are not integrated and often pursue smaller and/or riskier projects not attractive to most IOCs. These distinctions imply different objective functions and constraints for different players (see the section on production decisions below).

b. The empirical support for the OPEC cartel hypothesis is weak. For example, Gülen (1996) concludes that OPEC did not act as a cohesive whole and that Saudi Arabia stood out as swing producer. Alhajji and Huettner (2000) reviewed 13 studies, only two of which found statistical support for the cartel hypothesis. Smith (2009) contends that, over the years, OPEC failed in "shutting in" existing production capacity while succeeding in restricting capacity expansion by limiting new upstream investments.[17] Overall, OPEC probably does not matter but Saudi Arabia and its excess capacity can be treated explicitly given that the Kingdom has used that capacity to

[17] This observation also supports the earlier point regarding the inaccessibility of "high quality" resources. It is possible that these resources that are artificially taken out of the supply curve can come back to the market. High oil prices or higher revenue needs might actually induce some OPEC members and other resource-rich countries to develop these resources or reform their sectors to allow development by IOCs (e.g., the recent reforms in Mexico).

balance the market at various occasions. However, the spare capacity number requires due diligence as it is not clear how much it is and how willing the Kingdom is to use it going forward. There is some research on revenue requirements of OPEC countries among others that indicates about $100/bbl as the necessary price level for Saudi Arabia (Figure 6 is copied from Aissaoui, 2014). This line of research is reminiscent of the target revenue models, which imply a backward-bending supply curve for producers, that were proposed first in the late 1970s: if the Kingdom could produce and export more, a lower price might still yield the same revenues. Such considerations might be needed in the model.[18]

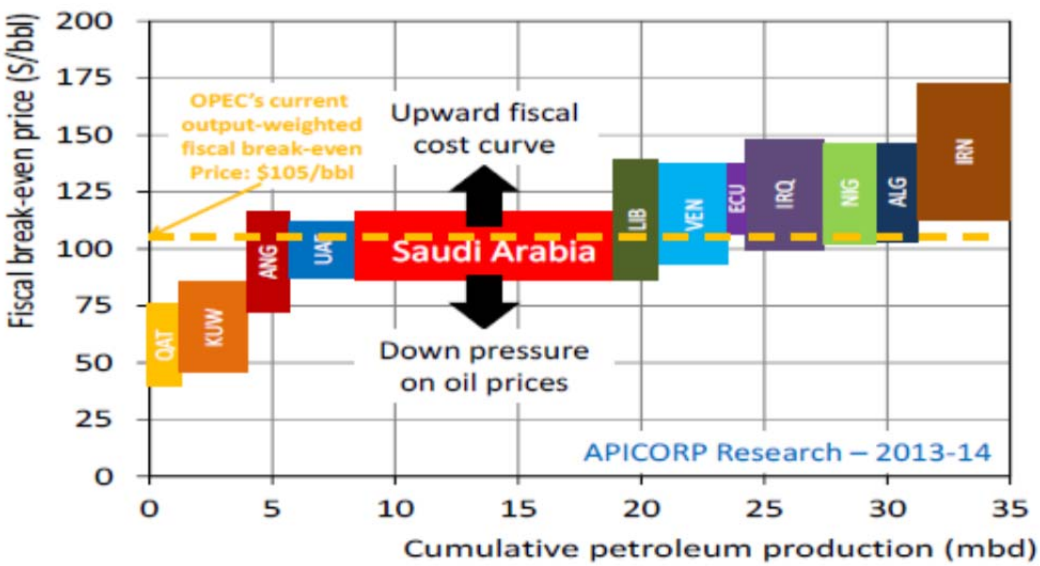

***Figure 6*. OPEC fiscal breakeven oil prices**

c. Geopolitics is inherently difficult to capture in a mathematical model. The first two bullets capture some aspects of geopolitics in the form of governments' use of NOCs for resource development, rent extraction and/or energy security; and Saudi Arabia's role as a swing producer. There are other geopolitical considerations that cannot be predicted such as disruptions of production and transportation due to wars, civil unrest or other conflicts. From an investment evaluation perspective, it is possible to evaluate geopolitical risk factors in different regions but these rankings can be subjective and transitory. There seems to be an increasing tendency for IOCs to avoid some of the riskier locations such as Nigeria, Venezuela, and even Russia. But it is not clear that all IOCs share the same criteria for all the regions; and independents seem to be willing to fill the void in many instances. The proposed field by field assessment would capture regional specifics and operator's risk tolerances.

2- Resource characteristics.

[18] Teece (1982) is the first formal treatment of the target revenue model. The model found some support in the empirical literature. It is important to note that one ends up with different price requirements depending on whether the objective is to balance government budget or the current account. Focusing on the latter, IHS comes up with a much lower price (about $60/bbl) for Saudi Arabia than the $85 to $115 range depicted in Figure 6.

a. Finding and development (F&D) and field production costs provide the starting point but transportation and processing costs should be included if these facilities are deemed necessary for new resource development or sizeable reserves growth. Most of these cost items but especially F&D and production costs need to capture the fiscal regimes in sufficient detail: royalties, taxes, NOC participation, local content, work commitment, cost recovery, and so on. The availability and depth of supply chain logistics (service industry) in the resource region will also impact the cost of project: if a lot of the equipment, supplies and crews have to be "imported," costs will be higher and projects will probably take longer. Offshore projects typically cost more on a unit basis but sometimes they are also seen as ways of avoiding some local risks.

b. Resources and reserves. PRMS offers a good template for resource classification. Resources towards the bottom of the resource pyramid such as kerogen and hydrates, which are not currently being explored heavily, should be treated separately if their development within the timeframe of EIA's long-term studies appears possible.

c. Low permeability resources that require hydraulic fracturing of long laterals with dense drilling of wells that have high decline rates are quite different than conventional resources. Special treatment of these resources outside North America is needed. The biggest challenge for global duplication of the U.S. experience include the lack of depth for the supply chain logistics, i.e, the service industry (drillings rigs, hydraulic fracturing and water trucks, fracturing fluid, pipes, compressors, and so on).[19] Other challenges include access to water, the absence of private ownership of mineral rights, which leads to increased local opposition in Europe, and governments' or NOCs' desire to control / operate.

d. Identifying production stream (oil, oil and gas, quality of oil, composition of NGLs) is very important and requires data on wells drilled, their production, decline profile, gas-to-oil ratio (GOR), and heat content if gas (to determine liquids yield). The industry and most analysts did not pay much attention to NGLs in the past but nowadays revenues from NGLs are very important for most shale producers in the U.S. The international experience is not likely to be very different. This historical data can also be very useful in developing analogues for new wells and plays around the world.

3- A field-level modeling is proposed; but fields can be aggregated to countries, organizations and/or regions of interest. There will be new exporters of oil and gas; some established players might reduce their exports or even become a net importer. Following are recommendations of countries that could be reported from the supply perspective; but this list should be subjected to further due diligence as to their relevance and availability of data.

[19] For example, the U.S. has more than half of the rigs in the world. There has been about 60,000 wells drilled in major shale plays in the last decade to yield the production levels we see today. So far, in Argentina, China and Poland, most active countries in terms of shale drilling, only a few hundred wells have been drilled over the last few years. Even if these wells yield promising results, the pace of drilling activity needs to reach much higher levels for shale production to contribute significantly. This higher pace cannot be achieved without a deep service industry and supply chain logistics providers in place.

a. The U.S., Canada, Mexico should be treated separately rather than as North America although the integrated nature of these markets (especially between Canada and the U.S.) should be captured. Both the U.S. and Canada may benefit from a more detailed regional representation primarily because of their liquid and competitive markets leading to pricing hubs and basis differentials that provide important information for investment decision-making. Mexico deserves separate treatment because of its large resource base, large economy, integration with the U.S. gas market via pipelines and the new energy sector reforms.

b. OECD Europe can be treated as a group for the most part it might be sensible to separate the UK, Norway and the Netherlands as major North Sea producers with mostly declining production.

c. Australia deserves individual treatment due to its significant role as a major LNG exporter.

d. Indonesia, and Malaysia deserve individual treatment because of their changing energy export-import status.

e. China and India require explicit treatment as large emerging economies with potentially large resource development opportunities.

f. Russia can benefit from separate treatment of major resource regions.

g. Saudi Arabia, the UAE, Kuwait, Iraq, Iran, Qatar and Oman should be reported separately as major producers. Egypt might deserve separate treatment given the size of its economy, gas exports and potential for further resource development. Consumption patterns have been changing in the region, increasing energy use, switching from oil to natural gas for power generation, and developing refining and petrochemical capacity. This change has not been uniform but should be tracked at least at the regional level as it can impact the amounts of hydrocarbons exported from the region.

h. The Sub-Saharan Africa remains under-explored. In addition to Angola, Nigeria, and Chad, emerging resource countries such as Equatorial Guinea, Ghana, Uganda, Tanzania and Mozambique among others should be followed.

i. Other countries that might require individual representation because of their large exporter status (current or potential) include: Algeria, Libya, Kazakhstan, Azerbaijan, Colombia, Turkmenistan, Bolivia, Trinidad & Tobago, and Peru.

Supply Curve

Is the world running out of oil and gas resources? This is not a question about whether oil and gas resources are exhaustible in a physical sense or not. Rather, it is a question regarding the relevance of this exhaustibility within the time frame of modeling goals, say 30 years. The peak oil proponents used to focus on "physically" running out of oil, which would imply a supply curve with a vertical (or almost vertical) portion as the world reaches the end of its oil resources; but that premise lost its credibility quickly and the focus has been on "economically" running out of oil, or the "end of cheap oil,"[20] which

[20] Even if it is more expensive to produce oil, it might be "cheaper" to consume. The share of gasoline expenditures in pretax income is about 4%, higher than the 2% in the late 1990s but lower than the 5% in the late 1970s and

implies ***a traditional supply curve but with a steeper slope to reflect the ever-increasing cost for fewer incremental barrels***.

The economics of developing different types of resources, be it oil or natural gas, is the right way of approaching the exhaustibility challenge within the timeframes of concern. The resource triangle discussed earlier suggests a natural progression of developers moving to “more difficult to extract” and/or “more expensive” resources. However, the recent unconventional resource development in the U.S. should not be taken as prima facie evidence of the world moving down the pyramid. Undoubtedly, a lot of the “high quality” resource at the tip of the pyramid has been produced. But, tight and shale gas and tight oil resource development of recent years in the U.S. cannot solely (or necessarily) be explained by the resource pyramid. Even in a mature province such as the U.S., conventional resources from the tip of the pyramid might be available but beyond reach due to restrictions on drilling in federal lands and offshore for environmental reasons. There is increasing discussion about using lessons learned from unconventional drilling by applying horizontal drilling and fracturing practices in conventional plays.[21] Equally significant, there are hundreds of oil and gas companies in the U.S., which is pretty unique in the world; these companies could still have taken the risk of developing unconventional resources because offshore conventional opportunities were probably too “large” for their financial and human resources.

Globally, given that governments control more than 90% of known reserves (and probably a lot more of potential resources) and the absence of markets in many areas where the resources might be attractive (e.g., landlocked parts of Sub-Saharan Africa or Siberia), it would be a very useful exercise to identify the amount of resources that exist but currently not available for development because they are either controlled by governments restricting their exploration or they are located in remote locations without local markets to justify initial investment.

These resources should be treated differently in the model as policy changes such as reforms in Mexico can shift the supply curve. Mexican reforms are still in early stages and internal politics can still set the reform process back, but the fact that the Mexican Congress passed these reforms is revolutionary given that the country nationalized the oil industry in 1938, much earlier than the nationalization wave of the late 1960s and early 1970s. This significant political achievement provides evidence for the inefficiency of nationalized industries and for the pressure governments feel when they start losing their fiscal revenues. Other countries might follow with similar reforms. An alternative route is for NOCs to become more efficient and globally competitive; PEMEX has never invested in the upstream internationally but other NOCs have. In an increasingly competitive oil market, NOCs and their governments might feel the need to develop more of their resources and/or invite IOCs to develop them especially if global oil demand growth stalls and the market share becomes more valuable.

Criteria to evaluate whether we need to be concerned about exhaustion of competitively priced oil and gas supplies within the timeframe of interest should at least include the following.

- Figure 7 from Foss et al (2013) implies that, even in a mature oil and gas producing region such as the U.S., the competitive industry has been able to replace oil production and add to the proved

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early 1980s. There has been an increase in cost of producing oil since the early 2000s but increasing efficiency and conservation in end use might revert the trend downward again.

[21] In URTeC 2014, there were presentations on these experiments. For example, Anadarko has been able to drill horizontal wells in the Wattenberg play in Colorado, which was developed via 15,000 vertical wells over several decades, and achieved the same level of production as those vertical wells with much fewer wells in just few years.

reserves between 1900 and 2010. Making the comparison for combined resources of oil and gas for a more recent period, 1960-2010, yields the same result: the industry has been able to replenish reserves.

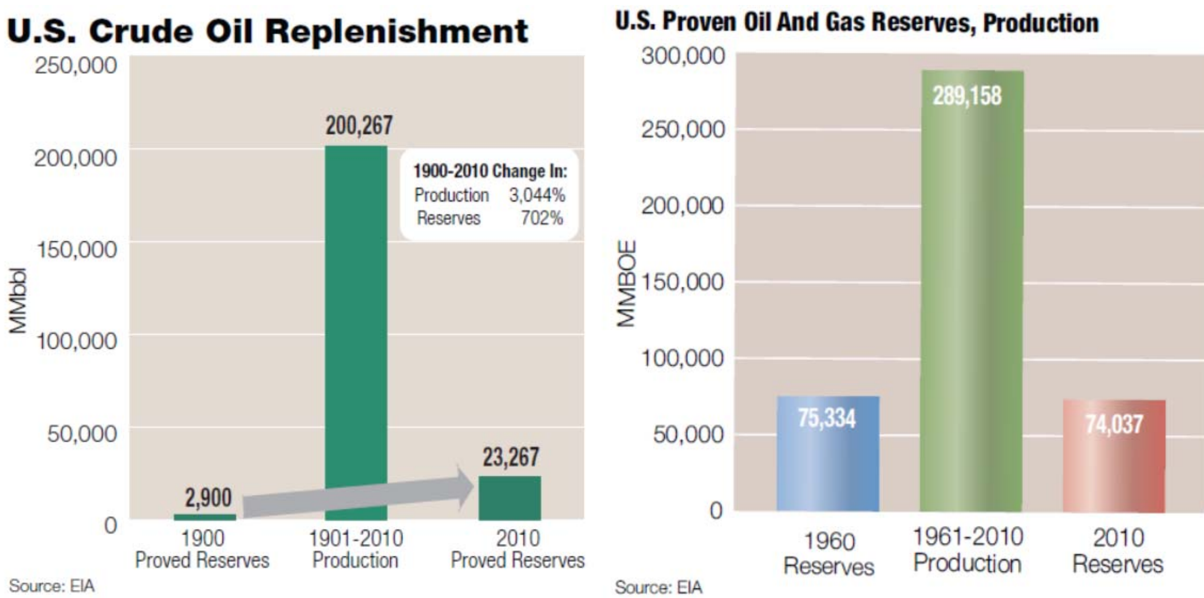

***Figure 7*. Reserves replenishment in the U.S.**

- Costs have been higher only in the last decade or so in real terms; but, the oil price is about the same as it was in the early 1980s although that period's price included a significant geopolitical premium. This time around, the price might be reflecting premiums owing to geopolitical factors, macroeconomic policies such as monetary easing, financialization of commodities, and environmental regulations among others.
    - There is general cost inflation for major infrastructure projects since the early 2000s. The global financial-economic crisis in 2008-09 appears to have curtailed this inflation for only a short period as costs returned to their upward trend quickly.
    - The "high enough price" is relative to cost of technology that is necessary for the development of new resources. Neither hydraulic fracturing nor horizontal drilling were new technologies in the mid-2000s when they finally were implemented with success to produce shale gas in the Barnett. However, the increasing prices in the early 2000s made it easier to justify experimenting with different ways of fracturing and various mixes of fracturing fluid. Similarly, higher oil prices in the 1970s and 1980s made it easier for companies to spend large sums of capital to pursue deepwater projects in the North Sea and Gulf of Mexico.
    - Overall, it would be difficult to conclude that upstream costs have been increasing solely because we have been moving down the resource pyramid; this assertion would likely have the causality backward. In a competitive upstream industry with individual mineral rights ownership, it is not surprising that smaller companies developed unconventional resources when the price (reflecting cost and premium) increased high enough.

- The amount of high quality resource that is not accessible is difficult to know because credible estimates cannot be generated if geologic and production data are not available. Some analysts such as Simmons (2005) raised legitimate questions about the reserves estimate of Saudi Arabia and, more importantly, about the peak production potential and eventual decline rate. But, until the nationalization of the oil and gas industry in the late 1960s, IOCs had produced a lot of oil from the Kingdom and developed a good understanding of the geology. As a result, Saudi reserves are probably much better understood than most other regions around the world, where the history of drilling is either short and limited or non-existent. Still, even ignoring these "frontier resources", there is significant resource potential not only in Saudi Arabia but also Venezuela, Mexico, Bolivia, Iraq, Libya, Siberia, Arctic and deepwater regions around the world that currently cannot be developed because either the governments are restricting access or logistical challenges are preventing development.[22]

Accordingly, at the end of analyzing these criteria, if one believes that resources are in general available and that access will eventually be provided to many resource-rich locations or economic growth will justify development of resources in previously low demand regions, we end up with ***a different supply curve: discontinuous and shifting over time***.

Lee (2014) offers a supply curve based on breakeven price for a large number of fields that are already producing or expected to be online by 2020 (slide 57 of the presentation). Although the curve represents both oil and gas projects (i.e., supplies are in barrels of oil equivalent, or BOE), it is the usual upward sloping supply curve, albeit probably not as steep a curve as imminent exhaustion of resources would imply. These fields will provide the incremental volumes that global oil and gas markets will demand and possibly more. This exercise of building a supply curve based on the costs of ongoing or recent projects is useful for the modeling logic and should result naturally from the recommended effort of developing a projects database.

Resource Representation

The Petroleum Resources Management System (PRMS) developed by several professional associations[23] can be the foundation for resource and reserve classification (Figure 8, left panel). SPE (2011) provides a detailed description of the system and guidelines on how to apply it. There are challenges in applying PRMS to unconventional resources; SPE (2011) offers recommendations on how to classify unconventional resources and reserves but this is an evolving area.[24] Also, around the world, somewhat

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[22] Logistical challenges could mean that you are moving down the resource pyramid. But the point here is more subtle: resource is of high quality (e.g., conventional light sweet crude) but producers cannot access it. This is different than moving down the pyramid to lower quality resource.

[23] Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE) and Society of Exploration Geophysicists (SEG).

[24] A consensus seems to be emerging as many experts in a panel on unconventional reserve estimation at URTeC 2014 agreed on principles of decline curves, at least for gas. With unconventional resources the risk of hydrocarbon presence and, to a certain extent, geologic uncertainty about the size of the resource, have been greatly reduced across a fairly well defined play area. The economics is the key question regarding the identification of "reserves" beyond the existing wells, whose reserves can be classified as proved. Definitions used for conventional 2P and 3P reserves and contingent resources might be too restrictive for unconventional plays.

different classifications are used even for conventional resources, for which SPE (2005) provides a mapping to PRMS.

Project maturity is useful to keep track of the evolution of reserves and resources (Figure 8, right panel). For reserves, the fields already in production and those that are approved for development can be modeled on the basis of decline curves to form the "base" forecast of production. The model should allow for technology improvements that could lead to lower well costs and/or higher EUR. Projects justified for development might also be forecasted as part of the base. Projects should be classified in this category only temporarily for the period of finalizing partner agreements and/or the final development plan before the final investment decision (FID). The PRMS recommends to limit this period to five years, i.e., if a project does not go to FID within five years, it can be dropped to contingent resources category.

Contingent resources are those with a negative NPV (for best estimate, 2C) and/or with unresolved contingencies. But 2C resources might be larger than reserves justified for development; and commercialization of technology in development, price, fiscal terms, and/or resolution of some contingency might allow for development in the near future. Projects classified as "development pending" must be undergoing advanced technical evaluation such as development concept design or subject to some non-technical issues such as relatively minor contract negotiations or environmental impact assessment. Typically, these projects would have a high chance of commerciality. When non-technical contingencies (legal, regulatory, geopolitical) are more serious and beyond the control or influence of developers, projects should be classified as "on hold." If the evaluation is not advanced and/or contingencies are not well defined, the project should be classified as "unclarified." Projects that are not pursued any longer because they have a low chance of commerciality should be considered "not viable."

Prospective resources are estimated probabilistically following the PRMS guidelines for (a) chance of discovery, which is typically assessed as the product of probabilities for having the right geologic conditions (source, trap, porosity, permeability, and so on),[25] and (b) chance of commerciality, which is defined as the probability of a positive NPV at the hurdle rate.

The NPV will be based on a cash flow model using a stochastic distribution for the size of the discovery. The common practice is to use "risked mean," which is the mean of the resource distribution that is commercial. Prospective resources are not usually reported by companies although governments may provide some estimates in order to attract investment. This is the category that requires most in-depth research and due diligence to balance two competing tendencies: being too conservative versus being too bullish. Historically, the resource estimation has been on the low side as evidenced by continuous ability of the industry to prove up more resources even in mature regions as prices justify experimenting with technologies that avail resources formally thought "not viable" or "unrecoverable."

Once a discovery is made, resources are moved to contingent resources. A discovery requires that there is at least one well drilled, providing some data on the existence of "significant quantity of potentially moveable hydrocarbons." The evaluation of the resource can be conducted via deterministic or probabilistic methods:

[25] This is sometimes called the geologic chance of success or adequacy.

- The volumetric approach calculates the initial hydrocarbon volumes in place as a function of the area (A), net pay zone thickness (h), porosity (ϕ), initial water saturation (S_{wi}) and hydrocarbon formation volume factor (B_{hi}): $IIP=Ah\phi(1-S_{wi})/B_{hi}$. This method is most useful in the early stages of a project when information is more limited than in later stages (Figure 9 from SPE, 2011).

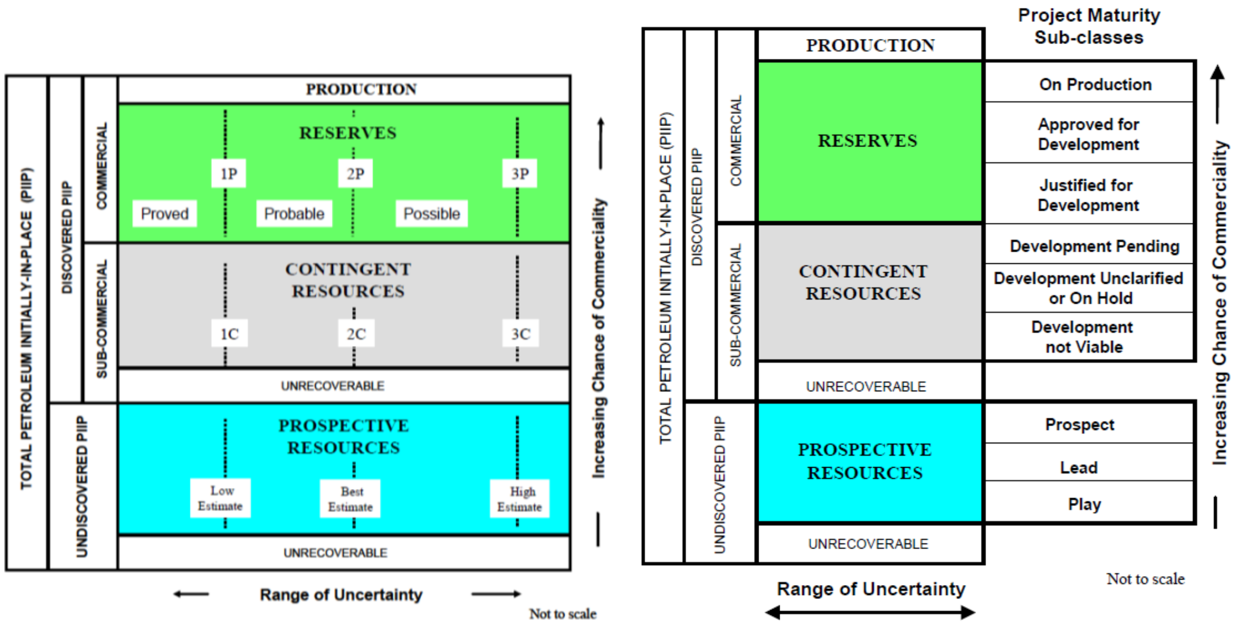

***Figure 8*. Resource and reserves definitions in the Petroleum Resources Management System**

- The material balance method uses performance data such as production history and profile, reservoir pressure and temperature, and fluid and rock properties to calculate IIP. This method can yield better results after some history of production as indicated in Figure 9.

- Reservoir simulation requires both geologic and production data as described in the first two bullets to build a model and calibrate it via a multidisciplinary team.

- Decline curve analysis is the most popular production performance test tool. It often relies on the hyperbolic equation (Arps, 1945) with two key variables: initial decline rate (D_i) and decline exponent (b). There are established b factors for conventional flows, where b lies between 0 (exponential decline) and 1 (harmonic decline). For unconventional plays, harmonic decline with a b value greater than 1 is often used. Alternatively, the decline can be modeled proportional to $1/\sqrt{t}$ for several years, after which hyperbolic or exponential decline takes over.[26]

Conventional field production lasts longer, and might have a plateau (can be sustained longer via lower production for strategic, geologic or economic reasons). Additional drilling or enhanced recovery could add EUR and lengthen life. Unconventional field production requires continuous drilling, has faster decline rates. Enhanced recovery of unconventional resources via refracturing or other methods is not yet proven sufficiently although the potential is large given the low recovery factor of original resource in place with current methods. Production also reduces uncertainty around the reserve estimate; Figure

[26] For example, see Patzek et al. (2013).

9 depicts an idealized example because in reality, the best estimate can change over time with more information and updated analysis. Figure 10 and Figure 11 convert the PRMS structure into organograms similar to the ones used in INTEK and Resource Consultants (2006).

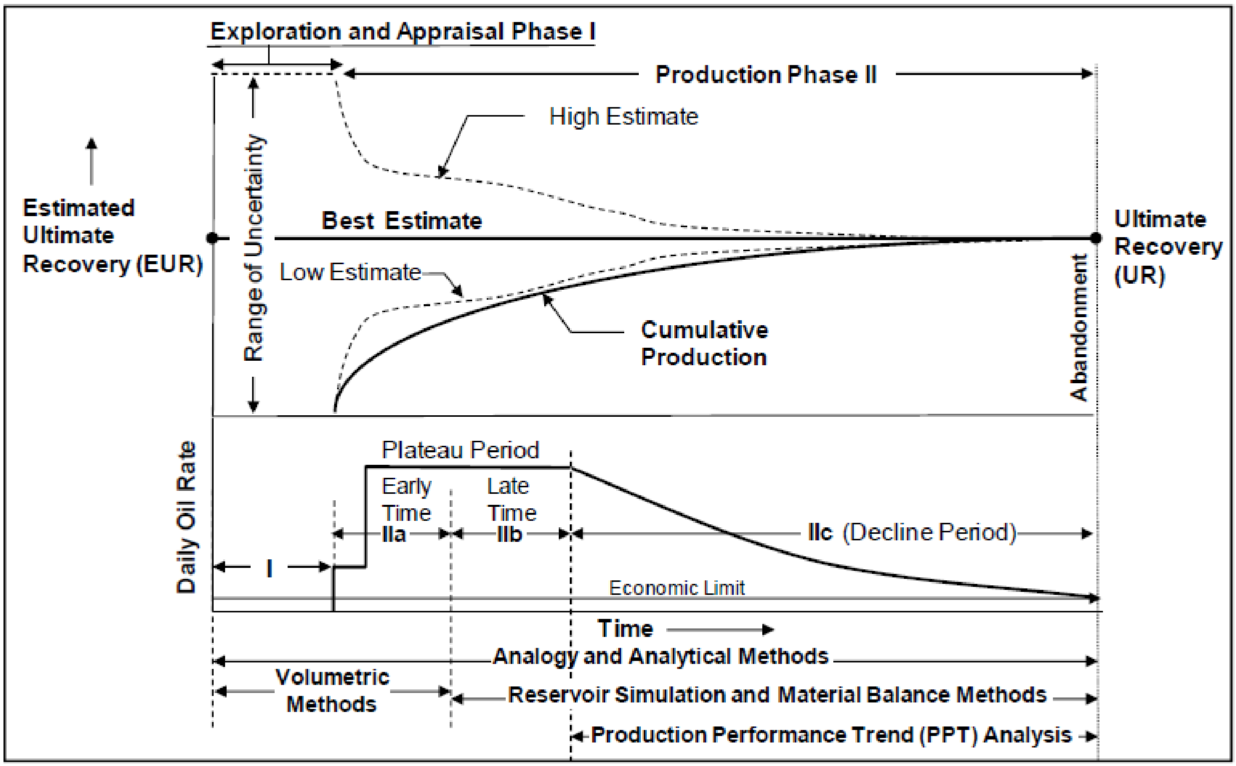

Figure 9. **Cone of uncertainty and assessment methods over the project life**

With these resource classifications, the following scenarios could be run with the model:

1- Reference: Reserves (All) + Contingent Resources (Development Pending)

2- Low Resources: Reserves (on production + approved for development)

3- High Resources: Reserves + Contingent Resources (except for projects classified as “not viable”)

4- Super High Resources: Reserves + Contingent Resources + Best Estimate Prospective Resources + Unrecoverable

The Low Resources case is provides a low boundary but it is probably too conservative. The decline curves should be subjected to technology improvement, and enhanced recovery should be allowed. The Reference case is conservative from a long-term perspective but probably realistic for the next 10-15 years. The High Resources scenario is realistic in a 30-year or longer timeframe. Faster demand growth can encourage earlier development of contingent resources. I would encourage using the Super High Resources scenario to test prospective resources beyond usual suspects and what is currently considered unrecoverable within the discovered IIP. This wider scope is particularly needed when considering deepwater, Arctic and unconventional opportunities not to mention resources that have traditionally been considered “landlocked” but might be viable in the future as local economies grow (unless these are already captured in contingent resources).

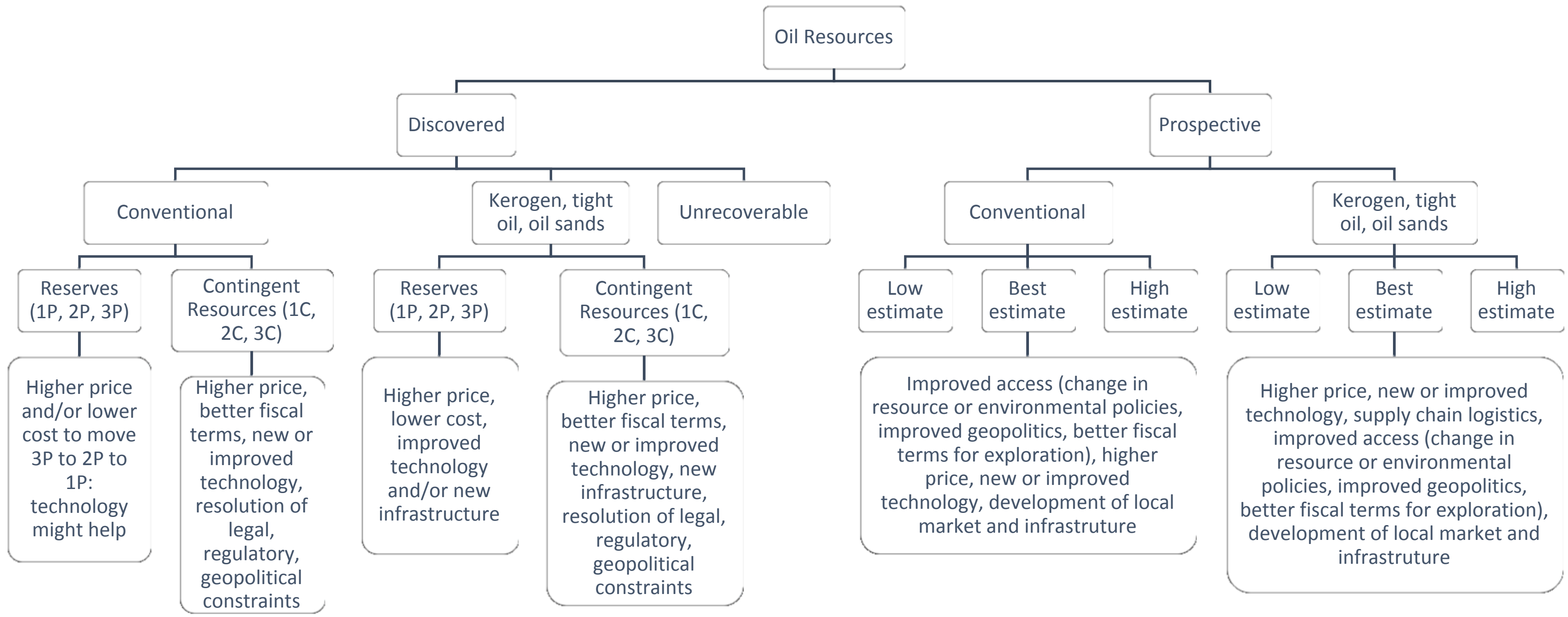

***Figure 10*. Oil resources/reserves classifications and the associated uncertainties to be captured in the modeling exercise.**

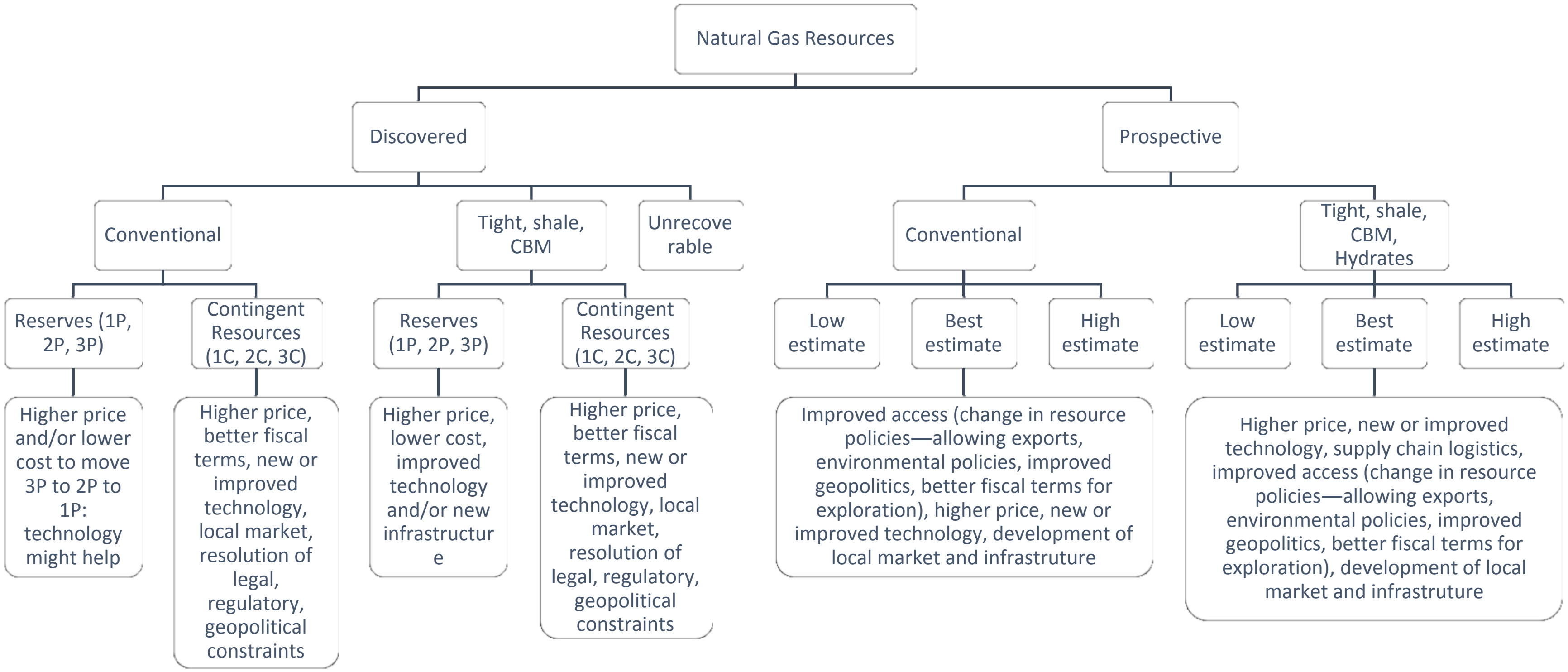

***Figure 11*. Natural gas resources/reserves classifications and the associated uncertainties to be captured in the modeling exercise.**

Role of technology

Technology improvement is an important driver of resource development. In the literature, technology captures various impacts such as increasing production or EUR from existing wells or fields, reducing cost of operation and allowing access to new resource plays. There is also a distinction between constant technological enhancement (flowing from routine research and development) and breakthrough technologies. For example, in shale plays, the improvements appear to be significant in early years but very limited in later years. From the perspective of resource classification, the movement across different categories matter.

In Table 1, a possible classification of different technologies across a 2x2 matrix is provided. Technology improvement that reduces well costs (quadrant I) can help re-classify not viable contingent resources as development pending or on hold depending on non-technical contingencies. The re-categorization of contingent resources into reserves may depend on commercialization of technology under development, which is proven in analogous locations (quadrant II). If technology is not yet proven resources should be classified as unrecoverable but note that these resources can then be turned into prospective or contingent resources if there is a new technology (quadrant III and IV). These considerations are important to classify the fields in the database and estimate their decline curves with the potential for enhancing EUR.

Scenario analysis could help test some of these differences in impacts and their significance, and whether the model might have to differentiate between gradual improvement in production rate and/or cost because of application of new technology or better use of existing technology. The former can presumably be captured from historical data as a percent per year (and might be different for deepwater, unconventional, onshore conventional resources as well as across regions and/or operators). The latter might have to be structured as a stochastic variable, based on historical analysis of how many times a "step change" in production levels can be attributed to application of new technology.

	Well cost decline	**New resources made available**
Technology improvement	I. Pad drilling; lower spacing; fracturing fluid mix; "walking" rigs	II. 1990s-2000s: Hydraulic fracturing and horizontal drilling for unconventional, play to play expansion
Technology revolution	III. Digital technology for remote sensing and control; imaging data	IV. 1970s-1980s: Horizontal drilling, 3-D seismic for conventional; platforms to allow drilling in deeper waters

***Table 1*. A possible classification of some upstream technologies**

INTEK & Resource Consultants (2006) offers four different market penetration profiles for new technology. Although the justification of the functional forms and assumptions is not clear, a bigger concern is that the overall approach, regardless of the profile, implies an orderly, routine process of technology development, implementation and enhancement. This assumption might be supported if we are trying to capture "routine well cost improvement" as discussed in the previous paragraph; but it does not seem to apply to major breakthroughs such as the perfect combination of hydraulic fracturing, horizontal drilling and "slick" water that led to the shale boom, which seem to be more random and "lumpy". On page 56 of the report, an example is provided with assumptions such as five years to develop a particular technology, six years to commercialize it and so on. These assumptions do not appear sound. At the least, some background research on actual pace of developing and commercializing technologies that had a material impact on EUR or costs is necessary. Service companies such as Schlumberger, Halliburton, Baker Hughes and others conduct such analyses for their commercial purposes and might be approached to share some data and expertise in order to develop a realistic representation of technology in the model.

Also, annual technology improvement that lowers cost have to be balanced against cost inflation. In Figure 12, upstream cost indexes for both capital and operating costs are shown. There seems to be a secular upward trend since the early 2000s. Questions of interest include: Does cost inflation make technology development and/or implementation easier / cheaper or more difficult / expensive? If there is already routine R&D investment, would higher cost not make it easier to implement new technology (unless price does not increase as high as the cost)? How long high cost / price should last before revolutionary technologies can bring contingent and/or undiscovered resources to the market?

While considering these questions, it is useful to keep in mind that technology implementation might have some unintended or counterintuitive impacts as well, especially over the longer term. For example, pad drilling, lower spacing and zipper fracking appear to provide economic benefits to shale producers by increasing production from a given area in the short-term. But, it is possible that total recovery might be lower in the long-term if, for example, these practices reduce pore spaces.

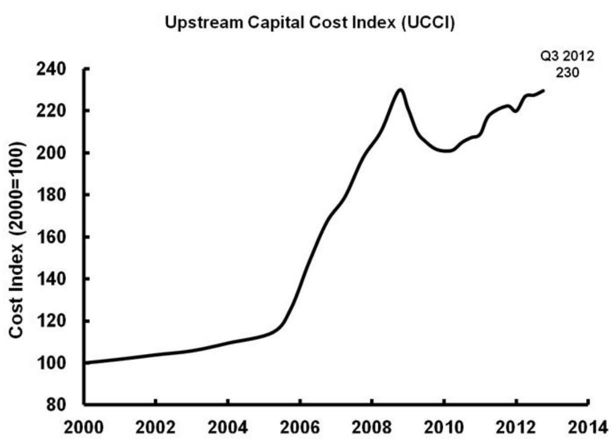

***Figure 12*. Upstream cost indexes from IHS.**

According to EIA (2013b), the INGM appears to use a cost scalar that balances "increases in asset/production costs and technological improvement." Although this approach does what was recommended above in terms of cost inflation, it is somewhat simplistic as it seems to be applied uniformly across different assets. In contrast, INTEK and Resource Consultants (2006) distinguishes between the technology levers that impact production, which are applied to the production curves, and the economic levers, which are applied to the cash flow analysis. A note of caution seems warranted: routine investments such as drilling an additional well would also increase production from an existing field beyond the level allowed by the original facilities design. It is not clear how such investments would be distinguished from production increase that is due to new technology. Similarly, project economics can be improved, especially in the early days of field development (and especially for new types of resources such as shale) because operators optimize their production systems to reduce costs.

Production decisions

Generally speaking, most companies pursuing upstream projects make investment evaluations with a long-term view, often using an internal price forecast that is distinct from forward curves from organized exchanges or over-the-counter markets.[27] This approach is particularly relevant for oil projects. Often, a company's internal price deck can be more conservative because the company wants to have a high level of certainty about the project's viability. But, as discussed before, there are exceptions when investment decisions are taken with a strategic purpose.

Most upstream investment (in particular, large conventional projects) is lumpy. Since it takes several years to bring a project online, there cannot be any price certainty (unless a long-term contract is signed for the gas off-taker but such contracts are less likely for oil) or reacting to price signals in the conventional sense. It might be worthwhile talking to big companies regarding their decision-making, keeping in mind that there will be differences between IOCs, NOCs and independents. Some distinctions are offered in Table 2 in terms of weighted average cost of capital (WACC), or hurdle rate, and risk premium; and Table 3 in terms of interests, preferences and capacities of different companies across onshore and offshore opportunities of various sizes.

Producer	WACC	Risk Premium
IOC	8-20%	0-10%
Independent	5-15%	0-5%
Internationally active NOC	0-10%	0%
Domestic NOC	0%	0%

***Table 2*. Indicative differences across four different types of upstream players**

These observations are indicative of relative perspectives of different companies and are not intended as absolute values or ranges; different companies within each category can have different criteria for different projects. With this caveat, IOCs are likely to have higher hurdle rates than NOCs and even most of the independents. Internationally active NOCs are often trying to secure resources for their home countries and they are not publicly traded for the most part. Smaller independents might be similar to some of the NOCs in their assessment of riskiness of opportunities. As shown in Table 3, most NOCs and independents are capacity constrained when it comes to larger opportunities, especially offshore. These constraints include the capacity to raise capital at attractive interest rates and/or to use their own equity, the competency with and/or access to certain technologies, and management of large, complex projects. As such, they may have to go with riskier projects and hence do not have the luxury to assign high risk premiums and/or to require very high returns.

Each project has to be evaluated on its individual characteristics. Preferences, capabilities and investment environments change over time. For example, over the years, IOCs gradually lowered the field size threshold from half a billion barrels to about 200 million barrels as larger opportunities were made unavailable by resource owners or geopolitical constraints. Over the same time period, some

[27] Slaughter (2014) observes that "price assumptions for investment are not always identical to market price as revealed by forward strip."

independents grew in size and capabilities as did some of the NOCs. Hence, it is almost guaranteed that the boundaries and interests depicted in Table 3 will change.

ONSHORE	Expected Reserves (million barrels)		
	<200	200-500	>500
IOC	Not Interested	Interested	Prime Target
Independent	Prime Target	Target	Capacity constrained
International NOC	Target	Prime Target	Capacity constrained
Domestic NOC	Some Capable	Capacity constrained	Not Capable

OFFSHORE	Expected Reserves (million barrels)		
	<200	200-500	>500
IOC	Not Interested	Interested	Prime Target
Independent	Target	Interested	Capacity constrained
International NOC	Target	Only a few	Only a few
Domestic NOC	Some Capable	Not Capable	Not Capable

***Table 3*. Indicative interests and capabilities of different types of upstream players**

Upstream bidding rounds at different countries could provide useful information with respect to different companies' interests as well as fiscal terms. Based on historical analogues and current market conditions, the modelers might be able to predict which of the blocks will be developed within what time frame after the bid round. At this stage, strategic investments can be captured via a lower hurdle rate and/or lower risk premium.

As discussed before, upstream-midstream boundaries can be blurred. In many cases, especially for gas, pipelines, processing and/or liquefaction will be necessary to deliver the resource to the market. In many of these cases, investment in these logistics projects should be considered as part of the overall resource development cost. Also, in some cases, state company might want to control the midstream investment (e.g., CPC pipeline), or the governments might pursue strategic pipelines such as Blue Stream, Nord Stream, and B2B pipeline.

Objectives

Most companies invest with the objective of maximizing returns. The internal rate of return of a project must be greater than the hurdle rate of the investing company. Although this requirement is probably not debatable for private companies, national companies may have different objectives. Even some of the private companies may pursue certain projects for strategic reasons. However, these differences can be captured via hurdle rates, risk premiums (Table 2) and constraints (Table 3 for some) once the model is built around maximizing net present value (NPV):[28]

$$NPV = \sum_{t=0}^{n} \frac{NCF_t}{(1 + WACC)^t}$$

For publicly traded companies, another consideration as a condition for development could be reserves replacement. The financial market expects more than 100% of production to be replaced in the form of new reserves on an annual basis. For upstream companies, especially for non-integrated independents,

[28] The INGM model is structured as a linear optimization problem with the cost minimization objective. Costs are defined as the negative of discounted net cash flows at the producer level.

reserves are their main assets. Note, however, that not all of the new reserves have to come from new development; they could be acquired or proved reserves in existing fields can increase owing to technological improvements and/or price increases.

For NOCs, the objective function can be different. They may be adjusting production from existing fields and investing in new field development with the objective of achieving a target revenue, which might be based on meeting overall government budget or simply the current account outflows (see discussion in the Supply section). For NOCs from countries with either no or insufficient resources to meet domestic demand, the objective could be securing of supplies.

Cash flow model

In order to compare projects of different duration for the CAPEX period (especially when midstream investments are included), it might be desirable to calculate NCF_0 up to the period of first production, q. Private companies might pursue this approach to rank projects in their annual capital allocation process. However, this consideration might not be that relevant in the global competition context. For large companies, a background modeling could involve the internal ranking of projects subject to company annual budgets.[29]

$$NCF_0 = \sum_{t=0}^{q} CAPEX_t (1 + WACC)^t$$

Otherwise, for any time period of production, the net cash flow can be calculated as follows:

$$NCF=PQ-Roy-Qtax-OPEX-CAPEX-Itax$$

Where PQ is the product sum of revenues from various hydrocarbons in the production stream (for any time period):

$$PQ = \sum_{c=1}^{m} p_c \times q_c$$

Where c represents hydrocarbons ranging from methane (one carbon atom) to bitumen (above 35 carbon atoms). However, in any given field, m does not need to be higher than 4 or 5 (oil, gas, C2, C3-C4, and C5+). A shrinkage factor is often used to calculate the amount of liquids from wet gas production; this factor is proportional to heat (Btu) content of the produced wet gas. There are generalized ratios for C2-C5+ depending on the Btu content of the stream; analogues will provide this information. Some production streams will be simpler (e.g., mostly methane in dry gas fields) and others more complex (e.g., methane through condensate in wet gas fields). Note, however, that revenues should only be counted if the products can be delivered to the market. Flared or vented associated gas has no value; the gas used as fuel at the field might have the value of avoided fuel expenses. Similarly, prices should be adjusted to what is received at the wellhead. For example, ethane left in the methane stream for pipelines should be valued at the price of natural gas. These prices will show regional variations owing to infrastructure bottlenecks as well as regulations and subsidies.

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[29] On page 27 of EIA (2013b), minimum acceptable supply price assumes all investment costs occurring in the first year of production. This assumption should not be applied to large field developments, especially offshore and/or if significant midstream investment is necessary to deliver the gas to the market. Such investments will take several years before a single molecule of gas can be produced.

The production profile (values for q_c at each time period) is based on one of the PRMS methodologies discussed earlier. The most straightforward option is probably the DCA approach.

Roy=PQr, where r is the royalty rate. Royalty rate can be based on a sliding scale, i.e., different rates for different levels of production. There could also be distinct royalty rates for different products. For example, governments could offer lower rates for methane and gas liquids if they desire to monetize those assets and/or use them to develop local industries.

Qtax=(PQ-Roy)t_q, where t_q is the effective production tax rate. Not all jurisdictions have this tax but it is common in most resource-rich countries and production sharing agreements.

In Figure 13, a summary of cost data needs is provided. It is modified from the graphic in INTEK and Resource Consultants (2006) to include (1) midstream investment that might be necessary to monetize oil and gas resources in the capital cost structure and (2) fiscal regime terms to reflect international conditions. A lot of the data used in detailed calculations of individual elements from the graphic described in pages 17 through 22 came from the EIA in addition to American Petroleum Institute's Joint Association Survey on Drilling Costs, SPE and Gas Technology Institute (GTI) publications. Although not as detailed as the INGM approach, a lot of these cost calculations might be too granular (e.g., separate treatment of water handling plant and water injection plant). In both cases, reasonable aggregation of some of these costs should be possible and certainly necessary for many international locations because of lack of data. In the spreadsheet provided together with this report and following discussion, some of these simplifications are provided.

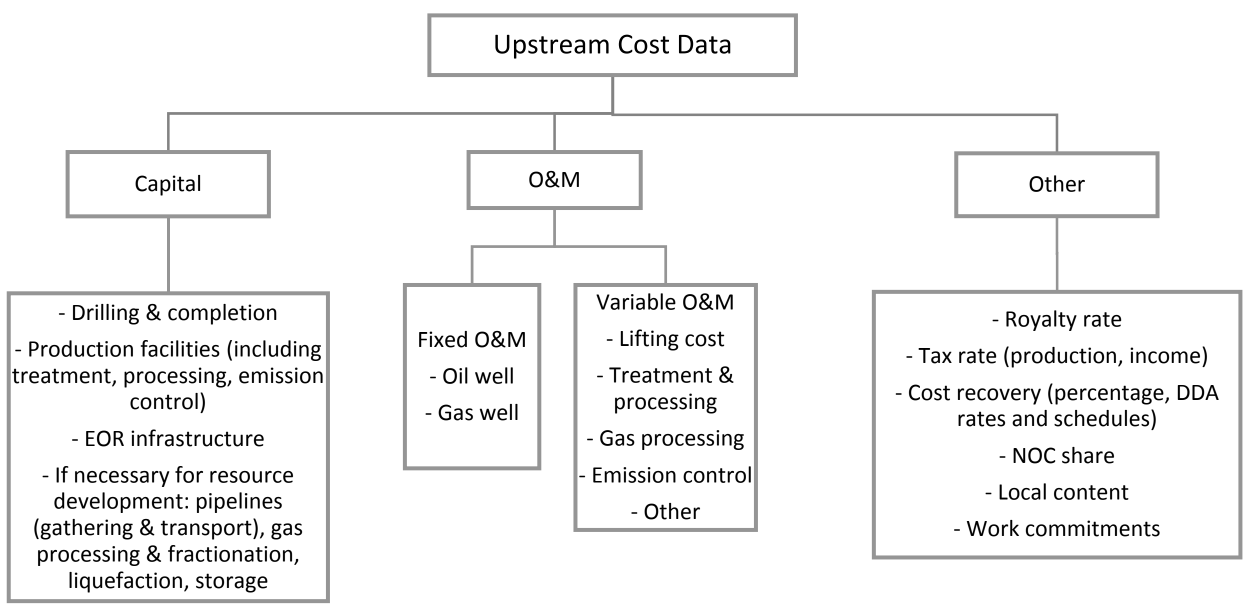

***Figure 13*. Cost data requirements.**

OPEX=(fixOPEX+varOPEX)(1+OPEXesc-OPEXtechimp)+G&A+transport.

Fixed OPEX represents the expenses necessary to operate the type and size of production facilities built and can be estimated as a percentage of CAPEX using analogues. Variable OPEX will change with the level of production and hydrocarbons being produced. It can be represented as a per barrel item.

It is often recommended to add a contingency in the range of 5% to 15% to allow for changes in facilities design and/or delays. Note that this is different from cost escalation, OPEXesc. However, technology improvement can counter some of this cost escalation, OPEXtechimp. These rates can be based on general industry trends and analogues but should be adjusted to individual projects to account for regional differences.

General and administrative (G&A) expenses are those costs associated with head office overhead and management. They can be captured as a percentage of OPEX. Transport costs should capture all types of hydrocarbons shipped to markets from the field. With simpler production streams, it could be easier to reflect the transport cost of oil or methane in the wellhead price as netback.

CAPEX=(tanCAPEX+intanCAPEX)(1+CAPEXesc-CAPEXtechimp)+midCAPEX(1+midCAPEXesc-midCAPEXtechimp)

CAPEX should be distinguished between tangible costs such as drilling and completion that are depreciated and intangible costs such as non-salvageable expenses incurred during the preparation of a production site. Intangible costs can be amortized or can be deducted from taxable income. Analogues can be used to assign the tangible-intangible split, often about 80-20.

As with OPEX, contingency, cost escalation and technology improvement should be captured. Between the initial evaluation of an upstream opportunity to actual production, anywhere from two to nine years can pass.[30] This time period is long enough to experience potentially significant increases in CAPEX (and in certain time periods, perhaps even some decline). In contrast, substantial technology improvement is not very likely within several years but CAPEXtechimp is an important variable to apply to future fields as their CAPEX is built from analogues of today or recent past.

In addition to upstream capital investment, as discussed throughout this report, the development of certain resources will require investment in transport pipelines, liquefaction, processing, upgrading, storage, or other midstream facilities.[31] This midCAPEX should be included in the CAPEX for the upstream project subject to its own cost escalation and technology improvement rates, which can be the same as the CAPEXesc and CAPEXtechimp.

Itax=[PQ(1-r)(1-t_q)-Bonuses-OPEX-Amor(intanCAPEX)-Dep(tanCAPEX)-Depletion-Other]t_i, where t_i is the effective income tax rate. Note however that this equation is a generalized representation. Fiscal terms applicable to each project have to be captured. There are several important considerations.

- As mentioned before, royalties might be based on a sliding scale and rates might differ for oil, gas and liquids.
- Deductible cost items might differ.
- Depletion, depreciation and amortization rates and schedules can be different.

[30] With unconventional resources in the U.S., this timeline is now more condensed but is still relevant for international unconventional opportunities for reasons discussed elsewhere in this report (e.g., the constraints associated with supply chain logistics).
[31] The cost of pipelines, processing, upgrading, storage or other activities handled at the field level as part of the original production facilities design should be included in the upstream CAPEX and treated as tangible or intangible as appropriate.

- Cost recovery percentages used to calculate cost oil will differ and can be tranched relative to production or gross revenue. Costs not recovered in the year they were incurred can be allowed to be carried forward or not.
- The IOC-NOC split of profit oil will be different.

This list is not meant to be exhaustive but covers most of the factors that could have a significant impact on the project viability.

Input/Output requirements

A field-level database is needed and a structure is proposed in the accompanying spreadsheet. For resource data, INTEK and Resource Consultants (2006) rely on petrophysical and geological characteristics for conventional plays (Figure 14). It is not likely that good quality geologic data will be found on many of the resources around the world. Nevertheless, this list can be useful when some due diligence might be necessary on available resource estimates, especially on volumetrics. Some of these data might be available in the literature or via industry contacts. The fields can be prioritized to focus on those resources that are largest and more likely to be developed within the timeframe of study.[32]

Original Volumetrics

- Original-Oil-In-Place
- Reservoir Area
- Net Thickness
- Porosity
- Average Initial Water Saturation
- Average Initial Oil Saturation
- Average Initial Gas Saturation
- Average Formation Volume Factor

Current Volumetrics

- Current Oil Saturation (Swept Zone)
- Current Oil Formation Volume Factor

Development and Performance Data

- Recovery Efficiency
- Well Spacing

Geologic Data

- Lithology
- Depth
- Temperature
- Original and Current Pressure
- Permeability
- Gross Thickness
- Dip Angle
- Geologic Age Code
- Geologic Play, Depositional System, Trap Type

Fluid Data

- Average Oil Gravity and Viscosity
- Initial GOR
- Current GOR
- Gas Impurities

***Figure 14*. Geologic data to calculate resources**

The EIA's 2013 report on global unconventional resources is a good starting point but it should be supplemented by data from other sources as discussed above. Since 2005, a large number of wells have been drilled in many shale plays and understanding of unconventional plays have significantly improved with significant research taking place within the companies, a lot of which is shared in the professional literature, and across universities.[33] A multivariate statistical analysis of data from multiple shale plays

[32] McGlade (2014) reports modeling 7,000 fields, giving a good indication of the scope of global oil and gas supply. Still, as seen in Figure 7, reserve replacement happen usually beyond expectations of many. This underestimation is primarily due to modeling efforts or scenario analyses not capturing "frontier resources" or simply being too conservative about technology development or a combination of these and other factors.

[33] Bureau of Economic Geology has been conducting an interdisciplinary assessment of major shale gas and oil plays since 2011.

could provide a more robust approach to predicting production and resources. The U.S. data can be used as analogues for international shale plays but with caution as there is significant variability across and within plays. Collaboration with local experts and companies drilling wells in those locations should be pursued to fine tune the use of analogues.

INTEK and Resource Consultants (2006) offer a detailed list of development constraint data needs with suggested data sources. Rig capacity, rig utilization and retirement rates and rig mobilization are key determinants how many feet of drilling can be realized. In the international space and especially for unconventional resource development, this type of "supply chain logistics" constraints will be of utmost importance. In the U.S., Baker Hughes can be a convenient source for data but internationally other data sources might be needed; other service companies and vendors of various equipment (not just rigs) could be pursued. For example, Rigzone might be a better source for international rig activity as well as other equipment. Oil and Gas Journal database and research services, World Oil, Upstream are all worth investigating. IHS, WoodMac, Rystad and perhaps some local consultancies at different regions can help fill any knowledge gap or conduct some reality-checking. In addition to resource potential, fiscal terms will determine where on the supply curve a particular field should be placed. AIPN, Van Meurs Corporation, Daniel Johnston & Co.[34] could be good sources of information and expertise on fiscal regimes.

The OLOGSS employs "play" as the unit of analysis for discovered resources and "accumulation/cell" distribution at the play level for undiscovered resources primarily based on data availability on a regular basis. In contrast, the INGM seems to be using "field" as their assessment unit (EIA, 2013b). Both models are based on primarily, if not solely, on the USGS data. As a global model, the INGM's focus on the field rather than cell can be explained by the lack of data at the cell level in many locations around the world. The choice of a play instead of a field for the OLOGSS appears to be the ability to expand production from a known province. Again, geologic data and analysis might not be as readily available or of high enough quality at the global scale for the INGM to focus on plays; fields, in contrast, are known producing units with presumably more data on them.[35] However, in order to capture as accurately as possible the potential production from unconventional plays, which are quite heterogeneous in terms of productivity, a cell-level approach is highly desirable subject to availability of data.[36]

The USGS has been the first choice for resource data for good reasons. The data and analysis by USGS scientists have been reliable and publicly available. Yet, a global modeling effort would benefit from (a) due diligence on track record of USGS estimates (how accurate have their estimates, especially for

[34] www.vanmeurs.org and www.danieljohnston.com.

[35] There seems to be some ad-hoc adjustments to the number of fields in order to match the resource since the average values used for a field were not sufficient (p. 23). This is probably an artifact of data limitations but the feasibility of improving on this approach should be investigated.

[36] USGS employs a quarter for a square mile for a cell according to INTEK and Resource Consultants (2006). This level of granularity might be unnecessary for most conventional resources and impractical for unconventional resources and most international locations in general. Similarly, bin classification approach (p. 10) might not be applicable for many international locations and for unconventional resources.

international resources, been? Has there been a systematic bias?)[37] and (b) investigation of alternative sources of data.

For example, in the U.S., the Potential Gas Committee (PGC) offers a valuable product every two years, not necessarily as an alternative to USGS but as a complement since it captures expertise from various stakeholder groups. Internationally, bidding rounds for upstream development should be tracked to reality check the data. Collaborations with the IEA, the JODI initiative,[38] regional or national entities in Russia, China, Australia and others could be useful. For significant regions or countries, IOCs and NOCs should be approached for data and/or expertise. Shell, ExxonMobil and BP have been conducting global energy modeling and/or scenario analysis for years and with offices in many countries have access to local experts, government statistical agencies and knowledge. The Society of Petroleum Engineers (SPE), their local affiliates around the world, vast SPE literature, the AAPG and other professional organizations in geosciences from around the world can also serve as resources along with their literature. The World Bank and IMF work in many countries where resource development is a major part of the economy and countries where it can be significant going forward (e.g., Tanzania, Mozambique). Even though these entities are not likely to have detailed data on resources, they will have data and knowledge on fiscal systems, political stability, existence of infrastructure, and the health of the economy, all of which will contribute to the ability of countries to develop their oil and gas resources. The Bank's research on NOCs can also be helpful.[39]

Conclusions and recommendations for the Upstream Module

On the basis of the discussion provided throughout this document, I recommend modeling the upstream on the basis of following guidelines. A possible model flow is depicted in , which is adapted from INTEK and Resource Consultants (2006) to fit the PRMS-based approach.

- Develop a field-level projects and resource database.[40] An example structure for such a database with the recommended data fields are provided in an accompanying spreadsheet. The Production Decisions section above presents the cash flow equations incorporating the criteria from this spreadsheet.
- PRMS project maturity classifications for Reserves, Contingent Resources, and Prospective Resources should be followed because they provide an established process and are used by the Securities Exchange Commission and other regulators around the world. There is also documentation on how to map at least some of the other classifications to PRMS.

[37] For example, because of data limitations, a consistently conservative approach might have been pursued. An analysis of resource estimates for fields that went through stages of development over the years would be informative.

[38] Joint Organizations Data Initiative (JODI) has evolved from the early 2000s' effort to increase transparency in global oil data. It now covers both oil and gas in more than 100 countries. In addition to the IEA, Asia Pacific Economic Cooperation (APEC) Energy Working Group, Gas Exporting Countries Forum, Eurostat, International Energy Forum, OLADE, OPEC and UN Statistics Division are partners.

[39] Bureau of Economic Geology's Center for Energy Economics collaborated with the World Bank to produce a couple of reports on 40+ NOCs. These reports and other World Bank NOC studies can be found at http://go.worldbank.org/UOQSWUQ6P0.

[40] The EIA appears to have and maintain a similar database for the OLOGSS model.

- There are two layers of research and modeling:
    - Background research, calculations and/or modeling to identify production stream (composition of hydrocarbons), various cost items along with relevant fiscal terms, reserves and resource estimation via decline curve analysis and/or other deterministic or probabilistic methods,[41] and other necessary assessments to complete the database.
    - A global supply model that would be simplified owing to the database. The model should be driven by the objectives and constraints of a few different types of producers. Four groups are recommended: IOCs, Independents, International NOCs, and Domestic NOCs.
- Unconventional resources need separate treatment for a variety of reasons. Resource estimation might require a slightly different approach. Logistics requirement and cost structures are often more complicated for the unconventional resources. Governments may develop different fiscal terms for unconventional plays.
- Fields on production and approved for development (from PRMS project maturity for Reserves) should form the "base production" following the decline curve analysis realizing differences between conventional and unconventional fields (Figure 15). The economics of enhanced recovery from fields that reach their economic limit in a given year are subjected to competition with other resources.
- The probability of moving forward with contingent resources and reserves justified for development should be based on background research on the resolution of identified obstacles and contingencies.
    - Reserves justified for development may be treated as "base" along with on production and approved for development or may be subjected to competition with contingent resources for the cases where the latter is significantly larger and close to development.
- Prospective resources are to be evaluated using the criteria discussed in the report: chance of discovery and chance of commerciality.
- All these projects are ranked by NPV but to distinguish among projects with similar NPVs additional criteria such as IRR, PWP, PWI, and reserves add can be used.
- Resources come online from top down to meet the gap between demand and reserves production forecasts. Note, however, that most upstream investment decisions are made years before the first production date. A fall in the price at that time will not stop the project; the production will still start. The drop in price might lead to shutting in some older production (e.g., economic limit is reached sooner at lower prices).

[41] PRMS outlines many of these methods and should be the starting point but the literature should be followed for updates or improvements to these methodologies, especially for unconventional resources.

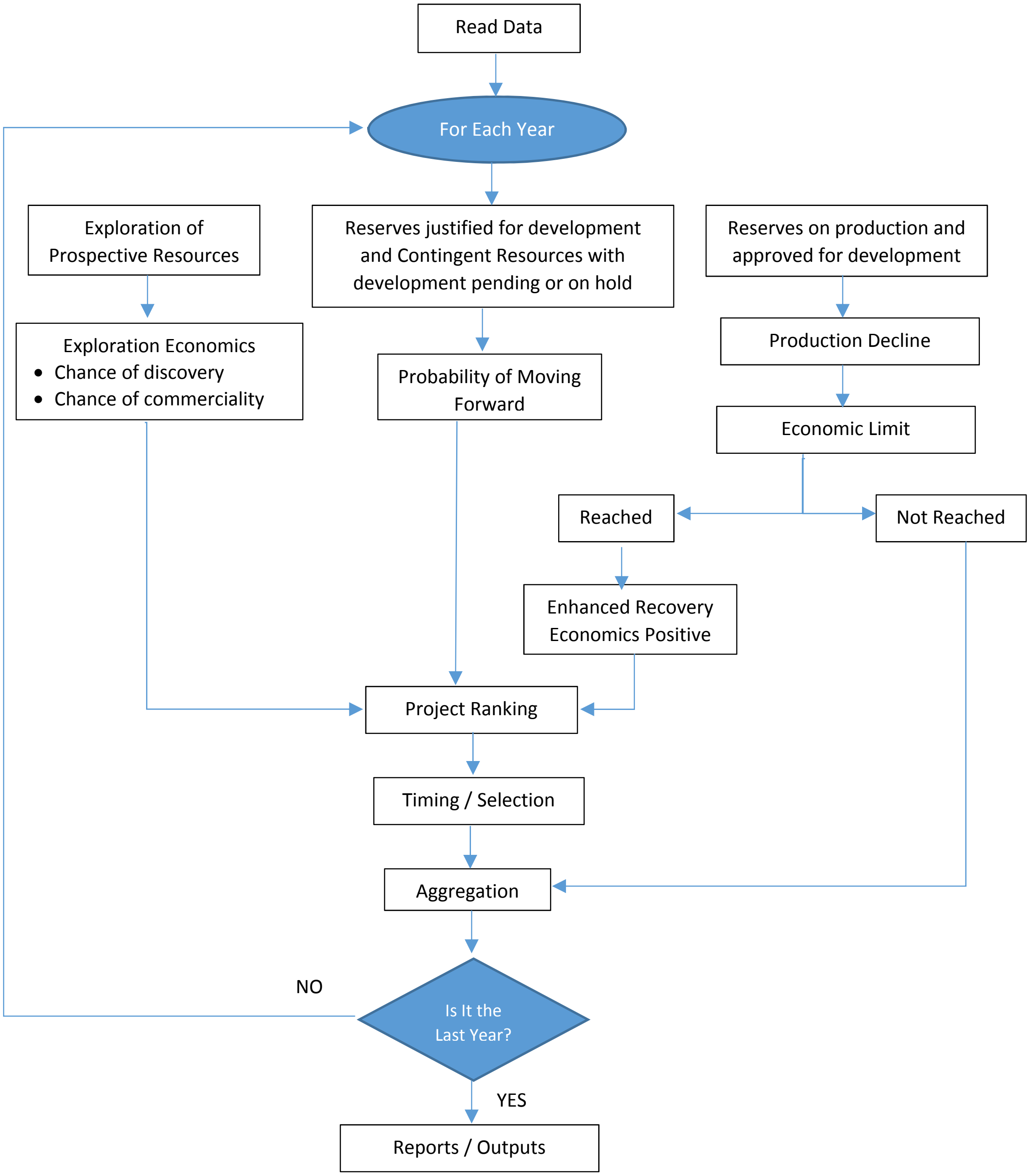

Figure 15. Model flow

Appendix: Existing model structures

It appears that INGM, OLOGSS, ArrowHead, MARKAL and its derivations such as TIMES and TIAM[42] can all deliver what the EIA desires. All of these models can be developed with a user-friendly interface, and processed in parallel fashion. However, they all need the right data to be inputted to function and their results should be subjected to “reasonableness” test by experts on different fuels, value chain segments and/or regions/countries. Calibration runs to approximate historical periods should be another tool to evaluate alternative models.

The INGM could be repurposed. Rice global natural gas model is modified from Deloitte’s MarketBuilder. But these are gas focused; a model connecting oil and gas value chains is more desirable given the increasing interactions between the two. ArrowHead discussed in Nesbitt (2014) could be an option. MARKAL and its variations are also available. For example, TIAM-UCL in combination with BUEGO as presented in McGlade (2014) sounds promising. EcoMod offers a somewhat different option for building a general equilibrium approach from scratch.

McGlade (2014) presents results from the model TIAM-UCL (the version of TIAM customized at University College London). Since that model does not have oil sector details, they also developed another model, Bottom-Up Economic and Geological Oil field production model, or BUEGO, to address field level oil production decisions, in which the modelers capture 7,000 producing, discovered and undiscovered fields, and 133 fiscal regimes. The oil price is generated endogenously.

The ArrowHead model is attractive in its apparent simplicity and detailed network representation. There still is the challenge of populating the nodes with the right equations, which requires the in-depth understanding of the market at that node.

The INGM is similar to ArrowHead in that it seeks “to maximize cumulative discounted sum of producer and consumer surplus” at each of its 61 geographic nodes for each year. This objective should theoretically yield the same results as balancing demand and supply at each node.[43] However, both approaches can be problematic for any or a combination of the following reasons:

1- Consumers do not always pay the market price due to subsidies (INGM seems to include subsidies in its demand equations).
2- Producers do not always get the market price due to government take, the machinery of which can especially be convoluted when NOCs are involved. The INGM captures government take as a fraction of natural gas price, which might work for natural gas but not necessarily when NOCs are the producers, or for oil, which INGM does not address.[44]

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[42] TIMES is created from MARKAL with the addition of Energy Flow Optimization Model (EFOM). TIMES Integrated Assessment Model, or TIAM, is a dynamic partial equilibrium model.

[43] However, the objective function provided on p. 57 seeks to minimize cost from a producer perspective. It is not clear that this representation is equivalent to maximization of the sum of discounted producer and consumer surpluses, especially given the caveats discussed throughout this report.

[44] In the international upstream business, most fiscal regimes are designed around oil, which is the more valuable product with its ease of delivery to markets as a liquid product. But, this preference might change with development of local markets for gas (first via power generation) and increased LNG trade with a large share for the spot cargoes.

3- Energy security drivers can lead to production decisions not driven by the objective of maximizing producer surplus.

4- The lack of perfect substitutes or time needed to switch may limit consumers' ability to change their consumption behavior. This can be addressed by setting the price elasticities to represent such discontinuities in the demand curve at different nodes.

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