RYSTAD ENERGY

UPSTREAM OIL&GAS ASSET BASED MODEL - CDR

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This document is prepared for EIA October 2014.

The document describes how an asset based global upstream model can be constructed to provide a robust and detailed view on future supply of oil and gas.

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1.   EXECUTIVE SUMMARY

1.1   Overall GUM model design

Background

EIA has been tasked to develop a dynamic representation (referred to here as GHySMo[1]) of the global production, processing, transport, distribution, and storage of natural gas and liquid fuels. GHySMO is used by the modeling framework WEPS+ (World Energy Projection System Plus) for analyses of the global energy situation and markets. It is proposed to split GHySMo into 3 sub-modules, for 1) upstream oil and gas production operations including natural gas processing; 2) logistics for transportation (and associated processes such as storage and liquefaction) of primarily natural gas, crude oil, and petroleum products; and 3) transformational processes such as in refineries, and biofuels production facilities.

This CDR is addressing the sub-module for upstream oil and gas production operations including natural gas processing, in this document called GUM – global upstream model.

Based on relevant input data GUM should provide forecasts of global oil and gas production with good granularity along a number of dimensions: geography, oil types, break even prices, commerciality. There is no limitation on the time window to be modelled.

GUM will provide input to the other sub-modules in GHySMo, and should be able to run both stand-alone, and by WEPS+ in an iterative scheme.

Overall Global Upstream Model – GUM – description

The Global Upstream Model as described here is based on how Rystad Energy's UCube is constructed. The model should comply with the requirements put forward by EIA.

GUM is asset based. The asset is the level where investment decisions are made and hydrocarbons produced. Ideally the assets represent actual named oil and gas fields, but aggregations may be required, or sub-field accumulations may be used. The purpose of GUM is to forecast production profiles for all assets in the model, based on the asset and modeling input supplied. A major challenge making a global model is the difficult availability of information. Emphasis will thus be on how to get the most out of sparse data. Relevant costs will be attributed to the assets to enable calculation of asset economics and break even prices. Break-even prices are key to the WEPS+ modeling project, as it may be assumed that assets with break-even prices higher than modeled oil prices will not be developed.

Each asset may be attributed a number of properties: geography, field type (oil/gas/gas-condensate; conventional/shale/oil sands/...), oil quality (API, viscosity, sulfur,...), water depth, development type (e.g. onshore/platform/floater/subsea), operator type (major, independents, NOCs, …), field size, etc. All such properties can be used to aggregate ("bin") assets to generate production data at higher levels, for instance at country level. The attributes will be used to apply different rules to different types of assets during modeling (e.g. subsea and onshore should be treated differently).However, populating assets with such attributes also enables in depth analyses of global supply along the given dimensions.

Figure 1 shows the schematic outline of GUM. The "Asset Input" data set holds all known information about the assets. All asset updates are made to the Asset Input data set. Assumptions (prices, forced country production levels, etc.) and model parameters (parameterization of production profiles, cost elements and levels, country factors, technology factors, etc.) are fed into tables and used in processing. Processing is done asset by asset after which the "Asset Output" data set contains production, costs and revenue profiles for all fields, as well as break

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[1] The Global HYdrocarbon Supply MOdel, EIA

even prices. The bottom-up sum of future production capacity may exceed global demand. When matched with a projected demand the cost of supply curve will determine which assets will be uncommercial and not produce.
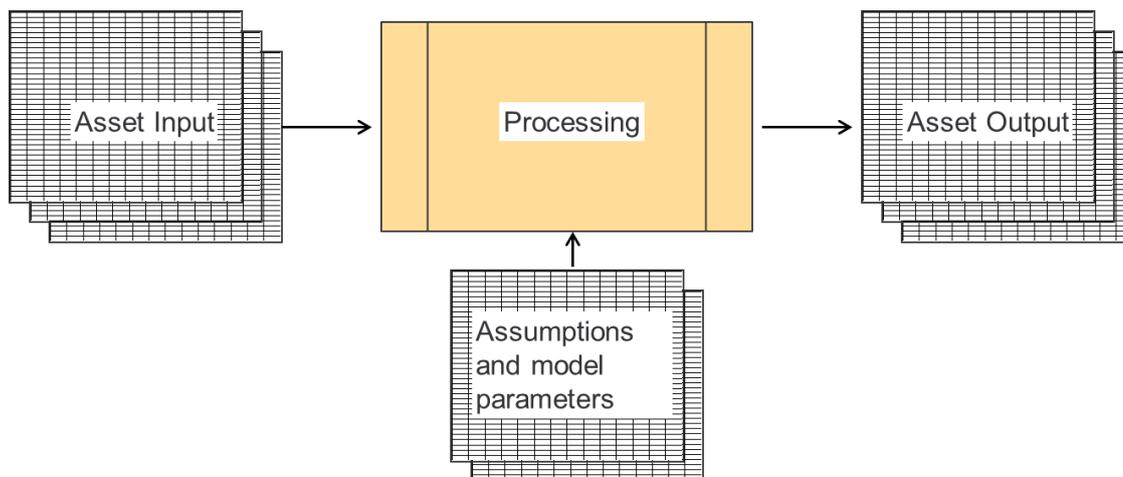

Figure 1: Schematic description of GUM

GUM can be run stand-alone once input and model parameters are defined. Processing the whole model is not so fast, but the Asset Output result will be valid as long as main assumptions are not changed. WEPS+ may need to only interact with the Asset Output dataset, and then e.g. obtaining a new oil price based on a projected demand is done in seconds.

1.2   Connections between GUM and other GHySMo sub-modules

The Asset Output data set will provide input to the GHySMo transportation module. GUM will provide volumes at the wellhead, and assets may be attributed with relevant delivery points, such as feeding into a specific pipeline, from which the transportation module should take over.

GUM can also be used together with existing more detailed models, such as OLOGSS or NEMS. The output of these models can be used as input into the Asset Input tables, or better, the models can be integrated into the GUM module, providing output on the same format as the international assets.

1.3   A note on making a global model

When making an asset based model like GUM the ambitions are usually high on precision. One example of this is when building well based models using actual IPs and decline rates to provide high precision production forecasts. Certainly, the more data available on the assets the better the forecast. However, when making a global model the challenge is rather to be able to populate the whole world with meaningful assets based on scarce and fragmented information. Not only should the assets "behave" realistically, they should also capture the industry dynamics that are important for the use with WEPS+. Thus structures must be flexible to cope with different levels of information, and the most must be done out of the information available. Robust models must be able to produce results based on minimum of information, and be able to utilize any information provided. Making qualified guesses will be an important tool for improving model realism and in lifting the data sets in terms of providing insightful information for analyses. Thus the challenge lies not in single asset precision, but in achieving completeness and realism.

To achieve this objective in reasonable time it is a good idea to avoid unnecessary complexity in the beginning. Robust and converging models that capture the fundamentals of the E&P industry should be implemented first, providing a working model, before finer details are included. For instance one could wait before implementing:

- Tax calculations - break even prices calculated on asset pre-tax economics usually do not differ much from after tax calculations in "neutral" tax schemes (profit taxation).
- Exploration licenses and exploration capex - when decisions are made on developing assets exploration costs are already sunk.

2 ASSET INPUT REQUIREMENTS

GUM models both oil and gas resources and forecasts the supply for the entire world onshore and offshore. This is ambitious, and simplifications and compromises must be made due to the variation in availability of data. One reason for choosing an asset based approach is that all decisions on development and production are made for assets, on an economical rationality basis. When applying even simple models to describe the development and production of assets, the global supply will still reflect the basic dynamics of the industry.

2.1   The Asset

An upstream database can have as its basic building blocks wells, pools, fields, plays, or basins. The choice depends on the availability of information. Precise models can be made with full insight into drilling schedules, IP's and decline rates, but such detailed information will not be available for most fields around the world. We conclude that the most practical unit for a global upstream model is the field. A field can be defined as a project to develop a production unit to drain one or more pools in a formation, usually with a defined ownership. Companies report on their activities and budgets for developing fields, and many governments report production at field level. Thus information is available for fields.

For US and some other countries more detailed well data are available enabling a sub-field granularity. In this case more detailed models can be used to provide the input at field level in the Asset Input tables, or GUM can allow for definition of sub-field level assets (wells, pools, acreage). Unless the calculations are very time consuming a good solution is to integrate the more detailed models into GUM to model the well based data.

On the other hand it can be a challenge to get data on all fields in other countries. In this case it can be convenient to let one asset represent a group of many fields. This helps to quickly populate the E&P universe and get early results, and provides a good basis for subsequently improving the model country by country. However, special care must be taken to assign realistic costs to the assets, or granularity and realism is lost.

A particular type of assets is the ones representing undiscovered fields (yet-to-find, YTF). Although they represent little or no industrial activity as of now, these must be included for long term projections. YTF assets can be based on ongoing exploration activity and/or geologic assessments of open acreage in basins. See chapter *Undiscovered resources*.

Each asset in GUM must be populated with certain attributes to be modeled correctly. The minimum information required to make a production profile is resource base and production startup date/year. Further attributes like development type, water depth, field maturity, conventional/unconventional, etc. will be used to control the model and provide more likely production profiles. In addition, the more attributes assigned to the assets the more the data can be analyzed along the corresponding dimensions. The below table shows required (bolded) and some useful asset attributes.

Table 1 - Asset input parameters

Asset Name	Comment
Asset Type	Can be used to distinguish between assets that should be treated differently by the model, e.g. "field based" vs. "well based", or e.g. discovered resources and undiscovered

	resources
Project	Useful if asset is part of larger industrial project that may put common constraints on all assets in project
Location	Geographic location, useful for aggregations of results
Sub basin	Geologic location, useful for aggregations of results
Reservoir parameters	Useful if used by model, or for aggregations
Water Depth and Altitude	Important for model in determining development type and costs. Useful for aggregations.
Original O MMboe	Field EUR oil resources. Required for production. See Resources chapter
Original G MMboe	Field EUR gas resources. Required for production. See Resources chapter
Original C MMboe	Field EUR condensate resources. Required for production. See Resources chapter
Original N MMboe	Field EUR NGL resources. Required for production. See Resources chapter
API Gravity	Used to estimate price discounts, and useful for aggregation into crude types
Viscosity (Cp)	Useful for characterization of heavy oils
Sulfur wt%	Used to estimate price discounts
H2S (ppm)	Used to estimate processing costs
CO2 (%)	Used to estimate processing costs
Unconventional oil	Extra heavy oil, Oil sands, Oil shale, Tight oil. Use to control costs and profiles in model
Unconventional gas	Conventional, CBM, Shale gas, Tight gas. Use to control costs and profiles in model
Award date, Discovery date, Commercial date, Approval date, First production date	Dates are used to assess current Life cycle, i.e. maturity of asset. Used in production profiling, and useful for aggregations. The dates start the life cycle phases: Awarded undiscovered, Discovery, Field evaluation, Under development, Producing.
Operator or operator type	Useful for analyzing e.g. role of NOC's, majors
Facility	Development type: Onshore/Platform/Floater/Subsea. Important for production and cost models, and useful for aggregations
Oil Price Factor	Discount to reference price in addition to modeled discounts. Used in revenue and break-even price calculation
Gas Price Factor	Discount to reference price. Used in revenue and break-even price calculation
Liquids peak capacity	When known will be used in production profile

(MMBoe/yr)	
Gas Peak Capacity (MMboe/yr)	When known will be used in production profile
Gas Export Method detail	Useful for feeding GHySMo transportation module
Oil Export Method detail	Useful for feeding GHySMo transportation module
Gas processing plant	Useful for feeding GHySMo processing module
Fiscal Regime	Useful if applying tax

Implementation-wise, all static asset attributes can be in one row per asset in a table, whereas time series (known production, costs) should be in separate tables.

2.2 Aggregation of data

The asset attributes above can be used to aggregate data along different dimensions. A part of the processing should be to aggregate the attributes in hierarchies in the Asset Output data. As an example, water depth is a number in Asset Input. In Asset output one can include two additional columns based on this: e.g. "Water depth group", splitting into Onshore/Shelf/Deepwater/Ultra deepwater, and "On-/Offshore", splitting into Onshore/Offshore. Querying Asset Output for onshore production for a given year is then a matter of summing all rows with "Onshore" and the given year, which is very fast. This can be used both in stand-alone analyses of Asset Output data and during iterations with WEPS+. Figure 2 shows how look-up tables can be used to aggregate production by geography at 6 different levels.
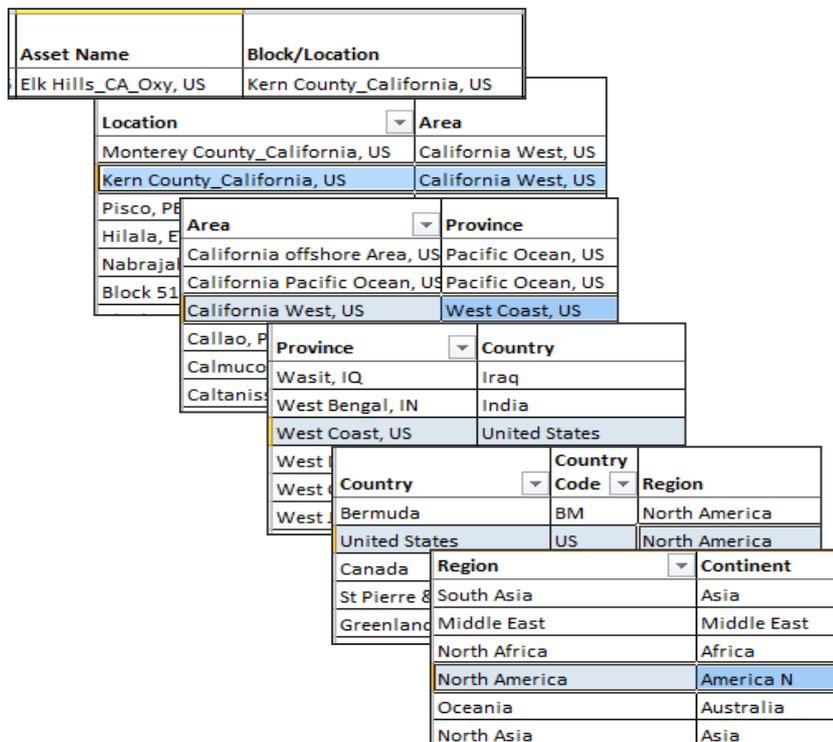

Figure 2: Building a geographic hierarchy allows for data at asset level to be aggregated at different levels, making it fast and easy to pull e.g. country production.

2.3 Asset resource data

The resources put into the model should be expected ultimate recovery resources (EUR), i.e. the volume actually going to be produced from the asset. This ensures an important internal consistency in the data, namely that the asset production sums up to the resource number.

However, EUR numbers are generally not provided, rather companies report 1P, 2P or 3P resources, or P90, P50, or P10 estimates, or even OOIP and OGIP (original oil/gas in place). An estimate of EUR should be made from these numbers.

If the in-place volumes are known EUR can be estimated from statistics on recovery factors for different asset types. By definition, EUR is the product of in-place volumes and ultimate recovery factor.

When in-place volumes are not published EUR can be estimated from 1P/2P/3P/P90/P50/P10 estimates. Analysis of historical data has shown that fields end up producing volumes between P50 and P10 (or 2P and 3P) estimates. Since the classification of volumes changes during field life the EUR estimate should be based on reserve estimates at time of PDO for consistency.

One could alternatively provide the reserve estimates above (1P/2P/3P/P90/P50/P10) as input, and let the model calculate a EUR estimate on the fly. We expect this will complicate the code and provide less transparency on the model. It is better to do the EUR assessment up front in a consistent manner and let the code be deterministic in how much it will produce.

It could be argued that a model should be based on 1P (proven), i.e. conservatively taking into account only sanctioned activities. This would not provide a useful model in reflecting what is going to happen. Operators will do more than initially planned to drain their fields once development costs are sunk, more is learned about the reservoir, technology evolves, and to get the most out of the field before it is closed down.

We choose to set the EUR number high enough to implicitly include technology improvements. Alternatively one may be more conservative on the EUR estimate (say equal to 2P) and include technology improvement as an external factor to boost resources in the model.

Within this framework EOR projects may be defined as separate projects with investments and incremental production.

It is an absolute requirement that all assets have EUR input numbers. Since EUR is a result of economics decisions one may increase the EUR resources for fields in high oil price scenarios and reduce them in low oil price scenarios.

2.4 Asset production data

It is convenient to split the production into hydrocarbon types crude, condensate, NGL, and gas. A finer (e.g. ethane, propane,..) or coarser (liquids, gas) splitting may be chosen. Whatever choice the historical production must include one time series for each hydrocarbon type. Also, EUR numbers must be given for all hydrocarbon types, and each hydrocarbon type will be "produced" independently. The important thing is that there is consistency between the EUR numbers and production streams.

The more historical production data available at asset level the better precision on historical numbers and also better starting point for the production profiler. For assets without known history also the historical production will be made by the algorithms. Since production levels will be uncertain it may prove necessary to macro-calibrate these generated historical data. This is described below.

To complete the supply picture other liquids (biodiesel, bioethanol, etc.) and refinery gains should be included in the model. These can be included on country level, i.e. one asset per country.

It is practical to keep all production data (historical and forecast) in oil equivalent volumes (e.g. MMboe). Then the resources and production numbers can be compared, and are additive and independent of dates, and can be converted to production rates at any time.

A choice has to be made on whether to use volumes (volumes for liquids, boe for gas), or oil equivalents (bbl for oil and condensate, 0.71xbbls for NGL, 0.8xbbls for other liquids, 0 for refinery gains, boe for gas). We recommend volumetric barrels for liquids.

2.5   Asset costs data

Historical costs should be logged just like historical production and include capital and operational expenses. However, it is harder to get good cost data than production data. Actual data do not only serve the assets where costs are known, they also provide a good starting point building cost models for assets without data. It may also be hard to get data at the granularity that it is natural to use for modelling and forecasting of costs. The data structure should thus allow for input of costs at different granularity levels, e.g. also total capex, not only facility capex, well capex, etc. Modelling will anyway become important to fill most of the holes, and any numbers can be taken into account to improve results. We propose to not include exploration capex as part of the cost, or to just include it in other capex. See *Exploration costs* below.

The world uses many currencies, but the whole oil industry relates to US dollars. This is the obvious choice of currency for the model.

3 ASSUMPTIONS AND MODEL PARAMETERS REQUIREMENTS

3.1 Price data

The most important external parameters to the model are the product prices, which determine when production is profitable and not. Due to differences in market access and product quality assets will achieve different prices when selling their production. This can be resolved by using different price strips. In UCube we do the following.

We apply Brent spot as a reference price for oil globally, except in North America onshore where we apply WTI (US) and WCS (Canadian heavy oil). Heavy oils or oils with high total acids are discounted according to an empirical rule.

Outside North America we assume that gas prices are linked to the oil price by a factor. Since most gas is piped to nearby markets this factor varies strongly with geography, since e.g. much higher prices are achieved in Western Europe than in Russia or North America. Further we expect these factors converging in the long run, expecting development towards a more global market for gas.

Linking gas to oil has been a reasonable assumption for a long time. It may be questioned whether this is a good assumption going forward.

The price strips in UCube are based on historical prices up to today, apply the ICE future curves for the next 12 months, and then apply 2.5% inflation going forward.

UCube includes three additional price scenarios to study price effects on production, costs and valuation – a low, medium and high scenario. These are defined by a next year oil price, and flat in real terms, i.e. just inflated going forward. Flat scenarios are easy to relate to, but any price strips may be applied.

Varying the oil price is clearly a way to analyze supply sensitivities. However, it is time-consuming to iterate the model for a number of price scenarios. One alternative is to calculate for e.g. three scenarios and interpolate between the three to obtain intermediate values. A second alternative is to calculate break even prices for all the assets. We believe the two latter approaches are more efficient.

3.2 Historical production calibration data

In order to "macro-calibrate" the historical production, actual aggregated production numbers are required. Most practical is to apply country level production, as this information is commonly known. However, reported information at lower level (e.g. province, state) provides better calibration. See chapter 4.2.5 *Macro calibration of historical production.*

3.3 Model parameters

The model parameters are required for running the model and are necessary to turn the input data into the output. There are also optional parameters (not mandatory) describing the specific behavior of groups of assets, helping to

add value and realism to the results. Asset level data and parameters should always be used when available, overriding more general parameters.

In order to make the algorithm as flexible as possible, factors applied in formulas or algorithms should be placed in tables as input parameters rather than being hardcoded directly in the program. This allows for easier control and modification of the model.

A scenario is the output from the model run with a defined set of input. The historical production and economics, and forecasting rules are similar for all scenarios, but different parameters result in different forecasted results, making each scenario unique.

Most often scenarios are run with different price strips, these are often called price scenarios. But it can be of interest to vary many other parameters than just the price. Below are some examples of parameters to vary, and the parameters should be available in an input table before starting the process.

Table 2 - Exogenous input parameters that define the scenario differences – economical, resource base, asset start-up

Scenario Parameters	Comment
Inflation rate (%)	The expected inflation rate for the future. The cost model will normally be in nominal terms, and costs and prices will be inflated going forward using the inflation rate.
Prices	Scenarios applying different prices are common. We propose to use low, mid, and high scenarios. It is practical to use flat oil prices (in real terms) for the scenarios, but any price strip can be used. Still several prices strips should be consider per scenario depending on the market, such as Brent, WTI and different gas prices.
Resource variation	It is best to have a simple lever when deciding how the resources should vary depending on the price scenario, or on new technologies. Ideally this should be expressed by in place volume and recovery factor, asset by asset, but this information is not always available. We suggest applying a percentage increase or decrease of the remaining EUR resources to reflect increased/reduced willingness to produce more.
Change start-up years	In a low price scenario it is likely that unsanctioned high breakeven projects will be postponed, and in a high price scenario the development of profitable unsanctioned projects may be prioritized. Shifting the start-up years in the scenarios has a significant effect on the supply picture.

All parameters that can improve the precision are useful for the model. This can be price factors for certain fields, transportation costs, different cost levels for different countries, etc. Such factors can either be asset specific (e.g. a contracted price model), for groups of fields (e.g. transportation cost through certain pipelines), at country or region level (e.g. gas price factors), or global. It can be practical to provide such parameters at all these levels, if possible. If there is no value for a specific asset, one can check for a value at area level, province level, country level, or region level. If there is no specific value at any of these levels a global value will be used.

4 METHODOLOGY DESCRIPTION

4.1   Model Objective

GUM provides forecast of global oil and natural gas production as the sum of forecasted production at asset level. The model has the capability to model any asset worldwide, and the assets must be complete in covering all E&P activity. Production can be broken down on oil type based on API, condensate, dry gas and NGL's from C2 to C5. There is no limitation on the time window the model can be applied to. The model forecasts production based on expected recoverable resources of the different hydrocarbon types (corresponding to the base price scenario). Different models will be applied to different field and development types. The model may take into account the uncertainty in the EUR resource base as driven by oil price and costs variations, by calculating several scenarios. GUM also calculates the costs at asset level in order to assess profitability for the owners and calculate break-even prices. The break-even prices are used to provide cost-of-supply curves, which are essential for the interaction with WEPS+.

As a standalone module GUM provides a powerful tool for in-depth analyses of the global supply along a larger number of dimensions. GUM provides wellhead production of specific hydrocarbons at specific locations, which should provide the necessary input to the GHySMO transportation and logistics module.

4.2   Model Structure

The processing steps of the model are outlined in Figure 3. After the Asset Input data set is established the data set will be checked for errors and completed. The following processing steps are done asset by asset. First step is to calculate from the input data all key parameters required for the model. This provides the basis for the next step, which is to generate the production profile. Based on the production profile and key parameters the economics times series are calculated, i.e. the investments (capex), the operational costs (opex), the revenues, and the government take and the free cash flows to the owners. Subsequently the break-even values for the assets are calculated from the cash flows. When all calculations are done results are written to appropriate tables, and some post-processing may be desired.
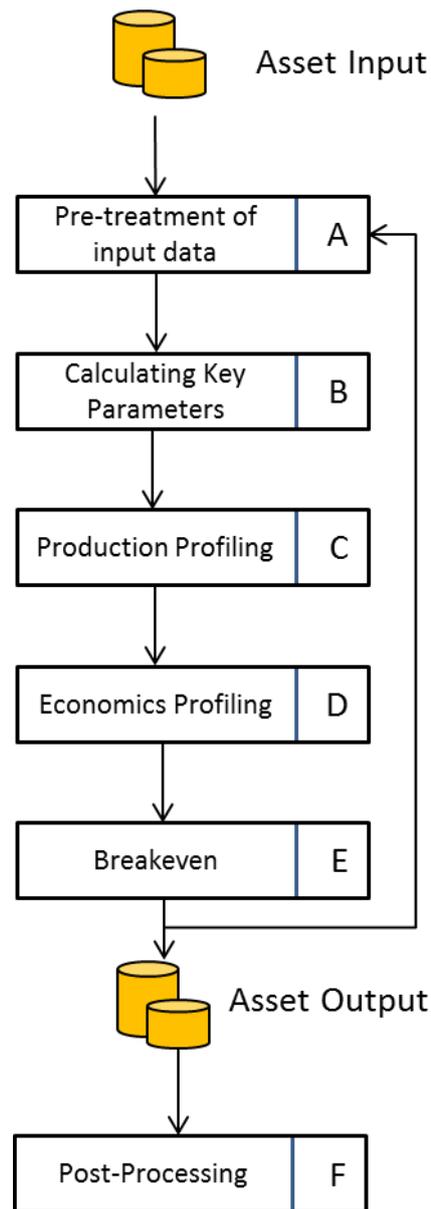
Figure 3: Outline of main processing steps

4.2.1 Asset Input

Before starting the processing the Asset Input data set is expected to include at least one asset parameter table like shown in chapter 2.1, and tables for historical production and economics. Supplementary tables used to make hierarchies should also be in place (see 4.2.7 below).

4.2.2 Pre-treatment of input data

The purpose of this module is to review and adjust the input data taking into account assumptions and rules determined by the modeler. With large data sets maintained by several people there is always a chance of errors, and such errors may make models crash, or may unnoticed propagate to errors in Asset Output. Also, it is challenging to provide a truly complete input data set, and the module will also complete the historical production profile for years where data are lacking and/or calibrate the values in order to ensure correct historical country production.
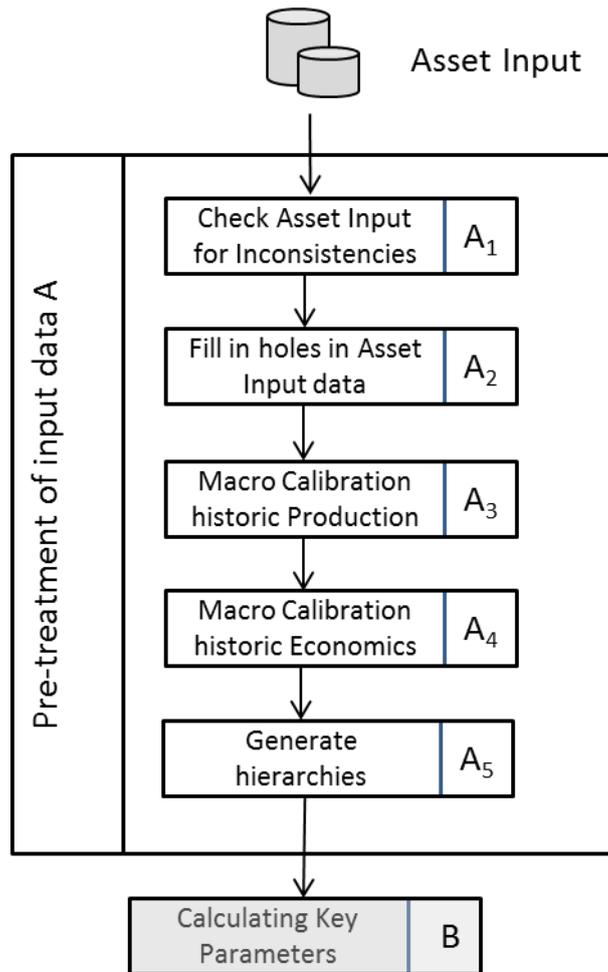
Figure 4: Outline of preprocessing steps

4.2.3 Check Asset Input for Inconsistencies

Unfortunately, despite all good efforts inconsistencies and errors may enter into the data. All deviations uncovered by inconsistency checks should be logged for follow up and corrections of either the values or the rules. Some common checks are:

Table 3 -Common checks to ensure consistency of data at the input side

Check	Comment
Are values within limits?	Many of the input variables must be within certain limits, for physical or other reasons. The tests uncover input errors, and out-of-bound errors may be replaced by "likely" values in order for processing not to crash at a later stage.
If values are in %	Percentage values may easily be recorded incorrectly due to confusion of using 0%-100% scale or 0-1. Should thus be checked.
Order of dates	Check that dates are chronologically correct. Since the dates are used by the algorithms it is important to ensure that they are chronological. E.g. an appraisal date should never appear after the start of production.

Facility for the field	Facility type can be checked based on the geographical characteristics of the field. Certainly we cannot have an FPSO on land.
Original and remaining resources	The model can accept original, remaining resources and production as input. It is important that these values are consistent. The sum of historical production and remaining resources should always sum up to original resources. Unit confusion may happen (MMBoe/y vs. kbbl/d)
Production levels	Plateau production may be introduced as input. It will be compared to historical production, and should not differ too much. Corresponding checks apply to similar input parameters.

4.2.4 Completing the Asset Input data

Missing data points in historical production and economics are filled in during the macro-calibration process. It is very useful to complete also other asset attributes. One important parameter is the water depth which has impact on the calculations below. If it is not known it may be guessed from the location. If the longitude and latitude are known a good estimate for the depth can be looked up in bathymetric maps, in 90% of the cases with good enough precision to make correct model decisions. Longitude and latitude can also be used to attribute assets to sub basins, basins, counties or other entities of geographic extent, such as assessment units, source rocks, etc. Since longitude and latitude are so useful – they are also the key to place all data and results on the map – they should be estimated if not known. Geocoding from pictures, maps or field outlines will normally provide sufficient precision for most classifications.

What we describe above is the importance of qualified guessing. There is enormous value add to obtain a *complete* data set. This goes for the production, of course, but also for other parameters used for analyses. It is interesting to know that at least 30% of production is from offshore and at least 40% from onshore, but it is of limited value if the origin of 30% is still unknown. Clearly, guessing will not be without errors, but using robust and "most likely" models, and top down calibration, at least statistically correct results should be achieved at aggregated levels. These "guestimates" should not be stored in the Asset Input data set. If the data point is not known the data cell should remain empty, to encourage filling it later with hard facts. The estimates can be stored in a look-up table, or calculated on the fly every time the model is run. The former is faster, the latter is more robust for changes in data and models.

Another example is to complete the asset dates – discovery date, approval date, production start date, etc. The dates tell the story about when the asset was in different life cycles – maturity or development stages. There is much insight in analyzing the maturity of the resources that build up the supply, so it is better to guestimate the missing dates to become roughly right than to abandon this lever for analysis.

4.2.5 Macro calibration of historical production

The data available at asset level may not aggregate to match high confidence benchmarks such as country production numbers (or global, or state or county level for USA). This will be due to lack of complete data sets, i.e. there are holes in the data. The historical production can be forced to match benchmark levels using macro-calibration.

In its simplest way calibration to macro numbers can be achieved by using the ratio between the macro number and the bottom up sum to scale up the asset level production numbers. However, the input data have different confidence levels. Assets with known historical production should not be changed, while assets that have their production profiled by algorithms are already uncertain and may be stretched to match the macro numbers. Efficiency is gained if the new calibrated profiles are written back as input data, with low confidence (we will refer to such data as forecasted within this chapter).

We split the process into the following steps:

1. Take into account all the assets within the geographic area to be modeled.
2. Check which assets have research data (high confidence data) for the year being evaluated.
3. Consider the researched data as a fact – remove that volume from the benchmark
4. Calculate the total volume from the remaining assets and compare to the new benchmark (initial benchmark – researched production), and calculate the % of adjustment required.
5. The calculated adjustment can be applied to all the non-researched fields. However, this may result in unreasonable year-to-year production profiles. Great improvement is achieved by assigning a maximum stretch for each asset. The maximum stretch takes into account remaining resources (large resources may stretch more) and year to year variations, which should not be too large. The algorithm should now increase the assets' production gradually based on the maximum stretch, checking year to year variations. The algorithm can be iterated a number of times, and the last iteration forces a match to the benchmark value. The more iterations the smoother the resulting production profiles.

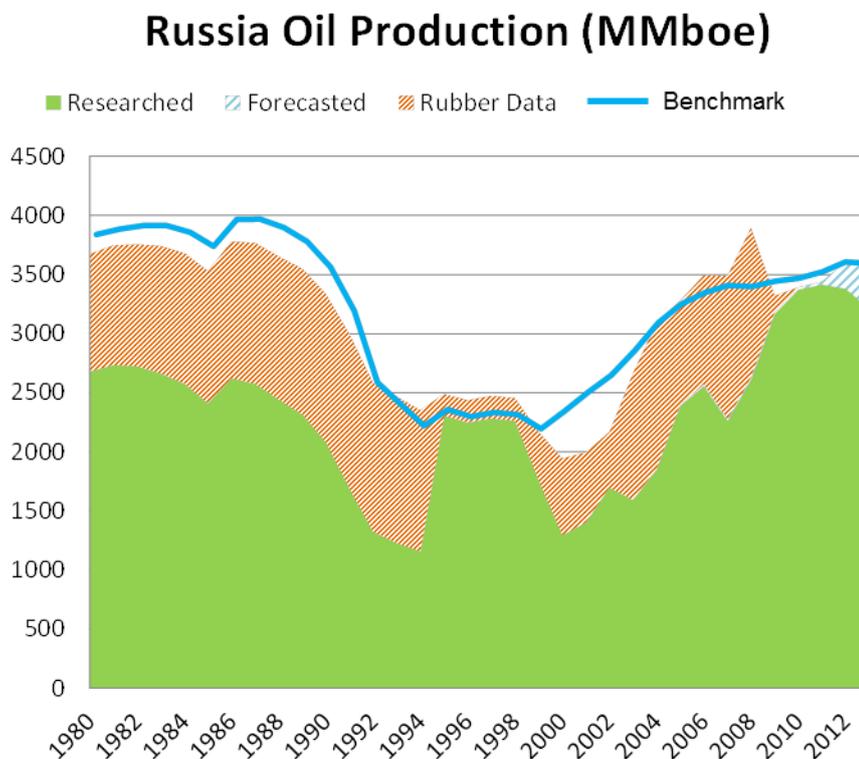The example below demonstrates macro calibration of the Russia crude production from 1980 to 2013.

Figure 5: Russia bottom-up sum of crude production (in MMboe) from 1980 to 2013 split according to input confidence level (researched, low confidence (rubber) data, forecast feed) and the benchmark for the country based on EIA figures. The bottom-up data do not match the benchmark levels.

In Figure 5 we find:

- The green volumes are the sum of production from assets with researched information (high confidence)
- The red volumes are the sum of production from assets with low confidence or low precision information. We label these assets "rubber data", since these will be stretched by the macro calibration algorithm.

- Forecasted represents the volume of production that is fed into the macro calibration system from the forecast algorithm, i.e. it represents forecasted production volumes for fields with no information for the specific year.
- The blue line labeled as benchmark represents the value that the macro calibration algorithm aims at matching. From 1980 to 1994 the algorithm will adjust the production volumes up, from 1995 to 1998 or for 2008 it will adjust the production volumes down.
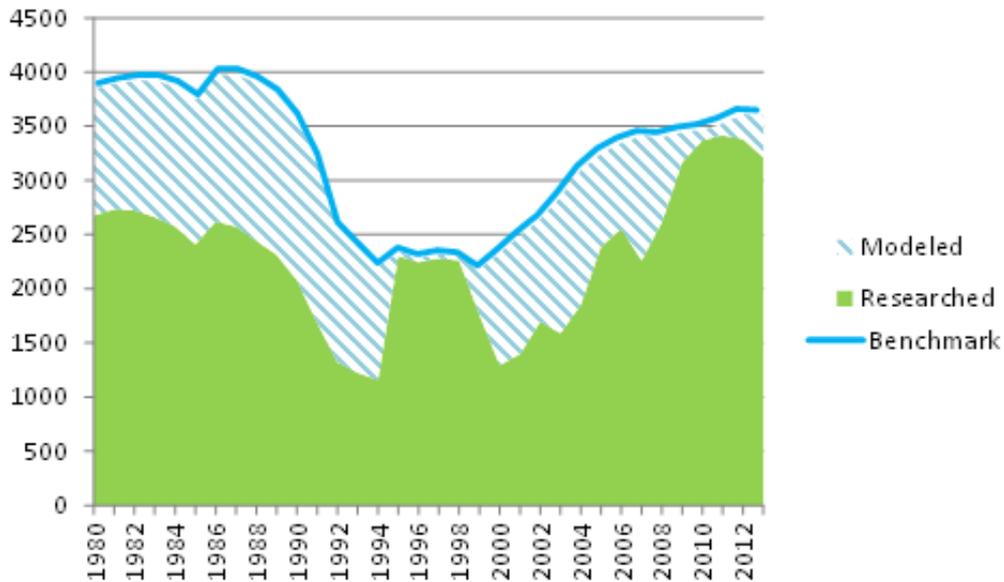-

Figure 6: Russia crude production (in MMboe) after macro calibration. This modified data set will serve as input for the production profiling module.

After the macro calibration has processed the rubber data and forecast data from the last run of the model we obtain the result in Figure 6 – the bottom up sum matches the benchmark. The modified data are now written back to the input data set and labelled "modeled data" (low confidence) since the data has been tweaked by the function. This complete and calibrated input set now serves as input to the profiling algorithm.

The researched data (high confidence) are never changed by the algorithm. If the benchmark is lower than the sum of the high confidence input data the end result will still be higher than the benchmark. Thus if all assets in a country have been researched, the calibration will not change any values.

4.2.6 Macro calibration of historical economics

Also economics can be calibrated historically at macro levels for which high confidence data points may be available (for example at country level, globally, or at state or county level for USA). The macro calibration for economics is done simpler than for production. The reason is that for the economic macro calibration the adjustment of the economics uses only one single factor for all the assets per year. Instead of determining an optimal factor to apply to each asset based on the lifecycle and previous costs, it will simply calculate the factor to apply as:

$$\text{Economic factor (y)} = \frac{\text{Macro number(y)} - \sum \text{Researched data(y)}}{\sum \text{Output data (y)}}$$

The sum of output data is the result from the previous run of the model written back as input, with low confidence. This calibration has the convenience of being very fast and easy to implement but will always require two iterations of the model to match any new or altered macro level benchmark value.

This calibration gets the cost levels right, which is useful input when making cost models going forward.

4.2.7 Generate hierarchies

As illustrated in chapter *Aggregation of data* above introducing a geographic hierarchy allows for aggregation of production at different levels. In practice one just sums all the rows in the database with e.g. the same province. In a similar manner one can build hierarchies over water depth and other parameters. A water depth hierarchy can for instance have 3 levels: a grouping of depths in suitable intervals, maybe 50 m, grouping into technology relevant shelf, deep-water and ultra deep-water, and onshore/offshore. The same can be done based on oil type, life cycles, operator types, etc.

4.3 Calculating Key Parameters

In this process step all the parameters are calculated that are required for the following calculations. Thus many of the model assumptions are implemented here in calculation of these parameters. Some of the parameters calculated in this step are:

Table 4 – Calculated parameters required for determining the production and economical profile of the asset

Reference	Calculated Parameter	Comment
I	Resources adjustment	based on the price strip vs. the base price
Ii	GOR (Gas oil ratio)	Determining the share of Gas to Oil used to identify if it is an Oil Asset or Gas Asset
Iii	PR (Production to resources) ratio	Production pr year at plateau /Original recoverable resources
Iv	Plateau Production level	Expected design capacity constraint if existing
V	Cumulative Production at start of decline	Amount of resources to be produced before production profile goes into decline
Vi	Nr of years for build-up	Number of years for the field to reach plateau production level
Vii	Date of decline	Time at which the field will enter decline
Viii	Lifecycle (t)	Time series containing the lifecycle for each year of the field
Ix	Expected Lifetime	How many years the field is expected to produce
X	Pre-drilling cost	Cost of pre-drilling wells prior to start of production (i.e. for subsea)
Xi	Platform cost	Cost for the facility (including structure cost)
xii	Structure cost (of platform)	Part of the platform cost which is related to the structure of the platform
xiii	Opex per bbl (variable cost)	Cost per produced barrel – variable opex
xiv	Fixed Opex	Fixed cost for operation
xv	Capex per bbl (drilling)	Drilling cost per barrel retrieved

xvi	Drilling cost per year in average	Average investment in drilling wells
xvii	Incremental cost per bbl	For cases of modification of facility to increase capacity
xviii	Nr of development years	Number of years from development starts to production is started
xix	Abandonment cost	Cost to plug wells and remove any structure at location
xx	Sales Price (t)	Prices at which the hydrocarbons for the specific asset are expected to be sold at
xxi	Cost cycling (t)	Used to let costs cycle with oil price. Based on a relation between price strip vs. base price
xxii	Main Hydrocarbon	The main hydrocarbon type the field is developed to produce, i.e. oil for oil fields, gas for gas fields. The other hydrocarbons are considered as upside

The above variables will be used in the models described below. The first time a variable is used we will describe how it is calculated.

However, main hydrocarbon and sales price will be described here as they are required for the forecasting.

Main hydrocarbon: An asset may produce more than one hydrocarbon, e.g. both oil and gas. One hydrocarbon type will be more valuable and basis for development, whereas the others are considered an upside. Which is the main hydrocarbon is important for the asset production profiling. We find it sufficient to split between liquids and gas. The algorithm should be run for the main hydrocarbon first, and then loop over the other hydrocarbons. To determine which is the main hydrocarbon we consider the current actual value of each hydrocarbon as,

$$Hydrocarbon\ value = Hydrocarbon\ Original\ Resources * Sales\ Price\ (at\ current\ year)$$

The sales price depends on:

- the chosen price scenario
- the location of the asset
- the characteristics or content of the produced hydrocarbons

and is described by the following formula:

$$Sales\ Price\ (y) = f(Location, HCT, API, Sulfur, ScenarioPrices, inflation)$$

When calculating the sales price for specific assets one should consider the following:

- The correlation factors between oil and gas prices are not constant, but vary over time. It is required to have a yearly factor correlating gas price to oil price.
- Gas prices are in large determined by access to market. If sold to a local market the price may be low, if exported through pipelines higher market prices may be achieved. A time series for gas-oil price correlation factors for the different gas markets may be required.
- It is useful to consider also a few markets for oil, such as Brent price for global sales and assets with easy export by tankers, WTI for some areas within United States, and WCS for western Canadian heavy crude.
- The resulting price strips and yearly correlation factors may vary from scenarios to scenario.

Thus the asset location should be used to determine which base price strip to use. The HCT determines which hydrocarbon to estimate the price for. API and Sulfur are used to apply a discount or premium to the oil base price. The relation can be determined by studying historical sales prices based on API, as reported by refineries. For lighter and sweet oil the sales price per bbl should receive a premium, while heavier and sour oil will be discounted.

The inflation parameter is used to calculate future sales prices for years where sales price is not provided. In such cases the algorithm calculates next year's price by applying the inflation to preceding year's value.

Figure 7 shows as an example the UCube sales prices for oil, condensate, NGL and gas for four different continents (Australia, Middle East, North America, and, Europe).
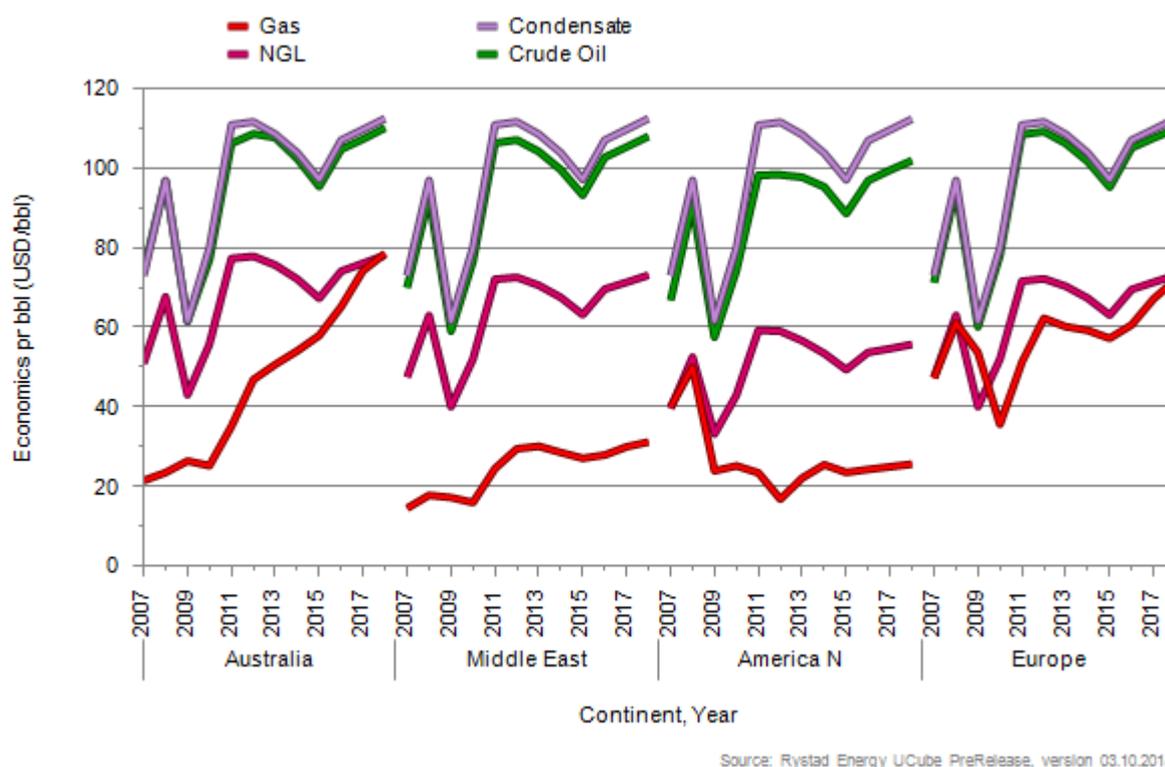

Source: Rystad Energy UCube PreRelease, version 03.10.2014

Figure 7: Average sales price for each HCT for 4 continents. The forecast is based on the forward curve price scenario as of October 3rd, 2014.

Figure 7 shows differences between locations. The gas sales price in North America drops compared to Europe or Australia as a result of the shale revolution. The gas sales price in Australia increases as more volumes are exported as LNG.

4.4   Production Profiling Module

The Production module will provide all assets with production profiles for all relevant hydrocarbons. The basic principle is to mimic the planning process done in the oil companies, optimizing the NPV of the project by balancing costs, off-take rate (capacity) and total recovery. I.e. the plateau level is a compromise of the cost of increasing capacity vs. delaying production. It is important that the module can produce realistic production profiles also when the information is sparse. We distinguish between three different cases:

1) Assets with yet no or not known production (generic profile)
2) Assets with historical production
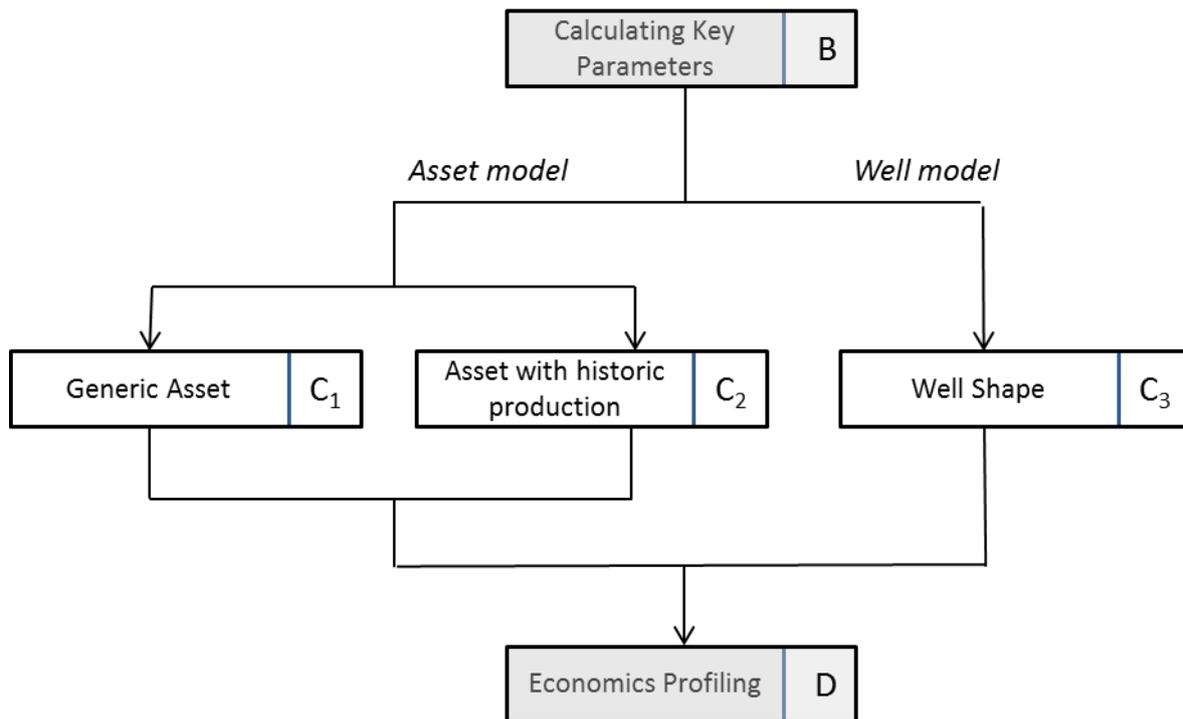3) Well based approach, typically for onshore developments

Figure 8: Production Profile Module diagram with multiple profiling options.

The following variables or parameters are used for the production profiling:

Variable	Comment
OriginalR	Total amount of EUR resources
Un-risked OriginalR	For YTF only. Total amount of un-risked expected recoverable resources, equal to OriginalR/riskratio. Thus for YTF the OriginalR is the risked volume. For discoveries or producing fields the un-risked resources are identical to OriginalR.
Cumulative Prod pre-decline	Total amount of MMboe expected to be produced up to when decline is initiated
Plateau Production	Yearly production for the field during its plateau phase
PR ratio	Production to Resources ratio which is determined based on Original resources, hydrocarbon type and onshore or offshore. The formula for determining the PR ratio is based on statistics from existing fields
Life cycle	Represents at which development stage the asset is at a certain time, ranges from un-awarded to abandonment
HCT	hydrocarbon type
API	API gravity
Facility	development type, i.e. land, platform, floater, subsea
Water depth	Average depth of the field in terms of location of the well head. Required to identify the difference of onshore and offshore behavior on plateau levels
Project Type	Represents the project type (conventional, oil sands, arctic,..), which influences the production profile.
Risk ratio for YTF	Describes the risk of the resources not being recovered or discovered. The risk ratio is the product of the probability of a wildcat being drilled (Pdrill) and the probability of the well making a

	discovery (Pdiscovery). This variable is only used for exploration licenses for which the aggregated future production should match the expected total production from actual resulting discoveries in the end. Many licenses will not contribute discoveries and production, thus the risked profiles
Opex ($/bbl)	operational cost for the variable production (excluding transportation and SGA)
Fixed Cost	fixed costs associated to the operational procedures
Sales Price	expected price to be realized on the sale of the hydrocarbon

4.4.1 Generic asset production profile

The basis for the generic asset production profile is that many fields are developed as a project to drain the resources within a certain time. Given the resource base and field particularities the production facilities will be built to produce with a certain capacity. The capacity limit can be determined by processing capacity or pipeline capacities. Wells will be drilled to fill the production capacity. After some years at plateau capacity production will decline due to reservoir pressure decline and/or increasing water production. This suggests the use of a generic "quarter-pipe" production model, as illustrated in Figure 9.
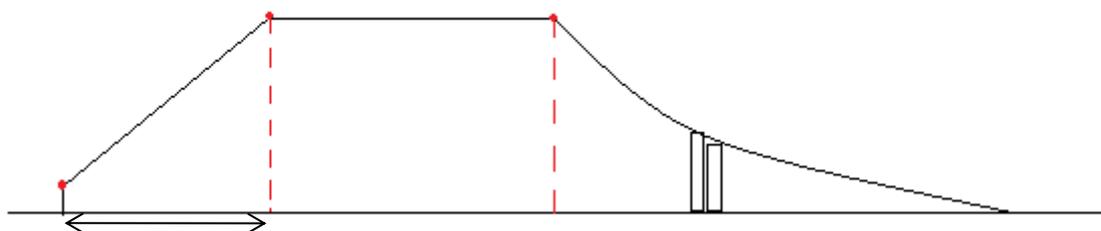

Figure 9: Generic asset production profile with build-up, plateau, and decline phases

Important parameters for the production profile are: plateau production level, initial production level, number of build-up years, number of years at plateau, and the decline rate. Figure 9 shows a preliminary production profile. During economics calculations an economic cut-off is determined, at which production no longer covers the operational costs. The production after this cut-off is subsequently removed.

Plateau Production: is defined as the production value in MMboe at which the field sustains the production for a period of time and such production value is close to the capacity constraints of the asset. The plateau level is usually the field's maximum production, or production capacity.

$$Plateau\ Production = f(OriginalR, PR\ ratio, Lifecycle, Riskratio)$$

PR ratio is Production to Resources ratio and can be described as:

$$Production\ to\ Reserves\ ratio\ (PR\ ratio) = k_1 * e^{-k_2 * Ln(OriginalR)}$$

The factor K1 and K2 are different for different hydrocarbons and for onshore or offshore. For onshore K1 would be half of the offshore value. The variation with hydrocarbons is:

Table 5 – Constants used per hydrocarbon type for the calculation of Production to Reserves ratio equation

Hydrocarbon	K1	K2
Crude oil	0.8	0.3
Condensate	0.3	0.2

Dry gas	0.25	0.2
NGL	0.3	0.2

The formula for the plateau production formula above includes some adjustments based on current life cycle and a risk ratio. The risk ratio applies to YTF, and is not relevant for the YTF-approach described in this document.

Historical analyses show that discoveries tend to produce less than the expected due to unforeseen technical difficulties. Such problems cause lower plateau values than planned. To avoid a too optimistic macro supply picture we use the current lifecycle to risk down the plateau levels. The more mature the field the higher the confidence it will reach expected plateau level. The plateau level is risked down more the further the field is away from development – before sanctioning, before evaluation phase, before appraisal, etc. Effectively this also takes into account that not all discoveries in the model will be developed.

For an asset with a mature lifecycle such as already in early stage of production the plateau production will be calculated as:

$$Plateau\ Production = OriginalR * PR\ ratio$$

Initial Production: represents the initial production level when the asset starts. The value is calculated using the formula:

$$Initial\ Production = f(OriginalR, HCT, Facility)$$

The calculation is based on statistics of historical assets developed with different facility types, hydrocarbon content and size of asset.

Nr of build-up years: represent the time in years that it will take the field to reach its plateau production level. The build-up phase reflects the gradual ramp-up of capacity and/or drilling of wells to fill capacity. Nr of build-up years is calculated with the formula:

$$Nr\ BuildUp\ years = f(Unrisked\ OriginalR, PRratio, Depth)$$

It is important to take into consideration some limitations on the number of years and that for very small resource bases the number of build-up years should equal 0. The thinking is that for resource bases that could be produced with a single well there should be no build-up as all the drilling is performed and the output from the well would represent the plateau production from day 1.

Cumulative Production before decline: represents the total production that the field will produce before decline phase is initiated. So the number of years at plateau is measured by the cumulative production before decline. This is measured by the formula:

$$Cumulative\ Prod\ predecline = f(HCT, OriginalR, Depth, API, Project\ Type, RiskRatio)$$

How much can be produced before the plateau production cannot be maintained at an economical efficient level is related to the above variables. The API is important for heavy oil production as it is possible to control the plateau production level longer than for lighter oils. The project type is useful also for cases like oil sands in Canada to which the production can be kept at plateau production for a larger share of the recoverable resources.

Decline rate: represents the rate at which the production will decline until the asset is shut down because of being uneconomical, and abandoned. The decline rate is calculated based on:

$$Decline\ rate = f\left(OriginalR, Cumulative\ Prod\ predecline, Plateau\ Production, Opex\left(\frac{\$}{bbl}\right), Fixed\ Cost, \right.$$

$$\left. SalesPrice\right)$$

The formula calculates the decline rate as, $Decline\ rate = \dfrac{Plateau\ Production}{OriginalR-cumulative\ Prod}$

The decline rate is applied to the calculation of the production during the decline phase as,

$$Production\ (y) = Production(y-1) * e^{-decline\ rate}$$

The economic variables above (opex, fixed cost and sales price) are used to determine the point of economic cut-off. This point is the moment at which the field is no longer profitable and therefore it would be economically better to stop the production. The cut-off production level can be determined using the fixed cost, the variable cost, sales price and the production. If no economical cut-off is calculated a minimum level of allowed production should be defined, otherwise the production will extend infinitely since it is based on an exponential decline.

Multiple hydrocarbons at the asset: As we have mentioned above, an asset might hold more than one hydrocarbon. This has an impact on the forecasting of production. If an asset has both liquids and gas resources the calculation of the generic profile must be processed twice. The main hydrocarbon is calculated first as it is considered the hydrocarbon that drives the development of the asset. When calculating the production of secondary hydrocarbons, it should take into account some key figures from the main hydrocarbon. These are:

- If the secondary hydrocarbon is gas, then it should only start being produced (sold) after the liquids production exits plateau. The idea is that the operator will keep the gas in the reservoir to maintain the pressure to enhance the production of the main hydrocarbon (liquids in this case). The below figure illustrates how the gas production would appear. The plateau level of the gas would depend on the gas resources in a similar way as described in the above formulas.
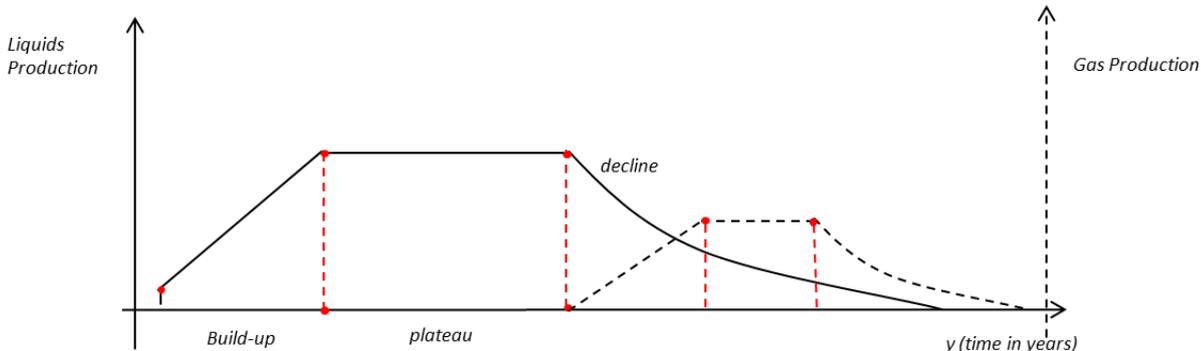

Figure 10: Illustration of the forecasted production of both hydrocarbons (liquids and gas) for an oil field in which the gas is the secondary hydrocarbon.

- If the secondary hydrocarbon is liquids, then the production starts together with the gas. We should assume the liquids must be produced within the lifetime of the gas production. Figure 11 illustrates a potential production profile for a gas field with liquids. Note that the liquid production is completed before the gas terminates. The logic is that producing the gas reduces the pressure to a point where liquid production is not profitable, long before the gas is all produced.
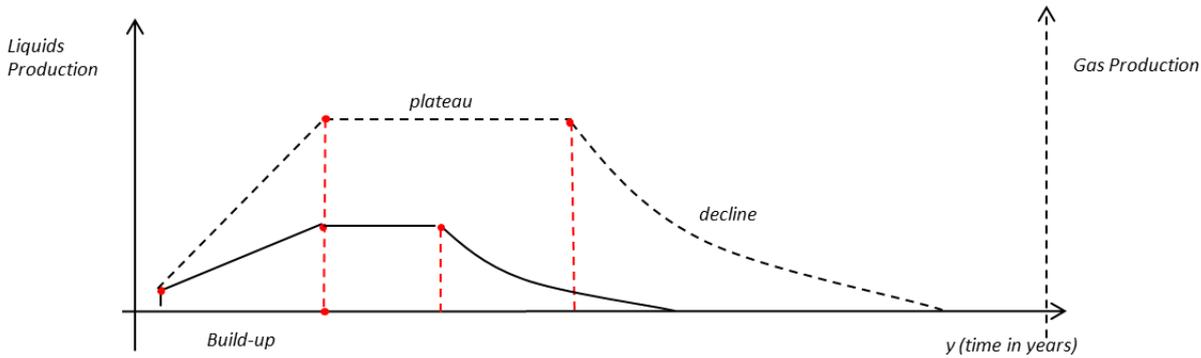
Figure 11: Example of production profile for a gas field with liquids resources.

4.4.2 Assets with historical production

When an asset has historical production the algorithm will combine the historical values with the expected quarter-pipe shape in order to forecast the future production. Here it is important to know the current lifecycle of the field. This is done during the calculation of key parameters (4.2.3).

Here are a few examples based on our output data:

- Field is in build-up phase:
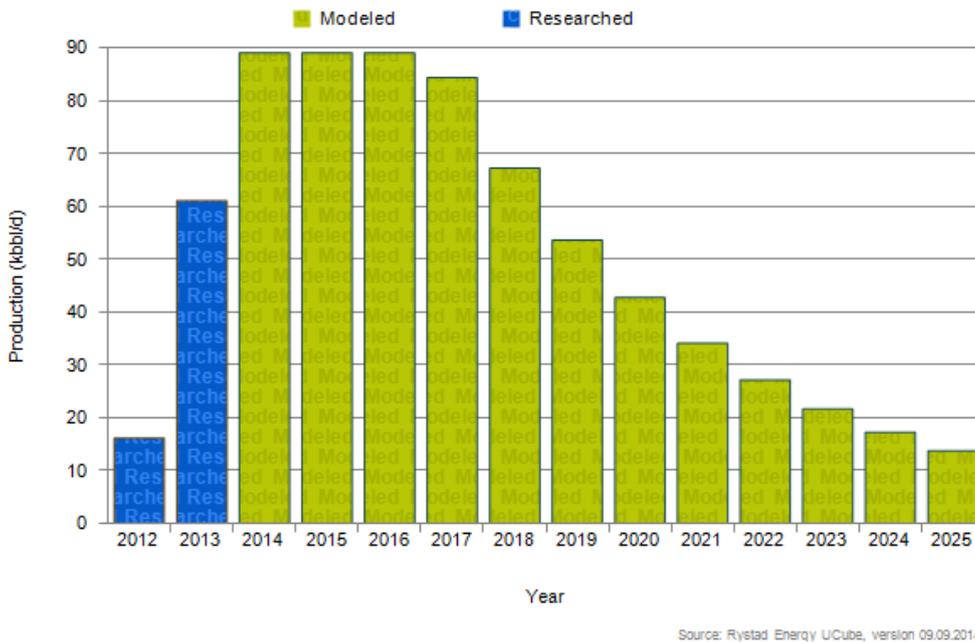

Source: Rystad Energy UCube, version 09.09.2014

Figure 12: Baleia Azul, BR production as kbbl/d from start of production up to 2025

In this case the historical production only includes the initial years. Since the lifecycle is determined to be in Build-up the profile will continue to grow to the plateau level, then it stays at plateau until decline, in line with the generic profile. The time it takes to reach the plateau is based on the historical production trend and the calculated expected number of build-up years.
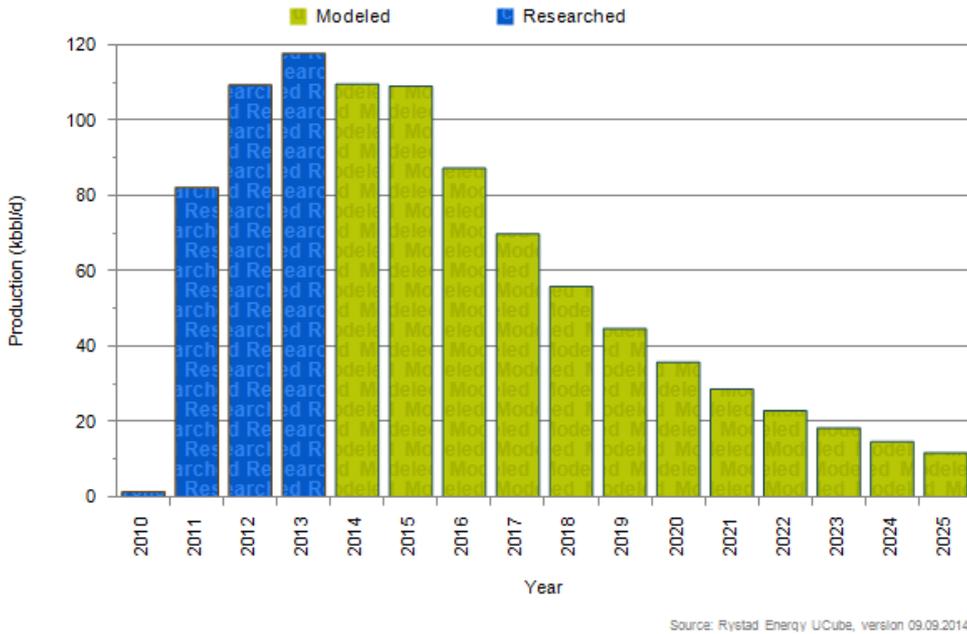
- Field is at plateau:

Figure 13: Jubarte 2nd phase, BR production as kbbl/d from start of production up to 2025

For the cases where lifecycle has been determined to be in plateau production, the algorithm will keep the production at plateau level until the field has produced more than the cumulative production pre-decline, after which the decline will start. In the above case the forecasted level of production is slightly lower than the historical value. This is because the researched plateau production value is lower than the historical production value. So for this case the future production is set at plateau using the researched plateau production value which was not changed in the inconsistencies check (4.2.2.) because the deviation was not enough to be triggered as an issue.

- Field in decline phase:
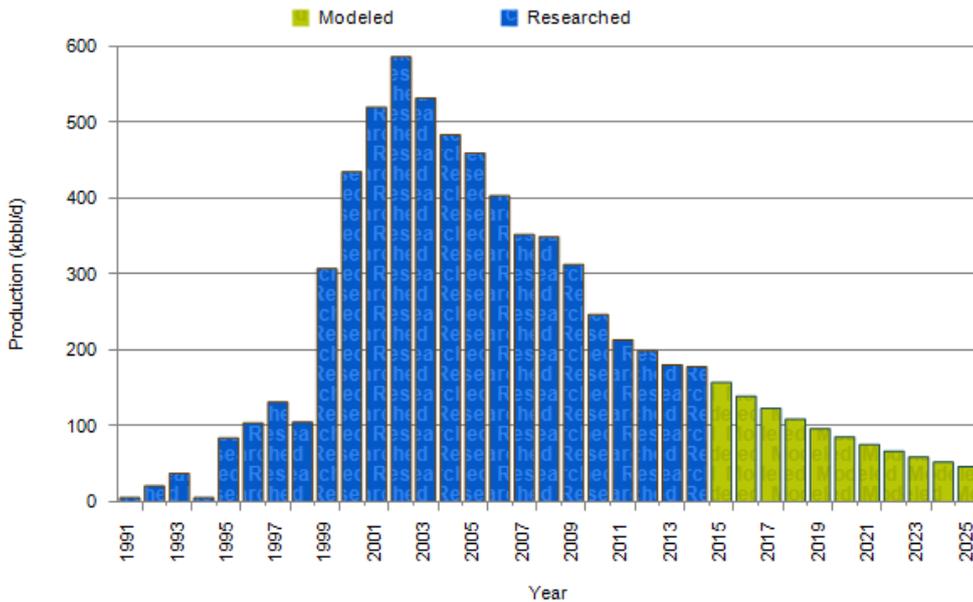
Source: Rystad Energy UCube, version 09.09.2014

Figure 14: Marlim, BR oil production as kbbl/d from start of production up to 2025

When the lifecycle is in decline, the future production will be declining based on the calculated decline rate taking into account the remaining resources and the economic cut-off.

4.4.3 Well based approach

A well based approach provides more realistic results, but also requires more detailed input. EIA uses this in OLOGSS, and Rystad Energy does this for their shale modelling. The model consists in forecasting a drilling schedule for each asset/acreage and attributing a well production profile to each well. Afterwards the production from all the wells is summed up to obtain the asset production.

The model requires a few new variables or parameters not used in the Asset model for production profiling. These variables are:

Variable	Comment
Acreage Area	Acreage that defines the asset
Well spacing	Density parameter, defining the space between each well
Utilization rate	Share of the acreage that the company will drill
Pilot number of wells	Nr of wells drilled per full year during the pilot phase
Plateau number of wells	Nr of wells drilled per full year during the plateau phase
Build-up phase	Number that determines the length of build-up phase in years
Plateau phase	Number that determines the length of plateau phase in years
Well IP	Well initial production
Well di	Initial decline, hyperbolic parameter. Together with b and IP it defines the well curve
Well b	Hyperbolic factor. Same as for Di

Well EUR	Estimated ultimate recovery per well
Well lifetime	Maximum life duration of a well. Useful when the IP production is very low
Deterioration after plateau	Yearly reduction of the initial production (I.e. IP decline) for wells after plateau ends, representing the reduced reservoir pressure and that the sweeter spots are taken
Well minimum decline production rate	Represents the lowest possible decline rate for the well

Nr Wells represents the total number of wells which will be drilled during the entire lifetime of the asset. The Acreage area and well spacing are used to determine the total possible number or wells. The utilization rate takes into account the amount of the area that will be drilled. Utilization rate may be given at play level, but for specific assets (e.g. one company's acreage in one play) more precise values may be known.

$$NrWells = \frac{Acreage\ area}{Well\ spacing} * Utilization\ rate$$

With the total number of wells desired for the entire lifetime known, we now calculate the well schedule.

$$Well\ list = f(Dates, NrWells, PilotNrWells, PlateauNrWells, BuildupPhase, PlateauPhase, HistoricWells)$$

The well schedule called Well list is calculated by determining a profile of nr of wells completed yearly which may be similar to the trapezoidal production profile mentioned in chapter 4.4.1.
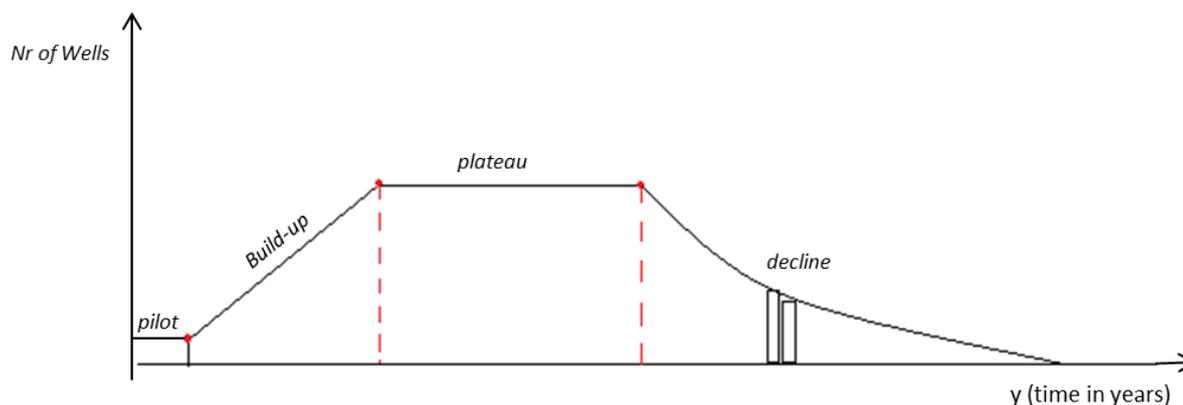

Figure 15: well schedule profile – nr of wells per year during the lifecycle of the asset

If the actual drilling plan is known the calculation is very simple, otherwise the number of wells per year depends on the input parameters. The calculations for each life cycle are:

- Pilot phase:
  During this stage we keep a steady number of wells per year. Note that the number of wells can be researched, if not it should be a % of the total of number of wells. Such default values should be made per

play if there is enough statistical information.

The pilot phase duration is also an input parameter. If no information is available it could be considered a % of the time required for the build-up.

- Build-up:

  The algorithm assumes a linear growth on the drilling activity from the pilot level to the plateau number of wells (maximum drilling activity stage). The duration of the build-up is an input variable. A default value should exist per play.

- Plateau:

  During this stage the number of wells per year is kept at a maximum. The duration of the plateau stage is based on the input variable "plateau phase". A default value should exist per play.

- Decline:

  The logic for calculating the step down rate is based on knowing the plateau level (nr of wells per year), the lifetime (how many more years the asset will drill wells for), and the remaining nr of wells (how many wells are expected to still be drilled). With these 3 variables it is possible to determine a decline rate which will provide the solution.

In the decline calculation the 3 required variables may be inconsistent. So far only two inconsistencies have been considered.

First, if the total number of wells based on the acreage, spacing, and utilization rate is too low we assume that the well schedule is concluded when it reaches the calculated total number of wells. Second, if the lifetime (number of years of drilling) is not enough to drill the expected number of wells (too low plateau, too few years) we extend the lifetime of the field in order to ensure that the total number of wells is always reached with a minimum decline rate.

Wells don't start production at the same date every year. The well list gives a number of wells per year, but must also contain information on when each well when will be drilled. The algorithm must distribute the wells equally in the date space of each phase. For instance if the pilot phase started at the middle of a year and it took only 3 months then during the 3rd quarter of that year the field would have to drill 25% of the number of pilot wells yearly during those months. However, the drilling rate would be higher in the 4th quarter of the year as it would enter the build-up stage where the drilling rate is higher.

When the algorithm is calculating the number of wells per year it must take into account the historical wells and adjust the time at which these wells are drilled to match with the expected profile. The easiest way is to introduce a correction factor called Well weight and apply the value to all the wells where there are historical data. Otherwise the value is seen as 1.

$$Well\ weight\ (y)\ = \frac{Historic\ Nr\ Wells\ (y)}{Calculated\ Nr\ of\ Wells\ (y)}$$

When the well schedule is done we only need to know the production for each well to calculate the asset production. For the well production we use a hyperbolic function.
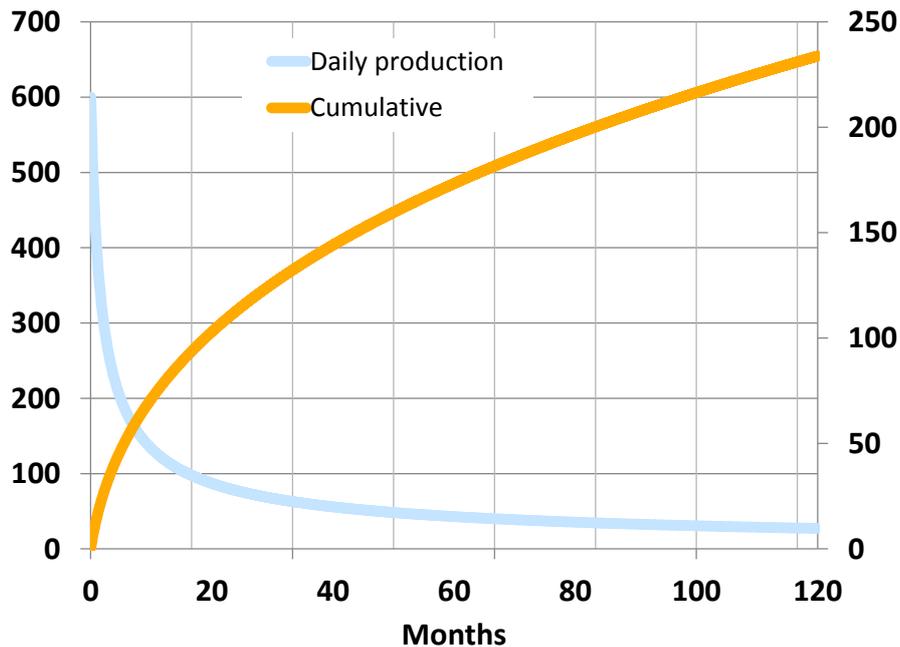
Figure 16: Sample shape of a well curve with IP = 600 (boe/d), Di = 0.019 and b = 1.5. Daily production in boe/d and cumulative production in kboe.

$$q(t_1, t_2) = \frac{q_0}{b * Di} * \left(\frac{1}{1 - \frac{1}{b}} \right) * [(1 + b * Di * t_2)^{\left(1 - \frac{1}{b}\right)} - (1 + b * Di * t_1)^{\left(1 - \frac{1}{b}\right)}]$$

In the above formula q(t1,t2) is the sum of production between days t1 and t2 (i.e. t1 = 0 and t2 = 1 returns the initial production IP), and Di and b are hyperbolical parameters defined in the table above.

The function will provide the volume of production for an interval of time, in days. Since we are interested in yearly production we will calculate the production for the well per year by using the dates at the beginning and end of year. For example if we try to determine the production level for the 2nd year and assuming that neither that year nor the 1st year of production is a leap year we would use for t_1 366, and for t_2 = 730.

Two other variables defined in the table above are important when calculating the production profile for each of the wells.

First, the *well minimum decline production rate* is the minimum rate of decline of production per year for the well. One implication of this variable is that the well profile is not only a hyperbolic function, but also contains an exponential decline in the late phase, a second implication that the decline will always be faster or equal to the minimum decline rate.

The second variable is the *Deterioration after plateau*. When calculating the production profile for the individual wells the deterioration effect should be used after the plateau to reduce the initial IP, reflecting the reduced response of the reservoir and assuming that the sweeter spots are taken.

After calculating the production for each well in a yearly time series we just need to sum it to obtain the asset production (total production).

We need split factors at asset level to split the production into crude, condensate, gas and NGL. These input variables must sum up to 100% and represent the share of each hydrocarbon. If no information is available for the asset a play or country default should be provided.
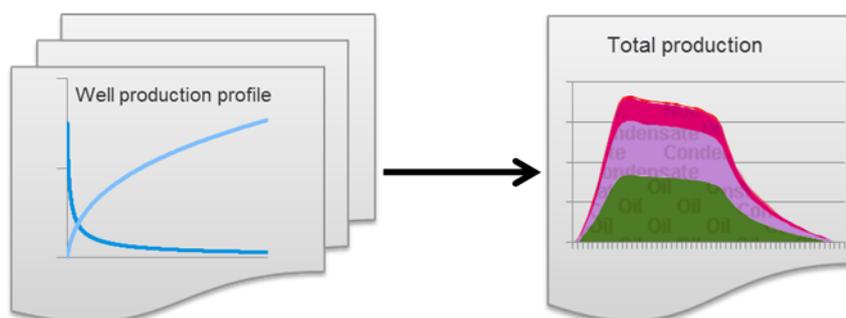

Figure 17: The production profiles of the individual wells are summed up to represent the asset production

When the asset profile is calculated based on a well model there is no hydrocarbon iteration. Since we know exactly the well production we will have as output the production based on the share of hydrocarbons per well.

4.5 Undiscovered resources

Undiscovered resources (or Yet-To-Find, YTF) must be included for the model to be realistic in the longer term. There will be more exploration, and more fields will be discovered, developed and start production. The challenge with YTF is that no facts are available about what is actually going to be discovered, so results will mainly rely on modelling.

There are two realistic alternatives for estimating the potential production from current and future exploration activities:

1)   The advanced, activity-driven approach is to collect detailed data on the companies' actual planned exploration wells in active leases. Assuming the oil companies are rational it is a reasonable assumption that the prospectivity of each lease scales with the cost of the exploration program. "Creaming curves" for the basin/play or analogs can be used to estimate risked/expected volumes found per dollar (finding cost). The expected volume in each license can then be calculated as cost of exploration program divided by the finding cost. This approach must be supplemented with a method for unawarded acreage.

2)   A more simplistic, resource-driven approach is to group all possibly prospective acreage into basin/country assessment units and estimate the undiscovered technical volumes for each assessment unit based on USGS or other sources. Such estimates should preferably be combined with a set of consistently applied factors to account for technical and commercial risks. In absence of USGS estimates, the technical YTF volumes can be estimated based on resource intensity (boe/sqm) for proven analogous basin/plays where analogy is given by sedimentary thickness and source rock quality (Kerogen type, thermal maturity, Tmax, TOC, thickness).

We suggest the second approach is adapted initially, both for active leases and for open acreage. The following data and assumptions would then be required/useful:

- Basin/country assessment unit name, ref USGS' TPS units
- Discovered volumes yet to date of crude, condensate, gas, NGL

- Technical volumes yet to find, implied by USGS or directly estimated. Volumes are assumed risked for probability of discovery, not for probability of drilling.
- Technical risk factor for exploration maturity and availability of geological data. This factor comes on top of USGS estimates and does not vary with price levels. This factor influences the probability of discovery.
- Commercial risk factor 0-1 on a scale given by infrastructure/industry maturity, cost levels, fiscal/price stability. This factor varies with price levels and influences the probability of drilling and time to development.
- Active exploration acreage (sqmi)
- Open acreage (sqmi)
- Typical size of acreage (sqmi) awarded per lease round
- Typical number of licenses awarded in each lease round
- Discovered resources per year. Low, mid and high estimate. Continuous trends in mid case, S-curve time distribution.
- Average risked discovery size, for crude, condensate, gas, and NGL. S-curve.
- Average time from discovery to production start, typically 7-12 years for large offshore fields.

One can proceed as follows. For a given basin/country assessment unit ("unit") establish the remaining technical risked resources and the technical risk factor. Also estimate a commercial risk factor for a mid scenario. The product of the technical resources and the two factors gives the YTF volume for the unit for the mid scenario.

Establish the discovery history for the unit. Extrapolate the discovery history into the future, distributing the YTF volume according to a S/creaming curve model. In the mid case the discovery trend should continue in the short term, and annually discovered volumes should trend downwards as most of the YTF resources have been found. This provides a discovered volume pr year pr unit ("annual volume").

If this unit has annual award rounds, divide the annual volume by the average number of leases awarded pr round. This provides the average discovery size.

When turning the discoveries into production calculate the generic production profile for a field with the average discovery size. Take into account all attributes that can be estimated for the field to get the most out of the profiler: onshore/offshore, platform/floater, oil/gas field, conventional/unconventional, etc. The production resulting from the annual volume is then calculated by multiplying the average discovery profile by the average number of leases awarded pr round. The result will be different than if one single profile was made for the entire annual volume. The time from discovery to production start is an important parameter in placing the resulting profile along the timeline. Whereas onshore discoveries may be developed quickly offshore developments start production typically 7-12 years after discovery. An improvement to the above is to sum the profiles for the average size discoveries using a distribution of start-up years (i.e. distribution of years to start-up). It may be practical to make one asset per annual volume per unit.

This should now be repeated for every discovery year for the unit, and for all the units.

In the high and low scenarios the commercial factor can be adjusted higher and lower than for the mid scenario. This results in higher/lower YTF volumes. The discovery trends can be made to increase/decrease relative to the mid case projection. Then production can be calculated as described above. One may consider shifting the number of years between discovery and production start slightly for the scenarios, but in any case it is rational for a company not to postpone development of a profitable field. It may be more relevant in the low case, where developing decisions may delay due to higher apparent uncertainty.

Costs can be added to the YTF assets, but this likely adds little value, given the uncertainty of the input. Still, it is meaningful to assign break-even prices to YTF assets. See chapter 4.6.7.

4.6   Economics Module

The Economic Module calculates both the revenue and costs for the asset.

4.6.1 Revenues

The asset revenue is simply calculated by multiplying the asset production with the relevant prices:

$$Revenue\ (HCT, y) = Production\ (HCT, y) * Sales\ Price\ (HCT, y)$$

4.6.2 Costs

The costs are split into two types. These are capital expenses (investments) and operational expenses. The main cost elements are:

Cost Type	Cost Group	Comment
Pre-drilling	Capex	Drilling of wells before production start, ready to produce at start-up
Drilling	Capex	Drilling of new development wells after starting production
Development cost	Capex	Initial costs of developing the field, before production start
Modification cost	Capex	Changes to facility and infrastructure required as field characteristics change
Platform cost	Capex	Cost of building/establishing facility
Feed cost	Capex	Cost of FEED studies
Concept studies cost	Capex	Cost of concept studies
Expansion cost	Capex	Cost of modifications to increase production capacity
Transportation cost	Opex	Cost of transporting hydrocarbons from wellhead to sales point
SGA cost	Opex	Administrative/overhead costs
Lease cost	Opex	Cost of holding leases
Fixed cost	Opex	Fixed costs of running operations, independent of production
Variable cost	Opex	Costs that scale with produced volume, e.g. transportation, tariffs.
Abandonment cost	Opex	Cost of decommissioning facilities and wells

4.6.3 Cost cycling

Before going into how each of the cost elements is calculated we discuss the concept of cost cycling. Cost cycling is used to reflect the fact that higher oil prices will increase demand for personnel, materials, products, and services, and thus drive cost levels. The opposite happens at lower oil prices. Cost cycling is applied to all the costs elements. The logic could be described by the diagram in Figure 18:
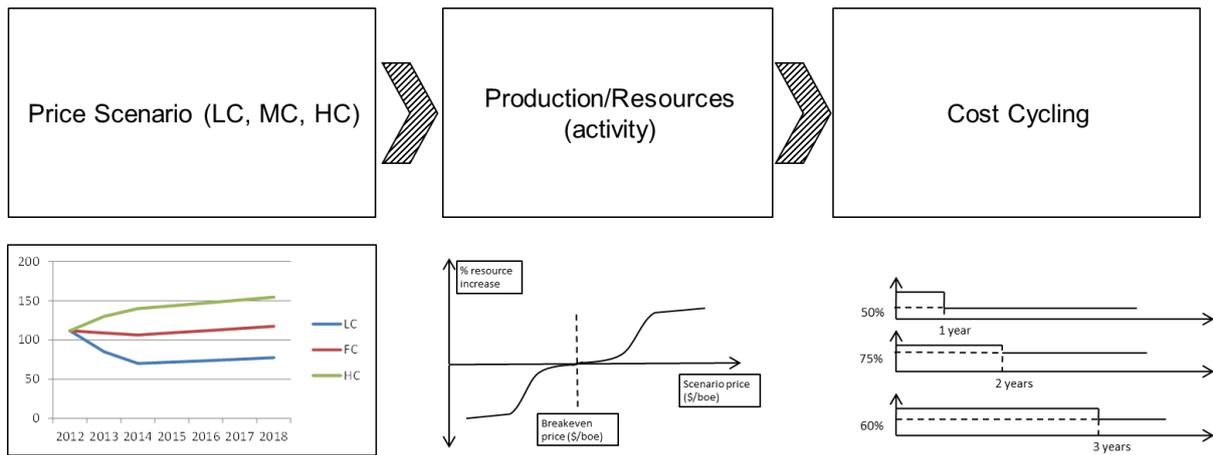
Figure 18: Cost cycling: different price scenarios (left) will generate different activity levels, driving unit prices, and resources (middle). The right chart shows different lead time for and price elasticity for different cost segments

Figure 18 shows that different costs segments respond differently to price changes. The cost cycling logic is based on costs varying directly with price fluctuations. In our model we have defined three key segments with different response to price variations; steel, engineering, and rig costs. Other segments are expressed as combinations of these. Steel costs will vary quite fast with oil price, while rig costs changes will be slower as they are based on multi-year contracts.

Since assets differ on facility, water depth and project type tone should determine the asset's dependence on the three segments. For instance, oil sands mining projects in Canada are not linked to rig costs. Thus when developing a cost cycling approach it is required to have a method for determining the impact of such 3 segments (steel, engineering and rig costs) on each type of assets. When applying cost cycling the price used for determining the variation should not be the local sales price, but the global market price.

The cost cycling is referred to a reference scenario. Cost cycling calculations are performed for all years. The reason is that the price scenario might change compared to the reference price. Figure 19 shows how the Brent future price differed from a flat (in real terms) 100 USD/bbl scenario in 2011, being higher in the short term and lower in the long term.
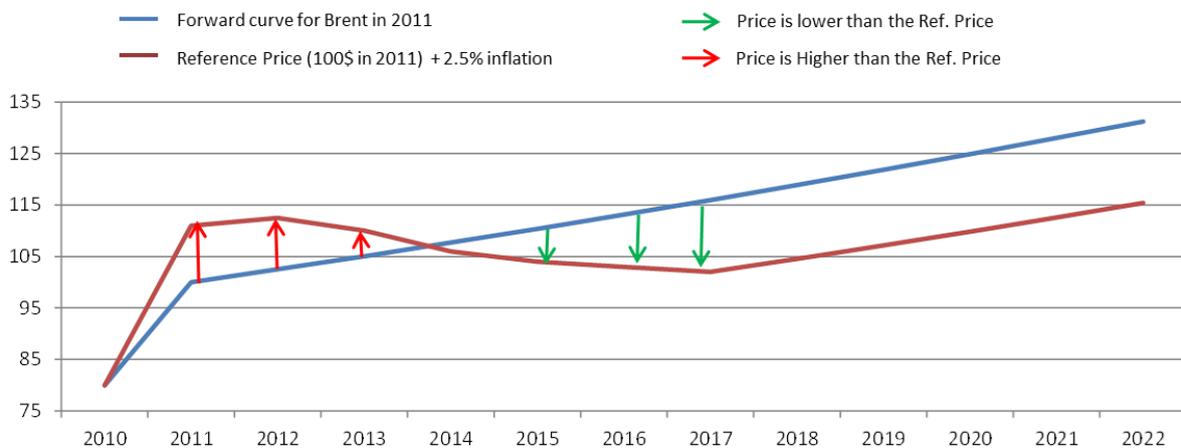

Figure 19: Forward curve price scenario for Brent vs. reference price (both of 2011) from 2011 to 2022.

In Figure 19 the red and green arrows indicate for years there is a deviation between the price scenario and the reference price, to which the costs are linked.

In Figure 19, assume you are in 2011, and the price has just increased. The cost cycling algorithm will calculate the impact of the price increase vs the reference price on steel, engineering and rig unit costs. Specifically, the price increase in 2011 is used to determine the steel cost for 2012, the engineering cost for 2013, and rig cost for 2014. This is repeated for all years. Correspondingly, the price difference in 2012 will be used to calculate the costs of steel, engineering, rigs in 2013, 2014, and 2015, respectively.

4.6.4 Capital expenditure

The capital expenses (capex) include all development costs related to facilities and drilling of wells. The initial capital expenses are related to establishing the facility and necessary infrastructure, as well as pre-drilling costs, often termed development capex. Throughout the field life capital expenses include drilling of more development wells (well capex) and modifications done to the facility, processing system or e.g. subsea infrastructure. For modifications the term modification capex is often used to include upgrades required to maintain current production capacity (e.g. larger separator), whereas expansion capex is used for investments that increase capacity (e.g. increasing processing capacity). Modifications are often mentioned together with maintenance and repair (MMR), but the two latter are operational expenses.

The platform/facility cost for an asset is calculated in three steps. First we calculate the total platform cost, and secondly the share of this cost which is structural. Finally we determine the distribution of these costs in a time series based on nr of years (duration) of development and the share of the costs for each of the years. The total platform cost is calculated as:

$$Platform\ cost = f(OriginalR, GOR, WaterDepth, Project\ Type, Facility, Stranded)$$

The platform cost is based on a facility cost per boe number. This number is taken from an average facility cost per boe-curve which is derived from analyses of historical data. The facility cost per boe varies with the original resources, and there are different such curves for each of the different combinations of the variables above (GOR, water depth, project type and facility). After obtaining the facility cost per boe we apply the original resources to determine the total cost. If the asset is stranded (no concrete development plans due to lack of infrastructure or technology) a premium is applied. This approach can be simplified by determining fixed factors for the different combinations of asset parameters, and applying these to one facility cost per boe- curve.

Figure 20 shows the platform cost ($/boe) for onshore conventional assets. The curve drops off quickly with increasing field size (OriginalR), reflecting the economy of scale.
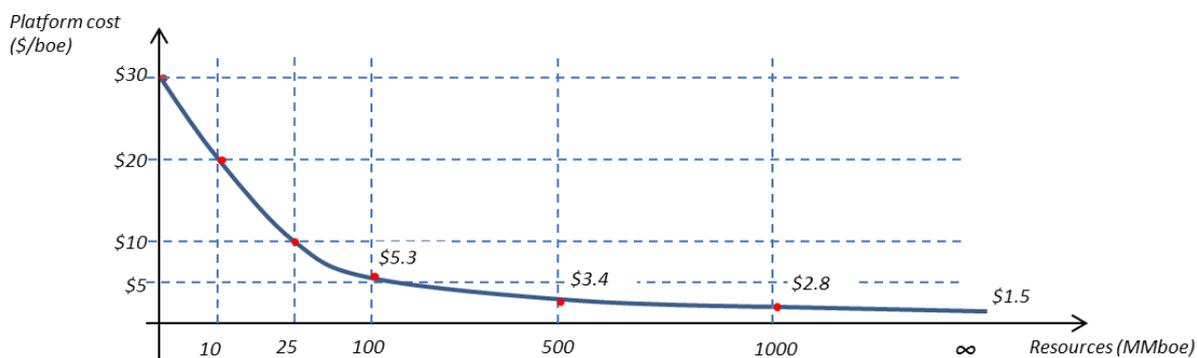

Figure 20: Platform cost ($/boe) for onshore assets

The structure cost ratio represents the share of the platform cost which is linked to the base structure of the facility. The structure cost must be calculated because this cost must be spent before the asset starts producing, and also because it will be linked to the main hydrocarbon. The structure share of the platform cost is directly dependent on the facility type:

$$Structure\ cost\ share\ (\%) = f(Facility)$$

The last step of the platform cost calculation is the distributing of costs. The distribution depends on the estimated number of years required for development, and the share of costs for each of the years. The distribution is calculated   from:

$$Development\ shape = f(Dates, Facility, OriginalR)$$

The number of development years must be consistent with the assets' timeline dates. Development must fit in between the Approval date and Production start date. Thus the dates provide a maximum number of years for development.

The Facility and asset size (by original resources) are used in a similar way setting limitations for the minimum and maximum   number   of   development   years. The combination of these limitations determines the number of development years.

The development costs must be distributed over the development years. This can be done using a normal distribution, where the mean and the standard deviation are estimated by matching the cost profiles of known development projects. Alternatively one may make fixed distribution vectors for different years of development and development types.

For pre-drilling the logic is similar. We determine a well cost per boe ($/bbl) number, and use the facility and resources to determine what share of the drilling will be made upfront. The pre-drilling can be described by the function:

$$PreDrilling = f(OriginalR, Facility, well\ cost\ (\frac{\$}{boe}))$$

where

$$well\ cost\ (\frac{\$}{boe}) = f(water\ depth, GOR, Project\ Type)$$

The well cost depends on whether the asset is onshore or offshore, on the project type, and on the asset being an oil or gas field. The total well cost for the asset is found by multiplying the well cost per boe by the original reserves.

The share of the total well cost to go into pre-drilling is determined by the original resources and the facility type. For example an asset with a small resource base of 10 MMboe developed using extended reach will have all the drilling costs as pre-drilling. On the other hand, when the facility is built with drilling units the amount of pre-drilling will be small.

The drilling cost (after pre-drill) is:

$$Drilling\ cost = OriginalR * well\ cost\ \left(\frac{\$}{boe}\right) - Pre\ drilling\ cost$$

This drilling cost must be distributed over the active lifetime of the field. For this the algorithm takes into account the facility, project type and the production profile.

$$Drilling\ cost\ (y) = f(Facility, Production(y))$$

For onshore, the drilling cost follows the activity, i.e. the Production(y), so the well cost for onshore fields mainly follows the shape of the production profile. For offshore the distribution of the drilling cost is not proportional to the production profile. Analyses show that the drilling profiles are typically different for assets developed with different facility types. Thus different drilling profiles should be applied to different asset types. The sum over the profile is

given above, and the profile is stretched to match the lifetime of the field. As an example Figure 21 shows the profile for an offshore platform without drilling units, where drilling is campaign driven.
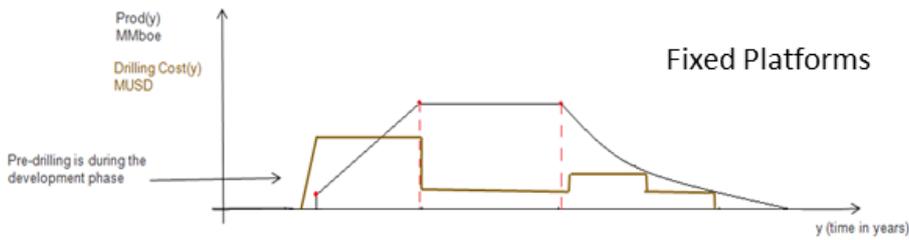

Figure 21: Typical drilling cost distribution for assets with fixed platform without drilling units

For subsea fields drilling of new wells is accompanied by additional considerable costs related to subsea x-mas trees, manifolds, and installation. We term this subsea brownfield capex, and it applies to assets with wet wellheads. The corresponding greenfield costs related to predrilling is the EPC cost. So the subsea brownfield capex is directly related to the drilling :

$$Subsea\ brownfield\ cost(y) = f(Facility, Drilling\ cost\ (y))$$

The Modification cost (for facilities) is related to the platform cost, the size of the asset (original resources), the facility and the lifecycle profile.

$$Modification\ cost = f(Facility, Platform\ Cost, OriginalR, Lifecycle)$$

The modification cost appears because as the asset matures there will be a need to do modifications to maintain production levels and integrity. Thus modification costs only start after the build-up phase. As the asset matures the costs will increase and a plateau for the modification cost is reached during the decline phase (determined by the lifecycle).

The modification costs plateau level is based on the asset size (original resources) and the platform cost, in which the larger the asset the higher the share of the platform costs. As an example the timing of modification costs for a FPSO is displayed in Figure 22 below.
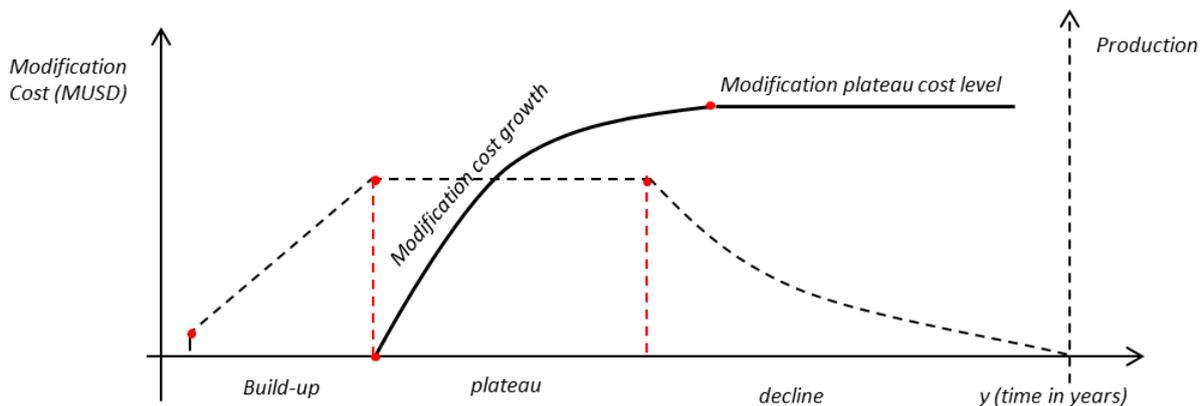

Figure 22: Illustration of timing of modification costs for an FPSO.

One exception to this calculation method is for oil sands assets where it is better to consider a fixed share of the development cost rather than a varying share depending on the field size.

4.6.5 Exploration costs

Exploration costs are costs of acquiring acreage, doing seismics, and drilling wildcats or appraisal wells to discover and delineate oil and gas fields.

We propose not to include exploration costs in this supply-demand model. The reasons are:

- When making decisions on developing a field the exploration costs are sunk, and the main thing that matters is the volumes discovered. Although developing a field in many cases is required to deduct the exploration costs this will likely seldom be decisive for development decisions.
- The methodology we have proposed for undiscovered resources does not rely on or include exploration costs.
- Also, modelling exploration costs may be tedious and hard to get right. It is straight forward to place exploration costs on the fields, but half of the exploration costs are spent on dry wells not making discoveries, and it adds little value to the supply-demand model to include this activity.

So although exploration costs may be deducted, and thus influence break-even prices, it does not add significant value to the supply model to include exploration costs, and complicating efforts are avoided.

4.6.6 Operational expenses

The operational expenses are all related to running the operations, i.e. costs that would disappear if operations were discontinued. We split these costs into transportation costs, SG&A, production and abandonment costs.

Transportation costs are calculated as an assumed fixed cost per boe produced throughout the field's entire lifetime, i.e. it is linked to the production. One must distinguish between liquids and gas production as the unit transportation costs are different.

$$Transportation\ Cost\ (y) = f(Production(y), GasTranspCost, LiqTranspCost)$$

The unit transportation costs should ideally be asset dependent, but usually fixed numbers for different geographies will do.

The SGA cost (sales, general, and administrative expenses) has two parts. The first part is linked to the bare existence of the asset and based on the size (plateau level of production) of the asset. Consider this part the base SGA cost.
The second part scales with the production. The SGA cost linked to production is usually larger than the SGA base cost. The SGA cost is thus calculated as:

$$SGA\ Cost\ (y) = \left(BaseCost\left(\frac{\$}{boe}\right) * PlateuProduction\left(\frac{boe}{year}\right)\right) + \left(VariableCost\left(\frac{\$}{boe}\right) * Production(y)\left(\frac{boe}{year}\right)\right)$$

The Production cost includes 3 elements. These elements are the lease, fixed and variable costs. The lease cost is used if the asset operator has chosen to e.g. lease an FPSO instead of developing their own. In these cases there will be no fixed cost as the Lease cost includes all the fees required for the structural operation cost.
The fixed cost represents the base or invariable cost associated with running the facility. These costs can be very different for offshore and onshore assets, from high offshore to in some cases negligible or nothing onshore. The variable cost is the cost associated with the actual production per boe, such as the cost for electricity, machinery,

salaries,　　　　tariffs,　　　　and　　　　other　　　　per　　　　boe　　　　expenses.
I.e.;

$$Production\ Cost\ (y) = LeaseCost(y) + FixedCost(y) + VariableCost(y)$$

The lease cost is calculated as,

$$Lease\ Cost\ (y) = f(Facility, Plateau\ Production)$$

The Lease cost applies only to assets with leased FPSO (or other leased production facility). It is assumed that the lease scales with the capacity, i.e. the plateau level.

The fixed cost will be 0 for the cases of leased FPSOs (or other leased production facilities) and for most onshore locations. For other assets the cost is based on,

$$Fixed\ Cost\ (y) = f(OriginalR, GOR, WaterDepth, Facility, Plateau\ Production, Project\ Type)$$

 The fixed cost is based on calculating the average fixed cost per barrel ($/boe) for the type of asset. For this we use the ratio of Oil and Gas (as it is cheaper to produce gas fields due to better natural lift/drive). In the formula the facility is used mainly to reduce the costs for subsea assets. These have a lower cost per barrel of production as compared to e.g. floater or fixed platforms at similar water depth. The project type serves to determine specific projects types that have different cost levels (for instance arctic projects). The original resources is used to determine the impact of scale, reducing the per boe base cost up to a certain limit. The calculated average fixed cost per barrel ($/boe) is then just multiplied with the plateau production to determine the fixed cost. As it can be observed in Figure 23 the fixed cost per barrel is a linear function from $8 to $3 at 500 MMBoe. From 500 MMboe no economy of scale has been observed as the size increase also increases some logistic and complexity costs that balance with the economy of scale factor.
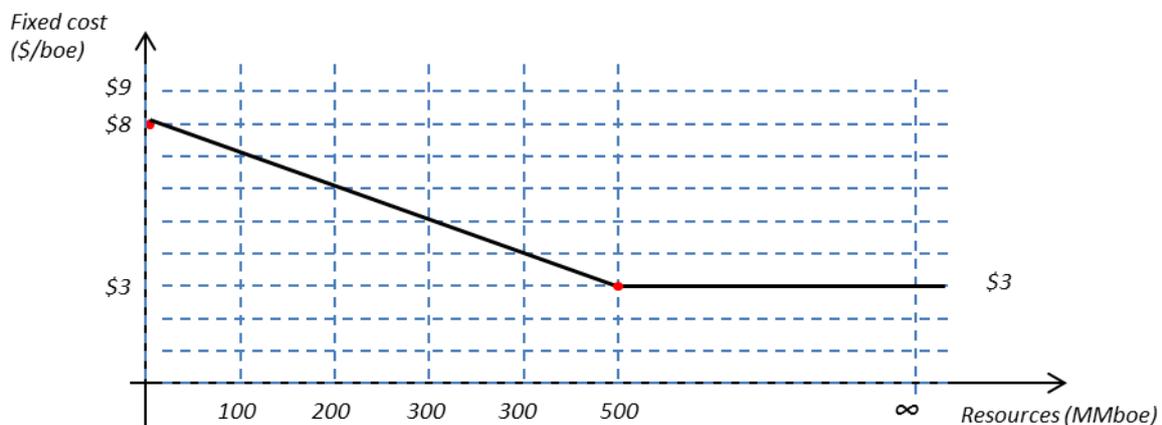

Figure 23: Fixed cost ($/boe) for conventional offshore oil asset

The variable cost is calculated as

$$Variable\ Cost\ (y) = production\ (y) * Opex\ Tarif$$

where the opex tariff is defined in table on page 22. The opex tariff is calculated as,

$$Opex\ tarif = f(\ GOR, WaterDepthAndAltitude, Project\ Type, API)$$

The opex tariff is based on 2 curves for average opex tariffs for onshore and offshore as function of oil gas ratio. The project type is used for adding premium costs for projects such as for example artic or oil sands. The API is applied to differentiate between non-upgraded oil sands projects with lower API and synthetic crude projects with higher API.

The abandonment cost is the last operational cost. The total abandonment cost is defined in the table in chapter 4.3 (xix). The value is calculated based on the function,

$$AbandonmentCost = f(Platform\ Cost, Facility)$$

The abandonment cost is linked to the platform (facility) cost - the larger the development cost the larger the complexity and workload of decommissioning. The Facility parameter determines the size of the abandonment cost as a share of the platform cost. Thus if an asset is onshore the abandonment cost will usually be quite low, while large fixed platforms with many wells will have the highest abandonment cost as a share of the platform cost.

The number of years from production shut-down to abandonment and duration of decommissioning is based on the facility type. These numbers can be determined by studying statistics from historical assets. The abandonment cost is then distributed equally onto the decommissioning years. As an example let's assume that for FPSOs we have the number of years to abandonment and the decommission duration of 2 years. If an FPSO is expected to stop production and operations in 2020 (still having production in 2020) the decommissioning would start in 2023 and would have half the abandonment cost in 2023 and the other half in 2024.

4.6.7 Break-even prices

The break-even module calculates 3 different break-even values for each asset. These break-even values are the base break-even, wedge break-even, and the asset break-even. The asset break-even is the break-even price for the asset, as seen from today. The base break-even is the break-even calculated considering only the costs and production from the base production (no new wells). The wedge break-even is the break-even for getting new production (new wells). For any asset which hasn't started production the wedge break-even will return the same value as the asset break-even, since their input data are identical, and one should avoid calculating both values.

All break-evens are calculated by finding the oil price that makes the NPV =0. This requires iteration: calculate NPV at one oil price, reduce/increase the oil price if NPV is positive/negative, repeat until NPV value is sufficiently low. They iteration converges quickly when using Newton's method. The NPV is the discounted sum of the free cash flow. Here we propose to discount the pre-tax free cash flow (see next chapter). The break-even price depends strongly on the discount rate applied, which reflects the oil companies profit requirement. We apply 10%.

We have implemented 3 ways to determine the break-even values. These differ in complexity:

- Basic approach: iteration process runs keeping the production and costs of the asset constant. The only variable is the sales price, which is varied in order to determine the break-even point. This approach has the advantage of being very fast in terms of processing as well as it is easy to replicate results using other tools like excel for verification.
- Cost variation: identical to above, but we allow the costs to vary based on the price change, i.e. due to cost cycling. Our experience is that the effect on the break-even price is not significant - around 1% -, while the complexity increases and the verification of the algorithm becomes harder.
- Full flexibility: both production and costs are varied during iteration. The costs vary due to cost cycling and because of change in production. The production changes with price because of the resources adjustment to the price. The result of this last approach has a larger effect on the break-even value, differing from field to field. On average the difference is less than 5% of the basic approach value. Verification of the algorithm is now rather difficult.

If we have a well based model it is optimal to use well information for both base and wedge break-evens. For base break-even one includes only the production from the currently producing wells, while for wedge break-even only new wells are included. If the future wells are identical it is sufficient to calculate the break-even for one well, if they are different all future wells must be included.

However, the majority of the production comes from assets for which well data are lacking. In these cases a fast way to determine a base and wedge break-even is by

- First determine a fast decline rate (expected decline rate if no more wells are drilled)
- Use the new decline curve to split the production into 2 profiles - a base production and a wedge production profile (see Figure 24).
- Place the costs accordingly into each of the profiles. While the wedge production profile should contain all the future capital expenditure the base profile should contain all the fixed operation costs. The variable costs or costs directly linked to the production should be split according to the production.
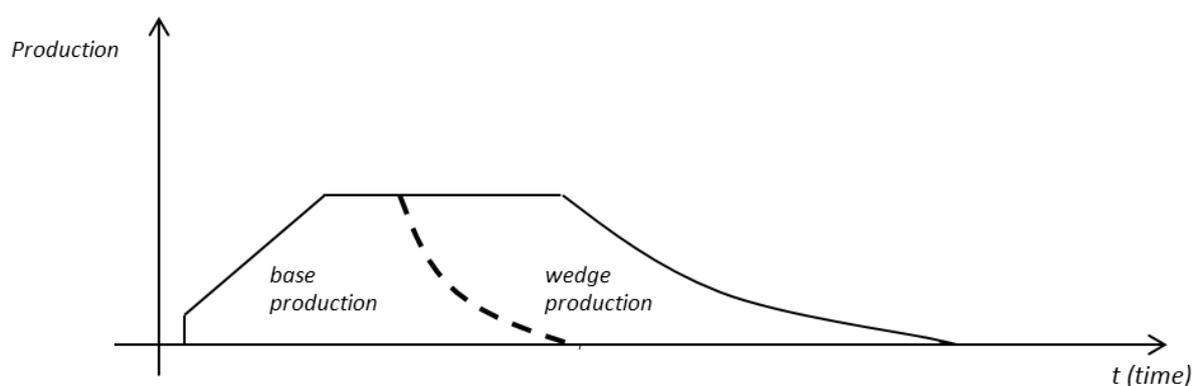

Figure 24: Wedge break-even can be calculated splitting asset's production into a base (no more investments) and a wedge production.

Using these 2 profiles it becomes straight forward to calculate the base and wedge break-evens.

For undiscovered assets we have proposed a methodology not involving economics (although it may be added). It adds value to the subsequent analyses if the YTF assets have break even prices. One could say that the technical and commerciality risk factors result in only profitable developments and assign low break-even prices (i.e. will contribute to supply). However, for the YTF assets it will be known whether they are onshore, offshore, conventional, unconventional, arctic, subsea, etc.. Thus e.g. a YTF asset in Canada expected to result in an oil sands development should be assigned a typical break-even price for oil sands projects (as known from the current oil sands fields). Further, if there are many YTF oil sands assets they could be assigned break-even prices spanning the same range/distribution we find in the current fields. This will bring more realism and dynamics into the future supply picture, helping to identify the marginal hydrocarbon sources also far out in time.

4.6.8 Tax and Royalty/Government take

Including tax and royalty adds complexity to the model. It is straight forward for countries with a standardized tax regime, but there are a broad variety of tax models or contract types at play around the world. Not only are they different, but can vary from field to field within a country, and the terms are not always disclosed. Thus it will be a challenge to get the necessary information in place. We propose to simplify to the doable by calculating the break-evens before tax. For pure tax regimes the tax doesn't change the break-evens, just the profitability for the owners. More complex tax models do influence the break-evens, but most of all determine the distribution of profit between owners and government. However, the break-even before tax tells if the field profitably can contribute to supply. If yes, the profit sharing is a technicality between government and owners. If the tax model makes the development

unprofitable for the owners (too high break-even for the owners) the owners will not develop the field. This is a loss-loss situation, and most likely the tax model will be negotiated to a win-win. Thus profitable-before-tax fields will be developed, and break-evens before tax are relevant for supply-demand analyses.

Below we outline some of the challenges related to tax calculations.

First, there is a large variety of different tax systems. The main types are Royalty-Tax, production sharing contracts (PSA, PSC) and service agreements. Within these categories of tax systems there are large differences. Here are some of the most common variations:

- Different taxes may be applied at different levels and different times in the algorithm. Some taxes apply pre-costs (like royalties), and in post-cost tax systems taxes may be deducted before or after profit oil sharing.
- Tax rates can be based on many different attributes such as depth, production level, cumulative production level, sales price, market price, year, IRR, API and others.
- In some cases the rates can be determines on a combination of multiple factors.
- In principle all the tax parameters may vary with the factors mentioned above, but usually some of them are fixed rates.
- When calculating deductible costs one must take into account cost ceilings, depreciation and uplift. Some tax systems treat the carry forward costs different, and ring fencing may also limit how costs can be deducted. There are many ways of depreciating assets of which some are: straight line decline (SLD), double declining balance (DDB), declining balance (SD), asset depreciation range (ADR), modified accelerated cost recovery methods (MACRS), sum of years digits (SYD), and unit of production (UOP). In many cases the bonuses, exploration costs and production costs are depreciated in different manners.

Some of the elements that can make the break-even for the owners lower than the pre-tax break-even are royalties, taxes that behave as royalties, cost ceilings which limit the deductible costs, the depreciation method, as well as possibility of uplift.

If the main purpose of including taxes is to estimate and analyze tax income for different countries applying an effective royalty and a government take would be much easier and straight forward. For this approximate tax rates should be worked out for each country, based on single asset modelling. One cannot apply the nominal tax rates directly, as uplifts, cost ceilings, depreciation rules etc. result in a different effective tax rate. One estimate can be to sum the government take over field life and divide by the sum of government take and owners' free cash flow, discounted or undiscounted.

In case one wants to include some tax effect on break-evens, the most important thing would be to remove the effective royalty from the revenue before calculating the break-evens.

5 ASSET OUTPUT

The results of the model run are written to the Asset Output data set. The data can be organized in many ways and tables.

The production profiles (historical and forecast) should be written to one deep table, and it is convenient to include the production from the scenarios in the same table. It is always a choice of how deep the table should be, e.g. in terms of making separate columns for crude, condensate, NGL, and gas in the table, or putting them below each other in the same column. It is our experience that the latter is practical. The same consideration goes for the economics table.

An important table is the table with asset properties. It is good DB practice not to duplicate data, and to organize data in related tables, to be combined with keys. An example of this is shown under *Aggregation of data* above, where the geographic hierarchy is built with look-up tables. However, this is not optimal for the Asset Output table. Rather this should be one large expanded table including columns for all asset parameters and hierarchies. While the corresponding Asset Input table would hold only the column Location, the Asset Output table will hold the columns Location, Area, Province, Country, Region, and Continent. This "flat" format is much more practical and faster to use when querying the data set for information, either for the supply-demand analyses run by WEPS+, or for analysis in general. If you e.g. want to pull out the US onshore crude production for 2015 you just filter out in the asset parameter table the rows with Country=USA and On/offshore=Onshore, and join with the production table, but including only the rows with Year=2015 and HCType=Crude.

A good way to analyze the data is to join the asset properties table with the production and economics tables and analyze the result with e.g. a pivot table in Excel. Even better is to build an OLAP cube that can be queried directly, or through cube viewers like Spotfire, Tableau, or Rystad Energy's Cube Browser. The OLAP solution is much faster and more convenient and fun to work with.

6 RUNNING THE MODEL

When input data are ready and model parameters are supplied the model should run to complete the Asset output data set. This data set is now ready for analyses, and need not be recalculated for sensitivity analyses. Two examples follow.

6.1   Iteration to establish supply-demand balance

Since break-even prices have been calculated it is suggested to use these to analyze the demand-supply situation. This example shows how this can be done. Based on the Asset output data set we can make the liquids cost-of-supply-curve in Figure 25. There is one bubble per 2 USD interval break-even prices, and the size reflects the volume produced at this break-even price. When WEPS+ has calculated a demand figure, say 90 MMbbl/d, we can read out the break-even oil price to be 101 USD/bbl. If this value is too high to support a demand of 90 MMbbl/d then the break-even price can be fed back into WEPS+ to calculate a new demand at this price. This will move the blue line to the left, bringing the break-even price down. This price supports a higher demand and WEPS+ will move the line to the right again. This will go on until the change in demand or oil-price is below some threshold. Thus in the interaction with WEPS+ GUM will respond very quickly, i.e. in a matter of seconds.

If the model includes dynamic price effects on production at asset level (i.e. production increases when oil price increases) the curve in Figure 25 should be recalculated for each new oil price tested. The break-even price for the asset does not change, but the production may change, slightly changing the size of the bubbles in Figure 25 and shifting the curve somewhat. The new volumes can be calculated by interpolating between the scenarios, which is fast. Again the model need not be recalculated.

The approach above has as its starting point that all potential supply is available in the model, but that not all of it will be commercial. Some projects will have break-even prices above the supply-demand balance point. If we look at the cost-of-supply curve for e.g. 2020 the implication is that these projects will not be developed. Figure 25 shows the curve for 2014. One should note that some of the fields with very high break-evens (as of today) are in
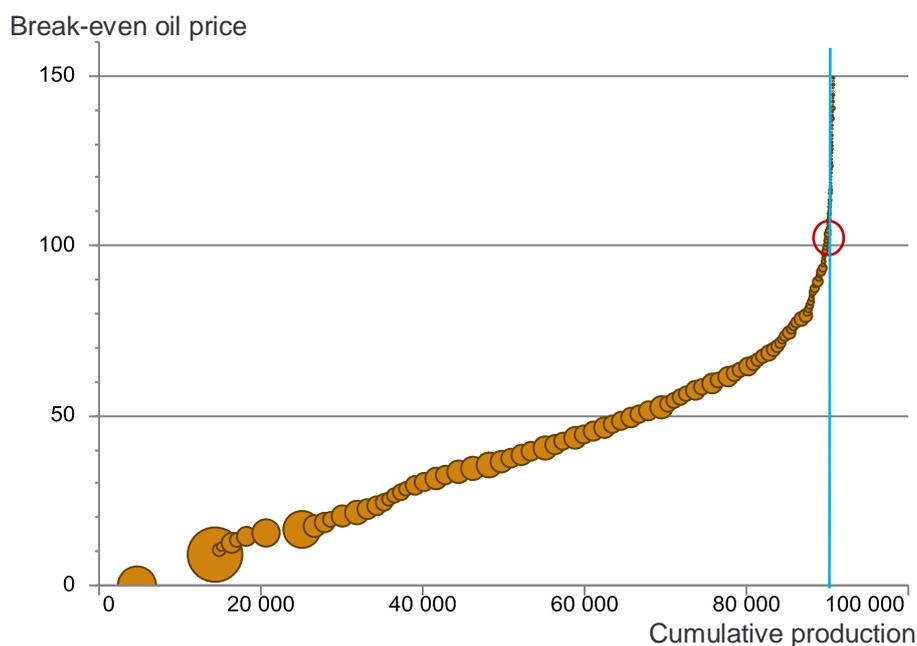

Figure 25: Cost of supply curve based on input data

tail production and will produce their last drops despite high break-evens. It is thus more meaningful to use cost-of-supply curves for the future.

6.2   Modeling effect on supply-demand of global events

One purpose of GUM is to calculate the effect on supply of e.g. OPEC production cuts, or production loss due to political unrest. As an example consider a Saudi production cut. To make a visible effect we assume that Saudi stops production from the Ghawar fields. Again we can make the same chart as above, just not including Ghawar fields in the data set. The result is shown in Figure 26. Removing Ghawar shifts the cost of supply curve 5 MMbbl to the left. WEPS+ will now have to move further to the left to find a new balance point, which clearly will be at a higher oil price point, which is what Saudi would want to achieve.
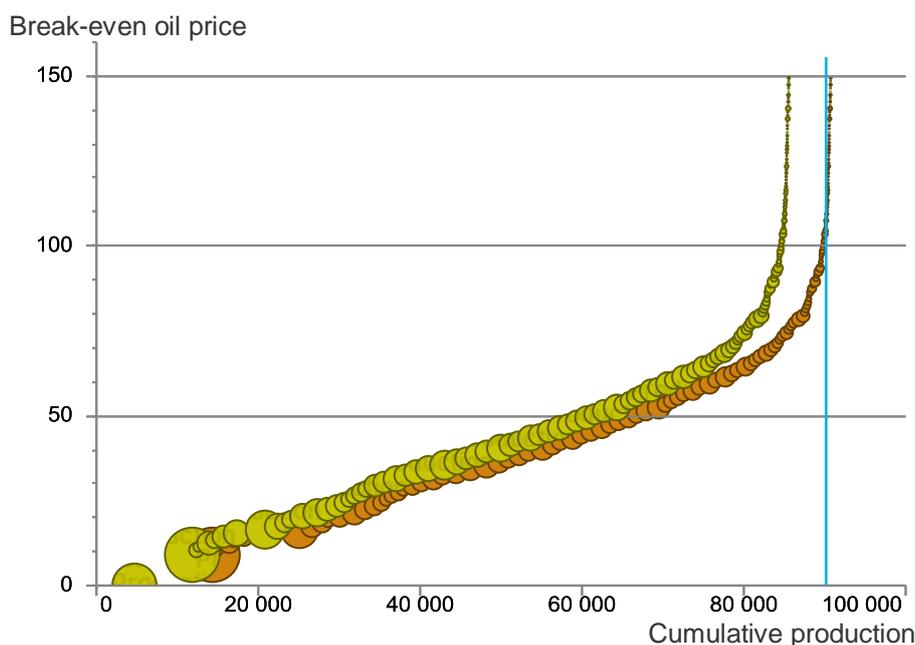

Figure 26: Comparing liquids cost-of-supply curves with (green) and without (brown) Saudi production cuts

6.3   Simulating different scenarios

There are several ways of simulating different scenarios with GUM. Different scenarios may include production cuts or disruptions, embargos, technology advances, etc., all which have influence on the supply of hydrocarbons. Below we assume that the analyses will be done as described above, i.e. matching demand with cost-of-supply curves. There is one proper way of implementing scenarios, and several short cuts.

Updates at asset level. The proper way is to translate the scenario effect onto individual fields, and make corresponding changes to these assets. E.g. if Iraqi production is hit by the war with ISIL, what is the effect? Some fields may totally stop producing, and others produce at lower capacity due to temporary shut downs or restriction on transportation, while the rest produce as normal. Production profiles can be forced for some years for some fields, or plateau levels reduced for others. Updates at asset level ensure consistency in costs and resources.

Post-processing forcing of production levels. If for instance the desired effect is to e.g. cap the production for a country, simulating a production cut, the new country level production can be supplied as an extension of that used

in the macro-calibration. GUM is an asset based model for which it is difficult to adapt to such a constraint while processing the assets one by one. The solution can be to apply the macro-calibration technique to the production output: calculate a factor per year to scale the country production to the forced level, and apply this factor to all the fields. This brings the production to the desired level, but the volumes cut disappear out of the model (will not be produced later), and at field level there will be inconsistencies between production and costs. However, assuming break-evens are calculated before the adjustment these effects are not so large.

Adjusting selection from database. A very flexible and easy way to implement effect of scenarios is to pull data selectively from the database, by eliminating some data or modifying them on the fly.

Leave out: Since the model implements the supply potential, most scenarios will have the effect of removing production. This is easily implemented by pulling only a subset of the data for the analyses described above.

- In the example of Figure 26 we implemented the Saudi sanctions by assuming that it would be done stopping all production on one field, Ghawar. This was done by excluding rows with Assetname=Ghawar.
- Embargo on Iran? Exclude all rows with Country=Iran when pulling the data.
- With the current oil price drop a scenario is no more investments in oil sands. Query for the data as usual, but exclude all oil sands projects that have not yet been sanctioned

Scale data on the fly: Adjustments like the forcing of production levels above can also be done when pulling data from the database. It requires a small separate layer between the database and the analysis part that can manipulate the data, i.e. do a linear transform on selected parts of the data.

- Take down Saudi production by 5%. All data from Saudi fields can be multiplied by 0.95, while all other data are unchanged. Or use different factors for different years.
- War in Iraq. Apply factors to suppress production for some years and then make a recovery to base numbers.
- Technology advance: New technology increases recovery from tail production fields. Apply factors to scale up production for fields in tail phase.

When to rerun the model:

The last example is a case where one should consider re-running the model. A technology advance that increases recovery has large revenue effects and added costs, and may e.g. cause fields to produce more years, push abandonment, and improve break-even prices. When scenarios have as an effect that they will most likely change the break-evens for many assets, in particular for assets that have break-evens near the oil price, the model should be re-run to maintain precision. In this case the technology advancement should be implemented in the production profiling algorithm.

7 IMPLEMENTATION

It is an obvious choice to implement GUM in a SQL database to take advantage of SQL and stored procedures, but the model can also be implemented using files and monolithic applications. The model can be programmed in any language that plays along with the database. Also the SQL databases directly support the querying required for the analyses.

Since processing of the model will not be fast one may consider implementing incremental processing; i.e. only running the assets that have been subject to changes. This is a good time saver. However, on model changes the whole model must be run.