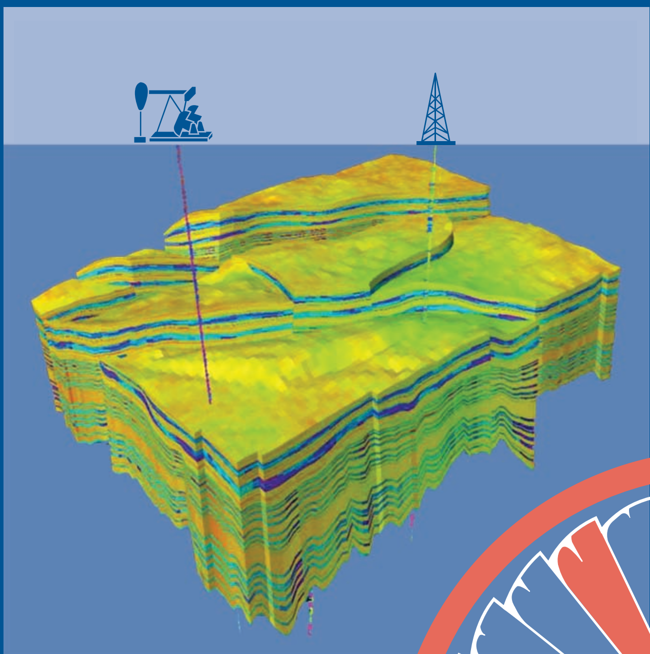
Shell Exploration & Production

EP 2008-9013

Production Forecasting Process Guide



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Production Forecasting Process Guide

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1. Introduction

1.1 Background

The objective of the production forecasting process is to provide technically sound input and a robust and auditable basis for economic decisions throughout the EP life cycle from exploration to abandonment. The Global business is managed through the EP business plan and quality forecasts are a key input to this process.

This guide provides rules and workflows for the effective generation and management of liquids and gas production and injection forecasts. Production forecasts are a fundamental input to all EP business decisions ranging from strategic aspects of the annual Global business plan, to incremental activity planning at the Asset level for mature fields. Robust forecasts are key to achieving Operational Excellence.

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1.2 Purpose

This guide is an update of EP 2003-5500 - Principles of Production Forecasting and reflects changes to the forecasting process over the last five years, notably the introduction of a new forecasting standard replacing the T&OE Minimum Standard, a change of functional ownership of the forecasting process from Production to Petroleum Engineering and Development, updated requirements for business plan forecasting, and the emergence of WRM and integrated system modelling tools. It contains:

- more definition on long-term forecasting
- a revised approach to uncertainty analysis
- discussion on integrated system modelling tools
- an emphasis on worked examples.

This guide contains practical instructions on how to generate forecasts but, for more detail, the reader is referred to the IRM (Reference 10), IPSM, WRM and PSO process documentation (Reference 14).

1.3 Audience

The target audience for this guide is supervisory staff involved in forecasting, i.e. lead Reservoir Engineers, Production Technologists and lead Programmers at TA1 and TA2 level and all practicing REs, PTs and Production Programmers.

In addition, the guide should be read by all EP and planning staff and managers who need to understand the significance and the limitations of production forecasts in an environment dominated by uncertainty.

1.4 Structure of this document

The flowchart in Figure 1 shows the four main steps involved in producing a production forecast, each comprising a number of activities. The steps are:

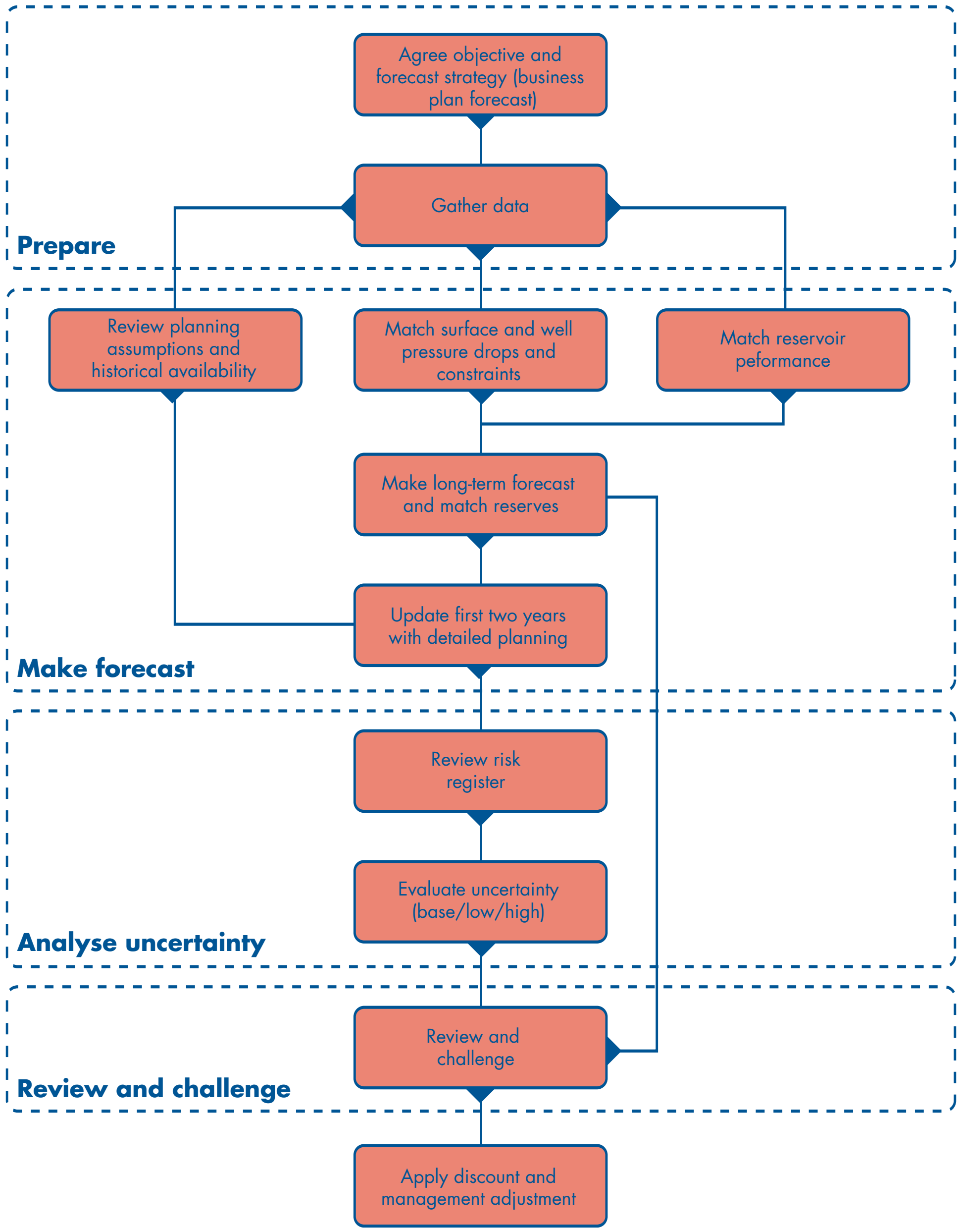
- preparation
- making the forecast
- analysing uncertainty
- review and challenge.

The flowchart shows the breakdown of these steps into a high level workflow for making a business plan forecast for a producing field. This workflow is used as the basis for structuring the guide and, whilst it is recognised that this process is generic, there may be differences in practice in some AoOs. It will give the reader a thorough understanding of forecasting best practice.

Thorough **preparation** (section 2.1) is an essential pre-requisite to making a robust forecast. This section describes how to define forecasting objectives which are used to develop an appropriate forecasting strategy. Finally, as data quality greatly influences the quality of the forecast, the important sources of data are discussed.

Make the forecast (section 2.2) concentrates on the steps required to make a base case production forecast with special emphasis on the business plan as this is the common thread for all forecasts throughout the EP life cycle. Forecasts must clearly distinguish between No Further Activity (NFA) and New Oil

Figure 1: Generic forecasting workflow



projects and the characteristics of each are covered in this section, as is the use of forecasting models.

As uncertainty in the production forecast is always present, a range of forecasts should be generated. Uncertainty analysis uses a number of different tools and techniques which are described in section 2.3.

Important and costly decisions are made on the basis of production forecasts and it is essential to ensure that all forecasts are robust, commensurate with underlying uncertainty. A process for quality assurance and quality control (section 2.4) must, therefore, be in place for this purpose.

Forecasts are managed and updated throughout the year, driven by new data, periodically required updates, material changes and new studies. How the long-term (section 2.5), medium-term (section 2.6) and short-term (section 2.7) forecasts are managed and their relationship with the business plan forecast is explained, as is the requirement to integrate the long and short-term forecasts (section 2.8). Whereas section 2.2 'make the forecast' refers to making the business plan forecast, all other forecasting objectives (including short and medium-term) are also described in terms of how they relate back to the BP forecast and how they should be scaled to achieve their objectives and maintain continuity.

Review and challenge (section 2.9) describes how feedback on the accuracy of forecasts can be used as an input to improving performance, and the guide concludes with an overview of recommended data management systems (section 2.10).

It is recognised that, in reality, every forecast has specific technical challenges which cannot be covered comprehensively in a generic guide. The Appendices, therefore, contain a number of recommended tools, tips and techniques for the practising engineer, including:

- the importance of emissions forecasts
- the use of forecasting models and recommended forecasting tools
- a discussion of uncertainty input distributions and aggregation methods
- the use of the reference limit diagram in forecasting
- how to analyse actual versus planned production injection
- key forecasting problems (and how to avoid them)
- technical considerations for special cases of oil and gas production forecasting and liquids injection.

Throughout the guide, much emphasis is put on learning from best practice examples and reference is made to selected examples from the Regions which can be found in the last section of this guide.

The references made throughout the guide to specific documents can be found in section 5.

2. Production forecasting guideline

2.1 Forecast preparation

Forecast objectives

The objectives of the production forecast must be clear and agreed, as they determine the forecasting strategy. The forecasting strategy in turn defines forecasting tools, resources, interfaces, the level of granularity or scaling of the forecast and the type of uncertainty assessment to be made.

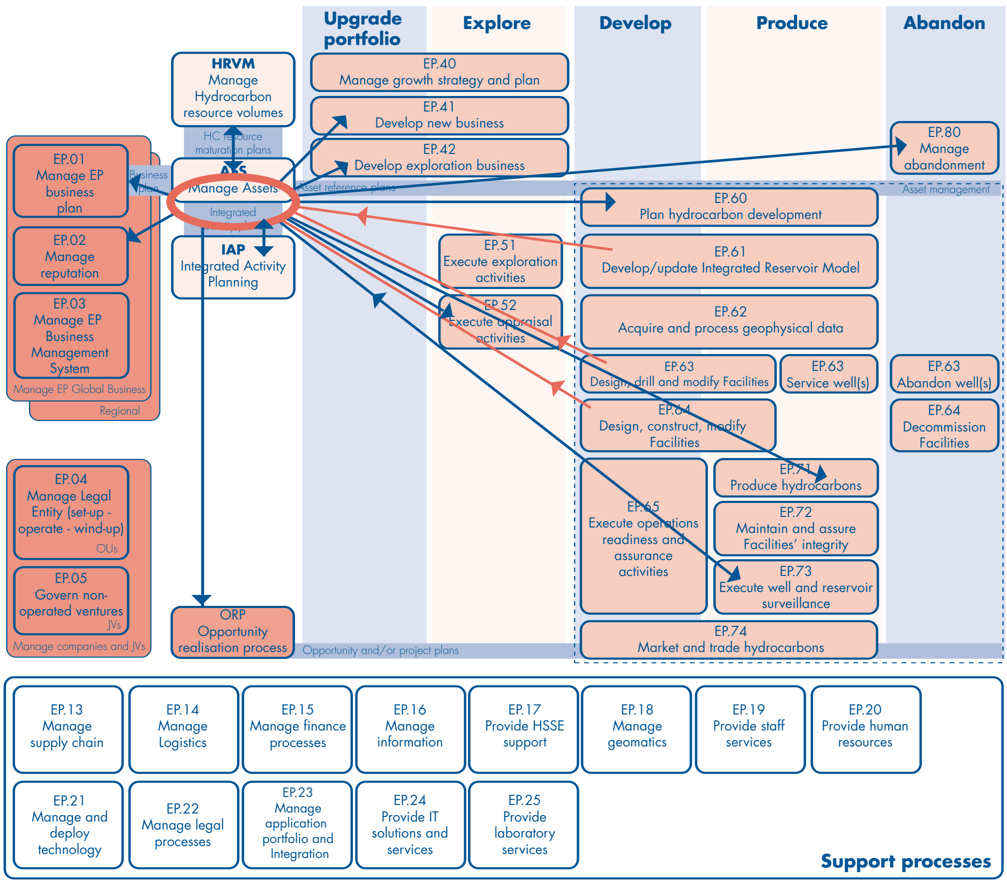
Robust forecasts are required in all phases of the EP life cycle and of the Opportunity Realisation Process (ORP). The primary forecasting objectives for each phase are as follows.

- Exploration (Identify phase of the ORP) - forecasts are made before the field is discovered, based on volumetric estimates, conceptual development plans and high level models. The objective is to support exploration venture plans, GIP (Group Investment Proposals), PIN, SFR initiation notes and VOI calculations to justify appraisal.
- Appraisal (Assess phase of the ORP) - the forecasts are refined as new data becomes available and uncertainty is reduced. The objective is to either justify further appraisal and/or testing or to demonstrate sufficient economic robustness to mature a development concept.
- Development (Select, Define and Execute phases of the ORP) - forecasting scenarios are used to determine the optimal development strategy. The objectives are to underpin concept selection, FDP, well planning and GIPs.
- Produce (Operate phase of the ORP) - forecasts are produced with several time horizons and objectives in order to optimise Asset management and to review and improve field development. Forecasting objectives in the Operate phase are:
    - Long-term: Asset Reference Plan (ARP), FDP and FDP updates and reserves management
    - WRM/PSO: justifying well interventions and de-bottlenecking activities
    - Medium-term: latest estimate (LE) generation
    - Short-term: Integrated Activity Planning (IAP) to optimise short-term activities, dispatching and tanker scheduling.
- Abandonment (Operate phase of the ORP) - a robust estimate of the remaining production potential is required to confirm that there are no remaining development opportunities, to determine when and/or how to abandon the field or to evaluate for divestment purposes.

Project forecasts, as described above, are rolled up to various levels, e.g. portfolio theme, AoO, Regional, Global, with the objective of driving the business strategy and plans. This includes managing relevant risks, allocating resources (including manpower), making portfolio choices and setting appropriate production targets, including those disclosed externally.

Forecasting is a sub-process of the Manage Asset process as all the above objectives help to manage Assets optimally in all phases of the EP life cycle, linking to both hydrocarbon resource management and the business planning process. Figure 2 shows how the forecasting process is linked with other processes in the EP Business Model (EPBM).

Figure 2: Forecasting in the EPBM



The forecasting process is driven by two main annual events, the EP business plan and the Annual Review of Petroleum Resources (ARPR), which are common to all phases of the EP life cycle as shown in Figure 3. Forecasts are managed and updated throughout the year, driven by new data, periodic updates, material changes and new studies. Generally, the NFA forecast is revisited at year end during ARPR and as part of the annual field performance review (see Reference 5 - Control Framework for Discovered SFR and Expectation Resource Volumes). New Oil forecasts originate from FDP updates or from business planning work. Long-term forecasts are revised in case of major changes, while medium and short-term forecasts are updated more frequently. All forecasts should be equivalent as the cumulative production at the end of field life (EOFL) must equal booked reserves and scope for recovery volumes. It is important to ensure the consistency and integration of these forecasts in the annual cycle.

Figure 4 shows a typical Asset forecast covering the full resource range. Note that every Scope for Recovery (SFR) slice

Figure 3: Forecasting in the EP life cycle

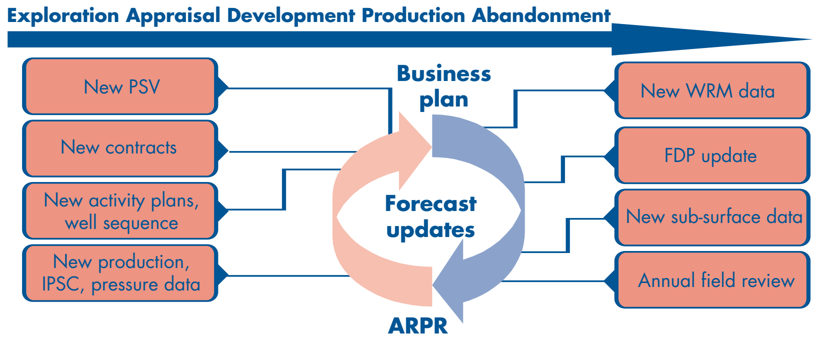
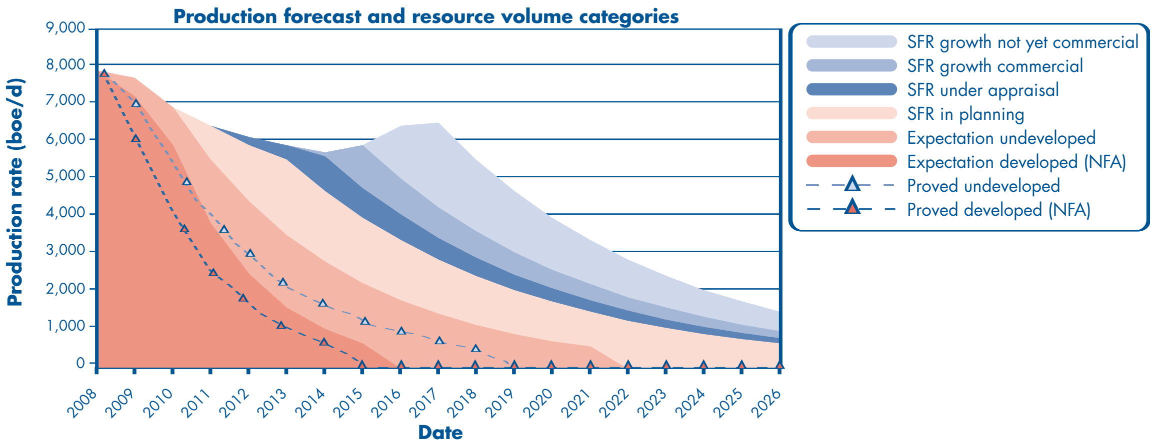


Figure 4: Typical Asset forecast



represents a distinct stage of maturity for various projects. The area of each slice (at the end of field life) constitutes the booked reserves and SFR for the Asset. It is important to achieve and maintain consistency between the various types of forecasts and booked resource volumes.

Similar principles apply to all forecasts, but with variations in the level of granularity and time horizon. If material changes occur, such as project deferment or acceleration, or reserves revisions, they will trigger an update of the forecast for the next decision gate, an event driven update of the business plan and a reserves update.

Production forecasting as shown in Figure 3 should, therefore, be seen as a continuous loop through the annual business cycle and the field and Asset life cycle. How to improve the forecasts by learning from the past, as well as from analogue fields in the same (or more mature) ORP phase, is explained in this guide.

Another important consideration is the continuity of models through various levels of scaling. Whilst the specific objective drives the tools for an individual forecast, it is important to keep continuity and scalability in mind so that models can be preserved and kept evergreen from forecast to forecast.

Forecasting strategy

The forecasting strategy implicitly defines forecasting tools, staff competencies, resources, interfaces, the level of granularity or scaling of the forecast, the type of uncertainty assessment, definition of workflows and forecast update frequency. The forecasting strategy should also address how to keep the short, medium and long-term forecasts aligned.

Example 1 in section 4 shows a successful strategy for making a business plan forecast for a major field.

Gather data

The quality of the forecasts is heavily dependent on the quality of the data that is used to produce them. The data is generated through various processes as defined in the EPBM and it is the responsibility of the forecasting engineer to gather a complete, up-to-date and consistent dataset upon which the forecast will be based. Important sources of data include the following.

- Produce hydrocarbons process (MRPW, business objects). Data is gathered about historic production and injection, including flaring and reconciliation factors.
- WRM and PSO provide interpreted well and reservoir surveillance data, including pressures and well capacities.
- IRM provides sub-surface models.
- IAP provides accurate and up-to-date system availability/ downtimes and scheduled activities.
- Market and trade provides contractual constraints for gas contracts.
- Wells and Facilities Engineering provide timing and system constraints for New Oil projects.
- Business planning provides overall project schedules incorporating Global strategic priorities.

2.2 Make the forecast

Prior to forecasting, the available field data must be carefully validated. Special attention should be paid to reconciliation of production volumes (metering), production allocation to individual wells/clusters, quality control of bottom hole pressures, and fluid contact movements and dominant drive mechanisms as inferred from relevant surveillance data.

The business plan production forecast is generated by the reservoir engineer, based on an appropriate forecasting model built according to IRM (EP.61) principles. The forecast will honour all system constraints, scheduling and availability requirements. All fluids (liquids and gases) produced and injected are forecasted using a consistent modelling approach and shall be consistent with the appropriate resource volume category. This is ideally done using an Integrated Production System Model such as MoReS/GAP, IPM or HFPT. Other forecasting models may be appropriate, depending on practical considerations, field maturity or resource constraints.

The following steps should be followed when making a forecast.

1. Determine whether forecast is NFA or New Oil.
2. Select a forecasting model.
3. Set up an audit trail.
4. Carry out or update the history match of the reservoir.
5. Identify well and Facility constraints.
6. Establish production system availability.
7. Make the forecast.
8. Keep a production risk and opportunity register.
9. Analyse uncertainty.
10. Review and Challenge.
11. Conduct AAR (Forecast vs Actuals).

Minimum requirements for production forecasts

A production forecast is an estimate of gross and net volumes (oil, gas, water) expected to be produced from a hydrocarbon accumulation over its remaining lifetime, as well as fluids injected to produce these volumes (water, gas, steam). The forecast must be aligned with the hydrocarbon life cycle development strategy and plans. Volumes are typically reported per well and per reservoir on an annual basis. In addition, the development of available well capacities, average reservoir pressure and fluid composition over time form an integral part of the forecast.

Forecasts must be consistent with booked resources volumes. NFA forecasts will be linked to developed reserves and the Opex activities carried out to maintain production/injection potential in the wells. New Oil is associated with the development of either undeveloped reserves or the appropriate SFR category through Capital Expenditure (Capex). These links should be fully transparent. Any major deviations between business plan forecasts and ARPR volumes must be understood and the reasons documented and will require an update of reserves at the next ARPR.

The minimum requirements for production forecasts are summarised in the EP Forecasting Standard (see reference 1), which has replaced the T&OE Minimum Standard issued in 2003. They are set out below.

- Each company shall have an embedded and auditable process in place for generating and managing production forecasts, covering short-term to end of field life, as a basis for effective Asset management.
- Each company shall compare actual performance against the forecast (including the key assumptions) on a regular basis (at least quarterly).
- Each company shall have clear single point accountability and responsibility for the quality of the production forecast for each major Asset, including quality of input data.
- Production forecasts shall be on expectation basis and fully auditable.
- Main threats and opportunities to the expectation forecast shall be identified, and the resulting range of uncertainty shall be quantified as 'high' and 'low' case forecasts and shall be documented and demonstrably managed in a risk register.
- Any management adjustment to the expectation forecast (upwards or downwards) to arrive at other production targets shall be fully transparent and documented at the company level.
- Production forecasts shall quantify all fluids (liquids and gases) produced and injected in a consistent manner and shall be consistent with the appropriate resource volume category.
- Production forecasts shall honour all constraints imposed by surface facilities, pipelines and wells and shall be consistent with the activities included and budgeted for in the business plan.
- Each business plan forecast shall quantify expected emission levels and energy consumption for all plan unit categories.

Note that Process Engineering is responsible for emissions forecasting, with significant input from the production forecast. Appendix 1 explains why emissions forecasts are important.

Forecast building blocks

The production forecast is governed by the interaction between the following building blocks, which are always integrated in a consistent forecasting model.

Hydrocarbon reservoir

Key reservoir characteristics, such as remaining hydrocarbon volumes, structure, architecture, phase contacts, rock and fluid properties, sand connectivity, heterogeneity, faulting, fracturing, drive mechanism and aquifer pressure support determine the future capability of the field to deliver production.

Well performance

The inflow and tubing lift performance of the production conduits impact the surface flow rates from the wells and their expected decline. Key aspects to consider are well design, perforation strategy, completion efficiency, lift curves, impairment, sand production, well integrity, coning/cusping potential, liquid loading, interference and availability of artificial lift and, in the case of injection, whether this is done above or below fracture propagation pressure.

Development strategy

Future production profiles and ultimate recovery from a field are affected by the envisaged development plan in terms of number, type such as horizontal or smart wells, density and phasing of wells, reservoir management policy such as Smart Fields or WRM, project timing, operating pressure displacement process, suitability of improved recovery techniques, injection volumes and licence expiry.

Surface facilities

Layout, sizing, design envelope, Operations policy, lifetime and minimum surface pressures will constrain the throughput of the Facility network (such as pipelines, separator trains, compressors). These constraints may change during the life of the field.

Production system availability

Production system availability is defined by scheduled and unscheduled maintenance and deferments, based on short and medium-term planning and calibrated with historical availability statistics and predicted Opex levels.

Commercial and economic constraints

These include contractual obligations (off-take limits, load factors, depletion policies, hydrocarbon sales specifications), economic criteria (abandonment conditions) and environmental constraints (H_2S, mercury, subsidence).

Appendix 2 describes how to combine these six building blocks into a consistent model. Appendix 3 gives an overview of recommended modelling tools. Appendix 8 describes techniques and considerations for specific forecasting environments.

No Further Activity forecast (NFA)

Forecasts must clearly distinguish between NFA and New Oil projects. The NFA forecast (also sometimes referred to as NFI - no further investment) is production that would result from existing wells and Facilities if there was no further capital invested and only Opex activities were carried out.

The NFA forecast (in the business plan) must be consistent with developed reserves and should, therefore, only include wells and Facilities that were on-stream as of December 31st of the previous year and were included in the ARPR as developed reserves. Wells and Facilities that were not on-stream will be grouped under New Oil.

Activities that safeguard or optimise the inherent natural decline of the developed reserves are assumed to be included in the NFA forecast as long as they are Opex activities. These include optimisation activities from PSO and WRM such as water shut-offs, well work-overs, gas lift optimisation and de-bottlenecking. Note that NFA is a classification for the business plan forecast. For internal Asset management and decision making, these Opex activities will still be justified with individual incremental forecasts (see section 2.8).

Example 2 shows how to forecast WRM/PSO gains due to Opex activities.

In addition, some AoOs make an LIO/LIG (locked in oil/gas) potential forecast. This refers to wells and Facilities that are shut–in and cannot currently be accessed to be re-instated. LIO is, in general, part of the NFA forecast and may lead to increasing NFA production over time. In some cases, LIO could move SFR to developed reserves and might be classified as New Oil.

The NFA forecast is anchored in historical performance. Examples include:

- NFA forecast aligned with decline analysis (DCA)
- system availability based on statistical analysis of historical performance.

In addition, a proved developed forecast must be made for the ARPR. This will be based on a "reasonably certain" estimate, compliant with SEC rules and will, in general, be based on decline curve analysis for oil and P/Z analysis for gas. It is considered good practice to make an expectation forecast based on a history matched dynamic model and a proved forecast based on DCA or P/Z and explain and document any difference between the two. Conversely, it is also good practice to compare DCA or P/Z based estimates and simulation NFA for expectation reserves to avoid over-promising these reserves. SEIC has recently demonstrated that proved reserves may be based on a low case simulation forecast if a very good history match has been achieved. It is expected that the new SEC rules will permit a wider use of high quality simulation models for proved reserves in the future, but that a calibration with DCA would still be required.

In summary, the NFA forecast:

- does not include any Capex activities
- must have cumulative production equal to expectation developed reserves
- includes WRM/PSO gains if these are Opex activities (water shut-off, de-bottlenecking, stimulations, Opex sidetracks).

New Oil forecast

New Oil is production that would result from new (growth) projects funded from capital expenditure (Capex). The New Oil portfolio of the business plan contains projects that are within the five-year business planning window and more notional projects beyond this period. Major new field developments, infill wells, gas compression and enhanced oil recovery projects are examples of New Oil activities. The New Oil forecast should be commensurate with the capital investment assumed in the economics, e.g. the number of wells or the size of the compressor funded and the Capex phasing.

New Oil forecasts are, in general, incremental forecasts. For infill wells, forecasts should be incremental to NFA, excluding any oil that is "stolen" or accelerated from neighbouring producers (interference). This also applies to surface back-out via shared Facilities in the case of a cluster development, or oil deferment in case of conversion from depletion to water injection. Even if a development seems to be completely stand-alone, issues such as rig availability or resource competition, may lead to a deferment of production.

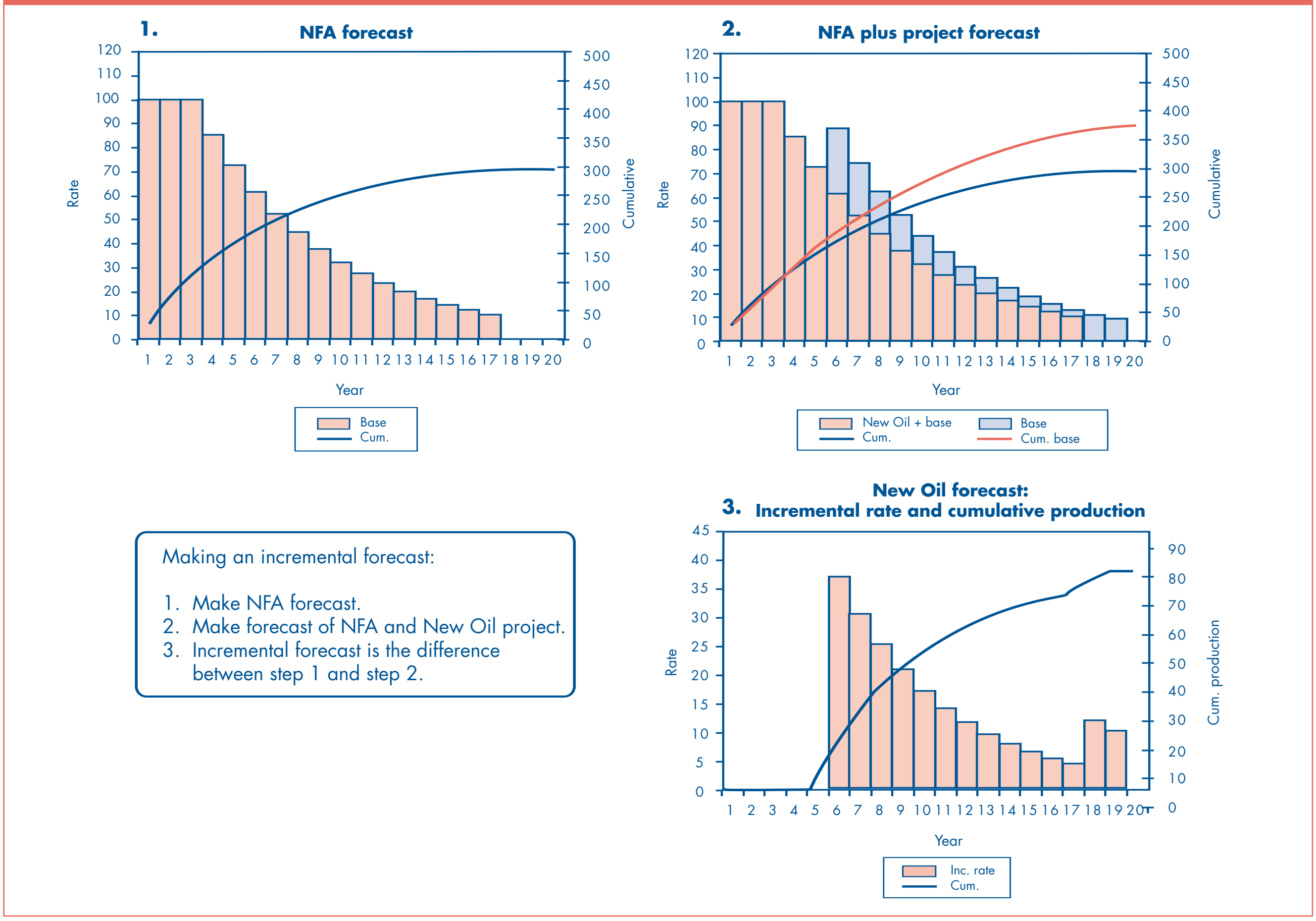
Example 3 shows an incremental forecast for shared Facilities, properly modelling pressure drops and surface back-out.

Example 4 shows a New Oil forecast for a stand-alone development with no external constraints.

Figure 5 shows the three steps in making an incremental forecast as follows.

1. Make the NFA forecast.
2. Make a full forecast with the targeted activity, taking all system constraints into account (note that several activities may be stacked incrementally to each other).
3. The project or New Oil forecast is the difference between step 1 and step 2 (note that this is almost always less than the production through the new wells).

Figure 5: Making an incremental forecast



Project forecasts must be linked unambiguously to the appropriate reserve and SFR categories.

The New Oil forecast is anchored in historical performance, for example:

- New Oil contributions (initial rate and volume) consistent with what has been achieved recently on wells in similar setting (analogues)
- takes into account long-term trends of diminishing returns in infill wells (creaming effect - the remaining wells are generally worse)
- scheduling of wells (drilling sequence) and project delivery estimates should be consistent with actual timings achieved during previous years, incorporating statistically expected levels of schedule slippage and ramp-up assumptions (in consultation with Well Engineering). Learning curve benefits from drilling campaigns may only be included after first improvements have been demonstrated. In many cases, unrealistic forecasts originate from over-optimistic timings
- expected well and Facility uptimes consistent with historical trends taken into account.

In summary, New Oil forecasts:

- refer to projects that are funded from the Capex budget
- must be strictly incremental:
  - o infill wells must take sub-surface interference into account
  - o conversion of existing producers to water injection must take into account deferred primary production
  - o surface back-out due to shared and constrained Facilities must be taken into account
  - o stand-alone developments may have to consider rig availability, Opex quota, gas demand and processing capacity.
- must consider historical performance and diminishing returns
- may defer field abandonment, i.e. extend end of field life by keeping unit cost above critical levels.

Audit trail

All forecasts must be auditable. Consequently, any forecast supporting an important deliverable such as FDP, GIP, ARPR, BP must contain a clear and unambiguous audit trail including a listing of prediction runs, assumptions, decisions and problems encountered and modifications applied. A recurring forecasting problem is that the previous year's forecasts can often not be re-generated or even understood due to the basic forecasting assumptions used in the preceding year not being documented.

The minimum requirement for an audit trail for the business plan forecast is a note for file (NFF) detailing:

- forecast background details
- methodology and tools used
- input data
- results
- diagnostic plots
- adjustments and discounts applied
- risk and opportunity register
- QA/QC performed
- sign-off
- clear naming conventions for individual forecasts allowing easy retrieval of individual forecasting runs.

2.3 Uncertainty analysis

Uncertainty in the production forecast is always present and may be significant. This may be due to an incomplete understanding of the reservoir, the unknown future performance of the wells and the realisation of potential incremental development activities (workovers, stimulations, Facility de-bottlenecking) and/or due to scheduling uncertainty in New Oil projects with regard to on-stream dates.

To reflect this uncertainty, a range of forecasts should be generated representing the full spectrum of potential future production profiles, taking all threats and opportunities into account.

Risk and opportunity register

The starting point of any uncertainty analysis should be a production risk and opportunity register. This register also complements the forecast audit trail by documenting the investigated uncertainties and must clearly describe all factors influencing the forecast. A common problem is that the biggest risks are often overlooked or ignored in the forecasting process and there are also the unknown unknowns! The production risk register should be maintained at the field or Asset level. It is owned by the Asset Team and is normally maintained by the Reservoir Engineer responsible for the forecast. Asset risk registers will form the basis for the Regional production risk and opportunities list required for the business plan.

The production risk register should detail:

- all risks (downsides) and opportunities (upsides) influencing the forecast
- mitigation measures
- the risk owner
- assigned action parties
- likelihood of occurrence
- impact (in general expressed as a reserves change, incremental system capacity or as an incremental forecast).

Refer to the risk management process (Reference 11) for more details on risk registers. The preferred tool is Easyrisk which supports these requirements. Based on data analysis, an assessment should be made of the uncertainty associated with each of the listed risks and opportunities. Uncertainties with the largest impact on the forecast should drive the future WRM/PSO strategy.

Risks and opportunities may include both controllable and uncontrollable factors influencing the production forecast, but should not contain Capex activities as these will, typically, be dedicated projects carrying an expectation forecast fully aligned with the uncertainty range. Examples of controllable and uncontrollable factors are shown in Table 1.

Example 1 contains a high level listing of production risks and opportunities.

Table 1: Controllable and uncontrollable factors

Partly controllable	Uncontrollable
Stimulation	HCIIP
Water shut-off	Reservoir compartmentalisation
Downtime	Water breakthrough
De-bottlenecking	Well failure
Reinstating LIO	Hurricane damage
Rig availability	Gas demand
Condensate banking	

Probabilistic methods vs deterministic scenarios

The purpose of uncertainty analysis is to establish an uncertainty range around a base case, such that there is reasonable confidence that actual production will fall within this range. Whilst it is good practice to investigate multiple production scenarios in line with the threats and opportunities described in the risk register, the uncertainty range of a forecast is ultimately described by three realisations, the low, base and high forecasts, representing approximately P90/ P50/P10 outcomes.

Note that the SEC has announced changes to its reserves rules effective January 2009. These changes are expected to encourage the use of probabilistic methods for proved reserves determination and to specify the proved reserves to represent a P90 outcome and the proved plus probable reserves to represent a P50 outcome. Forecasting has to be consistent with SEC rules, therefore, the following section reflects these anticipated changes.

Since a forecast is based on a timeline and not a single number, it is important to first establish a common definition of what a forecast range should be for this timeline (or in statistical terms, to establish the objective function) otherwise forecast ranges from different Assets cannot be compared or aggregated. The definition can be found in Table 2 and is designed to reflect the uncertainty in the short and long-term in a consistent manner. It is mandatory to use this definition for BP forecasting and strongly recommended for all other forecasting objectives (such as FDP and ARPR).

Discounted production or discounted cash flow NPV7 (net present value at 7% discount) was an objective function once commonly used to define forecast uncertainty. However, it led to narrow ranges and inconsistencies and should, therefore, not be used in conjunction with the BP forecast or for reserves forecasting.

Table 2: Definition of base, low and high forecasts

Base case (P50) forecast is defined as	Low (P90) forecast is defined as	High (P10) forecast is defined as
P50 with regard to cumulative production at EOFL	P90 with regard to cumulative production at EOFL	P10 with regard to cumulative production at EOFL
P50 with regard to schedule, system capacity and system availability	Reasonably conservative with regard to schedule and system availability	Reasonably aggressive with regard to schedule and system availability
Consistent model from short-term to EOFL	Consistent model from short-term to EOFL	Consistent model from short-term to EOFL

The P10 (or high case) is defined as the outcome which has a 10% chance of being exceeded.

The P90 (or low case) is defined as the outcome which has a 90% chance of being exceeded.

The P50 (or base case) is defined as the outcome which has a 50% chance of being exceeded, i.e. an equal likelihood of being above or below actual production.

The mean is the probability weighted average of all outcomes.

The expectation is defined as expectation = mean * PoS (Probability of Success).

Thus, for discovered Assets where the PoS is 1, the terms 'expectation' and 'mean' may be used synonymously.

In the case of a normal distribution, the P90 represents approximately 1.28 standard deviations from the mean. This is considered a good measure for high confidence. The Shell standard low case has previously been P85, representing approximately one standard deviation from the mean and hence a slightly narrower range. If the probability distribution is symmetric, then the P50 is equal to the mean. If the distribution is skewed to the high/low side, then the mean is slightly bigger/smaller than the P50.

P50 is not, in general, based on all the most likely input parameters as the input distributions will generally be skewed (asymmetric). Appendix 4 describes typical distributions, their skew and methods of probabilistic aggregation, which preserve the skew.

Method

There are two methods to generate the high and low case forecasts, probabilistically or using deterministic scenarios.

1. If the forecasts have been generated based on IRM principles with a fully probabilistic method (Monte Carlo or Experimental Design), then the low (high) case is simply the realisation that best represents a P90 (P10) outcome with respect to these objective functions:
   - cumulative production at EOFL
   - well rate, schedule and availability assumptions.

2. It is preferred in many cases to derive deterministic high and low case scenarios based on "proper engineering judgment" and analysis of past performance. These should fulfill the same criteria as the probabilistic forecast, that is:
   - reasonably low (high) cumulative production at EOFL (consistent with proved reserves)
   - reasonably low (high) production rates, conservative (optimistic) schedule and conservative (optimistic) uptime assumptions throughout the field life.

If deterministic scenarios are used, then it is not important to calculate a P90 (or P10) exactly. An estimate in the P50 to P10 range is perfectly adequate because it will always be impossible to accurately estimate all the input distributions. It is important to consider all risks and upsides from the risk register and to define the range in such a way that there is reasonable confidence that the actual production will fall within the envelope defined by the high and low case, i.e. the solid blue and red lines shown in Figure 6, throughout the forecast duration from short-term to end of field life. The range should neither represent a maximum/minimum (extremely unlikely) nor be very narrow. It is also important to represent the skew in the distributions properly.

In both methods, the base case forecast must be underpinned by statistical analysis of historical performance (for producing fields) and by analogue performance for greenfields and must reflect production risks from the risk register.

Example 7 shows best practice in deriving the low, base and high forecast using probabilistic methods (experimental design) for a mature field with history to match.

Example 8 shows the best practice method for deriving the low, expected and high forecast deterministically.

For business plan submissions (in Pmaster format), the high and low forecasts are reported as 'risk wedges', i.e. as the difference between the base and the low (high) case on an annual basis as rate vs. time. Figure 7 shows, conceptually, a high and an expectation forecast (in kb/d vs. time) and shows that the risk wedge may have negative incremental rates due to acceleration effects. This is inherent in forecasts and is not a problem.

Figure 6: Principle of base, low and high forecasts

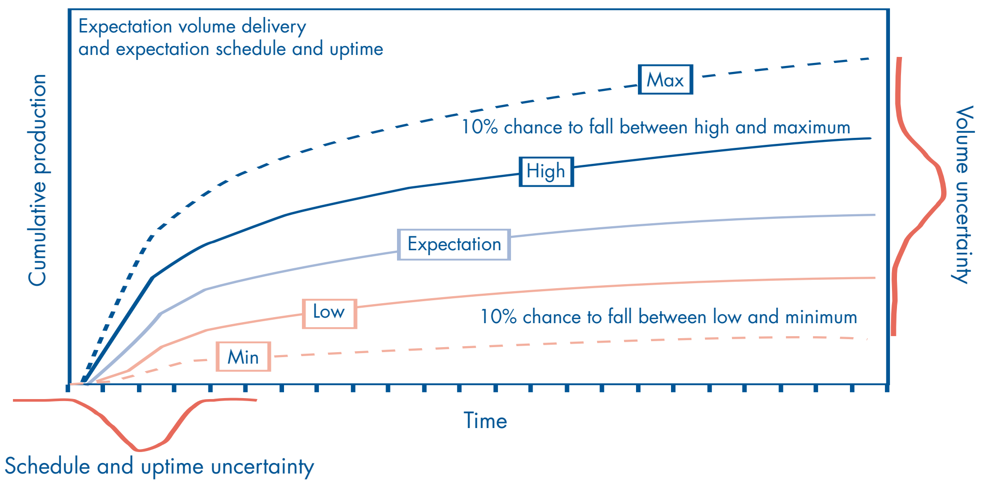
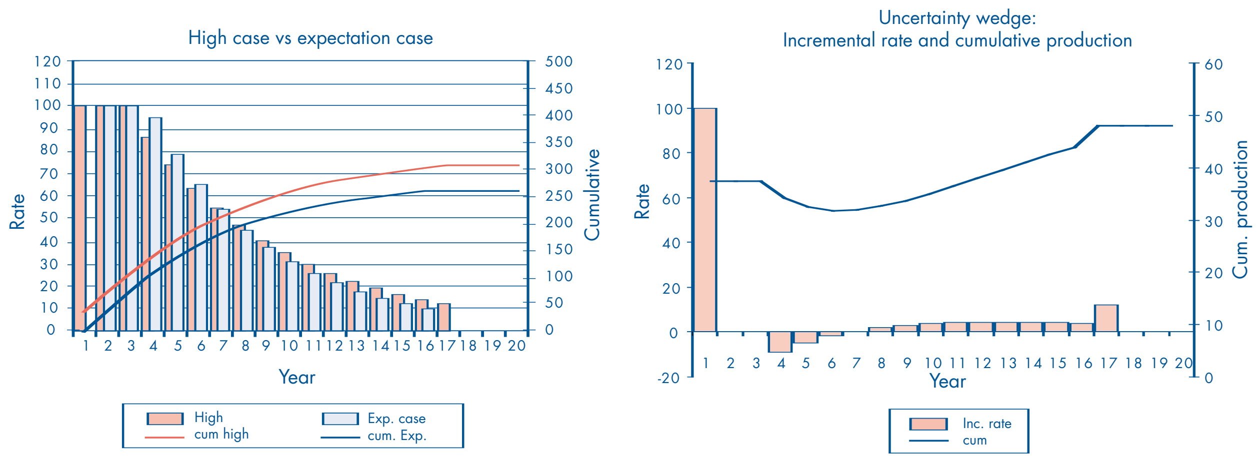


Figure 7: Risk wedge showing negative incremental rates due to acceleration



Discounting simulator forecasts

Despite sound technical work done on modelling and construction of the forecast, production is more often over-predicted than under-predicted. Historically, Shell has under-delivered on the BP production forecast, which justifies the need to maintain the challenge process and apply discounts to forecasts as appropriate.

Discounting of forecasts is not a reflection on the quality of the forecasting models, but a pragmatic measure reflecting that it is impossible to capture the full range of all the input distributions contributing to the forecasting uncertainties.

Technical reasons for discounting include:

- under-estimating schedule uncertainty
- optimistic uptime assumptions
- under-estimating the creaming curve effect for infill wells, i.e. future infill wells will tend to develop lower reserves than past wells
- under-estimating reservoir heterogeneities as dynamic models can never fully capture sub-surface complexity
- under-estimating back-out and interference effects
- perfect world assumptions, such as optimising infill well locations in the dynamic model, but the real reservoir may look very different than the model. See Appendix 7 for more 'perfect world' examples.

A non-technical reason for discounting that should be accounted for is human bias. There is a natural inclination to make projects look good. This is not a bad thing as it is important to identify and mature attractive projects, but it highlights the need for independent reviews of the forecast, which often recommend discounting.

Discounting should be applied in various stages. Firstly, by the forecasting team assessing all the risks and opportunities in a holistic manner and secondly in challenge sessions with experienced peers as part of the review and challenge process (see section 2.9).

Example 9 shows how to discount simulator forecasts based on observed field performance.

The discount factor is determined by technical judgment and experience and must be anchored in historical performance analysis of over/under performance, both for the field in question and for analogue fields, i.e. the gap between previous year's forecast versus actual should guide the discount factor. The discounting discussion should take into account the risks and opportunities outlined in the production risk register and should also answer the questions "what else can go wrong?" and "how bad can it get?".

Documentation of all applied discounts is an important part of the audit trail in order to avoid double discounting and to preserve the discounts for future forecasts, i.e. make them part of the improvement loop.

There are two ways to apply discounts to forecasts. These are:

- discount rates or decline of the forecast itself by a constant factor
- determine the root cause of the risk and adjusting model parameters (such as reduced availability factor, higher skins, adjusting relperms) to achieve the desired effect.

The latter is preferred as it leads to improved models for future forecasts and better and more consistent discounting with analogue forecasts.

Management Adjustment (MA) may also be applied to the forecast as a further discount on top of all the technical risks that have already been applied, reflecting a higher level assessment of the uncertainty, including insights in the commercial, organisational and political overprint. It is important to properly understand and review all the discounts already applied to avoid double discounting. For the business plan, it is mandatory to label MA as a dedicated Pmaster submission and summarise the rationale in a short statement in the description field. The statement should be short and concise, but should list all the reasons for MA explicitly.

Risking production forecasts

Risking is different from discounting. Risk factors will be applied to projects or fields to allow for the possibility that the reservoir may not be there, may not be commercially developable or may not be implemented, in line with the following definitions.

- PoS: probability of success is applied to undiscovered fields in exploration.
- PoM: probability of maturation.

The latter is applied if the development project:

- uses a recovery process that has no operational analogue in similar geological or geographical environments in the world (risk ½)
- uses a recovery process that has no operational analogue anywhere in the world (risk ½)
- is likely to be subject to environmental or political reservations due to the nature of the project (risk ½).

In general, risk factors should only be applied for pre-DG1 projects. However, in some exceptional cases (such as projects under appraisal where critical pilots or appraisal wells are being undertaken or where legal, contractual, political or environmental risks remain) it can be appropriate to carry risk factors through to DG2. See Reference 13 for the detail.

Note that the expectation is defined as expectation = mean * PoS, which means that for development projects expectation and mean are the same.

2.4 Quality assurance and quality control

As they drive important and costly decisions, production forecasts need to be extensively reviewed and quality controlled to ensure robust results. There are two components to the QA/QC process, leading potentially to updates to the forecast. These are:

- diagnostic plots done internally by the engineer or forecast team
- external review and challenge.

The internal QA/QC products form the basis of the external review and are used during the external challenge process.

Forecasting models should be reviewed as part of the IRM process (IMR0–IMR5) and are not discussed here.

Diagnostic plots

A key component of the internal QA/QC process and consistency checking is the use of standard diagnostic plots. There should be a consistent set of these plots and indices for quality assurance of forecasts and associated uncertainty ranges. These strengthen understanding of the issues and promote the use of the recommended practices.

Recommended examples are as follows.

- Demonstrate alignment of NFA forecast with long-term reservoir declines by:
  - plotting historical production, DCA decline trends (from ARPR) and proposed NFA forecast scenarios (low, base, high). This will immediately highlight any cases where the forecast is not reflecting long-term reservoir performance trends. Such graphs can be presented at different levels, e.g. well, field, cluster
  - plotting NFA (expectation) forecast with proved developed reserves forecast.
- Visualise the calibration of initial rates, declines and recoverable volumes for New Oil projects against achieved performance from recent (analogue) wells. This will expose cases where future infill wells in a mature field are assigned better attributes than those achieved for recent wells.
- Display variations in current versus previous year's forecasts, including the associated uncertainty bands to help answer questions such as:
  - why was last year's forecast not achieved?
  - what are the reasons for deviations versus plan?
  - was the actual production within low-high range?
  - which assumptions should clearly be revisited?
- Calculate the rate-life index, i.e. recoverable volume/current rate, which is a useful indicator to use to screen for suspicious forecasts at well or field level:
  - Low index values (< 3-5 years) possibly indicate cases where the current rate is (too) high compared to the limited remaining well/field life, while high index values (> 20 years) highlight cases with low current rate and unrealistically long remaining life.
- Cumulative plots are especially useful for oil production, water injection and gas injection.
- Forecasts should be compared to individual 'bottlenecks' such as pipelines, water disposal, gas compression, clearly showing the capacity of the bottleneck.

Review and challenge

The frequency of reviews depends on forecast scope and time horizon. Peer reviews are conducted by TA2 level REs, PTs and Production Engineers to ensure that medium and long-term forecasts are consistent and that activities, IPS constraints and availability are properly modelled. The business plan forecast and FDP forecasts are reviewed by the Regional or AoO Head of Reservoir Engineering (TA1). Expectation and scope volumes, which are underpinned by long-term forecasts, are reviewed on a periodic basis during Hydrocarbon Maturation Health Checks.

Reviews of prediction runs and forecasts are normally conducted at the TA2 level. Mandatory elements are specified in DCAF. See reference 6 for a definition of TA (technical authority levels) in DCAF.

DCAF requires sign-off for the quality of the forecast by the RE TA1 or TA2 of any ORP deliverable (FDP, ARPR, BfD, GIP), which implies some form of review. The planned and completed forecasting work will be reviewed during IMR1 , IMR4, 5 or ITR reviews, but internal discipline reviews (RE, PP, Programmers) should be scheduled before these mandated reviews. Regional forecasts are reviewed during the annual business plan robustness reviews.

Example 6 contains a Dynamic Modelling Checklist with focus on forecasting deliverables.

2.5 Manage long-term forecast (year 1 to EOFL)

Objectives and scope

As shown in Figure 3, the forecasting process is driven by two main events every year, the ARPR and business plan, and there must be full consistency between reserves and forecasts, i.e. the cumulative production at the end of field life must be equal to the appropriate reserves category. The annual field performance review is an important element of managing the long-term forecast and will result in updates to it and/or the forecasting models if necessary.

Furthermore, other long-term forecasts are made throughout the year fulfilling specific objectives. It is part of managing the long-term forecasts to keep the business plan and specific forecasts aligned.

The LT forecast is linked to the Asset ARP/ORP/BP and validated via the LT IAP (field life) process.

Managing the long-term forecast with the Annual Field Performance Review (AFPR)

Developed reserves (No Further Activity) and new projects (New Oil) will be revalidated as a minimum annually in terms of volumes, forecasts and costs. For producing fields, this includes a review of performance vs. forecast as part of the annual field performance review. Material changes to the building blocks of the long-term forecast (potential, schedule) will result in a reassessment of the forecast using the new input data. This should also include a comparison of the proved forecast with actual production.

The forecasting models should be reviewed and updated (history matched again if necessary) to reflect observed deviations in reservoir behaviour. Keeping models evergreen is one of the biggest challenges for an integrated surface team. It is good practice to keep the reserves stable where possible and only update them based on material changes in the forecast. However, material changes have to be documented and must lead to a revision of the reserves in the following ARPR. Determining the materialty threshold for reserves updates is an important decision in the forecasting process and should always be agreed with the TA2 Reservoir Engineer.

Integrating the business plan forecast with other long-term forecasts

Forecasts are made throughout the year to fulfill specific objectives. It is part of managing the long-term forecasts to keep the business plan and specific forecasts aligned.

Examples of specific forecasting objectives are:

- FDP updates
- review IOR/EOR opportunities
- provide data for economics or screening
- identify opportunities for infill drilling and optimising infill locations
- optimise water injection strategy
- incremental forecasts for WRM/PSO activities such as water shut-offs, stimulations, additional perforations, Facilities de-bottlenecking and gas lift optimisation.

The main difference between a BP forecast and specific forecasts as described above is that the business plan is based on an optimised development scenario, while the above forecasts aim to do the optimisation by comparing a base case reservoir development or management strategy with various alternatives and finding the best one, based on economic criteria.

Therefore, specific forecasts will normally be more detailed, both in the time and space domain, i.e. more gridblocks or timesteps to allow for a detailed comparison of the development scenarios. This can often be achieved by 'cutting-out' a sector model from the business plan 3D surface model and refining it to the appropriate level of detail, balancing model complexity with study objectives (Refer to IRM guidelines on scaling). How to include the updates and insights that result from the detailed modelling into the business plan model should be part of the forecasting strategy.

Alternatively, a full field or sector model may be built for the first time for an FDP update and should be built to such a scale that it can become the basis for future BP forecasts. Newly built models should not only be history matched with historic performance, but should also be compared to the existing forecasting models, explaining differences in the forecasts, in order to determine which will be the better forecasting tool for the future.

2.6 Manage the medium-term forecast (two years)

Objectives and scope

The medium-term forecast is used to:

- manage the medium-term Integrated Activity Plan
- set production and capacity targets as a basis for annually agreed sales contract volumes
- monitor performance against these targets, including the latest estimate.

It is derived from the long-term forecast as a snapshot of the first two years with more details of the activity plans incorporated. Where practical, it should be based on the same model as the properly scaled long-term forecast. Where this is not possible, it should be based on a decline curve analysis based on historical production trends.

Material changes in the medium-term forecast will initiate a change in the business plan forecast. Materiality levels and frequency are described in the event driven plan update guideline (Reference 16).

Medium-term production forecasts cover developed reserves and all resource categories with development activities planned to be completed within the medium-term production planning period. They should be split between the NFA and incremental New Oil contributions.

The MT forecast is linked to the Asset MT IAP (two years) to validate timings of shutdowns, WRM, NFI and build-up activities/events.

Managing the medium-term forecast

The main uncertainties to be addressed for the medium-term are, typically, planning stability (activities, projects) and new and existing well and system performance. External factors, such as oil price effects, and 'train wrecks' (typically random, high impact events) that play a role are managed at portfolio level. Project realisation/timing, reservoir performance, reserves and ultimate recovery become progressively more important for the longer-term. As such, the medium-term forecast is a multi-disciplinary effort, combining output from Integrated Production System Models with detailed activity plans, possibly in combination with real time data.

The medium-term forecast is managed by the Production Programmer and/or RE and PT and is reviewed and updated at least quarterly to reflect the latest activity schedule and surveillance data. Material changes in the medium-term forecast, outside of an agreed uncertainty band, will trigger a review of the long-term forecast.

In addition to the key factors for the LT forecast, the following parameters gain more significance for the MT forecast and should be addressed in more detail, including uncertainty ranges, especially where outside uncertainty bands of latest history matched IPSM.

- Recent well-test results.
- Recent (trends in) reconciliation factors (all phases), sales gas losses (flare/vent, power/re-injection).
- Production and reservoir management activity plans.
- Current Facilities' behaviour and constraints.
- Scheduled activities and their expected impact on the Integrated Production System (well and Facility potential, constraints and availability).
- Allowance for unscheduled deferments.
- Export logistics and product demand.

Definitions

The term 'planned activities' usually refers to those activities that have been identified and incorporated in the (business or activity) plan, but for which no fixed start and end dates are yet available. To prepare a forecast, however, dates need to be assigned for all activities incorporated in the plan.

Therefore, this guide refers to scheduled activities (with fixed start and end dates). Unscheduled activities are represented by a downtime factor in the production plan. Unplanned activities and events are those activities and events that have not been foreseen and for which no allowance was made at the time of the preparation of the forecast.

The same distinction is made between planned and unplanned deferments. Unplanned scheduled deferments are, for example, deferments from activities scheduled in the 90-day IAP, but for which no allowance was made in the year plan. However, these could also be activities which were not in the 90-day plan but were included at the last moment.

Note that system reliability is defined as:

- production/(production + unscheduled deferment)

System availability is defined as:

- production/(production + unscheduled +scheduled deferment).

Reference limit diagrams are used to quantify the technical, economic, cash and production limits of the Integrated Production System and compare them with actual production. They are discussed in detail in Appendix 5.

Planned activities

Planned activities (scheduled and unscheduled) that affect the IPSM must be taken into account, including new or planned changes to well and system potential and planned downtime, including those for reservoir management. There should be consistent planning between short, medium and long-term forecasts, facilitated where practical by a corporate activity planning database, which identifies those activities with a potential impact on production capacity or availability.

Deferments

The scheduled and unscheduled downtimes of the Integrated Production System shall be taken into account. Those parts of the IPSC that are not produced are known as deferments. If part of the IPS is not available for extended time, the IPSC may be adjusted and the reduction reported as 'opportunity' in place of deferment. Since all parts of the Integrated Production System influence each other, this is best understood by defining the availability of the (individual) system components within an IPSM.

Deferments should be split into:

- mandatory: activities that are imposed by the Company's own HSE standards, e.g. to safeguard technical integrity, or by local legislation
- required to generate additional potential due to investment activities. If this activity requires other wells or Facilities to be closed in, the resulting deferments should be allocated to, and included in the economic evaluation of the planned activity
- due to all other scheduled activities which can be further subdivided into deferments related to specific IPS components or by type, e.g. maintenance or surveillance
- unscheduled deferments
- allowance for customer demand.

These categories are used to define various production rates such as:

- Production Limit - the production rate resulting from IPSC less mandatory and investment deferments
- Production Availability - the production rate resulting from IPSC less all scheduled and unscheduled deferments but excluding the impact of allowance for customer demand

- Production forecast - the IPSC less all of the above deferments and provides the expected production rate/sales volumes.

Deferments should be included in the first two years of the IPSM and for effective analysis, differentiate between:

- deferments due to scheduled total system shutdowns
- deferments due to 'downtime' outside the major shutdowns, which may include a factor for unscheduled deferments.

The reference limit diagram should be used for forecasting (see Appendix 5) to ensure learning and opportunities are transferred to the medium-term forecast.

Export logistics

The impact of export into storage tanks or transport using Facilities shared with or dependent on other Assets or third parties must be taken into account, where applicable.

2.7 Manage the short-term forecast (90 days)

Objectives and scope

Short-term forecasts are used to optimise activity scheduling over the next 90-day planning period. The objective of this is to meet contractual (sales) obligations, maximise production revenues from available resources and identify sales opportunities on spot markets for gas where the producers load factors are relatively low. This will be balanced against longer-term requirements such as maintenance, WRM and be compliant with all standards, policies, procedures and targets, such as HSE. The short-term production forecasts or capacity plans:

- are mostly driven by firm and scheduled Opex activities and optimising the use of existing potential, e.g. the timing and impact of shutdowns, maintenance activities, well entries, system availability and gas lift optimisation
- have input from sub-surface disciplines limited to defining the expected decline rate for existing wells or expected new well behaviour and providing reservoir and well management requirements
- are the responsibility of surface discipline teams
- are generally prepared using tools based on activity planning and production system simulation, possibly in combination with real time data.

The ST production plan must be fully integrated with the short-term activity schedule.

The forecast should be expressed at sales conditions, but if this is not feasible, forecast conditions must be defined. An allowance for flare, vent and other losses, own use and re-injected volumes must be made. The activity schedule is optimised in terms of risk management (HSE), production revenues and resource utilisation.

The ST forecast is linked to the Asset ST IAP (90 days) to validate production impacting activity timings and support such as tanker scheduling or gas dispatching. The VST forecast is linked to the Asset VST IAP (28 days) to validate production impacting activity timings and support such as day-to-day tanker scheduling.

Managing the short-term forecast

The short-term production plan is usually updated each month, whilst certain gas production forecasts are updated on a weekly basis. In practice, the same approach is taken as when preparing the medium-term production plan and the same definitions apply. Major changes in reservoir behaviour are, generally, not expected over this time frame, therefore sub-surface input is generally limited to expected well behaviour, usually expressed as an extrapolation of recent well test results or real time data. Decline curves agreed with the sub-surface engineers responsible for the long-term forecasts should be used.

Where the ST production targets deviate from the medium-term (business plan) forecast, the deviations must be quantified and explained. If individual well information is not available, or deemed of insufficient quality, and if no production system model is available, the short-term production forecast can be based on:

- the actual IPSC (system test, 'perfect day' production)
- a top-down analysis of field performance
- the estimated impact of major activities during the 90-day planning period, including well optimisation, surveillance and integrated maintenance and engineering activities
- the expected behaviour from new wells and/or recently drilled wells provided by the sub-surface disciplines.

The simplicity of the forecasting process has an impact on the quality of the performance analysis as the more generic the basis for preparing a forecast, the less specific and accurate the analysis of actual performance against planned will be.

Prioritising production plan activities

The distribution that describes a short-term production forecast is usually negatively skewed. The downsides, i.e. difference between the P50 and P90 values, on average represent larger volumes than the upsides, i.e. difference between P50 and P10 values. It usually takes several upsides to compensate for one downside so managing downsides is typically more important than chasing the upsides.

In general, in order to realise a production target, resources should be allocated to:

- carry out the activities that form the basis for the 50:50 production plan
- mitigate downsides to the production plan
- realise opportunities (upsides).

Any planned activities to manage or reduce the uncertainty in the forecast must be incorporated into the approved, resourced activity plan.

2.8 Integrating the long and short-term forecast

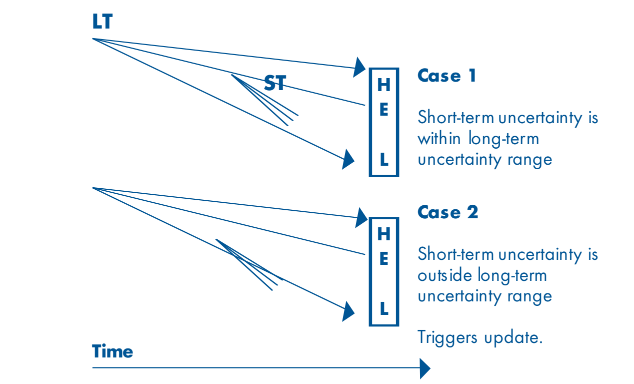
All forecasts must be team efforts. ST (90 days) and LT (EOFL) forecasts have different owners (Operations, RE) and are often derived in different ways. The MT (two-year) forecast is a multi-disciplinary product. In an ideal world, both the short and long-term forecast would be based on the same IPSM and would only differ in the very detailed modelling of downtimes and on-stream dates in the short-term. This would mean that long and short-term forecasts would be automatically consistent. Unfortunately, this is sometimes impractical, e.g. when the IPSM is too complex for LT forecasting, turnaround times are prohibitive for ST forecasting, or even because the IPSM is not kept evergreen for ST forecasting.

In cases such as these, Asset teams must take care to avoid systematic inconsistencies by:

- basing all forecasts on an agreed set of planning assumptions
- ensuring that all forecasts adhere to agreed reservoir management guidelines
- ensuring that LT forecasts undergo a reality check by Operations
- basing ST forecasts on approved well models and approved reservoir decline rates.

It is recommended to have agreed uncertainty ranges within which the forecasts may vary, before an update of the long-term

Figure 8: LT and ST forecasting ranges



forecast is triggered, whilst realising that the short-term forecast is attempting to achieve a much higher degree of accuracy on a day-to-day basis and is updated much more frequently than the long-term forecast. These checks and balances are part of the forecasting strategy. They start at the 'forecast preparation' phase and should not wait until the forecasts have been made.

2.9 Review and challenge

Continuous efforts to improve the quality of the forecasts should be undertaken by benchmarking components of the forecast against historical performance of the field and/or analogues for reservoir performance and schedule. These serve to improve both the forecast itself by reviewing and updating key forecasting assumptions, as well as the forecasting process by improving data gathering, simplifying the forecasting models and improving workflows and interfaces. The following activities can be used to support improvement.

- The WRM/PSO process provides continuous feedback of forecast vs. actual resulting in history matched IPS models that are kept up-to–date.
- AFPR - annual field performance reviews (AFPR, as per control framework, Reference 5) need to be implemented diligently. For the forecasting process, the AFPR provides a proper look-back, where answers are sought to crucial questions such as:
  - why was last year's forecast not achieved?
  - was the actual production within low-high range?
  - was risking applied based on the right risks and with the right magnitude?
  - were any key risks and/or opportunities missed?
- VAR5 and Post Investment Reviews are required for major projects and provide the opportunity to review, learn and improve the forecasting process for New Oil.
- TLVC and Top Quartile recovery factor reviews help calibrate the recovery to the upside. Note however that while TQ recovery is a worthwhile aspiration, most expectation forecasts can (by definition) not be top quartile.
- Operational Excellence (OE) Reviews check compliance with the best practice standard in the Regions and aim to improve the process. The forecasting element can be found in the Operational Excellence Standard (see Reference 4).
- Short and medium-term forecasts are, in general, calibrated monthly performance vs. actual. Appendix 6 gives a detailed method for analysing actual versus planned production.

2.10 Data management

The HRV-MS (Hydrocarbon Resource Volume Management System) will be deployed between 2008 and 2010. It will hold vintages of production forecasts, consistent with the reserves categories and reservoir and project information and will also link to Business One which will hold all planning data forecasts. It will become the mandatory system for storing all BP and ARPR forecasts.

Some Regions have developed (spreadsheet) tools with similar functionality, such as the Hydrocarbon Volume Maturation (HCRVM) Tool from EPE. These tools have served a very useful purpose prior to the introduction of HRV-MS, but will be phased out in the interests of Global consistency.

3. Appendices

Appendix 1 - Emissions forecasts

All forecasts must be compliant with the Group's, Business Unit's and OU's HSE and Sustainable Development standards, policies, procedures and targets regarding flaring/venting, disposal and other emissions, fuel consumption and energy efficiency.

In accordance with the Shell Group Corporate requirements, the HSE/Sustainable Development elements are covered by the principles of:

"Minimising impact on the environment", to be achieved by:

- the provision of environmental studies, such as environmental impact
- assessments and baselines
- meeting Group minimum environmental expectations.

"Using Resources Efficiently", to be achieved by:

- waste management through Asset life cycle
- life cycle assessment of energy and material use
- minimising land take.

"Maximising Profitability", to be achieved by:

- meeting economic screening criteria
- use of latest appropriate technologies (the 'limit')
- adoption of Strategic Cost Leadership (SCL) principles
- maximising recovery from reservoir.

Forecasts are instrumental in quantifying the expected impact from Production Operations on the environment, e.g. emissions, water disposal, energy consumption.

Following the Kyoto Protocol, Shell has set limits to the green house gas emissions levels for the Group. The consequences for Shell EP are that energy usage and flare and vent volumes must be reliably measured and controlled. The advent of emissions trading schemes and increased de-regulation of the energy market drives the need for effective forecasting of energy demand and emissions quantities for Shell-operated Assets.

At the lowest level, emissions compliance requirements are site-specific. These are not only restricted to emissions to air, e.g. CO_2 but can also cover disposal water quality.

At corporate level, the CO_2 emissions forecasts have an explicit financial value through the potential damage to reputation and trading of CO_2 emission allowances granted by the authorities. Over-forecasting on emissions could result in a lost opportunity to trade any surplus. Under-forecasting could result in the need to purchase CO_2 allowances to secure compliance.

Failure to comply could result in License to Operate issues or reputation damage. Failure to provide realistic energy demand forecasts could result in missing opportunities to optimise on fuel or electricity supplies or to take advantage of lower purchase rates.

To support optimisation and trading decisions, preparing forecasts for production, energy and emissions must be fully integrated and consistent. Practical guidance in how to construct Emissions and Energy Efficiency forecasts can be found in Reference 15.

Appendix 2 - Use of models

Choice of models and model set-up

Different methods may be used to model reservoir, Facilities and system availability when generating the production forecast. Their order of preference is as follows.

1. Integrated Production System Models.
2. Integrated static and/or dynamic reservoir simulation models.
3. Material balance and/or analytical models.
4. Decline curve analysis.
5. Analogue data.

The selection of the most appropriate forecasting method for a particular case depends on the forecasting objective and strategy. It should consider a number of factors including reservoir maturity, availability and quality of reservoir and/or production data, complexity of the sub-surface and/or recovery method, time scale of the required forecast as well as timing and cost considerations. For undeveloped fields, the emphasis needs to be on covering the full range of sub-surface and development uncertainties (the multi-scenario approach), and simple models may be the most appropriate.

Production profiles should be generated at an early stage using simple models, e.g. single cell (material balance), box-type, cross-section, sector or coarse 3D simulation models. These forecasts need not be of the highest accuracy, but must be technically sound and realistic. This allows identification of those uncertainties that have the largest impact on the production forecast. If required, the model can be refined successively to better represent essential geological features or dynamic phenomena, commensurate with the forecast requirements, strategy, business needs and available data, i.e. the 3D approach "all the way". As the model becomes increasingly complex, it is important to calibrate the results against analytical calculations, material balance analysis or simplified prototype numerical models.

Most developed fields, with an abundance of field data, will have history matched dynamic simulation models, which provide a description of the movement of fluids over time, thereby providing a basis for predictions of future reservoir production performance. Where possible, dynamic reservoir models should be combined with integrated multi-phase production system models, which link several sub-surface models to detailed descriptions of a surface network. Such models allow the prediction of interactions between different reservoirs, wells and Facilities and optimisation of the production from a portfolio of existing and/or future development projects. This is the preferred method. Complex systems with many reservoirs and drainage points may be modelled with IPSM if it is available. Sub-surface models for important (high rate) reservoirs are combined with type curves for less important reservoirs, e.g. through use of trend cards or fractional flow curves. This often provides the best balance between modelling the full system complexity and keeping focus on the main forecast drivers.

Decline curve analysis (DCA), may be the only practical way to make forecasts for very mature fields with a very high well count and, in many cases, it provides a robust forecast (see section 2.4). Note, however, that the EP policy requires consistent forecasts of oil, water and gas both produced and injected. Thus, if DCA is used there must also be a separate material balance calculation for the fluids that it does not address.

As a general rule, a forecast should be made with an IPSM of the appropriate complexity. The model forecast should be calibrated with analytical methods and DCA (for producing fields). For expectation reserves and business planning forecasts, the IPSM model will be the primary forecasting method with DCA and analogues as backup. For proved reserves forecasting, DCA and analogues will be the primary tool with IPSM providing additional and/or backup support and evidence.

Transition from history match to prediction

A history match must be carried out before a dynamic model is used to make quantitative predictions of future reservoir performance in producing fields, i.e. tuning of relevant static and/or dynamic reservoir model parameters, until an acceptable fit between simulation predictions of reservoir and well behaviour and recorded historical field data is achieved (satisfying pre-defined acceptance limits).

Due to the high degree of uncertainty in any reservoir model and the many parameters influencing the simulation results, no history match will ever be unique. IRM principles should be applied and a forecasting range should be generated satisfying the solution space constrained by the production history. Refer to DRM guideline (Reference 10), Chapter 10.

Checking predictability

Special care is required to ensure a smooth transition between the history match and the prediction part of the simulation run, and this is to some extent a quality test of the history match. Constraints at this point usually change from rate constraints to pressure constraints, e.g. BHP or THP which may cause unrealistic rate changes in the wells. This transition problem has a number of possible causes such as:

- insufficient matching of the well productivity index or drawdowns
- production constraints that played a role in the history have not been properly taken into account in the prediction mode
- well and Facility uptime is not properly taken into account
- lift data is inconsistent with historical rate constraints.

It is recommended that the last year of history is run in prediction mode and the actual production compared with the prediction. Whilst this should not be expected to give a perfect match, it will help to highlight major discrepancies in the model.

Example 5 shows best practice in ensuring a smooth transition from HM to prediction by running the last year of history in forecast mode.

Simulator forecasts should also be benchmarked to analogue performance and compared to analytical techniques such as material balance, Buckley-Leverett or Dykstra-Parson. A physically consistent explanation should be derived for any unusual behaviour of the forecast.

Comparison of NFA simulation results versus DCA

A good alignment between the NFA forecasts from the simulation model and from DCA will add a lot of confidence to the simulation results. It is, however, common to see large discrepancies between the two. This does not necessarily mean that either one is wrong, but requires an understanding of why they are different. DCA typically extrapolates the historical performance into the future.

Example

If new wells have recently been added, DCA will extrapolate them using the historical trend while the simulation model in this case may be more realistic. Overall, simulation models generally tend to predict higher NFA.

The historical performance could be a function of increasing BSW and/or reduction in gross/PI due to, for example, skin, reducing pump efficiency, increase in back pressure or decrease in reservoir pressure. If the reduction in gross is not captured in the simulation model, the model will over-estimate the forecast oil production but under-estimate the benefits of a pressure maintenance scheme. Therefore, gross production as predicted by the simulation model should be compared to the established trend in the field.

Treatment of well and Facility constraints

An incremental barrel can only be considered as produced when it arrives at the sales point. For a particular development option, a forecast should honour the system constraints imposed by the wells, flow lines, pipelines and Facilities. Schedule constraints, such as the drilling sequence can be handled as part of the development phasing. Well and Facility constraints must be applied to both NFA and New Oil forecasts.

FBHP is a function of back pressure, pump efficiency, gas lift volumes, skin, etc. Note that historic skins are not necessarily representative for future wells depending on the completion strategy. Apart from the FBHP, a maximum gross constraint should always be imposed to avoid unrealistic rates. However, it is not advisable to set existing wells to their last produced gross rate as the benefits of a reservoir pressure increase due to a pressure maintenance scheme would not be captured, potentially resulting in too many new producers being drilled. Vertical flow characteristics in gas wells and free flowing oil wells are an integral aspect of well capacity and/or potential estimation and should always be modelled. For injector wells, injection volumes should be carefully calculated based on the injection policy to either inject under frac pressure (matrix flow) or above fracture initiation and/or propagation pressure and assumptions should be clearly documented.

Only in exceptional cases, such as shallow well pump-off using beam pumps, ESP or PCP, should wells be modelled by applying a fixed FBHP, which will only give a rough approximation of the well performance.

Facility constraints are mainly related to pipeline erosional velocity and pressure limits, oil/water/gas processing capacity, compressor limits and fluid disposal systems. In some cases, they can be relatively easily taken into account by defining a gathering system in the reservoir simulator, which does not calculate pressure drops in the system, but allows for constraints to be put on user defined nodes. When this is inadequate, e.g. pipeline pressure drops, temperatures, compressor performance curves, horsepower limits, mixing of fluids, etc. are important, the next step up from a simple gathering system in the reservoir simulator is an Integrated Production System Model (IPSM) to calculate and account for pressure drops in wells and in the surface system. Appendix 3 gives a list of tools available and ranks their preference for use.

Production system availability

Prediction runs must always include a system availability factor to account for scheduled and unscheduled maintenance or operational problems with wells and Facilities. For the first two years, these are normally modelled explicitly and must be applied to both NFA and New Oil forecasts.

Uptime factors may vary between injectors, producers and Facilities, and over time. Historical system availability statistics are a good first indication of the uptime factors to be used in prediction runs and should always be used to support the forward estimate of availability. The uptime factor should, therefore, be based on sound statistical analysis of past system availability and proper forward activity planning. Historical system availability statistics will be an important part of the audit trail.

Optimistic assumptions on future availability improvements should be avoided. Improvement business initiatives often have ambitious targets, but their achievability needs to be demonstrated before they are worked into the forecast.

Abandonment conditions/end of field life

Wells and fields are closed-in once they reach their abandonment rate. The well abandonment rate is defined as the rate at which it would no longer be economically desirable to produce a well under assumed costs and operating conditions. The well abandonment rate is effectively the greater of:

- a technical producing limit or operational constraint, e.g. lift die-out. In simple terms, this occurs when a well is no longer able to produce on the right side of the lift curve minimum, Facility fluid treatment limit, falling below a flow assurance cut-off (minimum riser velocity or temperature)
- the rate at the time that the well would no longer rank on the workover sequence, e.g. pump replacement sequence increased by the half mean time between failures for the completion type of the well within the field

- reasonable assumptions on the remaining life of the well, based on the life expectancy of existing wells in analogue setting
- the well's Opex exceeds its revenues at the current oil price.

The field level forecasts will then be rolled up at a cluster level to determine the cluster or offshore Facility abandonment date, i.e. the year before the annual net operating revenue goes negative for the last time. This date will then be used to cut off individual field forecasts within each cluster. Note that abandonment is generally driven more by the Facilities' Opex than by well Opex.

In the case of offshore platforms, the abandonment date is often determined by major maintenance, such as the six yearly survey or FPSO design life.

A New Oil project could either defer or accelerate the abandonment date of a field, depending on whether the project has more effect on reserves or on acceleration as shown in Figure 9 and 10. Further abandonment criteria may be end of concession and/or end of license period or end of PSC contract.

Refer to Reference 4 for guidance on inclusion or exclusion of volumes post-licence expiry.

Figure 9: Abandonment - adding reserves

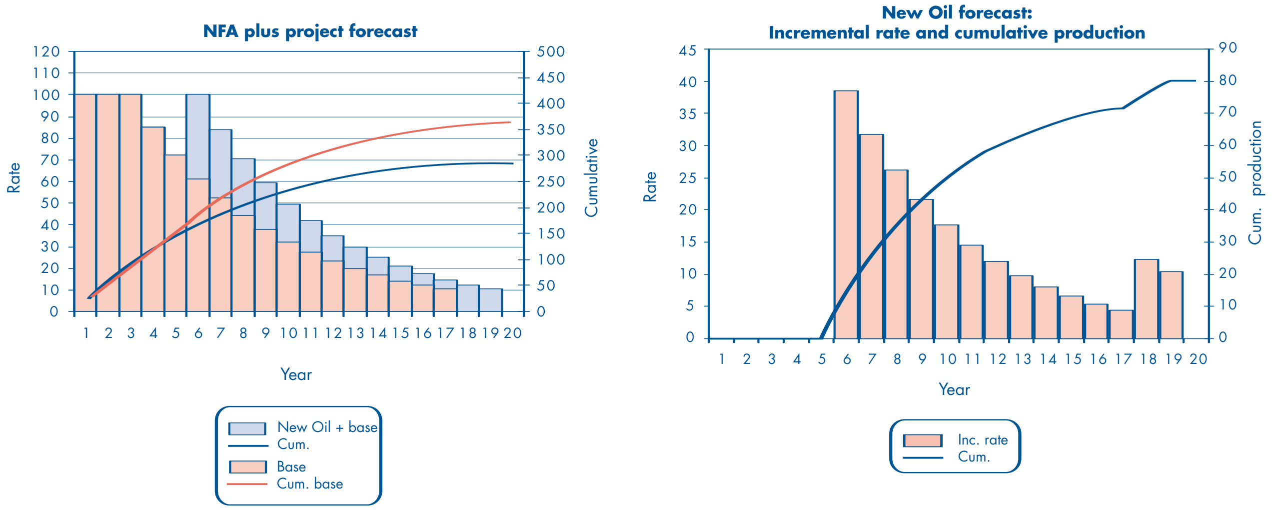
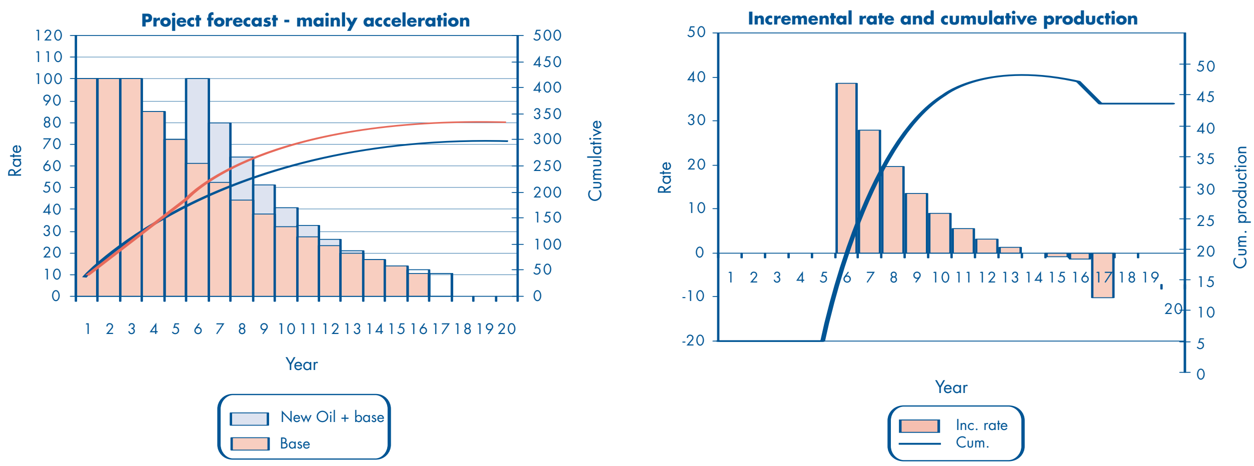


Figure 10: Abandonment - acceleration



Appendix 3 - Forecasting tools

Using the right tools is essential to achieve consistent results. Recommended tools have the functionality required to support the best in class forecasting standard. Alternatives are acceptable if they fulfill, in general, the minimum forecasting standard. It is understood that replacing legacy alternative tools might disrupt the business in the short-term but they should be replaced with recommended tools when the opportunity arises.

Spreadsheets, however, should not be used to make controlled official forecasts. These are hard to audit, review and maintain and can, potentially, have hidden mistakes in them.

Table 3 lists the recommended forecasting tools, some of which are described in this section.

IPSM tools

IPSM is the recommended tool for forecasting. The Global RE Leadership Team has issued this definitive guidance on modelling to Asset teams.

For new modelling projects

- Start with an MBAL-GAP model in order to optimise cross-functional integration.
- If the sub-surface cannot be described by material balance, use a MoReS-GAP model.
- If there are special high-end needs that cannot be covered by a MoReS-GAP model, and/or HFPT knowledge is available and the RE is doing most of the work, use HFPT.

Table 3: Recommended forecasting tools

Objective	Method	Recommended tool	By exception/alternatives
Most forecasts - standard black oil/gas	IPSM	MoReS/GAP	HFPT, Genrem DRMS (in the future)
Very simple sub-surface	IPSM	GAP/Mbal (IPM)	
Limited surface constraints and interactions	Sub-surface	MoReS	DRMS (in the future)
Mature fields/many wells/ proved reserves forecasts	DCA	OFM	
EOR	Special sub-surface simulators	Stars, GEM, MoRes	DRMS (in the future)
Portfolio management	Probabilistic	PetroVR	Pertmaster
Data management	Manage forecasts	HRV-MS	Spreadsheet solutions (until HRV-MS is fully rolled out)
Data management	Manage models	IFM	
Risk management	Risk register	Easyrisk	
Short-term prediction vs. actual, WRM		PFact	

Existing modelling projects

- Use existing models and encourage cross-functional ownership.
- No need to re-build unless project is not owned by integrated Asset team.

An IPSM is a software model representing the production system in terms of rates (oil, water and gas and pressures) from the reservoir through export and takes account of all constraints arising from the:

- reservoir
- wells
- surface gathering network
- surface processing
- sales point
- system availability.

An IPSM thus fulfills all the requirements for production forecasting. Examples include IPM (Mbal/Gap/Prosper or GAP/MoReS), HFPT, GENREM. If simpler, less integrated tools are used, it must be ensured that none of the above components are neglected.

Integrated Field Manager (IFM) is a new application from Petex that has three key business benefits.

1. Keeping models evergreen. This has always been a major challenge and a robust and easy to use tool is needed to keep the IPM models up-to-date. IFM supplies connectivity to different databases, e.g. EC, Primavera, PI including mapping and unit conversion, and has a structured process to follow.
2. Forecasting. IFM supports the production forecasting process and ensures consistency between ST, MT and LT forecasts. IFM will support the Shell production forecasting process and guidelines.
3. Surveillance. Apart from model maintenance, which provides key surveillance, IFM has a real-time calculation mode. IFM will allow the comparison of Production Universe data with model calculations in (near) real time. Deviations warn the user that something in the system is changing. It will also allow semi-real time forward looking calculations that can warn users when the forecast is beginning to deviate from latest expectations.

Oil Field Manager (OFM) is the preferred tool for decline curve analysis, i.e. when forecasting for proved reserves. A Shell template is available which contains useful features for DCA and will ensure proper use of the tool.

Portfolio management tools

PetroVR and Pertmaster are tools for probabilistic modelling for high level portfolio analysis of multiple fields and reservoirs. In this area, pressure drops can often be neglected and detailed reservoir models are less important than uncertainty in schedule and volume delivery and interaction of the hard constraints. These tools can also model Opex and Capex uncertainty and produce full life cycle economics. Shell has a Global License for both tools.

PetroVR and Pertmaster are tools that allow a full EP value-chain model to be built, encompassing:

- very simple sub-surface models (no pressure drops)
- surface gathering system and Facilities
- scheduling of study, appraisal, design, construction and other activities with associated costs
- scheduling of wells and rigs to meet production targets
- cost, revenue and economic indicator calculations.

The models can be run deterministically to examine different development options and, in addition, this is a key discriminator for this software, stochastic (Monte Carlo) runs can be made to evaluate project risk. Ranges can be entered for key value-driving uncertainties such as well productivity, construction duration and the effect of these combined uncertainties on value drivers such as NPV and on-stream-date can be evaluated through Monte Carlo analysis.

Appendix 4 - Uncertainty input distributions and probabilistic aggregation

Scheduling and ramp-up uncertainty

For all New Oil projects, the scheduling uncertainty must be included in the uncertainty range, expressed as first oil date (FOD) and is an important part of the short-term uncertainty.

Scheduling uncertainty is almost always a skewed distribution as shown in Figure 11, with much more scope for delay than for acceleration, i.e. more downside than upside.

This is because there is, in general, little scope to accelerate projects through optimised planning and good project delivery, but many potential reasons for severe delays, which are not fully in the control of EP, e.g. legislative, contractual, partner issues, political. This is equally true for major new projects, brownfield refurbishments and infill drilling projects. Generally speaking, more complex projects tend to suffer more delays than simple projects which are 'routine' for an AoO. Figure 12 shows a typical uncertainty range for a New Oil project.

For major projects, the scheduling uncertainty is calculated by Cost and Schedule Engineering using dedicated tools such as Pertmaster and PetroVR and the forecast has to be made with close co-operation between the contributing disciplines and functions.

Figure 11: Scheduling uncertainty - skewed distribution with more downsides

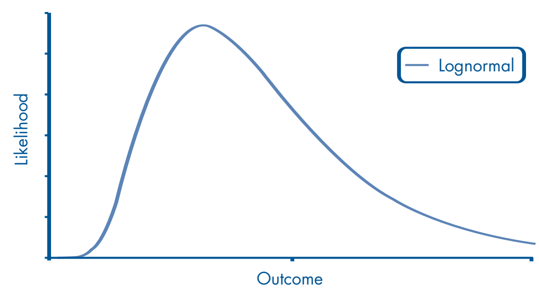
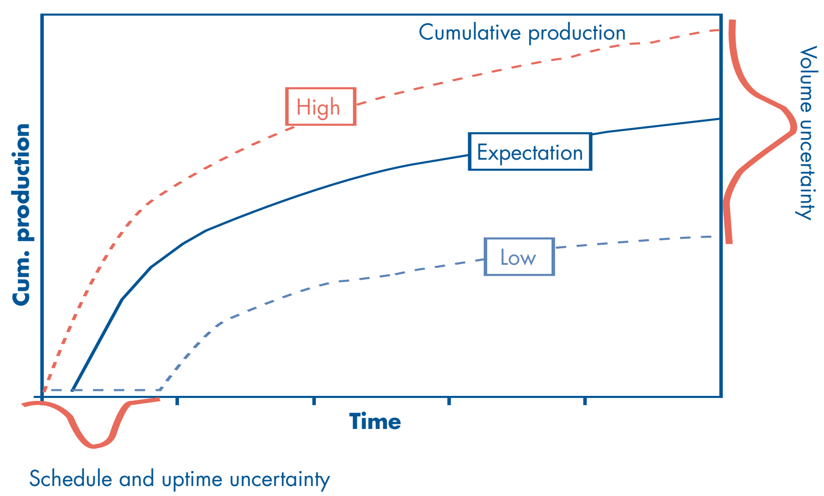


Figure 12: Typical uncertainty range - New Oil project



Similarly, a good understanding of ramp-up uncertainty for new wells and Facilities is needed. It should not be assumed that start-up is immediate. A look at historical performance for similar projects should give some indication of the likely outcome.

Scheduling delays are a major contributory factor to forecast under-delivery in the annual business plan.

System availability uncertainty

System availability is normally modelled as an average uptime factor, but should be modelled explicitly for the first two years based on scheduled and unscheduled maintenance.

It is usually skewed to the downside as shown in Figure 13, as there is normally limited scope to improve through optimisation and good planning. This is especially so if operational excellence is already high but potentially large deferments are possible due to unforeseen events, which are often not in our control. System availability uncertainty will have a significant effect on the short-term forecast and is fully discussed in sections 2.6 and 2.7.

Sub-surface uncertainty

Sub-surface uncertainty will dominate the uncertainty range in the long-term where the main uncertainty drivers are STOIIP/GIIP range, relative permeability, permeability, kv/kh, connectivity, PVT, aquifer influx and displacement efficiency, influencing reservoir pressure drops, rate decline, water breakthrough and ultimate recovery.

The sub-surface uncertainty distribution could be symmetric or skewed both ways as shown in Figure 14.

A typical reason for downside skew is under-estimating the sub-surface complexity resulting in, for example, premature water breakthrough. Integrated reservoir models, typically, homogenise complexity and hence deliver optimistic sweep predictions. Additionally, creaming curve effect is often not properly accounted for when forecasting infill drilling projects.

Typical reasons for upside skew are under-estimation of HC IIP (especially for big fields) and aquifer benefits or recovery factors in gas reservoirs. It is important to also highlight and properly address the upside in the forecast.

Figure 13: System availability uncertainty skewed to downside

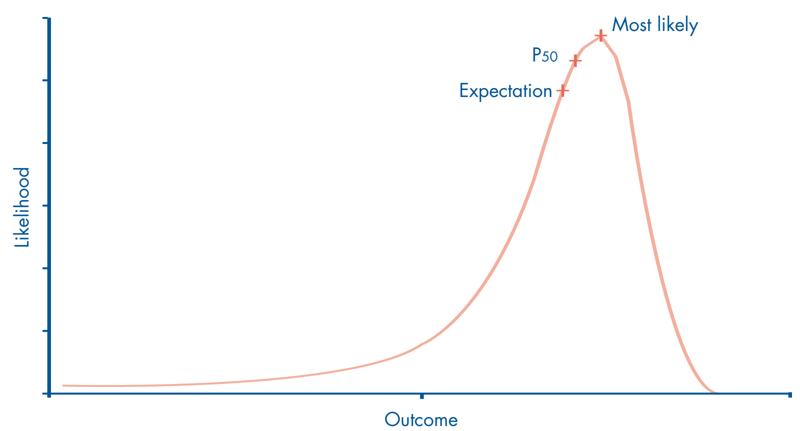
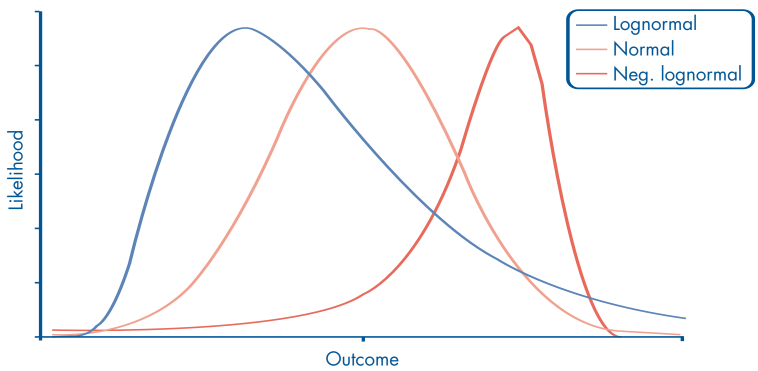


Figure 14: Sub-surface uncertainty symmetric or skewed both ways



Sub-surface uncertainty should first be analysed using a Pareto (or Tornado) chart to determine the bias and impact of the individual input range uncertainties and the major drivers put in a risk register. It is not always clear from the single parameter analysis whether the ultimate recovery range will be left or right skewed. Detailed guidelines on how to model the complex interplay of these sub-surface uncertainties, taking into account stochastic dependencies and constraints, are provided in the static/dynamic IRM guidelines (Reference 16). An appropriate level of sub-surface uncertainty is generally reflected in the reserves range quoted.

How to derive the uncertainty in ultimate recovery

Intuitively, the uncertainty in the forecast should increase with time, but this is not often observed in the actual forecasts. A possible reason for this observation is that there is often no up-to-date reservoir uncertainty study and there is no requirement to report high case reserves to guide the long-term uncertainty estimates. Furthermore, proved reserves are often below a P90 estimate due to non-technical SEC rules, specifically the ELT (economic limit test), LKH (lowest known hydrocarbon), the one offset rule and proved area definitions. Therefore, proved reserves are often not used to guide the low case forecast.

However, it is important to capture the long-term uncertainty properly, for the downside and upside, and these should be consistent with uncertainty in the reserves estimates.

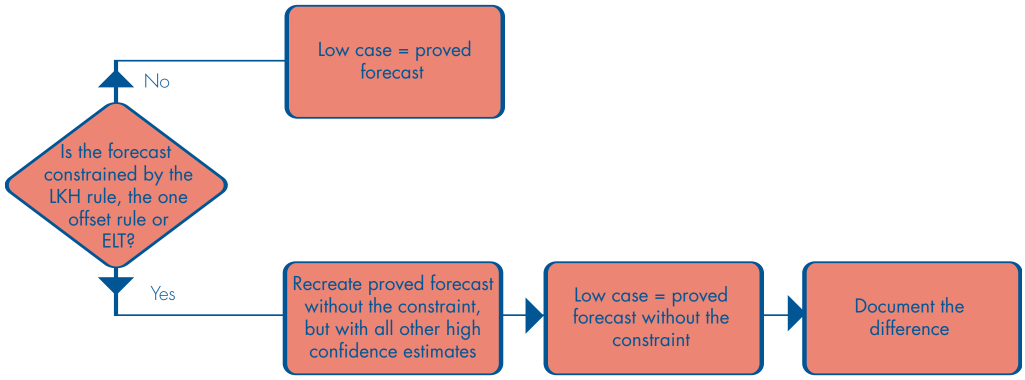
In the absence of an up-to-date reservoir uncertainty study, the following steps, as shown on the flowchart in Figure 15, should be followed to determine the long-term high and low case forecast ranges.

If the proved forecast is not constrained by a non-physical SEC rule, then the low case forecast is the proved forecast.

If the proved forecast is constrained by a non-physical SEC rule, (the LKH, the ELT, the one offset rule or proved area definition), remove this constraint and replicate the proved forecast without it. This will define the low case. Document the difference between the low case and the proved forecast.

Note that the SEC has announced changes to its reserves rules effective January 2009. These changes are expected to remove or replace all of these non-physical rules. In this case, the low case forecast will always be equal to the proved forecast.

Figure 15: Long-term high and low case forecast range determination



Example (for LKH)

If the LKH proved by a well is much shallower than the hydrocarbon–water contact derived from seismic or from RFT pressure gradients then the low case should be based on the deeper OWC from seismic or pressure gradients. It is, therefore, justified to have a higher low case than in the proved forecast (but all other high confidence estimates should be maintained).

A high case forecast should be made by inverting all the technical high confidence assumptions upon which the proved forecast is based. For example, if the DCA was used and proved was based on a conservative decline, the high case should be based on an optimistic decline assumption. However, if proved was based on no aquifer support and the expectation on moderate aquifer support, the high case should be based on optimal aquifer support. This approach will not normally result in a symmetric uncertainty distribution, but will give an indication of the skew of the uncertainty range. Symmetric uncertainty estimates with little underlying technical basis such as the application of a plus or minus 10% range should be avoided.

IPSC/metering uncertainty

Prediction runs are usually restarts of the model at the point where the history match finished. Uncertainties that remain at the end of the history match period should be carried forward into the prediction runs. One of these uncertainties is the accuracy of the historical production. As metering in some AoOs has been very poor in the past, oil and gas rates in particular may have a large uncertainty band around them.

Example 7 is a good example of experimental design (ED), which allows a certain historical production uncertainty at the beginning of the prediction period to be taken forward. Instead of homing in on a single 'best' history match, the ED methodology is used to map out the complete uncertainty space using a limited set of simulations and to find the areas where the model would be considered to match the observable data. This typically results in a set of 'history matched' models, which are then taken forward in forecast mode. The range of outcomes constitutes the uncertainty range on the forecast.

Managing forecast portfolio uncertainty

It is often necessary to investigate the forecast uncertainty for a portfolio of fields or reservoirs to evaluate, e.g. the risks and opportunities of an exploration portfolio, of a new business aspiration, for an urban planning study or to evaluate uncertainty in the Regional portfolio.

A portfolio could be:

- multi-reservoir fields
- cluster developments
- gas contract pool
- Regional/AoO portfolio
- Global BP - if forecasts are stochastically independent.

Example 10 shows how to treat uncertainty for a cluster development with multi-reservoir fields using IPSM modelling and a scenario tree.

Example 11 shows how to treat uncertainty for a gas contract pool.

It is important to understand whether the portfolio uncertainties are dependent or independent. The first three portfolios are, in general, dependent (with both positive and negative correlations) and share common system constraints. In this case, a comprehensive Monte Carlo analysis of the system is required that includes all the complex system interactions. PetroVR and Permaster are recommended tools for this type of analysis. If the uncertainties can be assumed to be largely independent, as in the Regional and Global portfolios, a simpler method can be used for the aggregation.

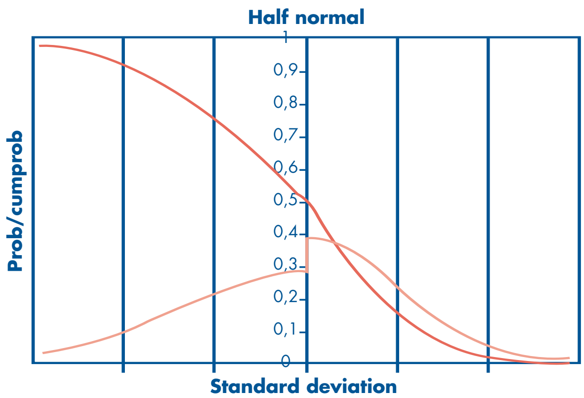
It is assumed that the individual forecasts are approximately equal to expectation forecasts and may therefore be added arithmetically, because the mean of the aggregate is equal to the sum of means.

$$\mu_{aggregate} = \sum \mu .$$

If the uncertainty range is very skewed then the P50 will differ significantly from the mean and a correction may have to be applied to aggregated forecast, reflecting the skew of the resulting uncertainty distribution.

For a normal distribution, the standard deviation of the aggregate is the square root of the sum of the squares of the

Figure 16: Half normal distributions



input standard deviations. If the input distributions are skewed, it is assumed that they follow a 'half' normal distribution as shown in Figure 16 and the upside standard deviation and the downside deviation are added separately.

$$P_{15} - \mu \approx \sigma_{upside}(aggregate) \approx \sqrt{\sum \sigma^2_{upside}}$$

Other confidence levels may be easily estimated as shown in Table 4.

Table 4: Estimating confidence levels

Upside confidence levels	Downside confidence levels
$P_{15} - \mu \approx \sigma_{upside} \approx \sqrt{\sum \sigma^2_{upside}}$	$P_{85} - \mu \approx \sigma_{downside} \approx \sqrt{\sum \sigma^2_{downside}}$
μ-P_{10} = $1.28\sigma_{upside}$	μ-P_{90} = $1.28\sigma_{downside}$
μ-P_{15} = $1\sigma_{upside}$	μ-P_{85} = $1\sigma_{downside}$
μ-P_{2} = $2\sigma_{upside}$	μ-P_{98} = $2\sigma_{downside}$
μ-$P_{0.1}$ = $3\sigma_{upside}$	μ-$P_{99.9}$ = $3\sigma_{downside}$

Note that the above formulas highlight the importance of focussing on the big ticket uncertainties. Assume that there is one field with an uncertainty range of 10 and there are 10 fields with an uncertainty range of 1, then the uncertainty range of the portfolio is:

$$\sigma_{aggregate} = \sqrt{100 + 10} \approx 10.5\,.$$

If the uncertainty range of the big field is under-estimated by 10%, i.e. 9 instead of 10, then the uncertainty range of the portfolio is:

$$\sigma_{aggregate} = \sqrt{81 + 10} \approx 9.5$$

A 10% error on the big uncertainty has more impact than ignoring all the 10 smaller uncertainty ranges! Thus, a lot of statistical analysis on minor uncertainties will not compensate for under-estimating the major uncertainty ranges!

The probabilistic forecast aggregation is done on a year-by-year basis and negative increments (for acceleration forecasts) are added to the other half of the standard deviation. Note that the assumption of stochastic independence is an idealisation and, in practice, there will be many 'hidden' dependencies. It is, therefore, recommended to always also calculate the arithmetic sum of the standard deviations, which would give the uncertainty ranges in case of fully positive dependency. Furthermore, the SEC mandates an arithmetic aggregation of the proves reserves for disclosure purpose, which is equivalent to assuming fully dependency.

Example 12 demonstrates the calculation steps for a synthetic case of three forecasts. It should be emphasised that this is only applicable if the outcomes can be assumed to be stochastically independent.

The resulting distribution is only an approximation, which is not a problem since there is an incomplete understanding of the input distributions, but it fulfills the following essential criteria:

- predictable
- repeatable
- exact if the input distributions are normal distribution
- fully preserves the skew of the input distributions.

An independent forecast may also be aggregated using a Monte Carlo method, but it must be clear that this also requires a number of assumptions about the distribution and how to approximate the mean of the input distributions and will not necessarily give more robust results. Using the algorithm described above will give more predictable results.

Appendix 5 - Reference limit diagrams

The reference limit diagrams are used in the Production System Optimisation process (Reference 14) to compare and match the individual component capacities to identify system 'bottlenecks', to quantify the technical, economic, cash and production limits of the Integrated Production System and compare them with actual production. They are called limit diagrams because they show the various potential and actual production limits of the Integrated Production System and its components.

There are three types of RLD, which are directly related to each other as shown in Table 5. Their values can only be compared, e.g. to quantify production limits/opportunities, if they are valid for identical time periods, e.g. average IPSC versus economic limits per year or per month.

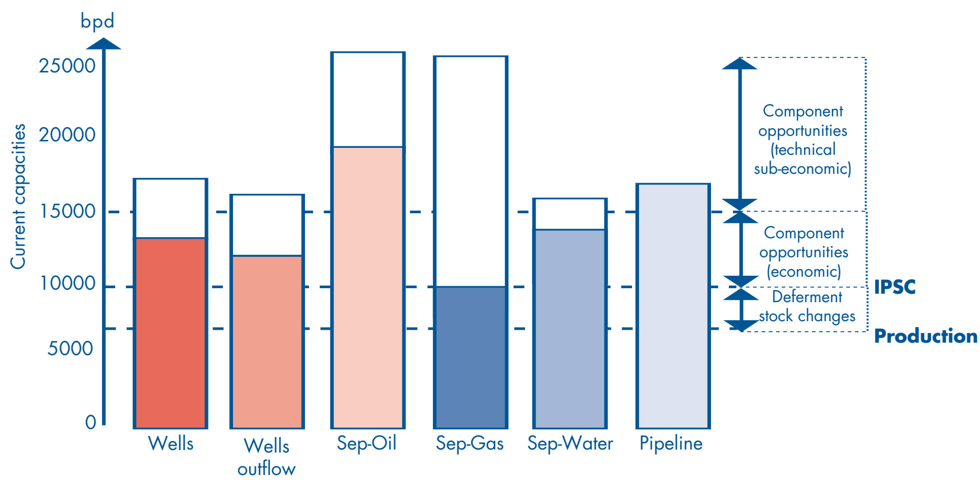
The component (or current) limit diagram, as shown in Figure 17 is used to show the capacities, e.g. net oil of the individual IPS components. It gives an indication of what the current system constraints are and what the next constraint would be if a component capacity was increased.

Table 5: Types of reference limit diagram

	Reference limit diagram	Process	Objective
CLD	Component or Current limit diagram	PtL, PSO	Identify IPS component constraints and opportunities
FLD	Forecast limit diagram	Production forecasting	Quantify opportunities and expected deferments
HLD	Historic limit diagram	HPIM	Quantify actual production and deferments

It is not suitable to quantify gains from PSO opportunities at system level as it only shows the component opportunities, i.e. the potential instantaneous increase in capacity at component level, and not the expected increase of production at sales point. It is not corrected for other flows (such as flare, own use, re-injection, losses), which, particularly for gas production systems, means that the actual IPSC will be different from what is shown on the CLD.

Figure 17: The component or current limit diagram



To determine whether or not opportunities are economic requires a production forecast to quantify the expected production gains from the opportunity.

The forecast limit diagram in Figure 18 shows the total sustainable incremental production capacity of the various types of opportunities over a specified time period at system level and taking production decline and changes in BSW and GOR into account. The values are represented at sales point, i.e. the associated well production is corrected for own use, re-injection, flare and other losses. The limits shown in the FLD are the technical, economic, cash and production limits.

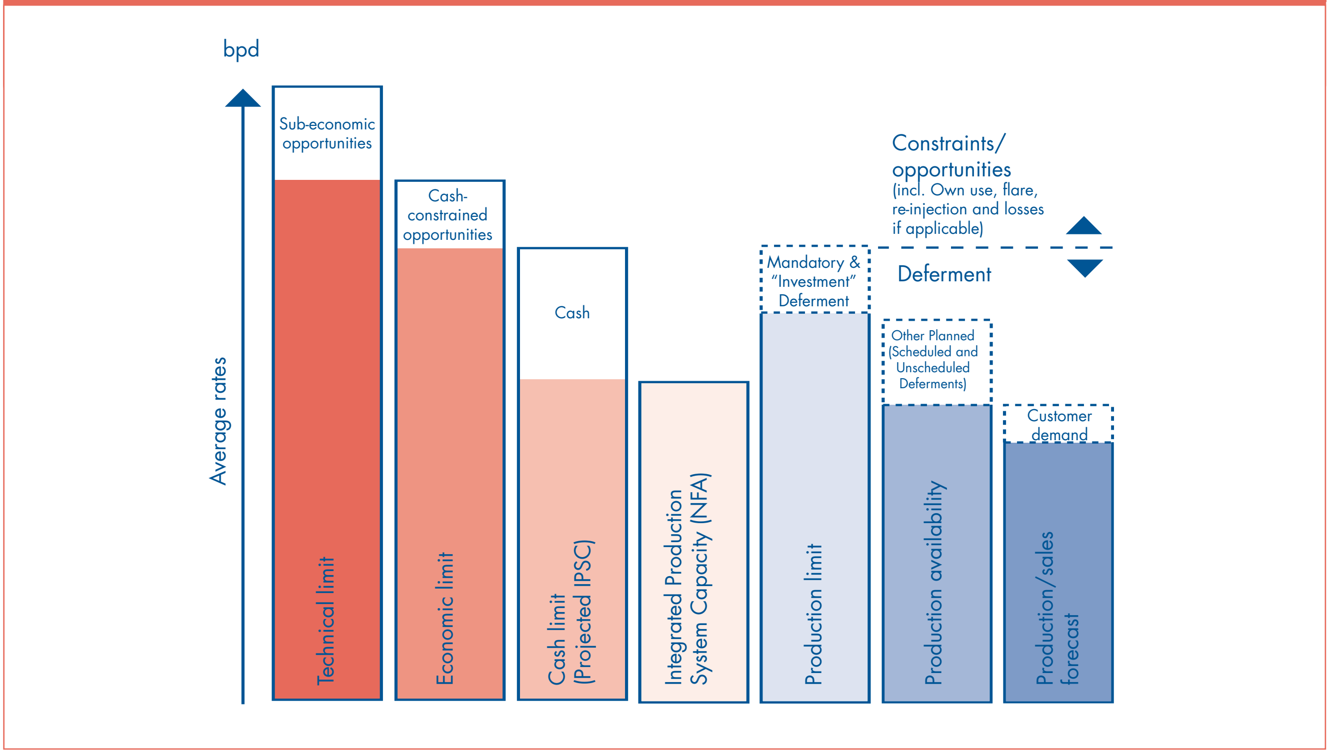
The base line for preparing a production forecast and from which the limits are quantified is the No Further Activity IPSC.

Since this is the forecast IPSC, which applies to a specified planning period taking system losses into account, this value will be different from the IPSC shown in the CLD.

Integrated Production System Capacity (No Further Activity)

This is the maximum average (net) IPS production rate at sales point over the time period considered under optimum conditions, at 100% availability, taking into account the reservoir, conduits and Facilities' constraints and compliant with current operating guidelines, e.g. restrictions in IPSC due to reservoir voidage or sand production control, energy management, flare limits, but excluding any further Capex and Opex investments to increase IPS capacity.

Figure 18: The forecast limit diagram



Cash limit (projected IPSC)

This is the maximum average (net) IPS production rate at sales point over the time period considered under optimum conditions, at 100% availability and including all further investments for which cash is available to increase IPS capacity.

The cash limit demonstrates the tension between available funds and economic opportunities for the IPS.

Economic limit

This is the maximum average (net) IPS production rate at sales point over the time period considered under optimum conditions, at 100% availability and including all economic opportunities to increase IPS capacity.

The economic limit should challenge current operating guidelines. It defines the point at which investment to increase the IPS capacity is currently uneconomic. The understanding of this parameter tends to feed into medium and long-term opportunities and forecast updates.

Technical limit

This is the maximum average (net) IPS production rate at sales point over the time period considered under optimum conditions, at 100% availability and including implementation of existing and near-term technologies. This includes currently non-economic opportunities.

The technical limit is an aspirational limit for performance, challenging existing paradigms, products and behaviours. The understanding of this parameter tends to feed into long-term opportunities and forecast updates.

Production limit

This is the maximum average (net) production at the sales point over the time period considered under optimum conditions, but including (planned) downtime due to:

- execution of the cash opportunities
- mandatory downtime, i.e. deferments due to activities necessary to safeguard technical integrity. Such activities may be imposed by the Company's own HSE standards or by local legislation.

This is the maximum (average) rate that can be produced over the planning period, as it includes all planned activities to increase IPSC for which resources have been approved, as well as all downtime which cannot be avoided.

Production availability

This is the potential average (net) production rate at sales point, over the time period considered and including all (planned) downtime related to:

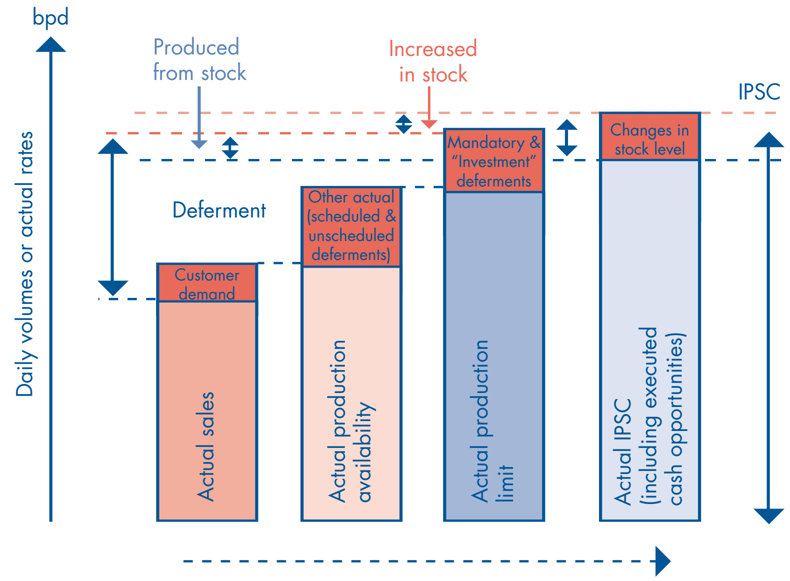
- the execution of the cash opportunities
- the execution of mandatory activities to safeguard technical integrity
- all other scheduled and unscheduled activities and events.

Production forecast

This is the expected average (net) production rate at sales point, over the time period considered and including all planned deferments, including allowance for restrictions in production due to customer demand.

Once the limits have been quantified and the production forecast and required resources to realise the cash opportunities have been approved, actual production and deferments are monitored and compared to those planned. The historic limit diagram in Figure 19 shows actual production and deferments and can easily be compared with the FLD.

Figure 19: The historic limit diagram



The HLD is built up from actual production as measured at the sales point, to which the reported (reconciled) deferment volumes are added and a correction for stock changes is applied to derive the actual IPSC. This can be applied each day to derive daily volumes. By monitoring the actual IPSC, undetected deferments can thus be identified/corrected. If this is done over longer periods, e.g. monthly, the average monthly production, deferment and IPSC can be compared with the forecast values. The effects of stock change corrections will diminish over longer time periods.

Appendix 6 - Analysing actual versus planned production

The primary objective of analysing actual versus planned production is to identify opportunities for improvement, both in terms of quality of the forecast and volume of realised production. Examples of questions to be used include the following.

- Were all threats and opportunities identified?
- Was all information, available at the time when the forecast was prepared, included?
- Were uncertainty ranges quantified correctly?

Understanding deviations in this way helps focus remedial action in the right area, e.g. lower well potential than planned or by higher than planned production deferment?. If actual production is as forecast, this helps identify 'hidden' problems and opportunities, e.g. if higher than planned potential was not realised because of higher than planned deferments.

If a production plan has been prepared using a deterministic method, it is recommended to use the technique described in the following section for analysing actual against planned production. This technique can be applied to any planning period, i.e. both the monthly and the annual production plans.

The building blocks of the production plan

The first step is to break the forecast down into discrete parts, distinguishing between the forecasted production potential or projected IPSC and the forecasted utilisation of that potential ('uptime', Asset utilisation, deferments).

A production forecast volume is in essence the outcome of:

- expected (average) production capacity (IPSC) = (wells and surface facilities)
- expected number of days in production = (planned major shutdowns)
- expected availability during days in production = ('uptime' outside IPS shutdowns. Planned downtime includes both scheduled and unscheduled deferments).

A month or year production volume forecast, i.e. 'planned volume' can thus be represented by the formula:

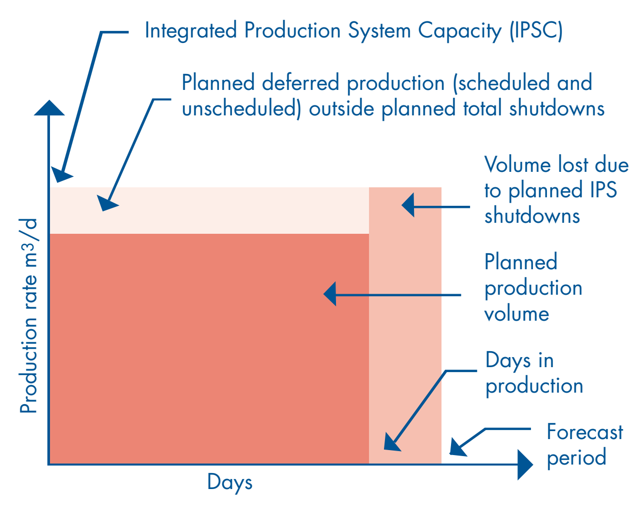
Planned Volume = (average) planned IPSC * (X – planned SD days) * (average) planned uptime outside SDs

Whereby X = number of days in planning period (month, year)

SD = shutdown

Note that the IPSC is likely to change over time. In Figure 20, the IPSC value refers to the average value over the forecast period, i.e. cumulative IPSC divided by days in planning period.

Figure 20: Production and deferment volumes



The three coloured blocks in Figure 20 represent:

- the volumes lost due to system (IPS) shutdowns
- the volumes lost due to downtime outside the system shutdowns
- the expected (planned) production volume.

The sum of the three areas is equal to the expected IPSC, multiplied with the number of days in the planning period considered, i.e. the maximum producible volume over the forecast period.

Actual versus planned (prime causes)

The main objectives of performance analysis are to determine to what degree planned production system improvement activities have been successful, where the reasons for deviation against plan must be sought and where performance can be improved. Comparing only actual production versus plan is insufficient.

Figure 21shows how comparing actual with forecast production would indicate good performance, i.e. actual production marginally exceeded the plan. However, actual deferment is much higher than expected mainly due to extended shutdown duration, but this is more than compensated for by actual production outside the shutdowns due to a much higher than forecasted production potential (IPSC). The opportunity to produce more would not be identified based on a comparison of actual versus planned production only.

In the example in Figure 22, actual IPSC is higher than planned but actual production is lower. The reason for under-performance is much higher than planned deferment (particularly the shutdown durations and unscheduled deferments).

In both examples, there is a 'high' rather than a 'low' issue, as actual IPSC is higher than planned. It is essential that this is correctly reported to highlight the opportunity to increase production.

Figure 21: Potentially hidden opportunities

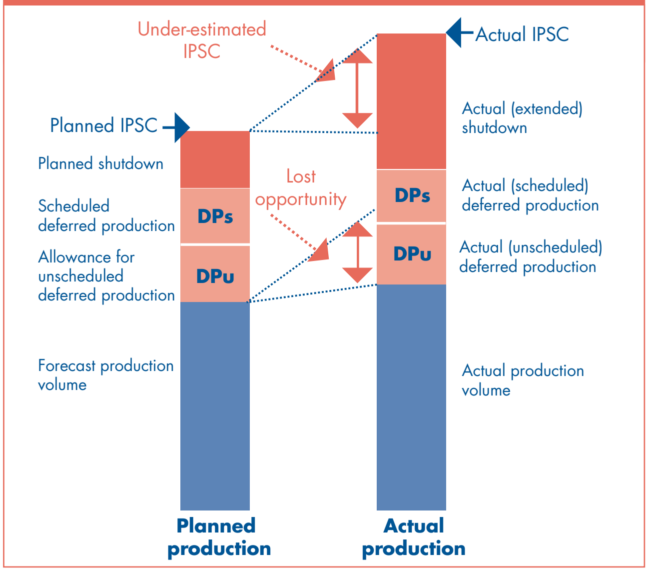
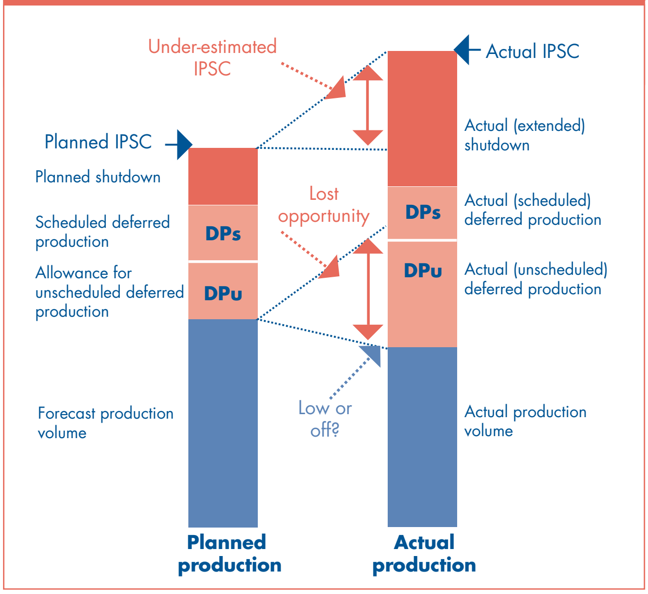


Figure 22: Low off or high and off



Data needed to analyse actual production against plan

To quantify the specific contribution of the three factors that may cause a difference between actual and planned production, i.e. the differences between actual and planned IPSC, IPS shutdowns and uptime (outside shutdowns), the following production data must be reported on a daily basis:

- actual production
- actual daily deferments and their underlying causes
- actual number of days in production (or total IPS shutdown).

From which can be derived:

- actual (average) production capacity (IPSC) (wells and Facilities)
- deferment due to shutdowns (major shutdowns)
- actual availability during days in production ('uptime' outside shutdowns).

Whereby:

IPSC excl SD =	Actual production + actual deferments (outside SDs)
Deferment SD =	Shutdown days * IPSC excl SD
ISPC =	IPSC excl SD + Deferment SD

and

Uptime outside =	Production/IPSC excl SD * 100% SDs
Asset utilisation =	Production/SPC * 100%

Although deferred production is the most difficult to quantify since it is not measured or produced, quality reporting of it is of key importance for effective production analysis.

A simple formula for automated performance analysis

The first step is to break down the difference between actual and planned production into three elements:

- difference in IPSC
- difference in 'uptime' outside the shutdowns
- difference in shutdown duration.

The following algorithm calculates specific contributions of these separate elements:

Actual – Planned = IPSC act – IPSC pl) * (365 – SD pl) * UT pl + (UT act – UT pl) * (365 – SD pl) * IPSC act + (SD pl - SD act) * IPSC act * UT act

All parameters used can be measured or derived and recorded. It has the advantage of enabling comparison between Assets in areas of production decline or locked-in potential (IPSC), shutdown planning and 'uptime' or 'Asset utilisation' performance (deferments).

Actual versus planned (at activity level)

Once the three factors for the deviation from plan have been quantified, they need to be broken down further to well, Facility or activity level. To do this effectively requires reliable deferment reporting and a production plan structure consistent with the hydrocarbon accounting structure.

Analysing the performance against the 'activity-targets' will provide insight on the underlying causes for deviation from the planned production. It will also provide valuable information regarding the uncertainty of input variables for new forecasts.

The second step, therefore, is to report actual performance against the activity targets.

Data needed to analyse actual production against plan

It is essential to keep track of the actual values of parameters and compare these with assumed values for the forecast to:

- determine the impact of changes to the plan
- identify main cause(s) for deviation from planned production
- assess the validity of the assumed ranges of uncertainty
- improve the quality of (future) forecasts.

This requires a transparent overview of input parameters as well as an agreed database or set of databases for actual (measured and reported) values such as the hydrocarbon production information database and a risk register. This in turn necessitates naming conventions, consistent production system models (networks) and standard definitions for the systems used.

Update and end of year reporting and review

Performance against the first year of the programme shall be reviewed as part of each AoO and total Shell performance in January by reviewing actual versus plan (difference in values and percentage variation).

- Oil production against Programme (broken down in the same categories as for reporting of the STPF, i.e. old well maintained potential, optimisation potentials, New Oil, NGL and third party additions, constraints, scheduled and unscheduled deferment).
- Oil production against reference forecast (broken down into the same categories as above).
- NFA potential decline against Programme.
- Year average New Oil potential against Programme.
- Water production against Programme.
- Deferment against Programme.
- Constraints against Programme.

The Oil production performance should also be related to the level of drilling activity collating data such as:

- percentage activities carried out in compliance with the Programme Build drilling sequence
- string months against Programme
- drilling cost intensity (DCI) and drilling time intensity (DTI).

Appendix 7 - Key forecasting problems and their underlying causes

Unrealistic base case forecast

- Underestimating slippage on drilling sequence, delays in onstream dates, late delivery of Facility projects (pre-DG3 project phasing).
- Forecast is based on assumptions not calibrated against recent performance.
- Some forecasts are not incremental, i.e. they ignore interference or back-out effects.
- 'Hard' system constraints are not honoured (flow lines, Facilities), up-to-date Integrated Production System is not available.
- Over-estimation of well and/or Facility uptimes.
- Activity plans exceeding organisational capacity.
- Unjustified optimism on future improvements, e.g. annual 5% increase in system availability.
- Human bias, e.g. insufficient disaster cases in project portfolio.
- Not taking full account of performance trends, e.g. reducing benefits of infill drilling due to dropping reservoir pressure, creaming effects, etc.
- Unrealistic assumptions on future well integrity and abandonment conditions.
- Simulation results not discounted (to account for ideal geology and physics in models) and others.

Perfect world assumed in forecasting models

- The 'perfect world' that exists in a simulator does not exist in reality. In a model, wells are always drilled at the correct side of the fault. In reality, the position of the fault is uncertain and wells might end up at the wrong side of the fault, which is particularly a problem for a producer/injector pair.
- In a model, horizontal drain holes are indeed horizontal at the correct elevation and in the right layer. In reality, geo-steering can only position the drain holes within a certain tolerance, usually a few metres.
- In a simulator, wells behave perfectly. For instance, vertical wells completed over multiple zones will produce proportional to the kH of each interval. Horizontal wells will inflow over the entire length of the well, pressure drops along the drain hole are usually ignored and multi-laterals will have contributions from each lateral. In reality, this will seldom be the case.
- Injectors can also exhibit significant conformance issues in real life. In sector models, the arial distribution of water injection is assumed to be proportional to the number of injectors but, in reality, this might be not be the case with some patterns taking more water than others.
- Well productivity index may decline over time due to scaling.
- In a simulator, Well and Reservoir Management is often assumed to be perfect. It is obvious which interval or lateral is cutting water or gas and immediate action can be taken to rectify that, e.g. by closing off a perforation. In reality, it may be unknown which interval is the culprit and considerable time may pass until the well can be surveyed and worked over - if the workover is economic at all. The workover might also not always turn out to be 100% effective.

Insufficient expression of uncertainty ranges in forecast

- It is not really understood which parameters have most impact on the forecast.
- Some uncertainties are frequently overlooked, e.g. historical metering issues.
- The low-high range is too narrow, not skewed and widens insufficiently with time.
- There is no bottoms-up aggregation of uncertainties impact.
- High-level sensitivities to the base case forecast are often devised at corporate level.
- Staff are unclear about the preferred approach and/or terminology, e.g. low, P90, firm do-able.

- Full probabilistics not do-able in most situations, e.g. P90, P50, P10 meaningless.

No systematic analysis of variance between forecasts and actual production, insufficient learning and improvement loops

- Look-back has low priority ("we prefer to rush into next task").
- AARs held but no deep analysis of problem root causes and issues not addressed.
- Learning from the previous forecast exercise not captured and disseminated.
- It is often unclear which forecast was actually submitted by corporate.

BP forecasts not tied to resource volumes booked in ARPR

- ARPR and BP seen as separate exercises.
- Processes driven by different parties, e.g. REs versus programmers.
- Inconsistencies triggered by time gap, e.g. Oct/Nov (ARPR) vs. March/April (BP).
- No clear steer on capturing changes in reservoir performance, project status between ARPR and BP.

Others

- Poor audit trail of forecast assumptions and adjustments.
- Inconsistencies and discontinuities between ST, MT and LT forecasts resulting from, e.g. different uptime, deferment, scheduling assumptions and misalignment between the various forecast owners.

Appendix 8 - Special considerations for various forecast environments

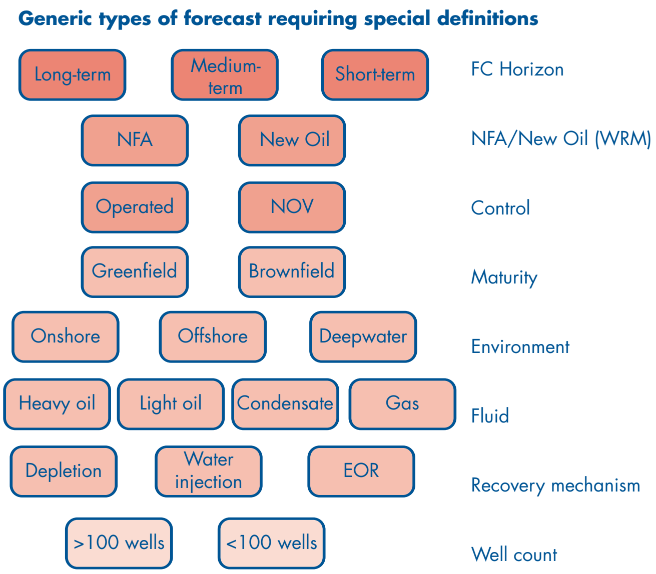
While this guide has been kept as generic as possible in order to make it applicable to the forecasting process in general (with distinctions only made for time horizon and NFA/New Oil), it is recognised that every individual forecast is different and requires special considerations. This appendix gives an overview of the main technical and commercial considerations to be applied to the main forecast types, grouped into control, maturity, environment, fluids and recovery mechanism as shown in Figure 23.

Operated/non-operated

In general, Shell has little control over NOV forecasts supplied by Partners and the amount of effort to put into NOV forecast adjustment requires judgment and an understanding of the operator's competency. Analysis of operator competency should determine whether operator forecasts can be taken with or without discounting. If the operator has a strong track record of production delivery, then the forecast can be accepted with little or no discounting. If the operator's track record is less satisfactory, or the forecast is not supplied with sufficient granularity, or not in time, simple models need to be set up to calibrate, validate and shadow the operator's forecasting activity. The operator should be prompted to supply forecast granularity at a level that at least allows to distinguish between NFA and New Oil forecasts. Where practical, a Shell forecast should be made and compared with the operator's forecast. This is also useful to challenge the operator's development proposals.

Example 13 shows an NOV forecast for a competent operator. Shell's input consists of analysing risks and opportunities and the operator's track record of past performance.

Figure 23: Generic types of forecast



Field maturity

Life cycle maturity has a strong impact on the way forecasts are made. As fields become more mature, more data becomes available and must be included in the forecasting models in order to reduce the uncertainty and improve robustness.

Exploration

In the early exploration stage, forecasts are often made even before Shell owns the acreage and before the first exploration well is drilled. These forecasts rely heavily on analogues and on conceptual models. HCIIP estimates and structural framework based on seismic may be available, as well as correlations of porosity and permeability vs depth. Fluid property correlations will be taken from analogues. Simple, consistent models should be built which cover the uncertainty range of these estimates and should be discounted for the effect of reservoir complexity not covered by data.

Appraisal

Appraisal forecasts will strongly rely on results from the exploration well to provide a better handle on rock and fluid properties and reservoir heterogeneity. Forecasts are used for value of information for further appraisal and well testing or to confirm feasibility. Uncertainty will typically remain high, but some information about reservoir complexity is available from the well and specifically from a well test (layering, baffles, boundaries, fluid properties). This should be included in an appropriately scaled model. Complexity is often modelled by using connectivity factors (Reference 12). Example 10 shows a forecast in the appraisal stage.

Development

A full appraisal data set is available, including reasonable well control, well tests, correlated with high quality seismic. Forecasts are made to determine and optimise the development strategy in terms of recovery mechanism, well types and numbers, Facility sizing and reservoir management strategy. Forecasts should take all data into account, yet cover a wide range of uncertainty commensurate with scarcity of the data available after appraisal. The goal is to demonstrate that a proposed development strategy is optimal over a wide range of sub-surface uncertainty outcomes. This may require very detailed models for specific optimisations. Best practice is to keep the full field model simple and address reservoir complexity in detailed sector models (such as condensate drop-out, modelling displacement fronts, detailed stratification, shale distribution for kv/kh when evaluating waterfloods). Results of these sector models should be incorporated in the full model results as discount factors.

Production

Results from development wells are available and, most importantly production and pressure data for a history match. 4D seismic may be available to constrain the forecast or data from WRM and PSO (cased hole logs). Metering uncertainty requires some attention as it is normally very good for oil and gas at the sales point, often poor for allocated oil and water at the wellhead and very poor for flared gas. Therefore, close cooperation with the WRM team is advised. Objectives of forecasts in the production phase are manifold and have been discussed throughout this guide. Example 1 gives a best practice example of a forecast of a producing field in the early development stage, while examples 7, 9 and 15 are good examples for mature field forecasts.

Onshore/offshore/deepwater

Developments become increasingly expensive and complex the more they move from an onshore environment to offshore and further into deepwater. Deepwater forecasting models are usually more detailed than equivalent onshore forecasts and will be extensively reviewed and challenged as there is little room for error (in deepwater it isn't possible to drill out of trouble).

The following points cover some specific challenges for making deepwater forecasts.

- Large well spacing makes well-to-well connectivity an issue, both from producer to producer and injector to producer.

The depositional environment is often turbidite and requires special modelling techniques (for example channel based shale drapes). 3D connectivity factors have been derived and are available in Shell literature to facilitate modelling (Reference 12).

- Well interventions are very expensive and complex (especially for sub-sea developments). This affects system availability and lift calculations.
- Limited well tests are available as these are very expensive. Sometimes deepwater developments are done without production well tests in the appraisal stage, making the forecast more uncertain.
- An IPSM for deepwater forecasting is essential to model the effects of vertical flow properly, flow through flowlines and Facility processing constraints.
  - Vertical flow: wells are often very deep with significant temperature variations affecting lift performance. Downhole ESPs are, in general, not feasible due to very expensive well interventions. Therefore, riser based gas lift or caisson ESP (installed at the mudline) are typically used for lift. Lift curves must be generated and periodically reviewed by the production technologist. Vertical flow performance has significant impact on rates and recovery.
  - Flow assurance is critical due to often long tie-backs in deep water, requiring dedicated modelling.
  - Processing constraints are normally severe due to weight limitations on the FPSO or TLP/Spar. This requires proper modelling of oil, gas and water processing, gas compression for export or re-injection and water injection capacity.

Examples 7, 9 and17 show forecasts in an onshore environment. Examples 2, 3, 4, 5 and 8 are from offshore developments whilst examples 1 and 18 are deepwater forecasts.

Oil/condensate/gas/unconventionals

For a conventional oil reservoir it is important to make a consistent forecast of oil, gas and water as well as water injected. Associated gas rates will vary especially if the reservoir pressure drops below the bubble point, but also due to gas coning and cusping. Assuming that the GOR will remain constant throughout the field life is unrealistic. Most oil reservoirs require water injection (unless there is a strong aquifer or high system compressibility), while gas due to its very high compressibility is almost always produced by depletion. Water injection is discussed in the following section.

Non-associated gas (NAG)

NAG forecasts are generally more straightforward than oil forecasts and recovery factors are determined by initial pressure and abandonment pressure by means of a P/Z vs Gp plot, unless there is a strong aquifer or high compaction. This makes gas forecasting more a commercial than a technical problem. It is important to forecast gas and possible water produced. Water production will affect gas recovery due to liquid loading and lift die-out.

Gas condensate

Forecasts are more complex than dry gas forecasts as the condensate will significantly influence forecasts and recovery factor. As a rule of thumb, retrograde condensate has initial cgr between 65 and 310 stb/mmscf (McCain). Keep in mind that condensate is a very valuable fluid (and is forecasted as oil) and, therefore, requires a lot of care and detailed PVT modelling in forecasting condensate recovery. CGR over the field life is not a constant, but a function of pressure and rate! For fluids near the critical point, it is advised to use a compositional model for the forecasts.

Complexity in condensate forecasting is due to the following.

- Condensate drop-out in the reservoir affecting the gas composition.
- Condensate drop out near the wellbore resulting in liquid blocking, especially in tighter reservoirs. In high rate reservoirs, this may be compensated to some extent by condensate stripping. Near wellbore effects should be investigated in dedicated single well models and built into the forecasting models as a pseudo-skin or effective relative permeability.

- Lift problems due to liquids dropping out in the production string. For deepwater, where temperature drops are significant, this effect can be dramatic. Lift curves must be generated and periodically reviewed by the production technologist.

Example 14 outlines the principles of gas condensate forecasting.

Unconventional oil and gas is becoming more important in Shell. Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called 'continuous-type deposits'). Typically, such accumulations require specialised extraction technology, e.g. dewatering of coal bed methane (CBM), massive fracturing programmes for shale gas, steam, wellbore heaters and/or solvents to mobilise bitumen for in-situ recovery and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale.

Unconventional oil and gas opportunities currently in Shell's portfolio are shown in Table 6.

A typical forecasting workflow for unconventionals would be to model production from a pilot with a sector model in some detail and then to derive type curves for typical well performance. These sector models should be adjusted to model other areas with materially different properties (such as high/low net/gross, crestal areas vs flank areas, areas with or without water contacts) and aggregate these type curves into a full field forecast. Full field models are generally not practical since a full scale development will encompass hundreds or thousands of wells.

Table 6: Unconventional oil and gas opportunities

Coal bed methane (CBM)	Natural gas contained in coal deposits, adsorbed in coal surface whether or not stored in gaseous phase. Coal bed gas, although usually mostly methane, may contain variable amounts of hydrocarbon or non-hydrocarbon gases. Development is by de-watering; water is pumped off until the sorption pressure is reached and the gas desorbs and flows via the cleats towards the well. Forecasts are affected by gas content, gas saturation, sorption isotherms, cleat permeability, coal compaction and shrinkage. Forecasting of water production is critical for economic assessment of CBM.
Basin-centered gas (BCG)	An unconventional natural gas accumulation that is Regionally pervasive and characterised by low permeability, abnormal pressure, no apparent seal or trap and lack of a down-dip water leg. Forecasts are affected by permeability, gas saturation and reservoir pressure. BCG is normally developed with fractured and/or under-balanced wells.
Shale gas	An unconventional natural gas accumulation that is hosted in shales, which is Regionally pervasive and characterised by very low permeability (0.1 – 0.6 micro Darcy). Normally self-sourced and self-sealed, i.e. the shale traps the gas and without massive fraccing it would not flow. Produced via massive hydraulic fraccing.
Oil sands	Sand deposits highly saturated with natural bitumen, also called 'Tar Sands'. Natural bitumen may be hosted in a range of lithologies including siltstones and carbonates. Recovery is by thermal methods.
Oil shales	Shale, siltstone and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).

Most unconventional plays are characterised by high variability in well performance, requiring some statistical modelling of well behaviour to estimate the range of production. Care should be taken to properly differentiate between uncertainty in the average well performance and in the variability of individual well performance across the field, the latter having a much wider range.

Sector models and type curves should be continuously updated with current field performance and should also be used to forecast incremental gains from infill drilling.

Gas capacity planning

The term capacity planning applies to gas sales contracts where the volumes delivered depend on daily and/or seasonal demand, therefore, a gas capacity plan provides the expected available production capacity based on the expected production profile, i.e. demand or off-take profile over the planning period. Gas production capacity and availability commitments form an integral part of most gas sales contracts in recognition that the operator needs to be compensated for their flexibility in providing fluctuating off-take volumes. Preparing a gas capacity plan is an iterative process to determine the optimum capacity that can be contractually committed to sales, keeping in mind that the expected available capacity from the reservoir will decline faster if the off-take rates increase.

This highlights the commercial difference between oil and gas. Unlike oil, gas forecasts are heavily dependent on the gas sales contract. Contracts vary from Asset to Asset and from Region to Region and also between domestic gas contracts and LNG, but a common theme is a long-term demand profile, often spanning 20–30 years and the supplier needs to drill wells and install compression in order to meet this profile and supply the committed capacity. There will be cash penalties if the committed capacity cannot be delivered.

Short-term forecasts are used to help gas dispatching manage the gas flow within the contractual constraints and to identify sales opportunities on spot markets outside the contract for gas where the producers load factors are relatively low.

Medium-term forecast are made to optimise the gas capacity nominations over the next planning period.

Long-term forecast are used to optimise development projects such as new wells, compression and UGS within the contractual obligations, balancing supply and demand predictions. Furthermore, forecasts serve to optimise the contract negotiations, i.e. to determine the value of a higher load factor or to compare domestic gas contracts with an LNG export scheme.

Gas forecasts should also track gas quality and composition. Gas contracts contain quality specifications (blending) covering gross heating value GHV, CO_2, H_2S, density and others. Gas pools can sometimes be used to blend high quality gas with lower quality gas to stay within the sales specification.

Some terms and acronyms commonly used in gas capacity planning can be found in Table 7.

Example 11 shows probabilistic modelling to optimise capacity nominations.

Example 15 shows gas capacity forecasting short-term and long-term.

Depletion/water injection/EOR

Any FDP and Asset Reference Plan for an oil Asset should contain a discussion on the optimal recovery mechanism for the Asset. Depletion may be optimal if the system compressibility is very high or if there is a strong aquifer. Water injection or EOR options almost always result in higher recoveries, but the cost may be prohibitive, especially in an offshore or deepwater environment. Clearly, sound forecasts are required to calculate incremental gains of water injection over depletion and of EOR over water injection and thereby provide economic justification for the proposed recovery method.

Depletion forecasts should be calibrated using material balance techniques. Main uncertainty drivers for depletion are system compressibility, aquifer strength and absolute permeability.

Table 7: Terms and acronyms used in gas capacity planning

Acronym	Description, term	Definition
ACQ	Annual Contract Quantity	Sales volume that the buyer has to take or pay over the contract period.
TRDQ DCQ	Total Reservoir Daily Quantity Daily Contract Quantity	The average daily offtake volume taken over the contract period (DCQ = ACQ/365.)
	Swing factor	The ratio of the contractually committed peak capacity throughout the contract period over the DCQ.
	Load factor	Reciprocal of the swing factor
	Gas capacity	Spontaneous capacity of gas available at the sales point.
	Take or pay	Commitment of the buyer to take the contracted volume or pay the contractual gas price.
	Gas pooling	Agreement to include a group of fields into a gas contract to allow for optimising capacity summer/winter swing.
UGS	Underground gas storage	Depleted gas field or salt cavern used to manage the summer winter swings and daily capacity peaks by injecting gas in periods of low demand.

Water injection forecasts should be calibrated using Buckley-Leverett or Dietz displacement calculations to establish the technical limit recovery factor. The Dijkstra-Parson method is recommended for stratified heterogeneous reservoirs. Main uncertainty drivers for water injection are mobility ratio, vertical and areal heterogeneity and residual oil saturation to water. The flood front should be modelled in some detail, also keeping good track of material balance of fluids produced and injected.

EOR methods are split into three types:

- thermal methods including steam injection or installing wellbore heaters
- miscible gas injection including CO_2, hydrocarbon gas or nitrogen injection
- chemical including polymer, alkaline surfactant flooding.

Similar to unconventional oil and gas, a typical forecasting workflow for EOR would be to model production from a pilot with a sector model in some detail, to properly model the displacement process, and then to derive type curves for typical well performance. These sector models should be adjusted to model other areas with materially different properties (such as high/low net/gross, crestal vs flank areas, areas with or without water contacts) and aggregate these type curves into a full field forecast. Upscaling a pilot is often done by model conditioning rather than history matching. Conditioning aims to set conditions in the pilot area (pressure, temperature and saturations) representative for the pilot area and then changes these conditions to what is expected in other parts of the field.

The oil/steam ratio (OSR) should be derived and carefully reviewed for any thermal EOR forecast. It is a key quality indicator for the steam flood efficiency and has significant impact on the project Opex and thereby its economics.

Full field models are often not practical for thermal and polymer since a full scale development will encompass hundreds of wells. Sector models and type curves should be updated continuously with current field performance and should also be used to forecast incremental gains from infill drilling.

Example 16 outlines a workflow for EOR forecasting.

Considerations for fields with many drainage points

Once fields or Assets are very mature, the well count may be very high (say greater than 100 wells) and since little or no infill drilling activity will typically be left, dynamic modelling may not be justified to generate routine forecasts.

Practical methods should be sought to make and manage forecasts in a consistent manner as forecasting becomes partly a data management activity. PDO has developed a robust workflow in OFM to generate forecasts using DCA, allowing instant review, challenge and storage of forecast and instant comparison of proved vs. expectation forecast as well as comparison with actual production and previous years forecast.

In example 18, SPDC manages the whole Asset in a single HFPT model with a combination of type curves and dynamic models. This is an elegant method as it allows for good forecast data management and auditability, dynamic models and type curves where justified, the honouring of all production constraints which can be imposed and changed at various levels in the production system (see example 17).

Note that the EP standard requires a consistent forecast of all fluids produced and injected (oil, water and gas), which means that any forecast based on decline curves or type curves should be accompanied by a calculation of associated water and gas forecasts in line with the reservoir management strategy (using material balance or otherwise).

Example 17 shows a practical approach to forecasting many wells, using HFPT.

Example 18 shows a workflow for using OFM for mature fields forecasting using decline curves.

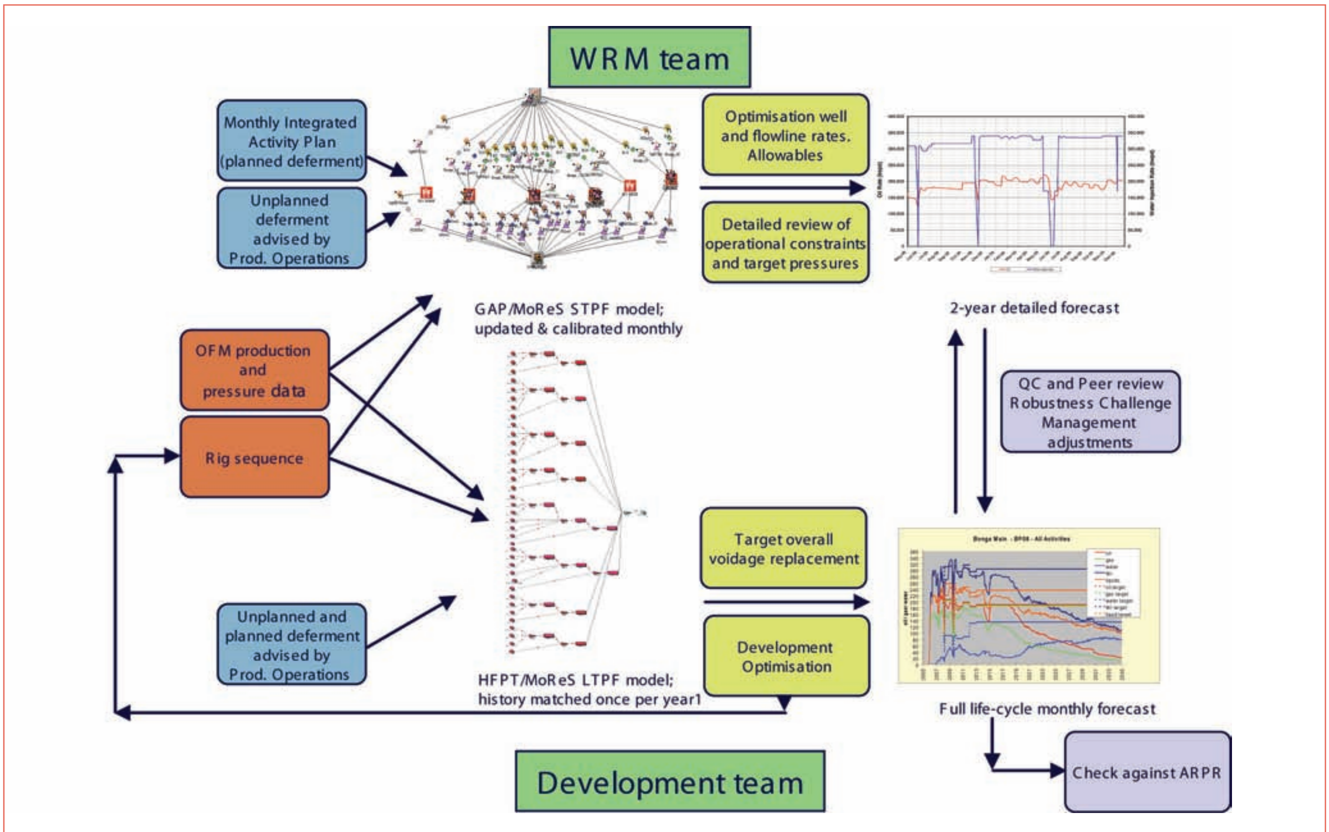
4. Examples

Example 1: Best practice forecast workflow

Best practice example of a forecast workflow for a major field

1. The objective is to make the business plan forecast.
2. Data is gathered by the WRM Team via OFM and the pressure database.
3. The sub-surface models (MoReS) are history matched annually by the development team.
4. The long-term forecast is made by the development team, matching reserves.
5. Availability is optimised by WRM and IAP and calibrated with historical availability.
6. Risks and opportunities to the forecast are listed in a risk register.
7. The low/expectation/high forecast is made based on the identified risks and opportunities.
8. The first two years are updated monthly in the IPSM, using the same sub-surface model as the development team.
9. Monthly updates of activity plans and calibration of system pressure drops by the WRM team help keep the model evergreen.

Bonga BP08 production forecast - workflow



General principles forecast

- ARPR volumes honoured.
- Non-commercial SFR and commercial dSFR considered not sufficiently robust (e.g. no PIN) not included.
- Capex projects:
  - deterministic forecasts
  - detailed reservoir models and integrated production models used where available and QC'ed
  - producing fields: history match for 31.12.07 ARPR + production updates to May 2008
  - incremental build-up at project level
  - Low and high scenarios with articulated 'events'.
- Expex projects:
  - assumed Facility sizes, or tie-back to existing FPSO
  - deterministic IPM models with simple network constraints.
- NOV fields as per operator-provided forecast - discounted if necessary.
- Profiles played out beyond PSC expiry and up to economic limit:
  - as advised by Legal/Commercial
  - production gaps assumed for major FPSO refurbishments.
- Tight integration between:
  - short-term (two-year) production forecast:
    - based on monthly integrated activity plan
    - detailed review of, and optimisation against system constraints
    - utilising regularly (monthly) updated IPM model.
  - Full life cycle production forecast
    - long-term development and reservoir management optimisation
    - annually history-matched sub-surface models.
  - collocation of WRM and Development teams. The same MoReS models underpin both the long and short-term forecasts.

Models

MoReS/HFPT

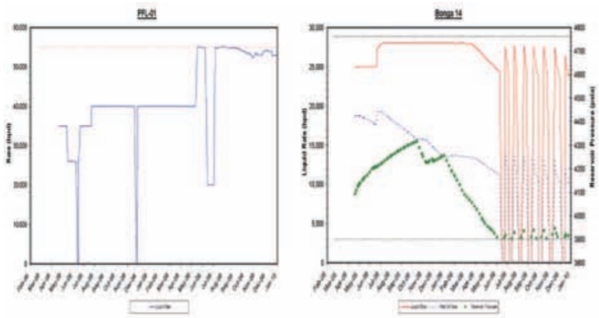
- History matched to end of August 2007:
  - current actual injection rates overestimated by model; constrained to levels advised by WRM group (consistent with GAP model)
  - predicted well declines/watercut increases verified against DCA (ARPR).
- Rate and pressure history updated to end of April 2008.
- Matched water breakthrough in B14/B19/B15/B9/B10.
- No reservoir models available; latest simulation results EPT-S translated into rate-cum curves and linked to HFPT model.
- Water injection network implemented in HFPT (improvement over BP07).
- Simulation results verified against ARPR volumes.
  - Volumes increased from 262 to 389 MMstb.
- Implemented monthly uptime profiles 2008-2009.
- Medium-term 2008-2009 verified against IPM model.
- Results used primarily for 2010+.

GAP/MoReS

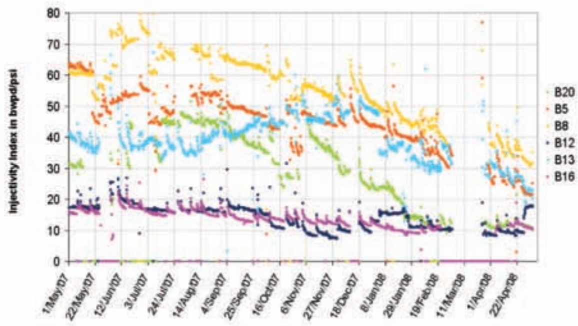
- Same MoReS models.
- Additional detailed matching of well rates, pressures.
- Monthly IAP.

System constraints and optimisation

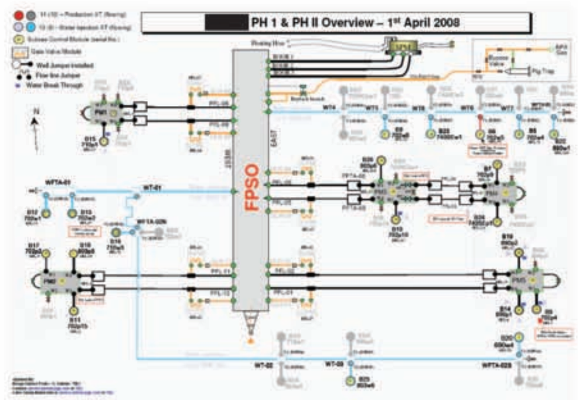
- Review of actual well performance over time, slot availability, sub-sea system constraints.
- Integration with monthly activity plan, first-pass simulation to identify key bottlenecks.
- Definition of mitigation and optimisation options, e.g.:
  - temporary production curtailment
  - fast track of acid stimulations
  - accelerating new wells.
- Generate optimised short-term forecast, including unplanned deferment.



First-pass production optimisation

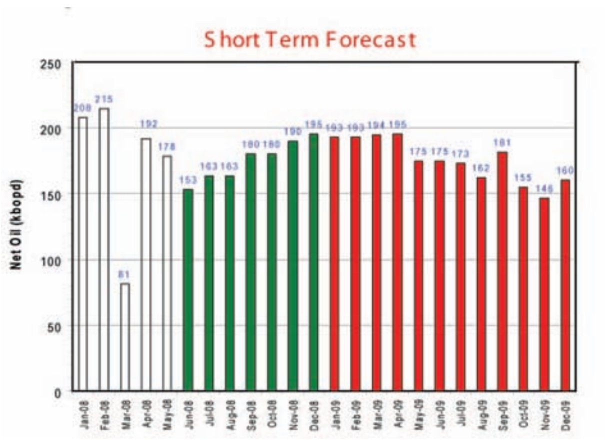


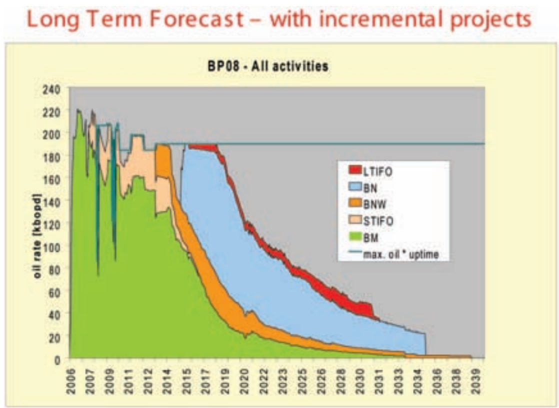
Well performance

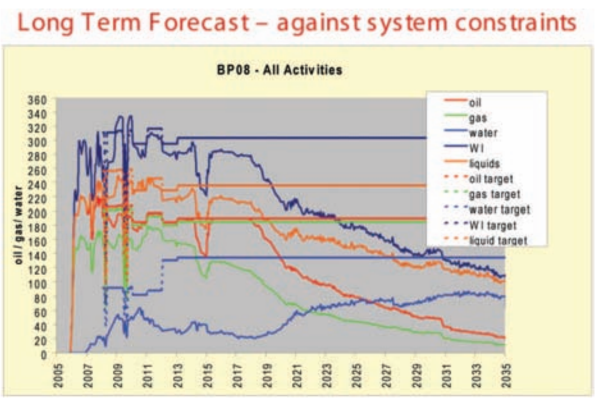


Subsea system overview

Integrated forecast





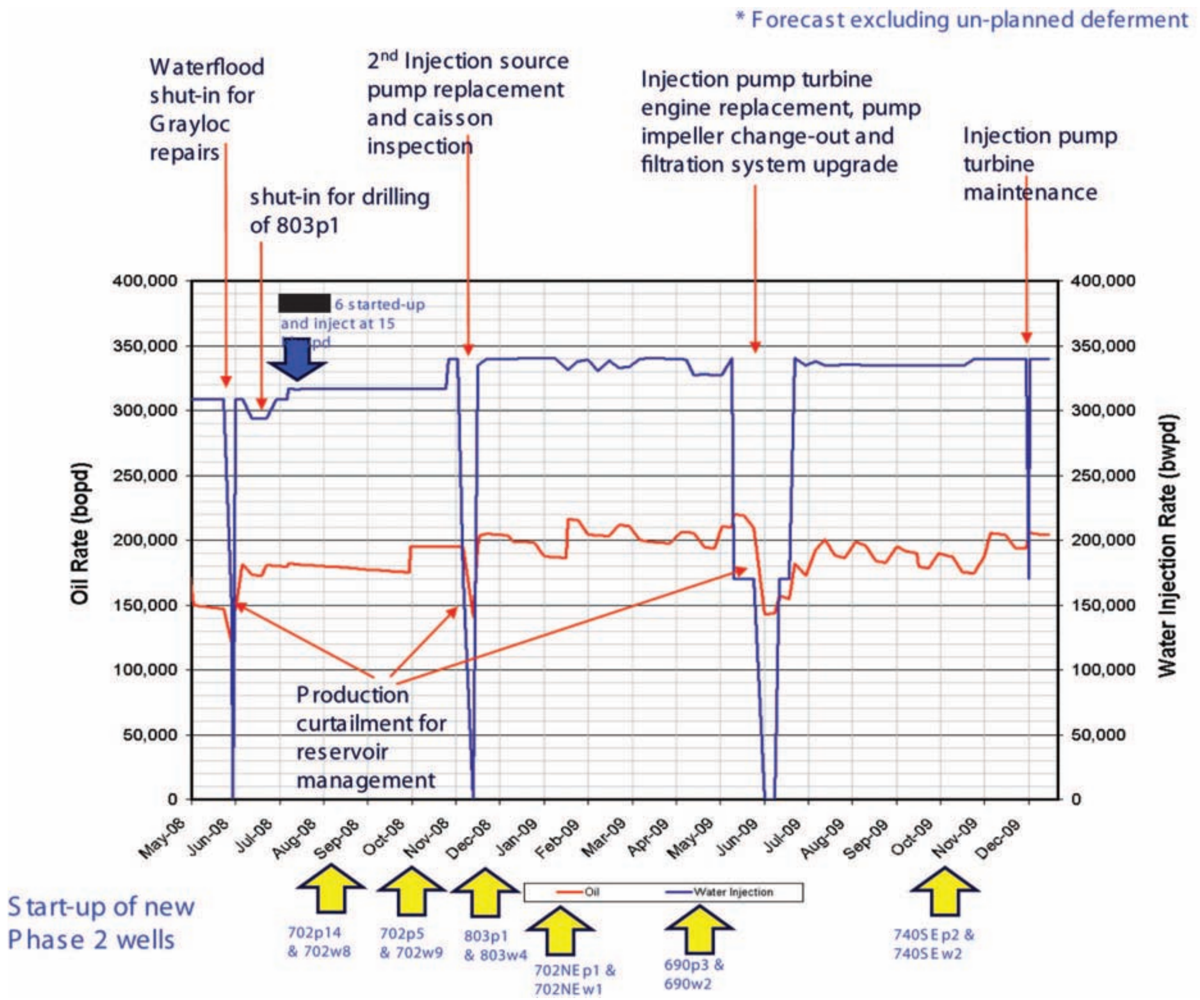


BP08	Avg. oil [kbopd]	Avg. WI [kbwpd]	Uptime [-]
2008	175 (-16)	255 (-44)	87.1% [-0.1%]
2009	180 (-18)	295 (-15)	84.1% [-5.3%]
2010	175 (-20)	285 (-22)	81.9% [-5.2%]
2011	190 (-12)	306 (-11)	87.8% [-2.7%]
2012	192 (-14)	279 (-42)	87.8% [-1.6%]
2013	184	283	84.3%

2 year lookahead mainly driven by STPF model

3+ year lookahead mainly driven by LTPF model

Key planned activities - (2-year)



Main risks and uncertainties

- Bubble point and reservoir pressure
  - 702 reservoir close to bubble point. Over-injection and pressure banking required before rates can be increased.
- Water injection system:
  - no pressure buffer, i.e. all water injection downtime will result in immediate production reduction
  - limited intervention capability in injection wells
  - no redundancy, 2 x 50% capacity, vulnerable to upsets (greylock seals, turbines, etc.)
  - no excess water capacity (both surface and sub-surface) to make up for lost injection.
- Water breakthrough uncertainty:
  - could be risk or upside in 702 reservoir.
- OPEC and MER quota.
- Well approvals:
  - Phase 2 + 2 wells approved (34 wells). Phase 3 not approved (14 wells)
  - ST IFO approved on case by case (i.e 740SE), late Phase 2 wells pending field performance and 4D seismic.
- System constraints:
  - no excess water injection capacity
  - sub-sea constraints on PM3 and PM4.
- Others:
  - Phase 2 completion delivery performance, causing further delay in well delivery
  - well integrity (currently no issues) (downside).
- Risk and opportunity register used to generate low/high production forecasts.

Low and high

Low

- Lower water injection uptime/capacity and faster injectivity decline.
- No production of 702p14 in 2008 and 2009 due to low pressure.
- Water breakthrough in B7 during 2009.
- 803p1 in high GOR area, reduced production.
- No or late approval for wells not beyond FDP Rev4 scope/late approval for FDP Rev7, 1 year delay.
- Acid jobs not successful.
- B6 not effective.

High

- No communication between 702p5 and B8, resulting in later water breakthrough.
- Water breakthrough later than predicted in B18, B11 and B17.
- Optimisation of sub-sea well/flowline configuration (flowline constraints).
- Reduced downtime for WI turbine changeout.

oil [kbopd] Low	oil [kbopd] High
170	176
165	176
168	180
186	195
173	182
189	187

As simulated

	oil [kbopd] Base	-7% oil [kbopd] Low	+3% oil [kbopd] High
2008	175	163	180
2009	180	167	185
2010	175	163	180
2011	190	176	195
2012	192	179	198
2013	184	171	188

Adjusted

Deferment (scheduled)

Total deferment		2009			2010			2011		
Production system 50/50 -->		5.3%			13.7%			4.2%		
Waterflood system 50/50 -->		15.9%			18.1%			12.2%		
Scheduled	Cause	days	deferment	Comments	days	deferment	Comments	days	deferment	Comments
Production system			**1.4%**			**10.1%**			**0.3%**	
Wells			**0.3%**			**0.3%**			**0.3%**	
	LOT 12hrs every 6 months	1	0.3%	PTA, ESD taken as opportunity	1	0.3%	PTA, ESD taken as opportunity	1	0.3%	PTA, ESD taken as opportunity
			0.0%			0.0%			0.0%	
SubSea			**0.0%**			**0.0%**			**0.0%**	
			0.0%			0.0%			0.0%	
Topsides Process			**1.1%**			**9.9%**			**0.0%**	
	FPSO SD				28	7.7%	Main SD BSW RP-A Modification & Tie -in (RP-A Shutdown 4 weeks tbc) & BNW Bellmouth, BNW shut down, relieve valves		0.0%	
	Gas compressor engine c/o (x1). 26 days per engine, assuming no flaring allowed results in 30k bopd flare contrained, which is 4 days full production.	4	1.1%	Assuming flaring is not allowed	8	2.2%	2 gas compressor engines will be changed out at the beginning of 2010		0.0%	
Export			**0.0%**			**0.0%**			**0.0%**	
	none scheduled		0.0%			0.0%			0.0%	
Waterflood			**6.2%**			**8.6%**			**2.1%**	
Topsides WF			**6.0%**			**8.5%**			**1.9%**	
			0.0%						0.0%	
	21 full days total down time for WI pump engine c/o, injection pumps upgrade (each side down for 21 days)	21	5.8%			0.0%				
	FPSO SD				28	7.7%	Main SD BSW RP-A Modification & Tie -in (RP-A Shutdown 4 weeks tbc)	0	0.0%	
	Turbine maintenance	0	0.0%	Alinged with engine c/o	2	0.5%	Turbine maintenance (partly done during main SD)	6	1.6%	Turbine maintenance
	Harmattan condition, GT filter c/o	1	0.3%	Harmattan condition, GT filter c/o	1	0.3%	Harmattan condition, GT filter c/o	1	0.3%	Harmattan condition, GT filter c/o
Wells related		**0.5**	**0.1%**	inj wells closed in for well commissioning	**0.5**	**0.1%**	inj wells closed in for well commissioning	**0.5**	**0.1%**	inj wells closed in for well commissioning

Deferment (unscheduled)

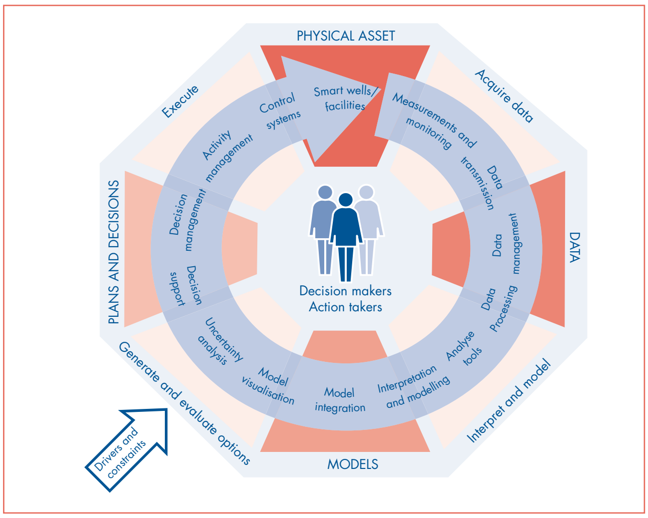
Total deferment		2009			2010			2011		
Production system 50/50 -->		5.3%			13.7%			4.2%		
Waterflood system 50/50 -->		15.9%			18.1%			12.2%		
Unscheduled		days	deferment	Comments	days	deferment	Comments	days	deferment	Comments
Production system			**4.0%**	Corrected for scheduled downtime		**3.6%**			**4.0%**	
Wells			**1.2%**			**1.2%**			**1.2%**	
	well failures	4.5	1.2%	Assume 1 workover/20 years @ 90 days duration	4.5	1.2%	Assume 1 workover/20 years @ 90 days duration	4.5	1.2%	Assume 1 workover/20 years @ 90 days duration
SubSea			**0.5%**	based on GOM data		**0.5%**	based on GOM data		**0.5%**	based on GOM data
			0.5%	Mortality rate 20%/well/yr, 10 day restoration time		0.5%	Mortality rate 20%/well/yr, 10 day restoration time		0.5%	Mortality rate 20%/well/yr, 10 day restoration time
Topsides Process			**1.2%**			**1.2%**			**1.2%**	
		4.5	1.2%	Assume 1 trip/month, 9 hour trip duration incl recovery time (based on historical data)	4.5	1.2%	Assume 1 trip/month, 9 hour trip duration incl. recovery time (based on historical data)	4.5	1.2%	Assume 1 trip/month, 9 hour trip duration incl. recovery time (based on historical data)
Export			**1.0%**			**1.0%**			**1.0%**	
			1.0%	Tanker delays		1.0%	Tanker delays		1.0%	Tanker delays
Waterflood			**9.8%**	Corrected for scheduled downtime		**9.5%**			**10.2%**	
Topsides WF			**5.0%**			**5.0%**			**5.0%**	
	current deferment level		5.0%	Current unscheduled deferment level based on past experience		5.0%	Based on historical data		5.0%	Based on historical data
Wells related			**5.4%**			**5.4%**			**5.4%**	
	injection well part	4.5	1.2%	Assume 1 workover/20 years @ 90 days duration	4.5	1.2%	Assume 1 workover/20 years @ 90 days duration	4.5	1.2%	Assume 1 workover/20 years @ 90 days duration
	injection well impairment		4.2%	Assume 2 inj impared to 50% inj cap every year for half a year.		4.2%	Assume 1 inj impared to 75% inj cap every year for half a year.		4.2%	Assume 1 inj impared to 75% inj cap every year for half a year.

WRM and model update

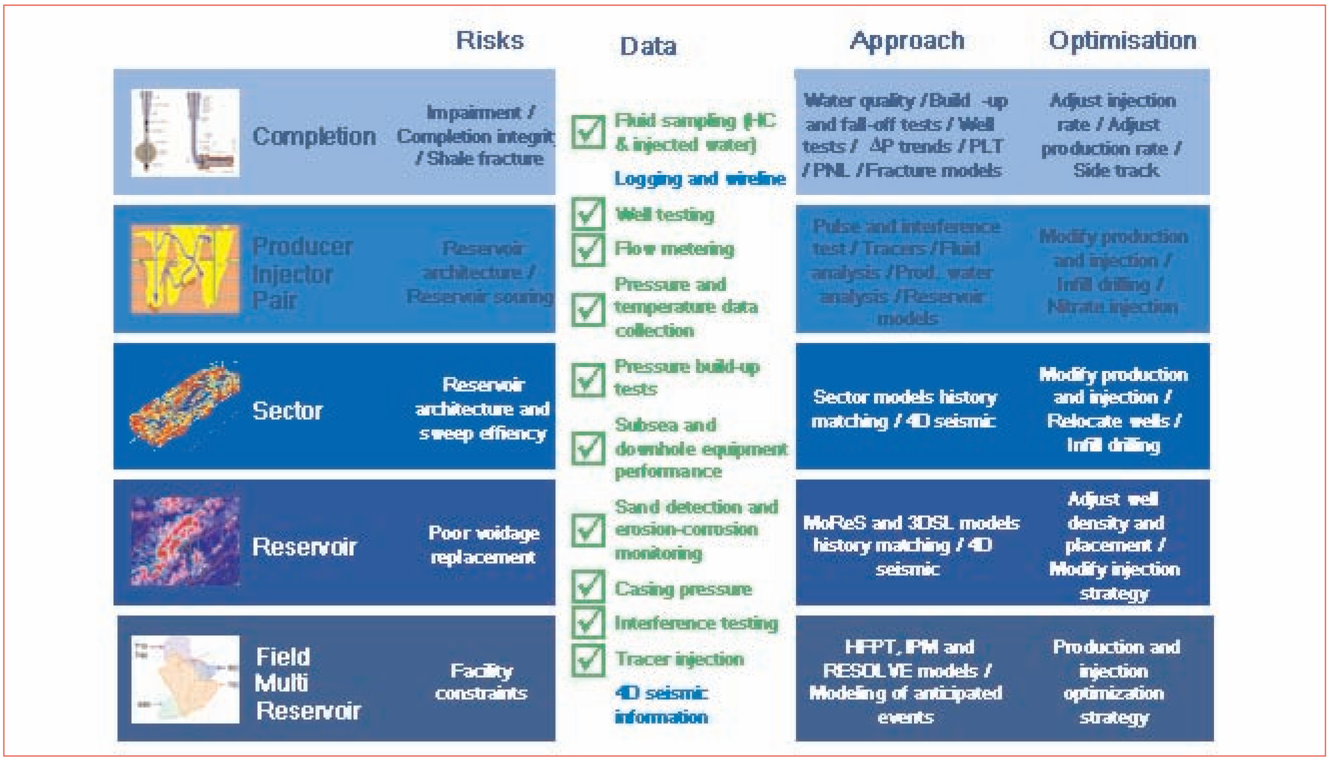
Facility is Smart Field Mark 1 compliant

Calibration of IPM model done on regular basis:

- routine well test on all wells
- real time pressure, temperature data and flow data
- 6-monthly multi-rate test on all wells
- flow assurance data.

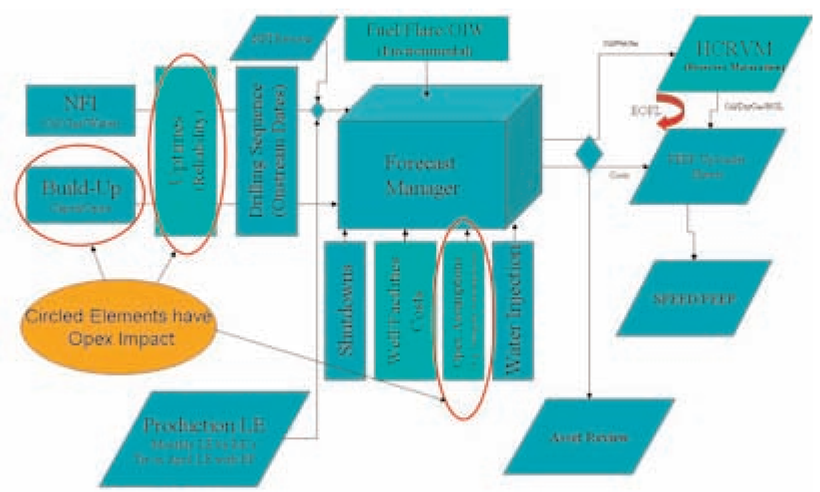


Surveillance approach

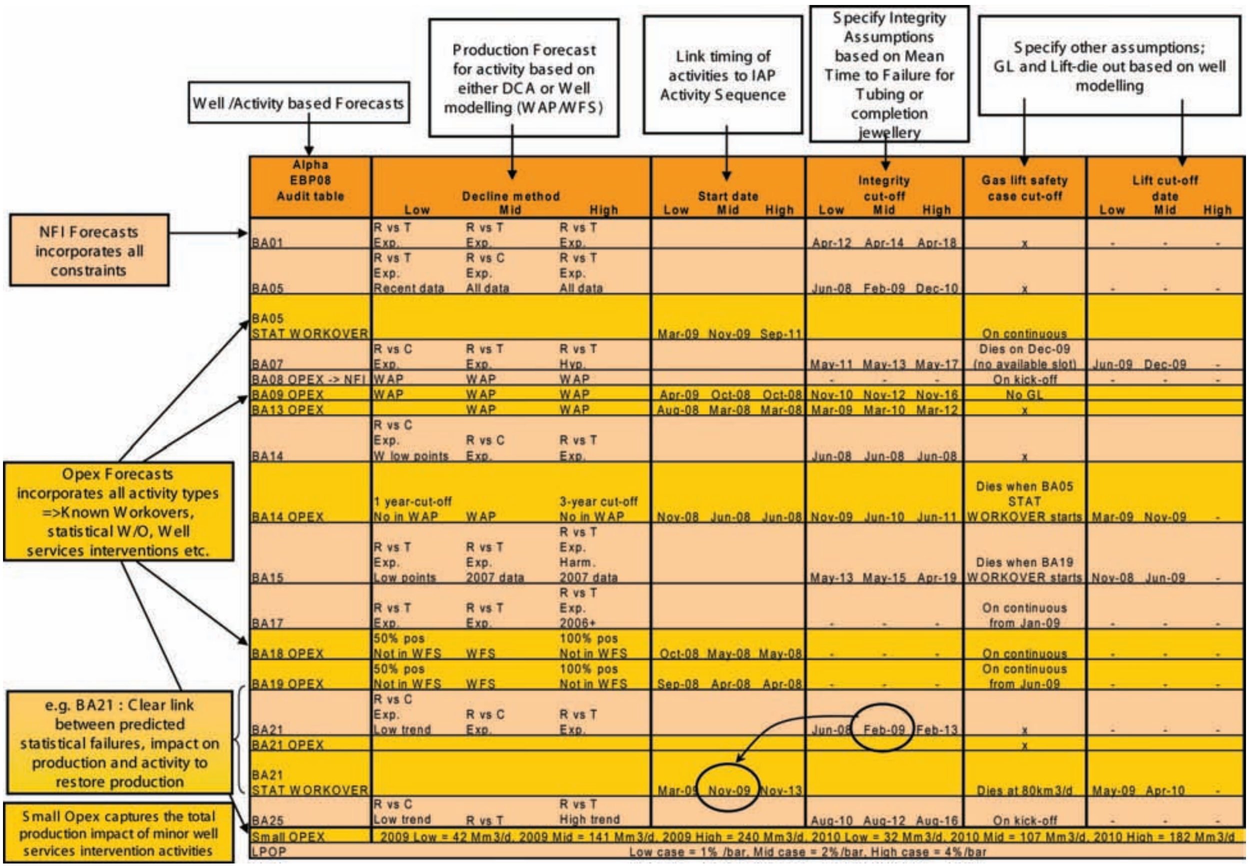


Example 2: Forecasting WRM/PSO gains due to Opex activities

- Objective: Fully integrated production/cost/activity sequence for Opex activities.
- Workflow:
  - start with creating an Opex activity plan incorporating the following (activities and timing):
    - pre-emptive activities: preventive maintenance (Scale squeeze jobs, etc.; Well Services)
    - restoration: restoring production from wells currently or expected to be (statistical) shut-in (Integrity issues, Gas Lift valves, etc.; Well Services, Main Rig)
    - build-up activities: production generating (add-perfs, WSO; Well services/Main Rig Workovers)
    - surveillance: Data Acquisition for WRM (PLT, RSTs, etc.; Well Services/Main Rig).
  - generate incremental production profiles for each of the activities, taking account of any back-out or interference effects:
    - pre-emptive: will lead to loss of production during the activity, but will preserve production in the longer-term
    - restoration: will lead to production increase from currently shut-in wells, and production decrease from statistical shut-in wells => forecast based on historical well performance
    - build up: will lead to production increase => forecast based on well models
    - surveillance: will lead to loss of production during the activity.
  - Integrate production profiles while honouring the following constraints:
    - do-ability: platform personnel on board (POB) using Integrated Activity Planning (IAP) sequence
    - do-ability: resource (Well Services and Main Rig Crew) constraints
    - Total Opex limit constraints
    - production profiles incorporating: historical performance (DCA), lift-die out, system constraints
    - timing: all activities based on integrated sequence. Statistical integrity issues timing based on Mean Time to Failure for tubing/jewellery in use.

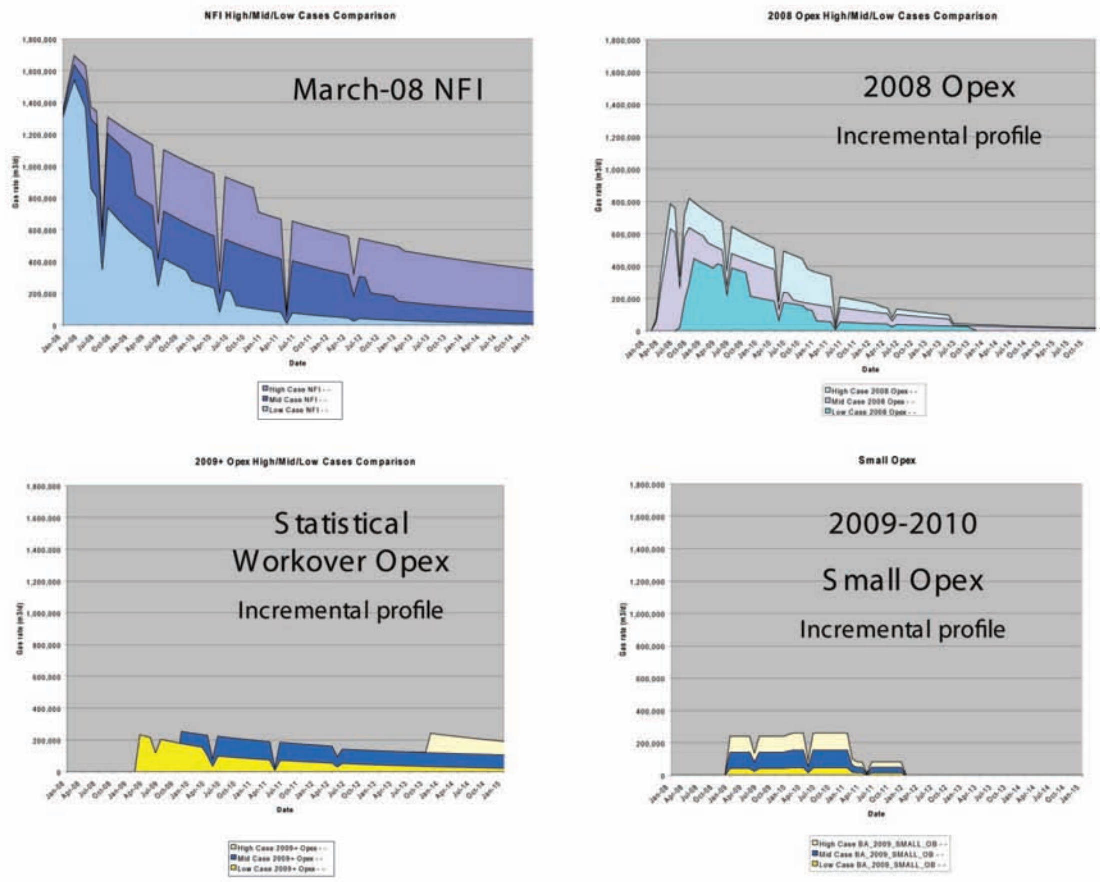


Forecast integration



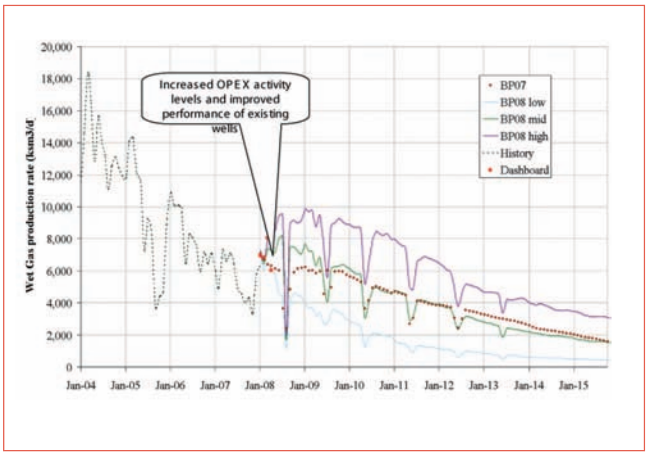
Alpha EBP08 Audit table	Decline method Low	Decline method Mid	Decline method High	Start date Low	Start date Mid	Start date High	Integrity cut-off Low	Integrity cut-off Mid	Integrity cut-off High	Gas lift safety case cut-off	Lift cut-off date Low	Lift cut-off date Mid	Lift cut-off date High
BA01	R vs T Exp.	R vs T Exp.	R vs T Exp.				Apr-12	Apr-14	Apr-18	x	-	-	-
BA05	R vs T Exp. Recent data	R vs C Exp. All data	R vs T Exp. All data				Jun-08	Feb-09	Dec-10	x	-	-	-
BA05 STAT WORKOVER				Mar-09	Nov-09	Sep-11				On continuous			
BA07	R vs C Exp.	R vs T Exp.	R vs T Hyp.				May-11	May-13	May-17	Dies on Dec-09 (no available slot)	Jun-09	Dec-09	-
BA08 OPEX -> NFI	WAP	WAP	WAP				-	-	-	On kick-off	-	-	-
BA09 OPEX	WAP	WAP	WAP	Apr-09	Oct-08	Oct-08	Nov-10	Nov-12	Nov-16	No GL			
BA13 OPEX		WAP	WAP	Aug-08	Mar-08	Mar-08	Mar-09	Mar-10	Mar-12	x			
BA14	R vs C Exp. W low points	R vs C Exp.	R vs T Exp.				Jun-08	Jun-08	Jun-08	x			
BA14 OPEX	1 year-cut-off No in WAP	WAP	3-year cut-off No in WAP	Nov-08	Jun-08	Jun-08	Nov-09	Jun-10	Jun-11	Dies when BA05 STAT WORKOVER starts	Mar-09	Nov-09	-
BA15	R vs T Exp. Low points	R vs T Exp. 2007 data	R vs T Exp. Harm. 2007 data				May-13	May-15	Apr-19	Dies when BA19 WORKOVER starts	Nov-08	Jun-09	-
BA17	R vs T Exp.	R vs T Exp.	R vs T Exp. 2006+				-	-	-	On continuous from Jan-09	-	-	-
BA18 OPEX	50% pos Not in WFS	WFS	100% pos Not in WFS	Oct-08	May-08	May-08	-	-	-	On continuous	-	-	-
BA19 OPEX	50% pos Not in WFS	WFS	100% pos Not in WFS	Sep-08	Apr-08	Apr-08	-	-	-	On continuous from Jun-09	-	-	-
BA21	R vs C Exp. Low trend	R vs C Exp.	R vs T Exp.				Jun-08	Feb-09	Feb-13	x	-	-	-
BA21 OPEX										x			
BA21 STAT WORKOVER				Mar-09	Nov-09	Nov-13				Dies at 80km3/d	May-09	Apr-10	-
BA25	R vs C Low trend	R vs T	R vs T High trend				Aug-10	Aug-12	Aug-16	On kick-off	-	-	-
Small OPEX	2009 Low = 42 Mm3/d, 2009 Mid = 141 Mm3/d, 2009 High = 240 Mm3/d, 2010 Low = 32 Mm3/d, 2010 Mid = 107 Mm3/d, 2010 High = 182 Mm3/d												
LPOP	Low case = 1% /bar, Mid case = 2%/bar, High case = 4%/bar												

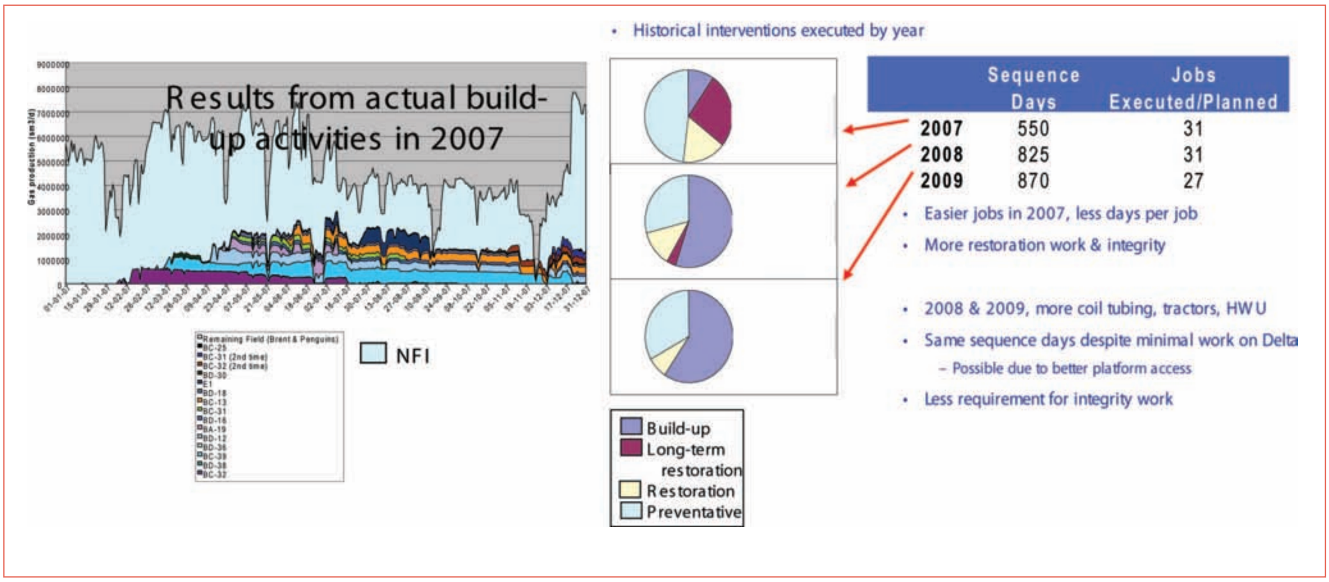
Example: Individual NFI and Opex tranches (high/mid/low)



QCs of Opex production forecast

- Tie in business plan (BP) forecast with Latest Estimate (LE) for the year; e.g. 2008 Dec LE and Dec-08 BP08 forecast should be in agreement (within ~5 %).
- Check against last year's business plan and production so far this year - understand the differences.
- Compare Opex promises (UTC, days per activity and increment per activity) with recent Opex activity performance.
- Check rolled-up promise with past delivery - understand the differences.





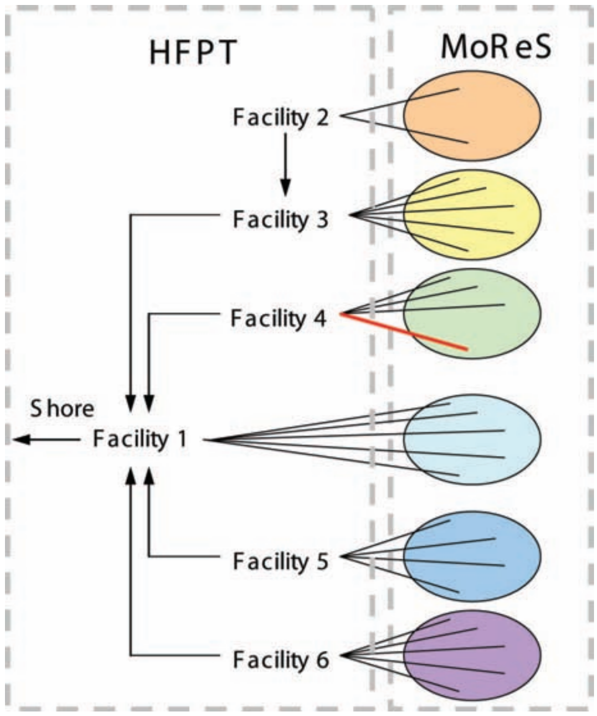
Example 3: Incremental forecast for shared Facilities, modelling pressure drops and surface back-out

Incremental forecasts - why and how

- Why:
  - to account for sub-surface interference
  - to account for changes in back pressure in the surface network
  - to account for any other effect a project might have on NFA profiles.
- How:
  - an integrated model is necessary
  - run a forecast with the new project included
  - run a forecast without the new project included
  - subtract both profiles to obtain the incremental profile.

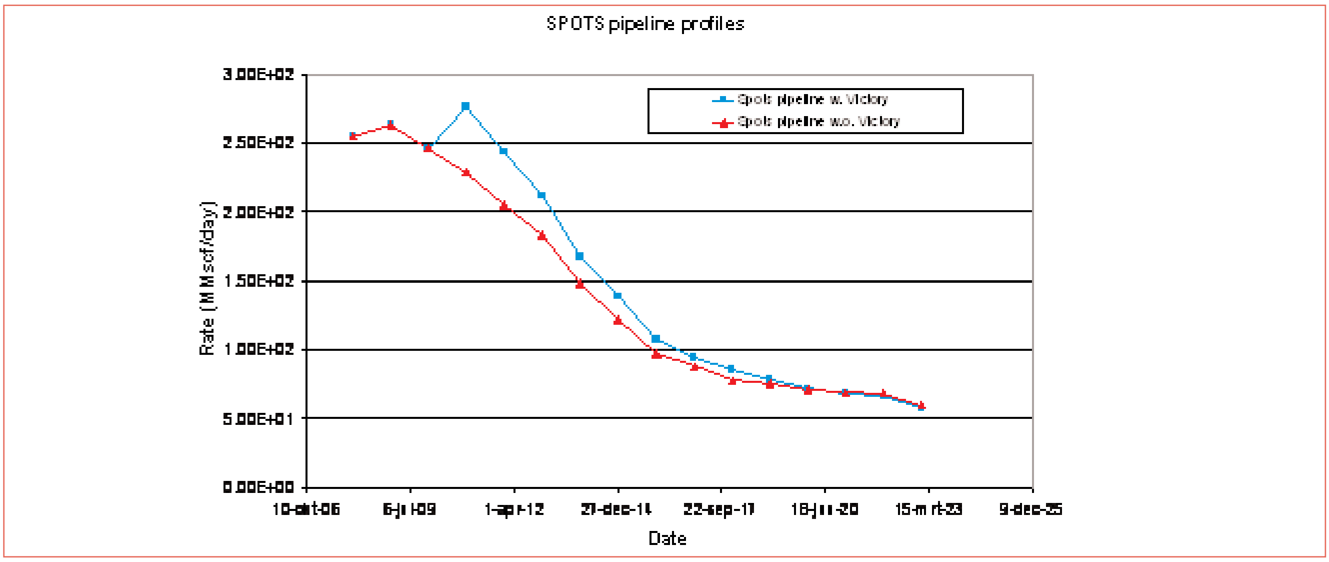
Incremental forecast - example

- MoReS:
  - wells could find reservoir depleted
  - sub-surface interference modelled in MoReS.
- HFPT:
  - used to couple all MoReS models
  - models backout effects and surface constraints
  - calculate the incremental profiles at the pressure sink (Shore).



Incremental forecasts

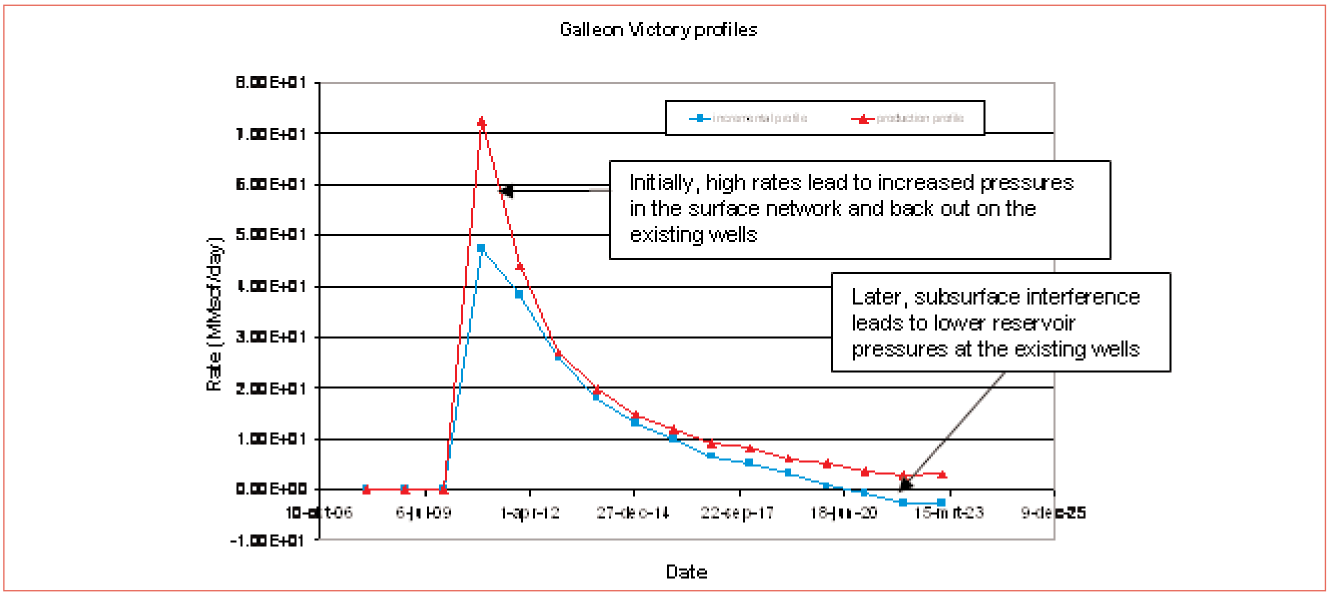
Example: profiles



A new gas well, to be hooked up to the SPOTS pipeline.

Incremental forecasts

Example: after subtraction



Example 4: New Oil forecast for a stand-alone development with no external constraints

Case description

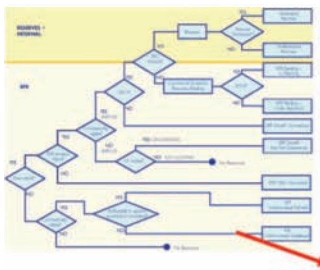
Integrated Oil and Gas Development initially comprises HA, HD and JK fields.

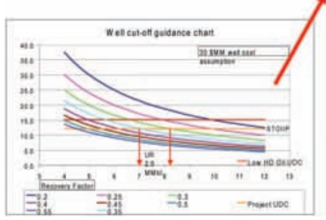
Basic concept

To roll up, in a transparent and consistent manner, individual well and reservoir forecasts to overall field-level and then to nodal forecasts in order to test the economics of selected concept against a wide spectrum of forecasts and to test specific capacity constraints against a suitable range of extreme cases.

Methodology

1. Classify the resource volumes in HD, JK and HA as per EP 2007-1100.
2. Create a number of independent field-specific building blocks.
3. Define nodal realisations by selecting combinations of field-level building blocks.
4. Create and validate the model based on HFPT (rate-coupled and not pressure-coupled, with sub-surface components represented by cumulative production type curves).
5. Analyse nodal production forecasts.





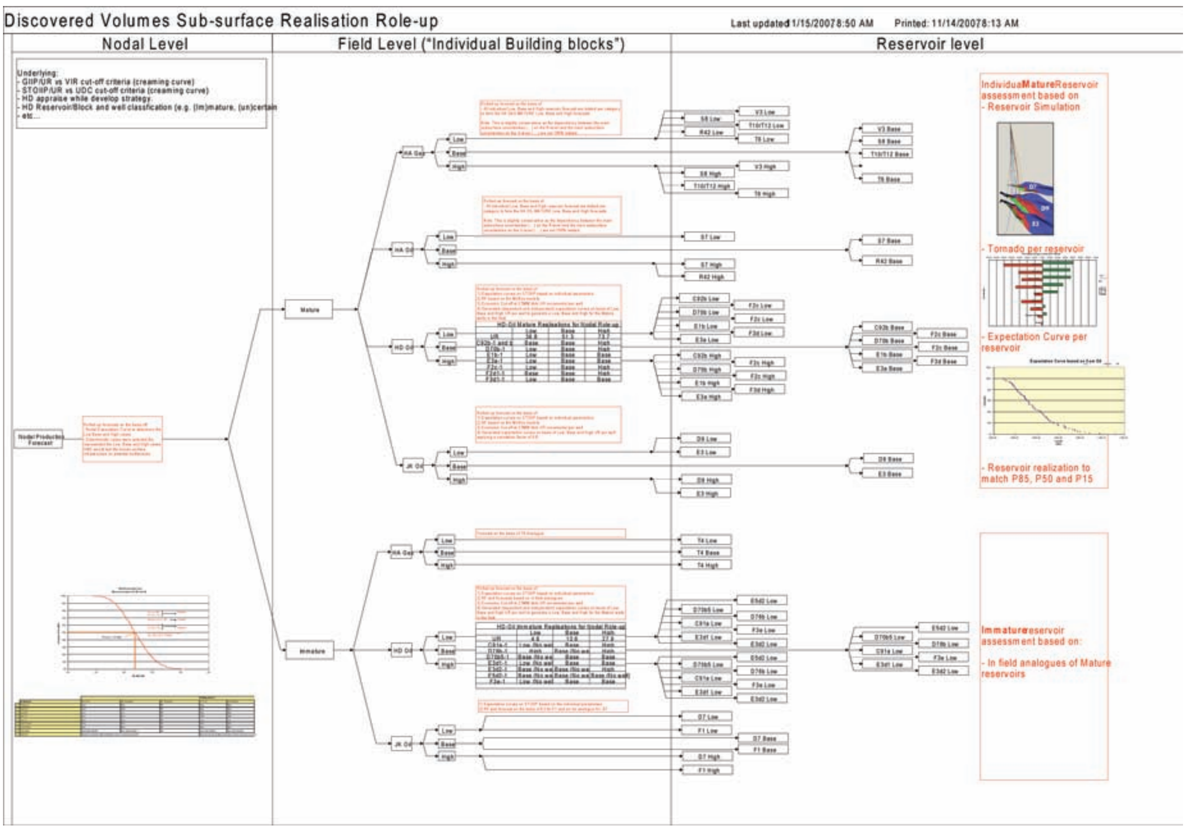
	Category		Example	Objective	Modelling approach
	Volume	Well			
Discovered SFR Pending-in planning	**Mature** *HD+HA oil:* • Oil found by well • Low case: STOIIP > 10 MM bbl, UR > 2.5 MM bbl (based on UDC) *HA gas:* • Gas found by well • Low case: GIIP > 50 Bcf, UR > 30 Bcf (based on VIR of 0.25) • Development concept in case of oil rim	**Certain** Well is justified in low case	HD-D70 block B	FDP concept selection, provide basis for well proposals (well optimisation)	Dynamic simulation model (some wells might move to immature)
		Contingent • Well is justified in high case (upside potential of a mature volume) • 'Develop while appraise'	HA-S7-3	FDP concept selection, strongly dependent on appraisal, no well optimisation	In-place volumes from static model, RF from in-field analogues or dynamic simulation model (if work already done)
	Immature *HD+HA oil:* • Oil found by well or strong indications (by structure, DHI) for communication with proven block • Low case: UR < 2.5 MM bbl • High case: UR > 2.5 MM bbl *HA gas:* • Gas found by well • Mature criterion not met and/or availability of gas uncertain due to presence of oil rim	**Contingent** • Well is justified in high case • 'Develop while appraise'	HD-E1 block A	FDP concept selection, strongly dependent on appraisal, no well optimisation	In-place volumes from static model, RF from in-field analogues or dynamic simulation model (if work already done)
Undiscovered SFR Undiscovered - defined	**Undiscovered** • No oil found or no clear indication for communication with proven block	**Contingent** • Appraisal by development well • Near field potential	HD-D69	Identify potential upside which could mitigate downsides in the FDP concept selected	In-place volumes from static model, RF from in-field analogues

Reference: Petroleum Resource Volume Requirements EP 2006-1100, September 2006 (release 4.0).

Nodal realisations

Workflow

Reservoir
↓
Field building blocks (mature vs immature)
↓
Nodal



Sub-surface realisations (discovered)

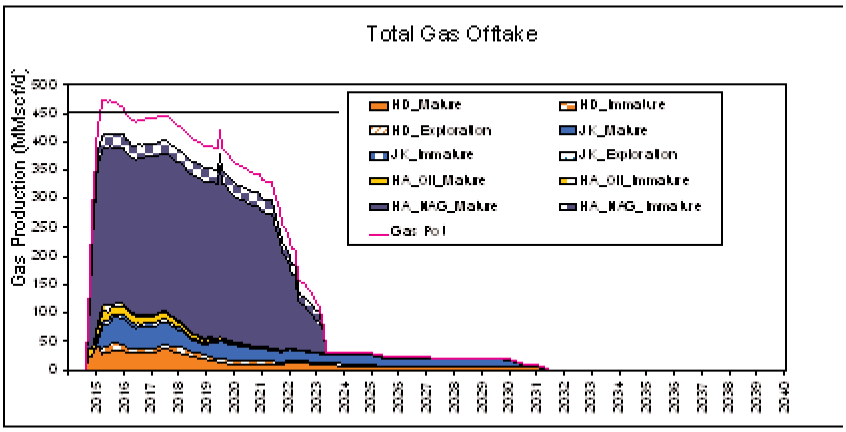
	Realisations	"Building Blocks"								Results			
		HD-Mature	HD-Immature	HD-Undiscovered	JK-Mature	JK-Immature	JK-Undiscovered	HA - OIL	HA - NAG	UR [MMbbl]	UR [MMscf]	Oil Exp.	UR (JK-VAR-3 Close Out) [MMbbl]
1	Reference Discovered	Base	Base	NA	Base	Base	NA	Base	Base	212	1061	P58	233
2	High HD	High	High	NA	Base	Base	NA	Base	Base	250	1089	P16	290
3	Low HD	Low	Low	NA	Base	Base	NA	Base	Base	189	1041	P87	164
4	High JK	Base	Base	NA	High	High	NA	Base	Base	249	1077	P15	270
5	Low JK	Base	Base	NA	Low	Low	NA	Base	Base	186	1066	P85	189
6	High HA gas	Base	Base	NA	Base	Base	NA	Base	High	244	1282	-	-
7	Low HA gas	Base	Base	NA	Base	Base	NA	Base	Low	182	619	-	-
8	High water	Early peak water = Appr. Low Case						Base	Base	156	1006	P99.5	-
9	High AG	Early peak water = Appr. Low Case						Base	Base	136	1037	P99.9	-

HD changes partly offset by:

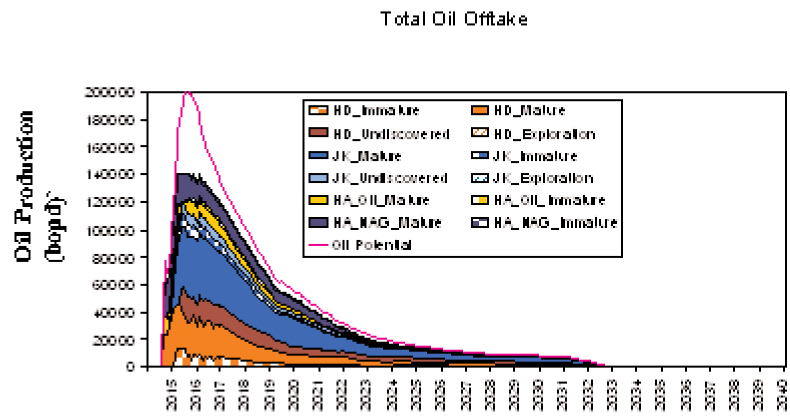
- increase in HA oil and condensate recovery from 15MMbls to 33 MMbls
- additional gaslift: 7.5MMbls).

Forecast analysis: NAG

- Nodal reference gas forecasts per building block.

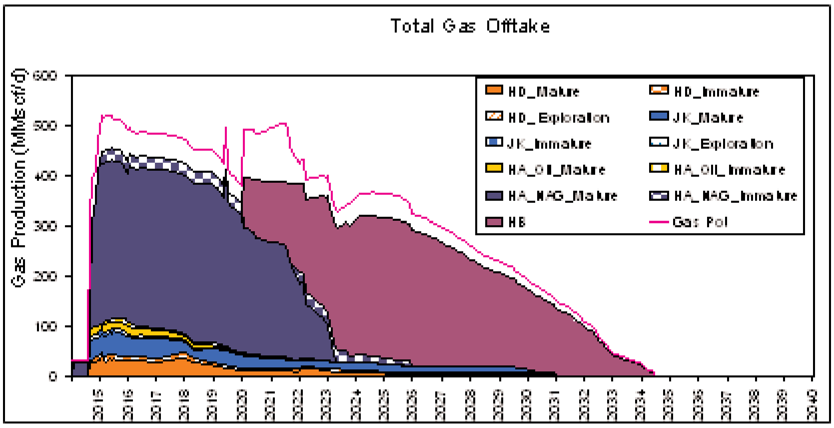


Forecast analysis: Oil (building block build-up)



Forecast analysis: NAG (including HB)

- Nodal reference gas forecasts per building block.



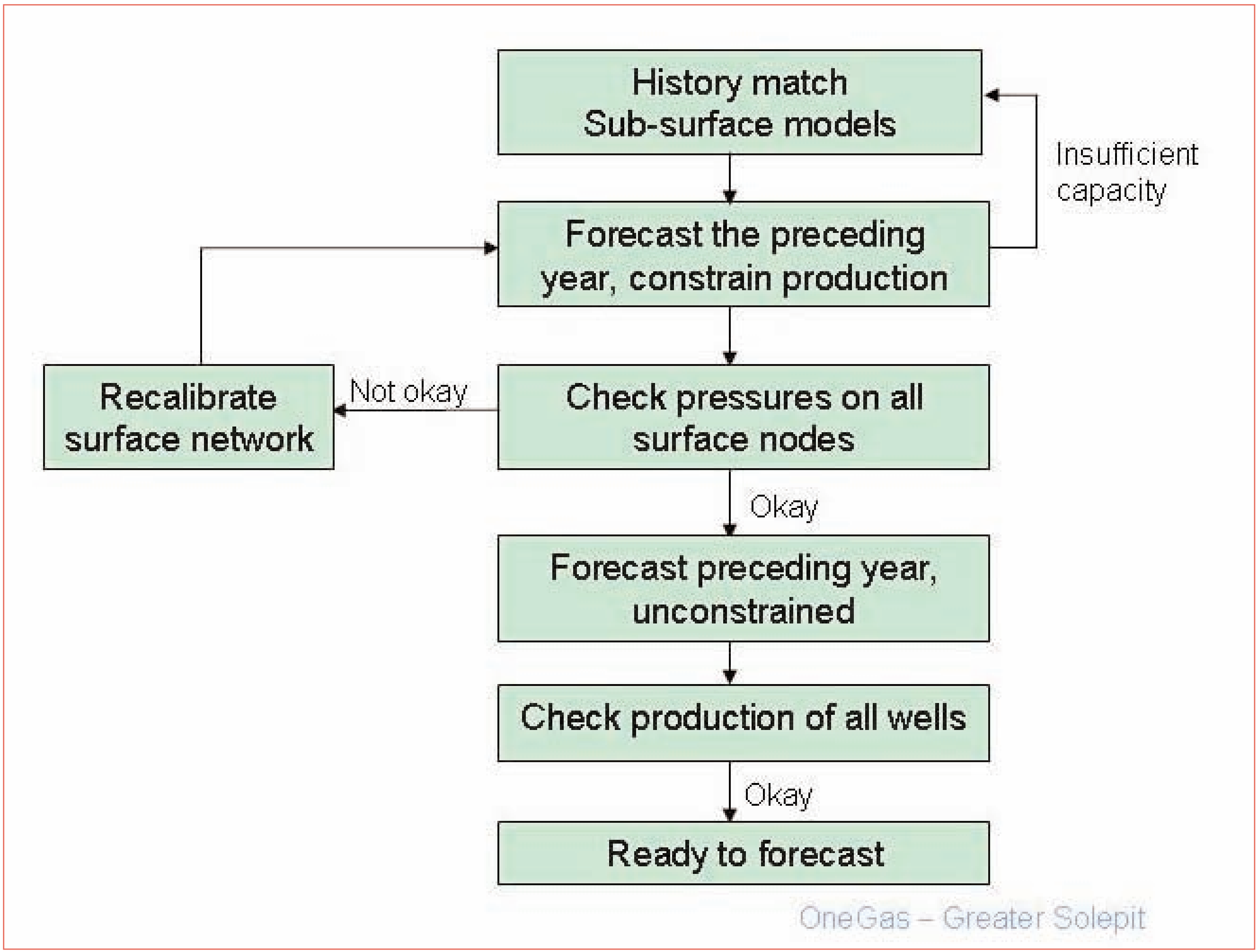
Example 5: Smooth transition from HM to prediction by running the last year in forecast mode

History matching is normally done by imposing rate constraints and matching the reservoir pressure.

Once a satisfactory pressure match has been achieved, the last year of production is run in forecast mode, i.e. without rate constraints.

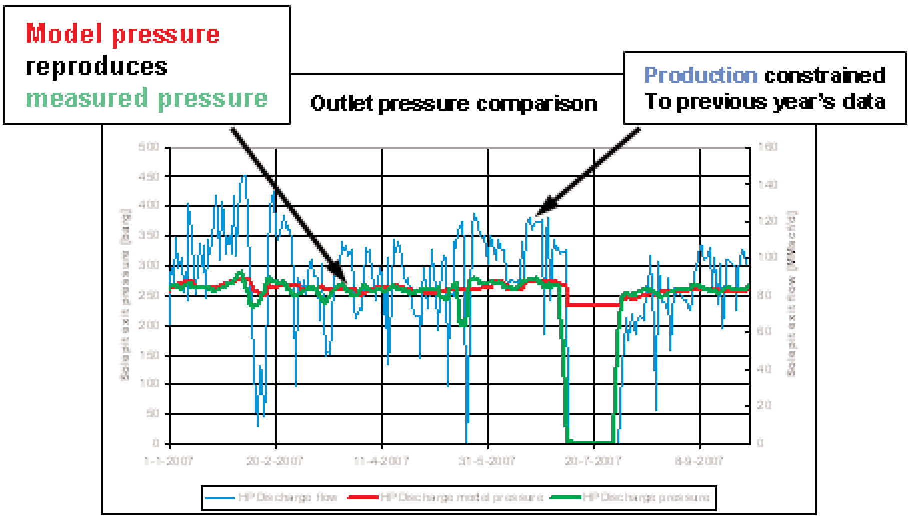
One should not expect a perfect match, but if there are major deviations, this would indicate a problem with the lift curves, the well models or with surface pressure drops.

Model calibration steps



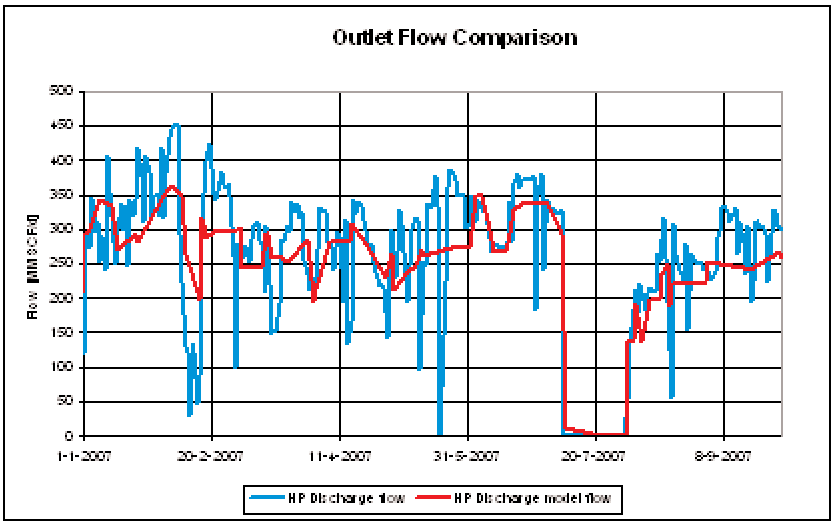
Model calibration

Forecast previous year (constrained)



Model calibration

Forecast previous year (un-constrained)



Example 6: Dynamic model checklist with specific forecasting questions

Reservoir Engineering Checklist for Peer Reviews			
Opportunity Name :		Type of review:	
Date of review:			
Project Team RE:	-	Team Leader:	
Reviewer:			

ORP-focus

Focus of THIS REVIEW	Identify @ VAR1	Assess @ VAR2	Select @VAR3		RATING	NARRATIVE / COMMENTS
				High Focus Moderate Focus Low Focus	A - absent D - deficient F - fit for purpose B - Best Practice N/A - Not applicable	
0				**Introduction: Scope of review**		
				Has the purpose of the review been clearly stated? (i.e.Peer Review, Technical Endorsement for VAR)		
				Is the timing of the review appropriate?		
				Are the appropriate people present?		
				Are the objectives of the study (phase) clearly articulated?		
1				**Data collection and QC**		
				Has the available data been cleaned-up and QC-ed ?		
				Is there an inventory of available data ?		
				Has a data gap analysis been made ?		
				Has a data acquisition proposal been formulated ?		
2				**Reservoir pressure analysis**		

		Have RTF and BHP data been reconciled ?
		Has PBU data been assessed for evidence of drainage boundaries ?
		Have KH values from well tests been reconciled with static data ?
		Are there any documented regional trends and/or anomalies ?
		Has the pressure analysis been documented ?
3		**PVT analysis**
		Have the measurements been adequately QC'ed and has this process been documented and reviewed?
		Is there any indication of different areal PVT regimes and/or compositional grading with depth?
		If the PVT properties are derived from another field, have the PVT-data that have been used been based on the most appropriate analogue or correlation method?
		If PVT properties are a key uncertainty, has additional data acquisition been considered ?
		Has a suitable method for PVT-modeling been choosen (i.e. black oil, volatile oil, compositional)?
		In case a compositional model has been built, has the number of pseudo-components been determined rigorously?
4		**Assessment of relative permeability data**
		Have measurements been adequately interpreted and QC'ed and has this process been documented and reviewed?
		Do relperm results compare well with data available in global databases for similar fields? If not has a proper explanation for this been developed?
		If analogue data has been used, has the most appropriate analogue been choosen?
		Have the wettability conditions been described in a document, including all evidence ?
		If relperm data is a key uncertainty, has acquisition of additional SCAL data been considered?
		Are 3-phase flow effects expected to be important and if so what is the basis for the assumed 3-phase relative permeability model?
		Are end-point saturations consistenty used between the relative permeability and capillary pressure data?
		Are hysteresis effects important?
5		**Assessment of capillary pressure data**
		Have experimental data and log data been reconciled ?
		Has a field-wide variation been categorised in terms of lithology, porosity, permeability and interfacial tension ?
		Have the results and methods used been documented ?
6		**Reservoir performance analysis**
		Have production data been analysed for quality and consistency ?
		Have discrepancies and trends been documented ?

	Have interdisciplinary well reviews taken place ?
7	**Uncertainty analysis**
	Has an uncertainty assessment work-flow been identified to establish the ranking of the uncertainties (realisations, sensitivity analysis)?
	Has parameter upscaling/mapping, and resulting uncertainty propagation, been discussed/agreed between PG, PP and RE ?
	Has a reference case been articulated?
	Have a sufficient number of subsurface realisations been identified based on combinations of key uncertainties?
	If applicable, has a data acquistion plan/recommendations been made to address key uncertainties and is it incorporated in to the FDP,FSN surveillance plan ?
8	**Modelling strategy**
	Have material balance and analytical calculations been performed prior to dynamic modelling ? ***Has material balance been applied to assess aquifer strength and size?***
	Has the most appropriate type of model(s) been selected given the objectives of the study (phase) ?
9	**Upscaling and QC of static model**
	What method has been used for permeability upscaling (i.e. arithmetic, geometric averaging)? ***What is the basis for assigning the kv/kh value?***
	Have porosity and permeability variations been adequately captured ?
	Have dynamic data (RFT, PBU) been used to QC the upscaling ?
	Has it been demonstrated that the faults from the static model have been preserved in the dynamic model?
	What is the basis for assigning the transmissibility barriers across faults? Has the full range of uncertainties been incorporated?
	Has a grid sensitivty been done ?
	Has all the above been documented, including evidence for quality ?
10	**Pseudo saturation functions**
	Has the validity of using the 'rock' relative permeabilities been addressed and documented ?
	If pseudo functions had to be used, has the validity of the chosen method been documented?
11	**Model initialization**
	Have the volumetrics from dynamic and static models been reconciled, including documentation ?
	Has a "zero-rate" test been performed to test equilibrium ?
12	**History matching**
	Is the history match phase based on a sensitivity analysis, and have Tornado diagrams been constructed to illustrate these sensitivites?
	Have realistic criteria been set for history matching, taking due account of business objectives, uncertainty in data and study phase ?
	Has the quality of the history match been demonstrated and documented at the appropriate level ?

	Has predictability been verified based on known performance of recently drilled wells ?
13	**Forecasting,** ***well and facility modeling***
	Have all prediction runs been documented, detailing any problems and how they were resolved ?
	Have all H/M/L oil/gas/water forecasts been documented in the FDP?
	Has the transition between history and prediction been handled successfully ? *Are the PIs of future wells in line with available data?*
	How does the NFA simulation forecast compare to DCA?
	Has the uncertainty range of the forecasts been covered sufficiently? *Has the uncertainty in historic production been taken into account in the uncertainty range of the forecasts?*
	Is the simulation model suitable for predicting the envisaged recovery mechanism? How representative is the model? What discount factors are being applied?
	Are the constraints and uptime factors representative for the future production of the field and in line with the envisaged operating philosophy? Has the operating envelope been captured?
	Has vertical flow in the well been modelled and have lift tables been derived adequately? Is the pressure drop along horizontal drainholes relevant and has it been modelled adequately?
	What is the forecast period and is the economic limit understood?
14	**Assessment of reserves and scope**
	Is there a detailed report on the reserves analysis, including all assumptions made in generating the estimates?
	Has a probability distribution for the reserves been constructed and documented ?
15	**Integration among disciplines**
	Are there documented examples of work flow iterations between different disciplines ?
	Are all key findings fully supported by all disciplines represented in the team ?
16	**Reporting**
	Have all aspects of the RE work in this study been fully documented ?
	Is a full audit trail available ?
17	**Close out**
	Have UNIX and PC back-up tapes been created, after clean-up of the data ?

Example 7: Deriving the low/expected/high forecast using experimental design for a mature field

Background

In order to understand the impact of the many uncertainty parameters, design of experiments (DoE) and response surface modelling (RSM) techniques were applied to the static and dynamic modelling of the project. This approach allows a systematic quantification of the impact of all relevant uncertainties and their interactions on future development options of the field (pre-DG2 stage).

A 'complicating' factor is the 40-year production history: only those reservoir realisations that reproduce historical performance are valid.

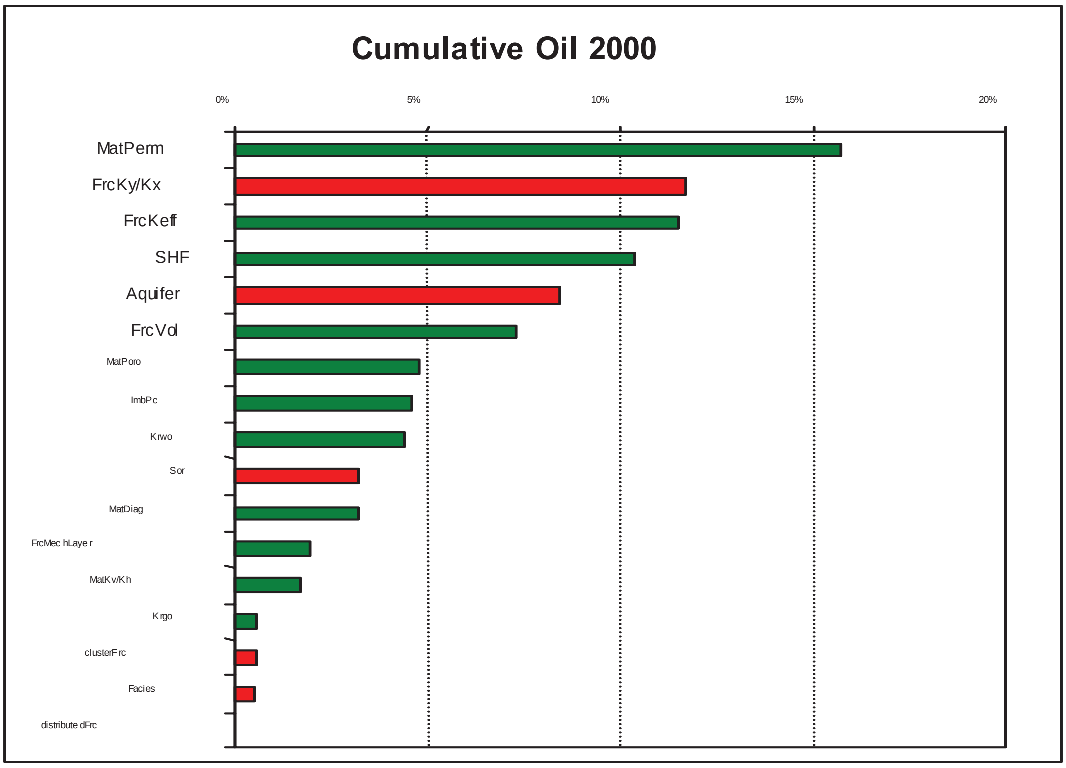
The workflow steps

History match

1. Initial screening step

Determine the relative impact of each uncertainty parameter on the reservoir performance during history using a Plackett-Burman (screening) design: the significant uncertainties (for the history match) are identified and plotted in a Pareto plot as shown below.

1. Pareto plot for the cumulative oil in year 2000



2. Response surface modelling step

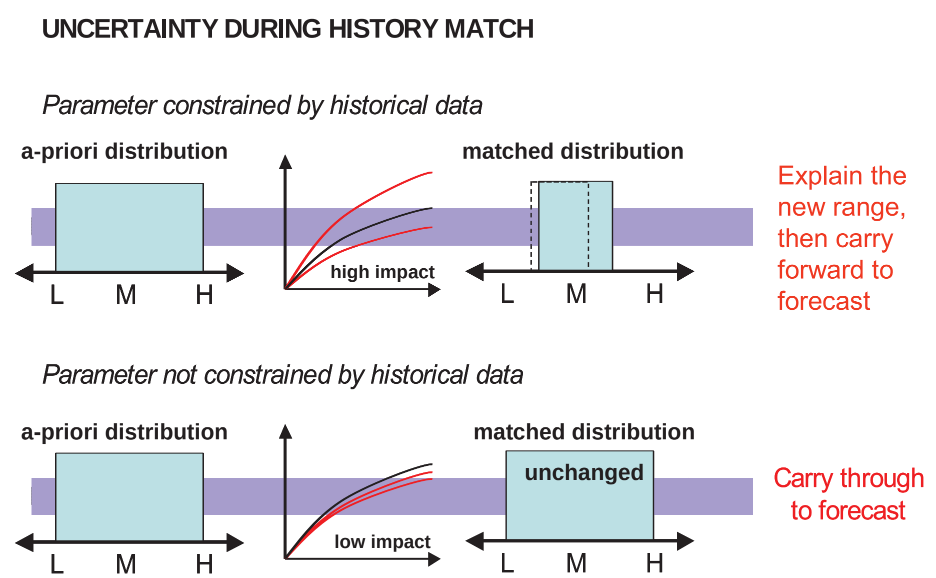
Create a quadratic RSM for each response of interest (like cumulative oil, BHP, watercut, etc.) using a Box-Behnken (RSM) design. The higher resolution of this design allows a quadratic RSM with better accuracy, but also results in a larger number of runs. Therefore, a limited set of most significant uncertainties (as indicated by the screening step) is considered. The resulting RSMs, after validation, are used as a proxy of the dynamic model.

3. Filtering step

Filter the multi-dimensional uncertainty space using the RSMs. An appropriate objective function, that captures the key features of a history match is used to gauge whether a realisation results in an acceptable match of historical performance. The filtering may result in a highly complex solution space of valid history matches.

The uncertainty parameters are then constrained individually to correspond with the solution space. This, obviously, is a simplification that ignores the dependencies between the parameters, but it has proved to be effective. The end result is a set of reduced uncertainty ranges for those uncertainties that impact the historical performance most (see figure below). Within these reduced ranges, all realisations will satisfy the history match criteria.

2. The impact of historical data (history matching) on uncertainty parameters



Forecast

1. Screening step

Determine the relative impact of each uncertainty parameter on the reservoir performance for the forecast using a Plackett-Burman design. The reduced uncertainty ranges obtained in the history matching, are applied for the uncertainty parameters. This step was done for each development option.

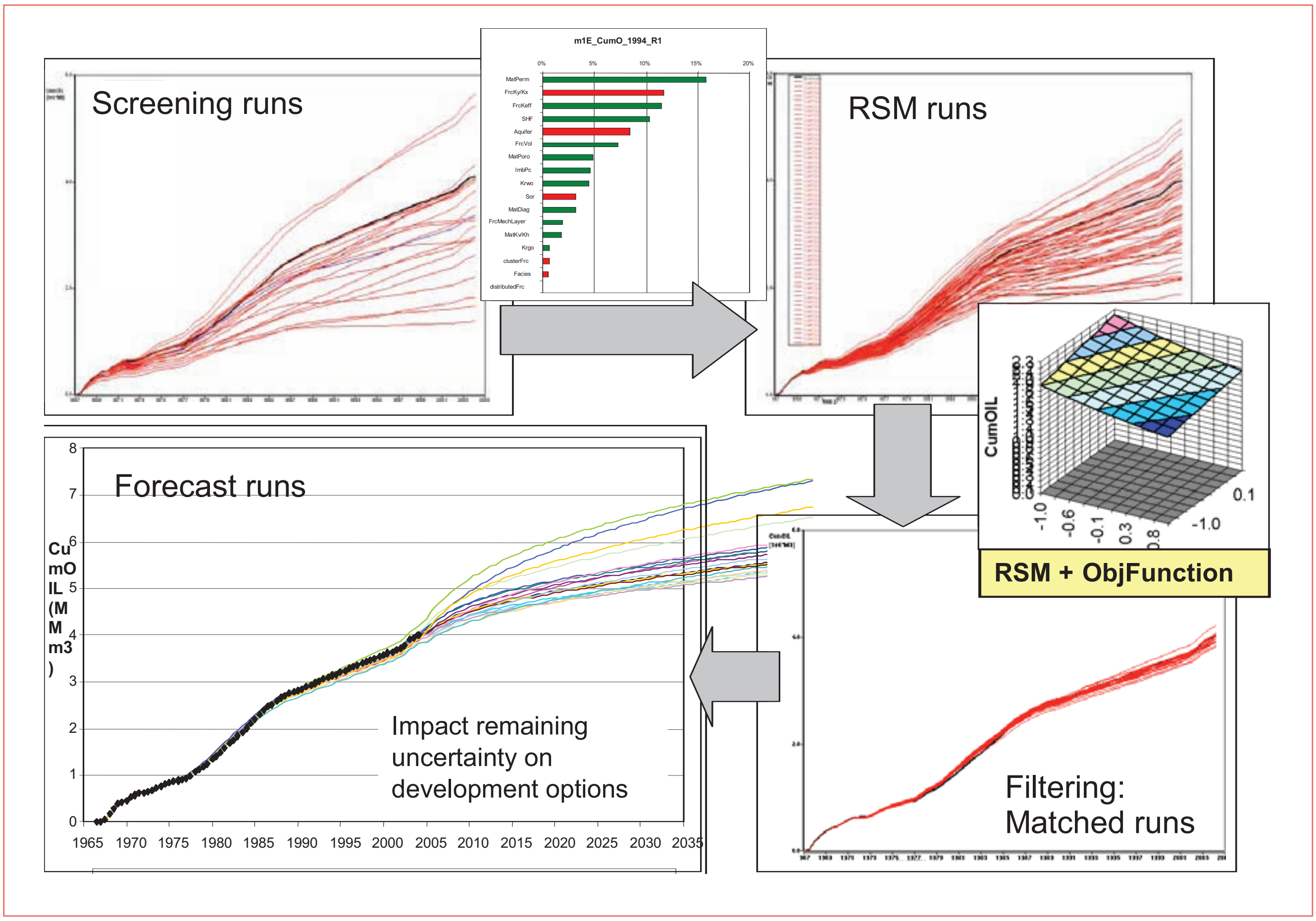
2. Response surface modelling step

Create a quadratic RSM for each response of interest using a Box-Behnken (RSM) design. Again, a limited set of most significant uncertainties (as indicated by the screening step) is considered. The resulting RSMs, after validation, are used as a proxy of the dynamic model. This step was done for each development option.

3. Evaluation step

Determine the PDFs for cumulative oil (or any other observable) for different development options using the RSMs and Monte Carlo analysis. A direct comparison can be made of expected recovery.

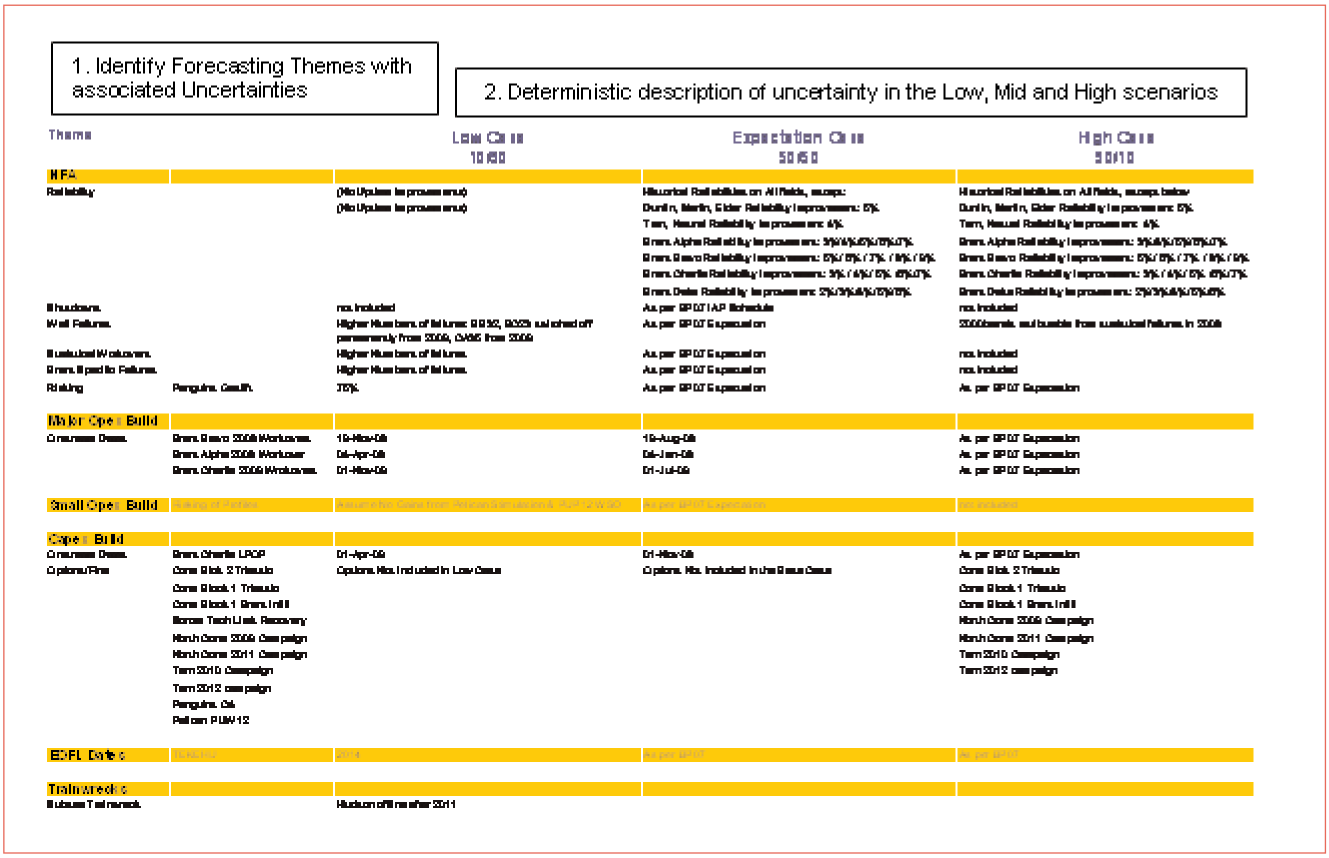
History matching and forecasting workflow using DoE and RSM



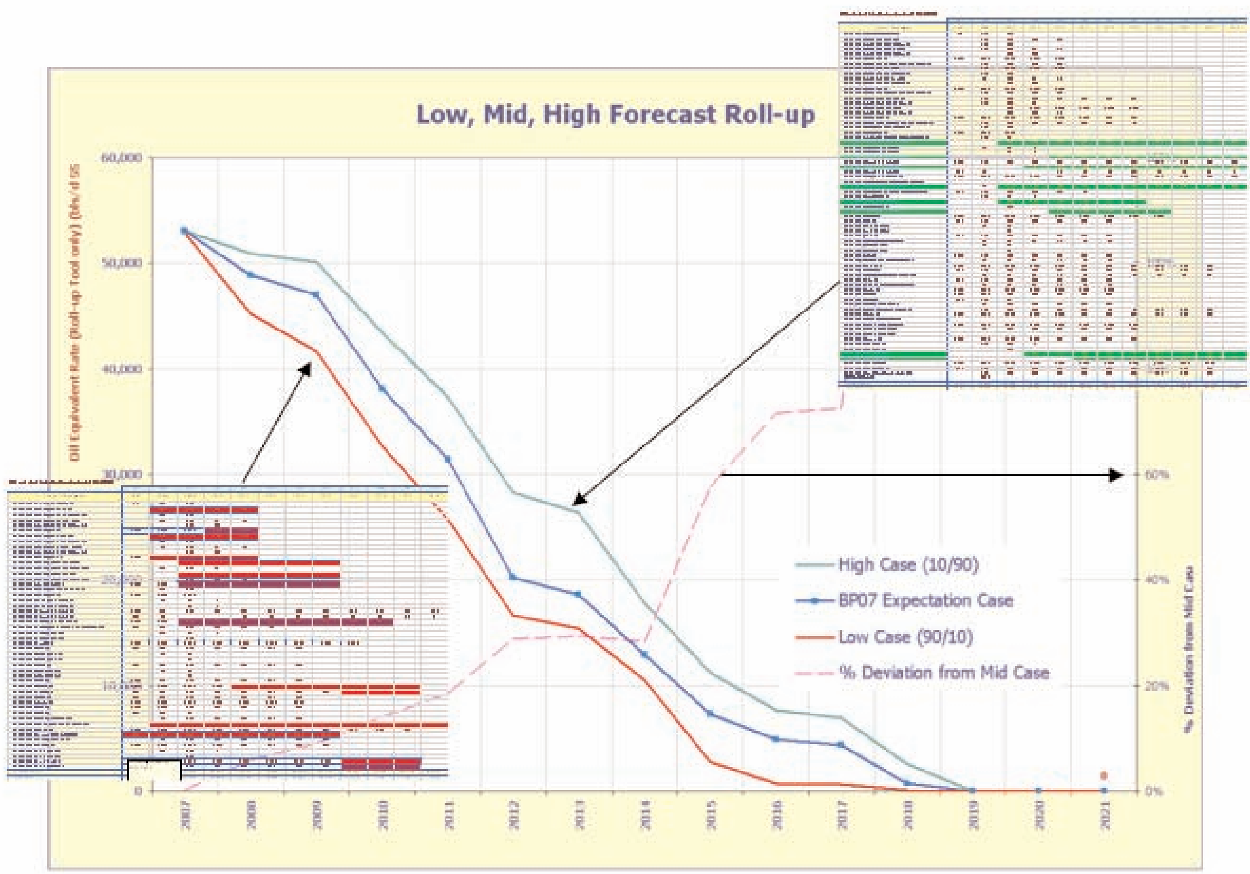
Example 8: Deriving the low/mid/high forecast deterministically

- Objective: Fully Integrated low/mid/high production forecasts based on deterministic assumptions
- Workflow:
  - start with creating a list of individual components of the production forecast and create activity themes
  - identify uncertainties associated with each theme:
    - NFI uncertainties => reservoir performance, uptimes, shutdowns, well failures, etc.
    - Opex activities uncertainty => production rates, timing of activity, etc.
    - Capex activities uncertainty => production rates, timing, in/out of plan, etc.
    - Generic uncertainties => end of field life assumptions, train wreck assumptions, etc.
  - for each uncertainty, identify the range of outcomes and select a representative low - mid - high outcome
  - generate production profiles for each of the scenarios
- QC: Qualitatively check the spread of low/mid/high profiles, if required (e.g. mid case is highly skewed towards the high case) revisit assumptions made to construct the mid case.

Forecast uncertainty



Forecast integration



Example 9: Discounting simulator forecasts based on observed field performance

Forecasting methodology

Case description

Discounting an unrealistic long-term forecast from a simulation model for a multi-well infill campaign to properly account for well interference, creaming effects and sub-surface risks.

Basic concept

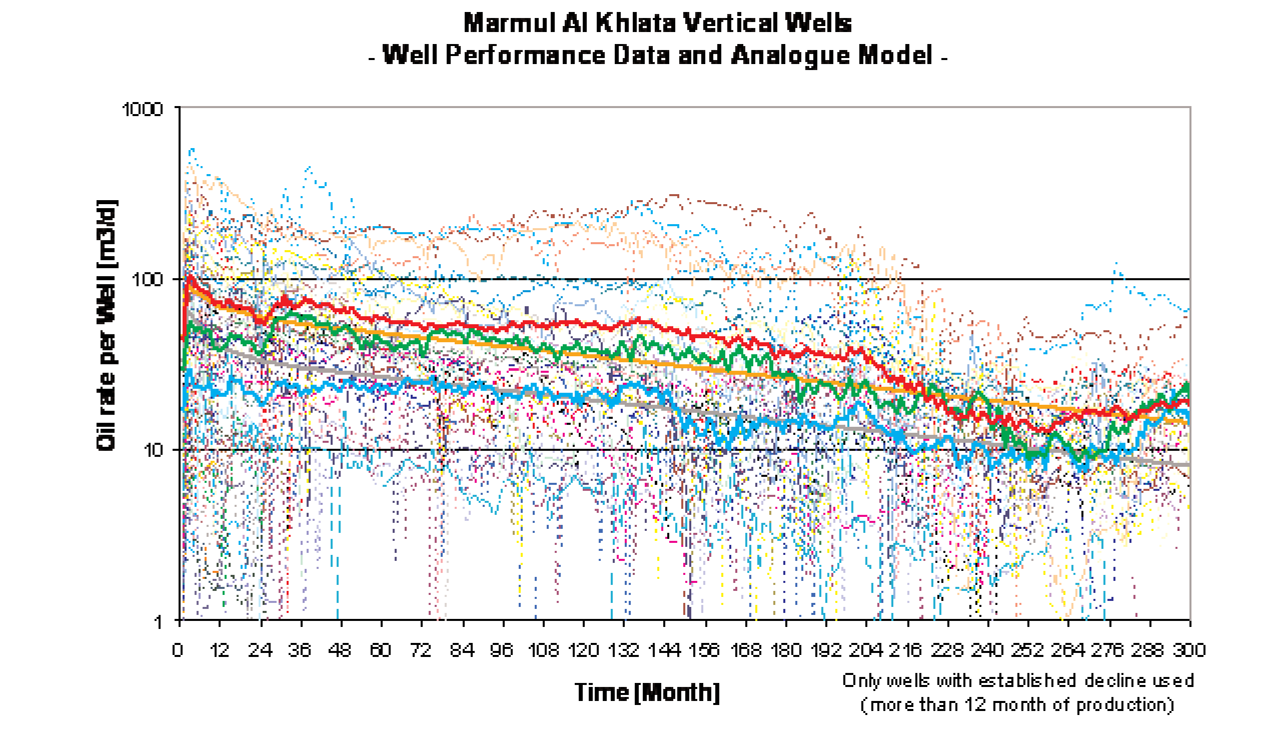
Exploit the large existing well count for statistical analysis to generate incremental forecasts for future wells of the same type in similar geological/dynamical settings.

Methodology to derive well analogue models.

1. Group the existing wells according to their well design.
2. Analyse historical performance data to estimate start rates and declines for each group.
3. Creaming of the portfolio is represented by reducing start rate of the analogue model based on minimum decline.
4. Constrain producers by an economic cut-off rate.

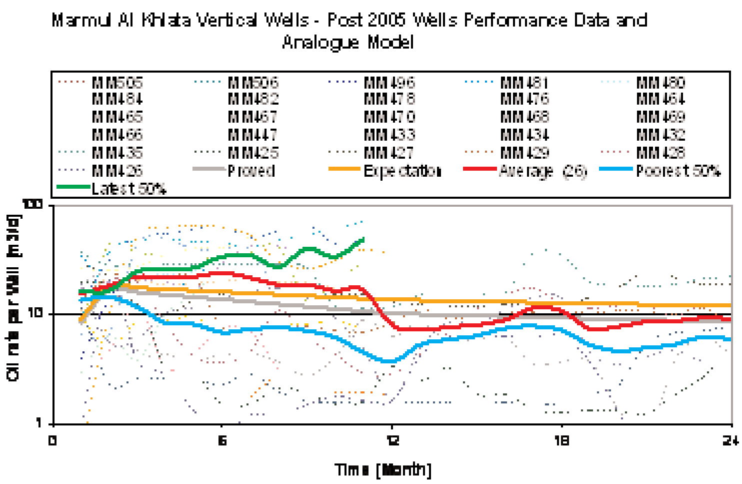
Vertical oil producers - declines

Fit proved and expectation declines - vertical producer. The figure below shows well performance data and analogue model.

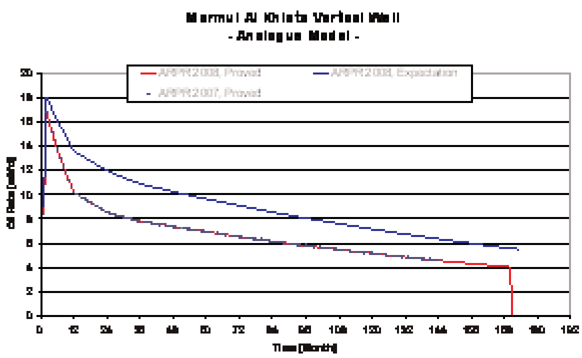


Vertical oil producer - initial rates

Use most recent wells to establish initial rate for expectation and proved reserves. The figure below shows post-2005 well performance data and analogue model.



Vertical oil producer - analogue model



		ARPR 1.1.2008		ARPR1.1.2007	
		Proved	Expectation	Proved	Expectation
	qi [m3/d]	17	18	17	18
		Exponential Decline		Exponential Decline	
Monthly Declines	Year 1	5.00%	2.83%	5.00%	2.83%
	Year 2	1.46%	1.07%	1.46%	1.07%
	Year 3	0.75%	0.80%	0.75%	0.80%
	Year 4+	0.50%	0.50%	0.50%	0.50%
	EUR [m3]	34.3	62.8	30.0	62.8

No change of start rate and decline to ARPR 1.1.2007
Proved Cut-off changed to 4m³/d.

Example 10: Treating uncertainty for a cluster development with multi-reservoir fields

Forecasting methodology used in opportunity scouting

Case description

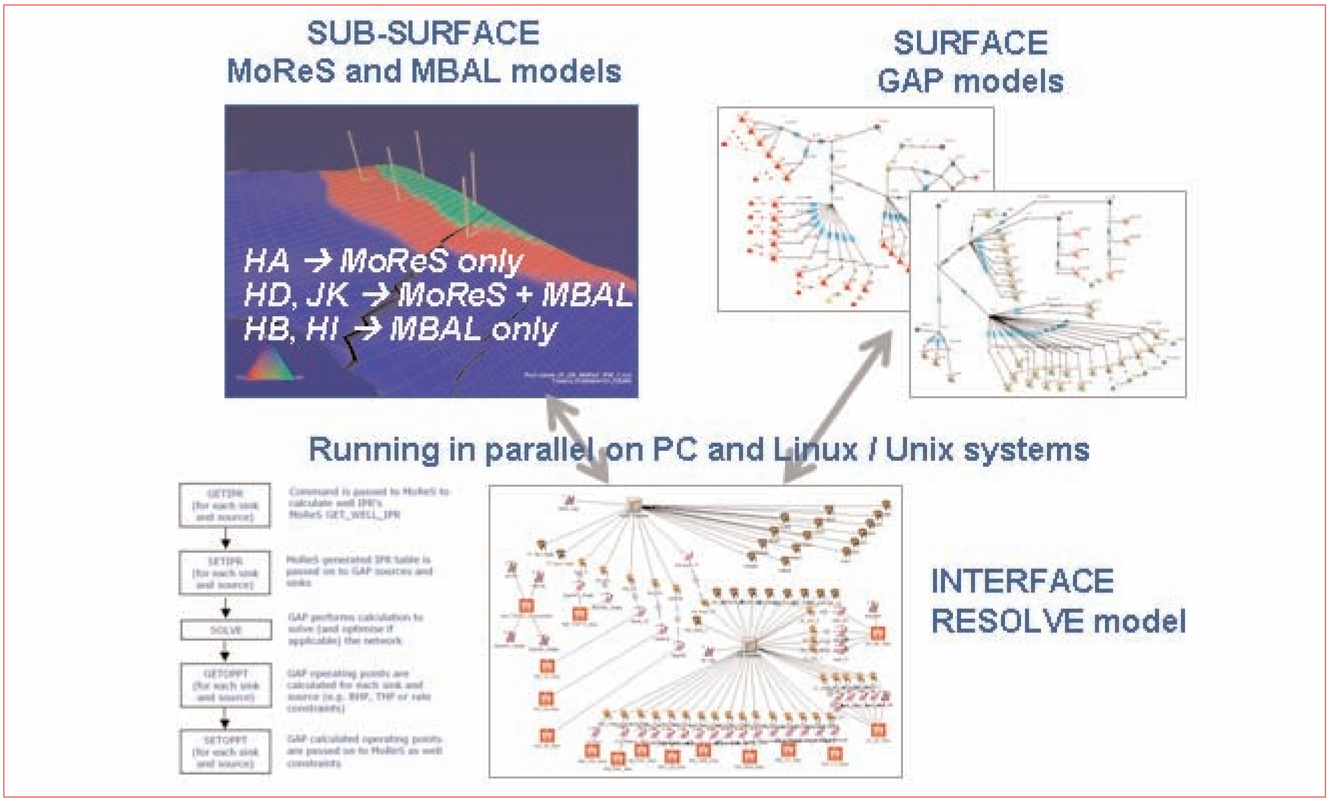
Oil development initially comprises HD and JK fields.

Basic concept

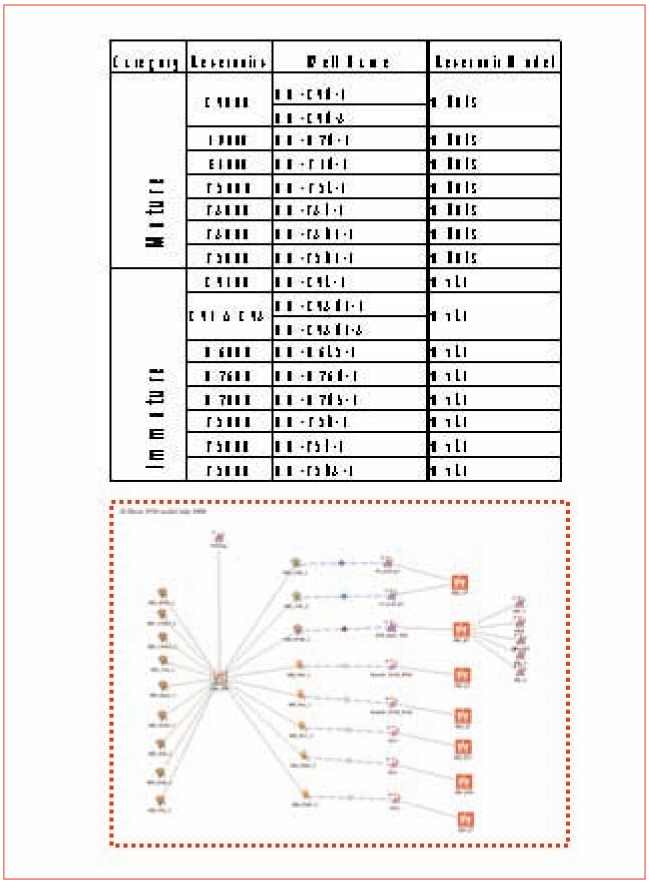
Roll up in a transparent and consistent manner individual well and reservoir forecasts to overall field level in order to test the economics of concepts against a wide spectrum of outcomes given the sub-surface uncertainties. Test specific capacity constraints against a range of extreme cases.

Methodology

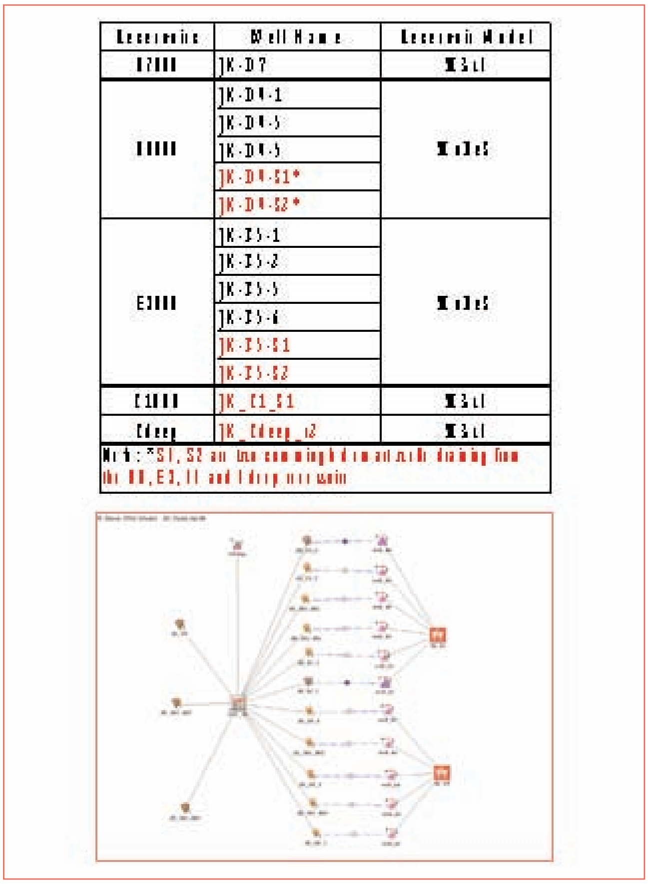
1. Classify the resource volumes in HD and JK as per EP 2007-1100.
2. Identify a number of independent field-specific building blocks.
3. Define nodal realisations by selecting combinations of field-level building blocks.
4. Create and validate the model based on IPM (pressure-coupled GAP linked to sub-surface components. represented by respective MoReS and MBAL models).
5. Analyse field production forecasts.



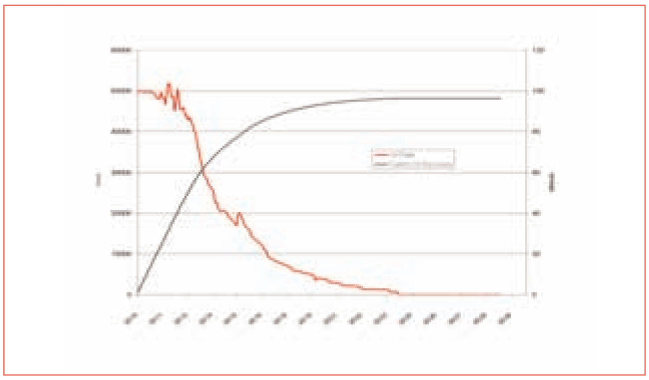
HD field



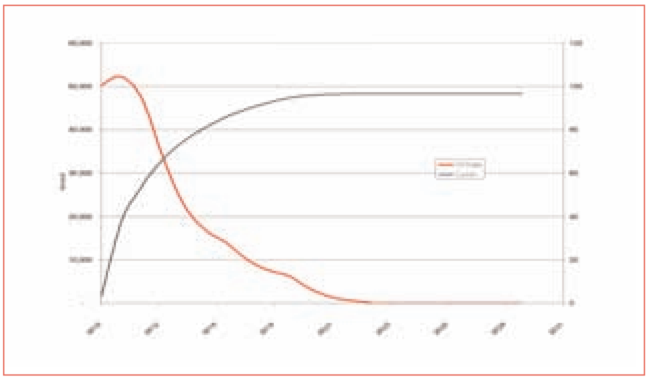
JK field



HD field



JK field



Example 11: Treating uncertainty for a gas contract pool

Example of how probabilistic analysis is used to define the confidence envelope in which nominations can be set.

Nomination process: overview

Contract situation:

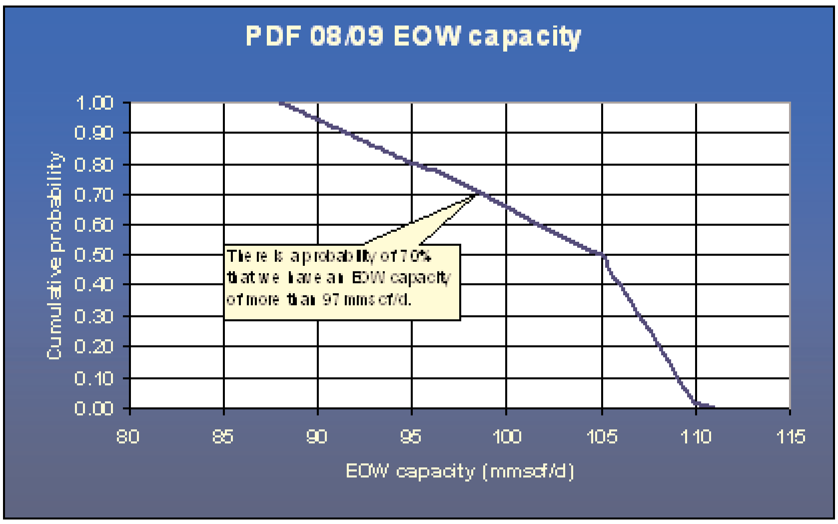
- We nominate our TRDQ (Total Reservoir Daily Quantity), based on End of Winter (EoW)-capacity, 3 years in advance.
- Customer may take up to 130% of TRDQ on any given day.

Uncertainties:

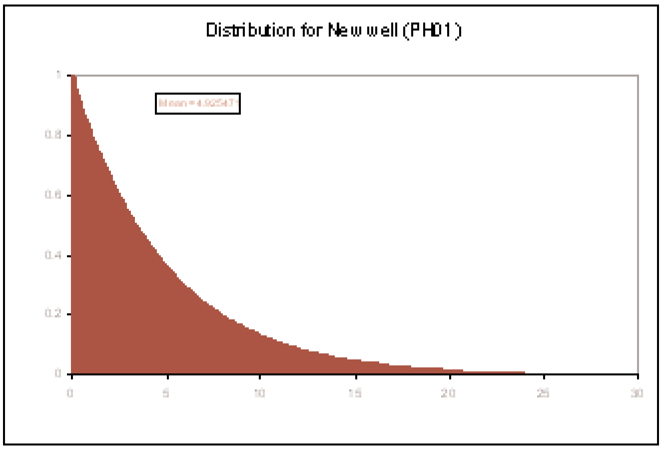
- Main uncertainty is customer take.
- Additional uncertainties need to be taken into account:
  - capacities of planned wells
  - liquid loader capacities
  - model uncertainties.
- use Monte Carlo methods to determine most likely capacity.

Nomination process: sensitivity due to take

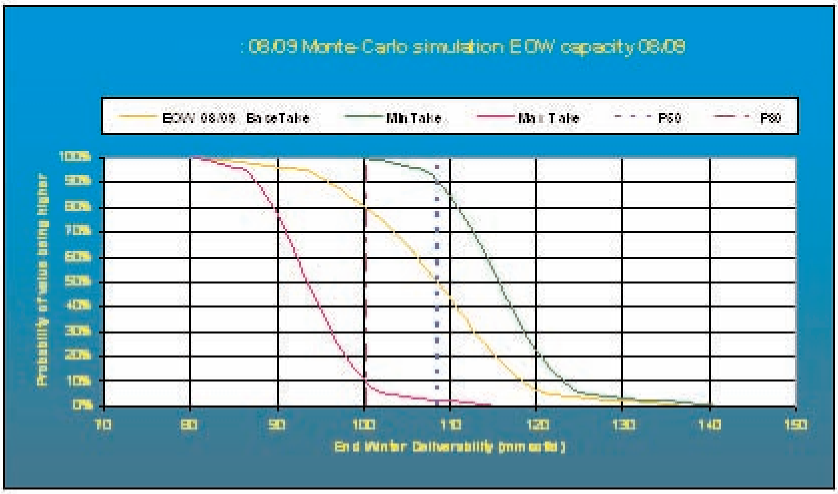
- Obtain different take scenarios and their probability
  - Shell commercial.
- Determine correlation between End-Of-Winter capacity and take
  - using model.
- Combine both to obtain probability distribution of EOW-capacity.



Nomination process other uncertainties: new well 0-30 MMscf/d



Nomination process: Monte Carlo results



Example 12: Calculation steps for aggregating stochastically independent forecasts (synthetic example)

This is a synthetic example to demonstrate probabilistic aggregation used for a portfolio of Assets assuming full stochastic independence of the forecasts.

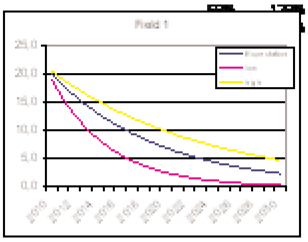
Calculation steps.

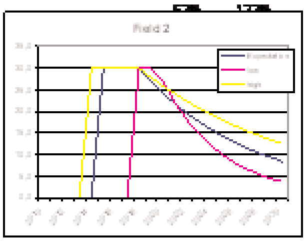
1. Calculate increments.
2. Sort low increments.
3. Calculate low variances.
4. Calculate low standard deviation.
5. Repeat steps 2-4 for high variance and standard deviation.
6. Calculate the low case as expectation – low standard deviation and high case as expectation high standard deviation.
7. QC: compare results with deterministic summation and with Monte Carlo addition.

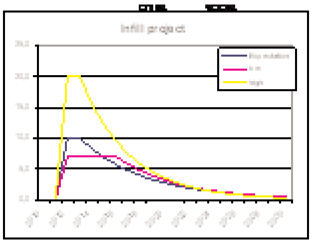
Consider three forecasts representing.

1. Mature field with uncertain decline rate.
2. New Oil project with uncertain start date and plateau production.
3. Infill project with uncertain drilling time and well performance.

	Field 1: mature field declining			Field 2: Major new development			Field 3: Infill campaign (uncertain ramp-up)		
	Expectation	low	high	Expectation	low	high	Expectation	low	high
start (yr)	2010	2010	2010	2015	2017	2014	2012	2012	2012
plateau (yrs)	0	0	0	4	3	5	2	5	2
In. rate (000 b/d)	20	19	20,5	30	30	30	10	7	20
decline	10%	18%	7%	10%	18%	7%	17%	18%	22%
2010	20,0	19,0	20,5	0,0	0,0	0,0	0,0	0,0	0,0
2011	18,0	15,6	19,1	0,0	0,0	0,0	0,0	0,0	0,0
2012	16,2	12,8	17,7	0,0	0,0	0,0	10,0	7,0	20,0
2013	14,6	10,5	16,5	0,0	0,0	0,0	10,0	7,0	20,0
2014	13,1	8,6	15,3	0,0	0,0	30,0	8,3	7,0	15,6
2015	11,8	7,0	14,3	30,0	0,0	30,0	6,9	7,0	12,2
2016	10,6	5,8	13,3	30,0	0,0	30,0	5,7	7,0	9,5
2017	9,6	4,7	12,3	30,0	0,0	30,0	4,7	5,7	7,4
2018	8,6	3,9	11,5	30,0	30,0	30,0	3,9	4,7	5,8
2019	7,7	3,2	10,7	28,0	30,0	28,9	3,3	3,9	4,5
2020	7,0	2,6	9,9	24,3	28,0	25,9	2,7	3,2	3,5
2021	6,3	2,1	9,2	21,9	22,1	24,1	2,3	2,6	2,7
2022	5,6	1,8	8,6	19,7	18,2	22,4	1,9	2,1	2,1
2023	5,1	1,4	8,0	17,7	14,9	20,9	1,6	1,7	1,7
2024	4,6	1,2	7,4	15,9	12,2	19,4	1,3	1,4	1,3
2025	4,1	1,0	6,9	14,3	10,0	18,1	1,1	1,2	1,0
2026	3,7	0,8	6,4	12,9	8,2	16,8	0,9	1,0	0,8
2027	3,3	0,7	6,0	11,6	6,7	15,6	0,7	0,8	0,6
2028	3,0	0,5	5,6	10,5	5,5	14,5	0,6	0,6	0,5
2029	2,7	0,4	5,2	9,4	4,5	13,5	0,5	0,5	0,4
2030	2,4	0,4	4,8	8,5	3,7	12,6	0,4	0,4	0,3
Np at 2030	178	104	229	314	193	392	67	65	110







1. Calculate increments.

Step 2 Calc. Increments						
	sigma upside					
year	low-exp	high-exp	low-exp	high-exp	low-exp	high-exp
2010	-1,00	0,50	0,00	0,00	0,00	0,00
2011	-2,42	1,07	0,00	0,00	0,00	0,00
2012	-3,42	1,53	0,00	0,00	-3,00	10,00
2013	-4,10	1,91	0,00	0,00	-3,00	10,00
2014	-4,53	2,21	0,00	30,00	-1,30	7,30
2015	-4,77	2,46	-30,00	0,00	0,11	5,28
2016	-4,85	2,63	-30,00	0,00	1,28	3,77
2017	-4,83	2,77	-30,00	0,00	0,99	2,66
2018	-4,73	2,86	0,00	0,00	0,77	1,84
2019	-4,56	2,92	3,00	0,90	0,59	1,23
2020	-4,36	2,95	2,70	1,65	0,45	0,80
2021	-4,13	2,95	0,27	2,26	0,34	0,49
2022	-3,89	2,93	-1,53	2,76	0,26	0,27
2023	-3,64	2,90	-2,83	3,16	0,19	0,12
2024	-3,39	2,85	-3,74	3,47	0,14	0,01
2025	-3,15	2,78	-4,34	3,70	0,10	-0,05
2026	-2,91	2,71	-4,71	3,87	0,07	-0,10
2027	-2,68	2,63	-4,89	3,99	0,05	-0,12
2028	-2,47	2,55	-4,94	4,06	0,04	-0,13
2029	-2,26	2,46	-4,89	4,09	0,02	-0,13
2030	-2,07	2,37	-4,76	4,09	0,01	-0,13
cum	-74,2	50,9	-120,7	68,0	-1,9	43,1

2. Sort increments into positive and negative contributions.
3. Calculate low variance.
4. Calculate low standard deviation.

Step 3 sort uncertainties						Step 4 calculate variance	
Low variance							Step 5 std deviation
add all exp-low if positive			add negatives (high-exp)			sumsq	sqrt (sumsq)
-1,00	0,00	0,00	0,00	0,00	0,00	1,00	1,00
-2,42	0,00	0,00	0,00	0,00	0,00	5,86	2,42
-3,42	0,00	-3,00	0,00	0,00	0,00	20,73	4,55
-4,10	0,00	-3,00	0,00	0,00	0,00	25,84	5,08
-4,53	0,00	-1,30	0,00	0,00	0,00	22,23	4,71
-4,77	-30,00	0,00	0,00	0,00	0,00	922,71	30,38
-4,85	-30,00	0,00	0,00	0,00	0,00	923,55	30,39
-4,83	-30,00	0,00	0,00	0,00	0,00	923,32	30,39
-4,73	0,00	0,00	0,00	0,00	0,00	22,33	4,73
-4,56	0,00	0,00	0,00	0,00	0,00	20,83	4,56
-4,36	0,00	0,00	0,00	0,00	0,00	19,03	4,36
-4,13	0,00	0,00	0,00	0,00	0,00	17,10	4,13
-3,89	-1,53	0,00	0,00	0,00	0,00	17,49	4,18
-3,64	-2,83	0,00	0,00	0,00	0,00	21,27	4,61
-3,39	-3,74	0,00	0,00	0,00	0,00	25,48	5,05
-3,15	-4,34	0,00	0,00	0,00	-0,05	28,75	5,36
-2,91	-4,71	0,00	0,00	0,00	-0,10	30,63	5,53
-2,68	-4,89	0,00	0,00	0,00	-0,12	31,15	5,58
-2,47	-4,94	0,00	0,00	0,00	-0,13	30,52	5,52
-2,26	-4,89	0,00	0,00	0,00	-0,13	29,04	5,39
-2,07	-4,76	0,00	0,00	0,00	-0,13	26,99	5,19

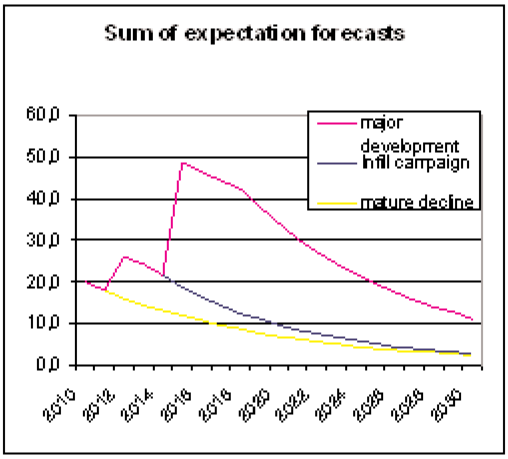
5. Repeat this for high case.

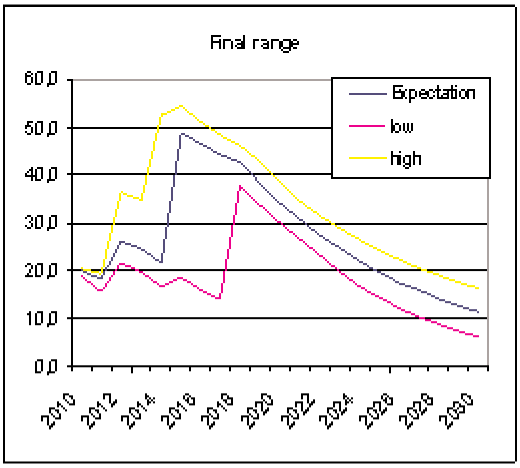
Examples

6. Calculate:

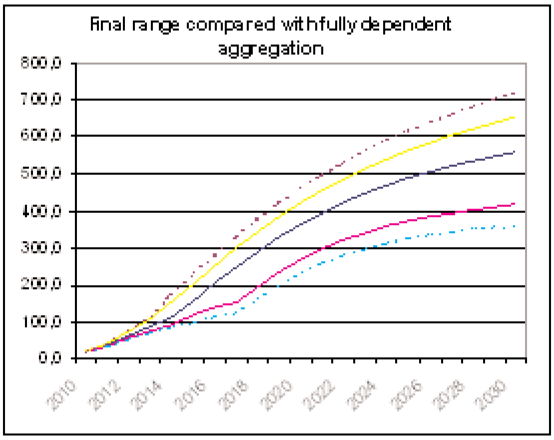
- sum of expectation forecasts
- low case = (expectation - low std deviation) and
- high case = (expectation - high std deviation).

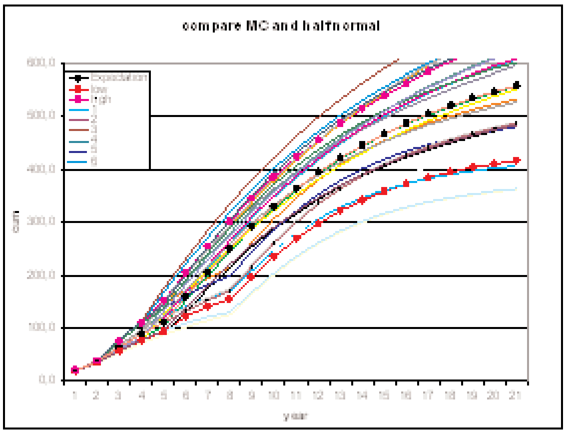
	Aggregate FC Expectation	low	high
	20,0	19,0	20,5
	18,0	15,6	19,1
	26,2	21,6	36,3
	24,6	19,5	34,8
	21,4	16,7	52,4
	48,7	18,3	54,5
	46,3	16,0	51,1
	44,3	13,9	48,3
	42,5	37,8	46,0
	38,0	33,5	42,5
	34,0	29,6	38,4
	30,4	26,3	34,2
	27,2	23,0	31,2
	24,4	19,7	28,6
	21,8	16,8	26,3
	19,5	14,2	24,2
	17,5	12,0	22,2
	15,7	10,1	20,5
	14,1	8,5	18,9
	12,6	7,2	17,4
	11,3	6,1	16,0
cum. Production	558,6	385,5	683,4
		69%	122%
% deviation		-31%	22%





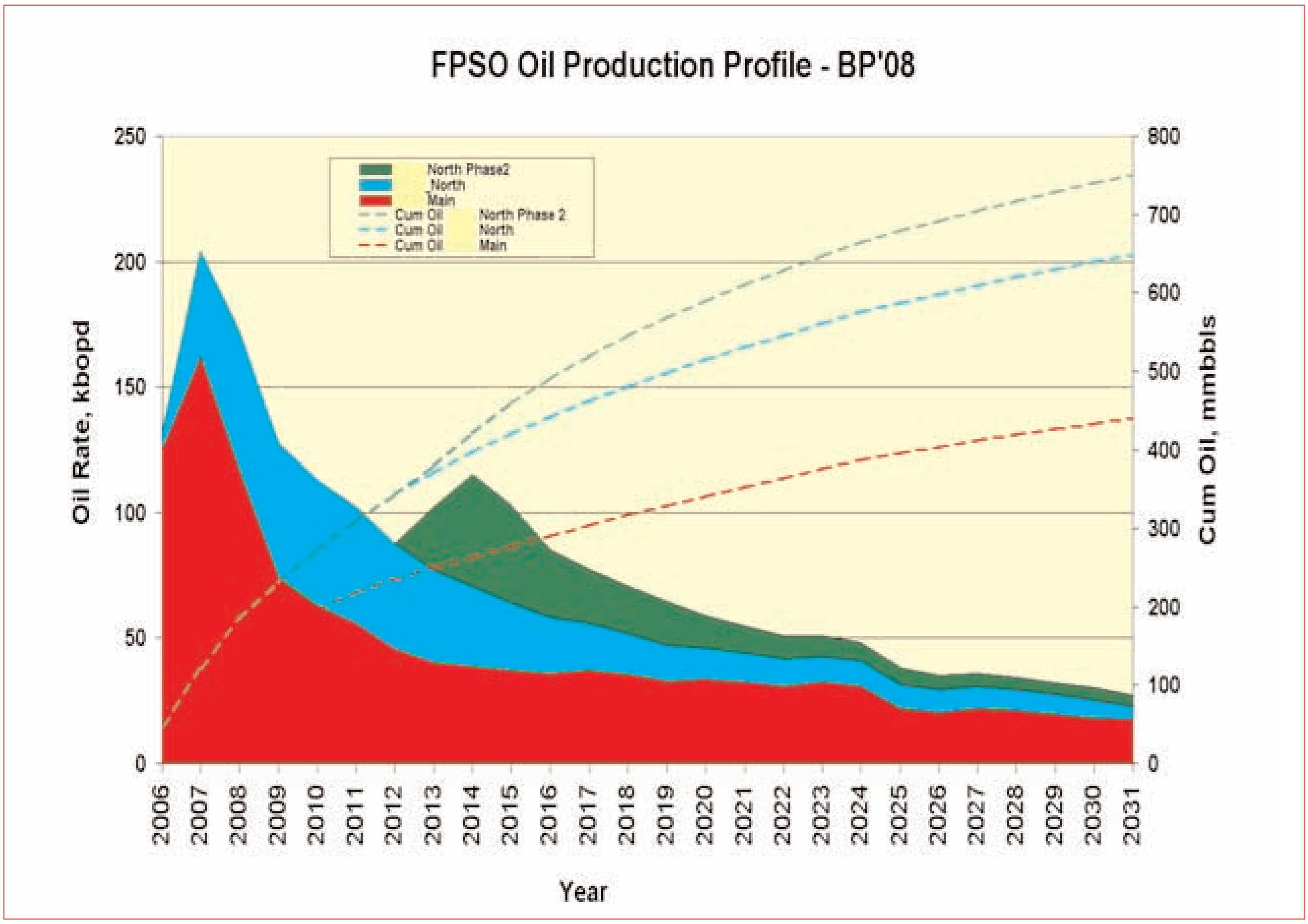
7. Results are converted to cumulative production and are compared with deterministic addition (i.e. fully dependent aggregation) and with Monte Carlo addition.





Example 13: Making a NOV forecast

- NOV fields are forecasted as per operator provided forecast.
- Risks and upsides quantified.
- Compare actual production with previous operator forecasts (to determine operator track record).
- Discount if necessary based on risks and track record.
- ARPR volumes honoured.



Main field issues, risks and opportunities

Issues

- Vertical and horizontal cracks on jumper insulation materials. This leads to zero cool down time. In the event of unplanned shutdown, expected ~7 days for mitigation (1 Mlnstb i.e. >2% 2008 production).
- Well and Reservoir Management will be sub-optimal due to surveillance issues.

Risks

- Early water and or gas breakthrough. Currently three wells producing at high GOR. This was taken into account in the forecast. However, expect ~2 Mstb at risk in 2008, 2009 and 2010.
- Compression and water injection downtime. 20% and 8% water injection and compression downtime is assumed in the forecast. With extra 2% compression downtime, expect ~2 M stb at risk in 2008, 2009 and 2010.

Opportunities

- Better than expected well performance. Current TD average ~145 kstb/d vs 117 kstb/d forecast.
- Opportunity exists with infill wells following the results of 4D planned Q4 2008 (4 infill wells are currently assumed in BP08). Average daily rate is expected to be 30, 23 and 17 kstb/d in 2011, 2012 and 2013 respectively but operator's view is not communicated.

Field North issues, risks and opportunities

Issues (Phase 2)

- Hot market conditions and high cost inflation rate.
- Increasing delays in NNPC approvals.
- NNPC directive on domestication of future work (Phase 2 development) activities.
- Ullage/capacity availability at FPSO.
- Potential brownfield project implications.
- Multizone completion Injectivity.
- No production issues until 2012 as North Phase 2 Planned on stream date Q1 2012.

Risks

- Early water breakthrough.
- Compression and water injection downtime.
- Total of 5 Mls stb at risk in case of early water breakthrough and unexpected downtime.

Opportunities

- Current YTD average (end April) ~52 kstb/d (without P06) vs 55 kstb/d forecast.
- Opportunity exists with infill wells following the results of 4D planned Q4 2008.

Example 14: Gas condensate forecasting

Basic concept

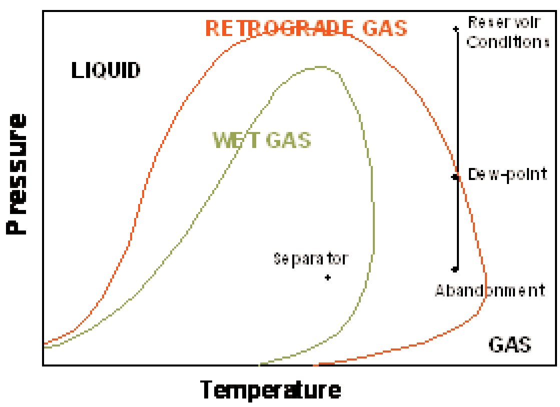
As the condensate in reservoir conditions is originally dissolved in the gas, the gas forecast should be made first. Then make a forecast of the producing condensate gas ratio (CGR), taking into account the considerations. The condensate production can then be obtained from multiplying the CGR with the gas rate forecast.

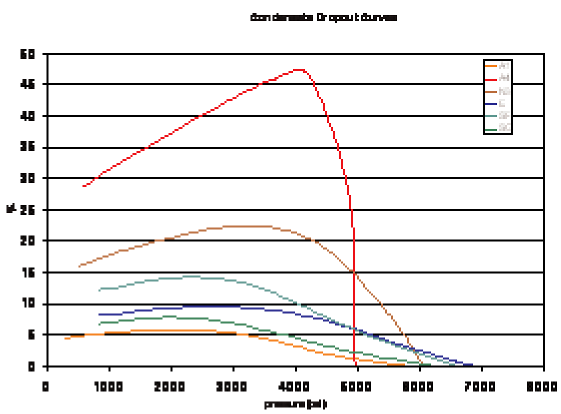
Things to consider

A. Wet gas. In the reservoir, the phase envelope (green) is never intersected during the life cycle. CGR remains constant over time. Condensate may drop out in the well bore.

B. Retrograde gas. CGR reduces after the reservoir pressure has depleted below the dew-point (intersection of red envelope). Condensate drops out in the reservoir. The impact on the recovery factor depends on the richness of the gas (richer gases tend to have higher losses) and the pressure drop during depletion (strong aquifer drive will keep the CGR higher).

C. An additional issue may occur in tighter formations, when the pressure drops below dew-point in the near well bore region, which can lead to an accumulation of condensate. This has a negative effect on the gas relative permeability and can potentially lead to a substantial loss of gas productivity and therefore impact on the gas forecast. A rule of thumb is that this needs to be considered if kh <1000 mdft.





Some examples

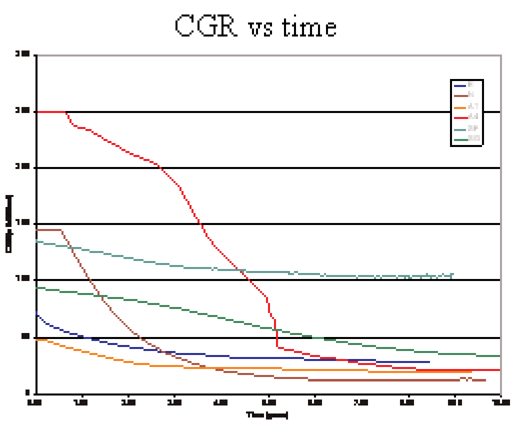
Examples of CGR forecasts are shown below, illustrating some principles. The same reservoirs are used here as for the dropout curves on the previous page.

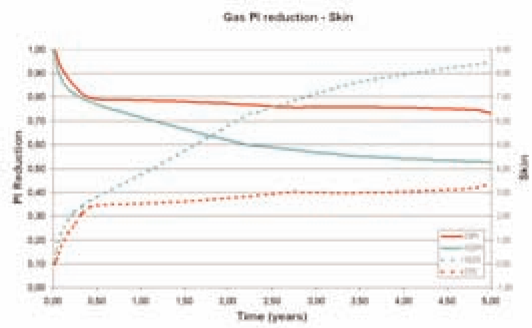
In all reservoirs, a declining trend in CGR is observed, representative of case B (reservoir going through the dew-point). In three cases (A1, A4 and N) at first the CGR is constant showing dew-point has not yet been reached, the other three are saturated in initial conditions.

Reservoir SF shows a much lower decline in CGR than for example reservoir N, which is due to the fact that reservoir SF has an aquifer drive, keeping the pressure reasonably high, and therefore leaving the CGR high as well.

Impact of condensate dropout

Accumulation of condensate in the near well bore region in tighter formations can drastically reduce the gas deliverability of the well. An example of a simulation is shown with PI reduction of the gas well for two different fluids with CGRs of 23 and 102 stb/MMscf respectively. The PI reduction can also be translated as a skin. In the simulations shown here, the value of the CGR is not much affected by the banking as most of the produced gas originates from further away in the reservoir. Note that the PI reductions shown here are relatively moderate. PI reductions to 0.1 of original PI due to banking have been reported in literature. The banking effect should be modelled with a very fine grid model to assess the impact. Relative permeability data are fundamental input for these simulations. Note that these can be dependent, e.g. on velocity (viscous stripping). Results of the fine scale study can then be translated into larger models via, for example, a pseudo-skin. A correction for the condensate banking effect in coarse models will be made available in MoReS 2009.1.





Example 15: Gas capacity forecast, short-term and long-term

Business context

The basis BP08 forecast is not a technical forecast but a commercial forecast - as the actual sales are based on the GasTerra's portfolio dynamics. Because of the flexibility in GasTerra contracts and the sensitivity to temperature, there is a large degree of uncertainty in volumes for any given year in the planning period (and beyond).

Biggest levers on the forecast

Commercial - captured in volume and capacity demand:

1. Exports - this is due to GasTerra contract terms (see above). Although this does include a temperature effect, the largest and least predictable effect is commercial optimisation of GasTerra customers.
2. Inland market (including both a direct temperature effect and commercial flexibility).
3. TTF sales - dependent on opportunities and offered prices.

Technical - captured in the IPSM:

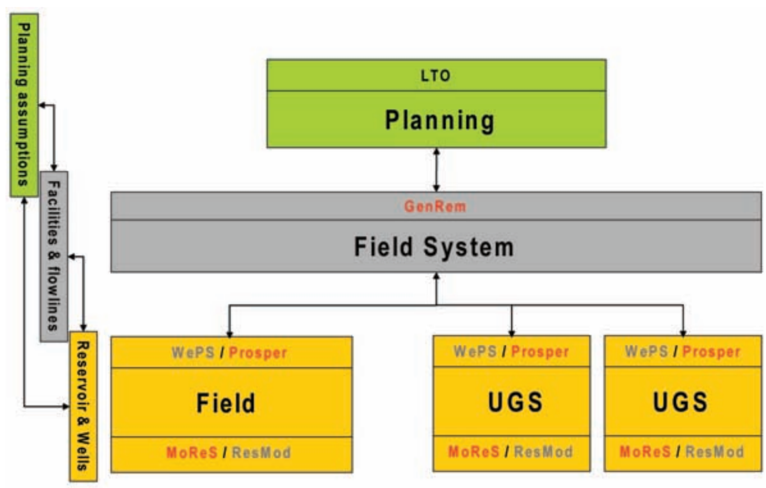
1. Asset availability - planned un-availability due to construction (compression), maintenance (routine and required by law).
2. Back-out - key areas: the in-field pipeline system, satellite cluster set-up and reservoir (intra-cluster).
3. Compressor efficiencies - field capacity at varying compressor power and compressor set-up (1st, 2nd and 3rd stage).

System specific

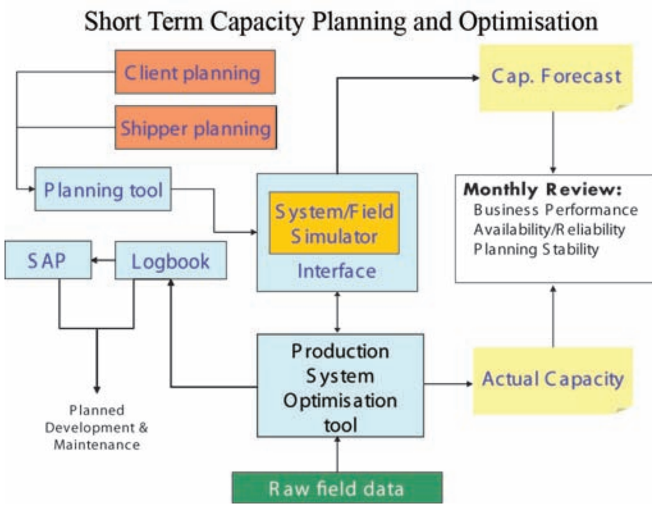
System forecast - the interaction between field and UGS is important. A system forecast is required to properly establish where investments are best made, or where investments - with possible downtime - influence the system capacity.

The forecast is made by integrating the Demand (Commercial) and Supply (Technical) in the IPSM (GenRem).

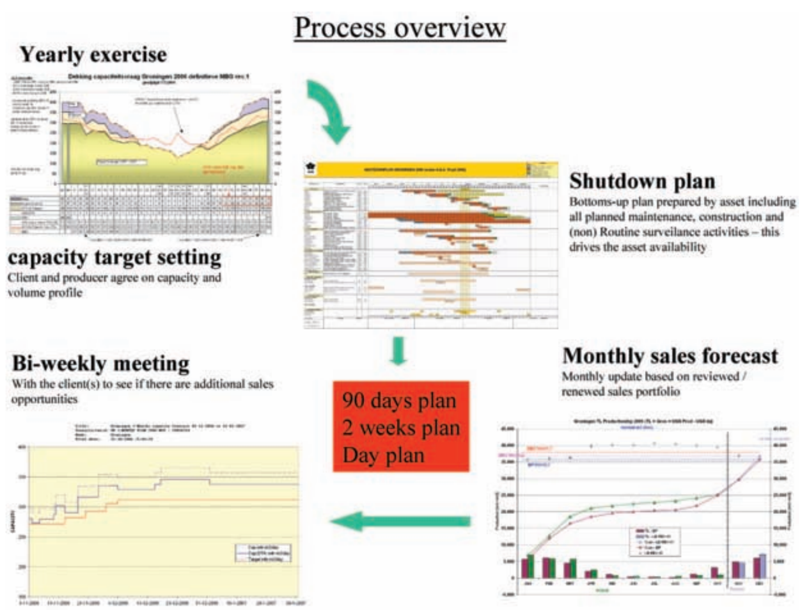
System forecasting



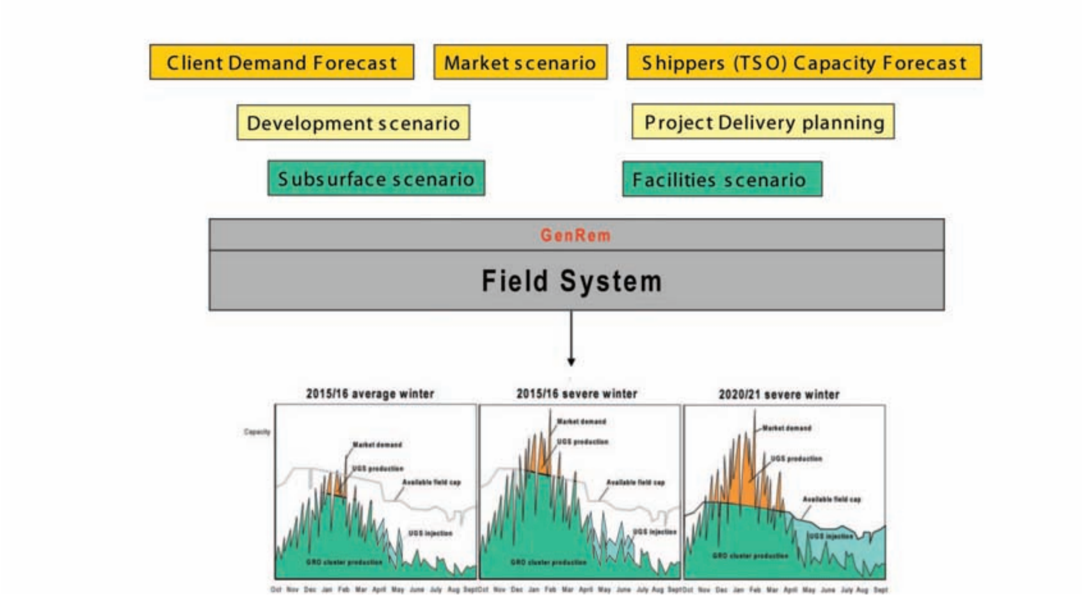
Short-term capacity planning - I



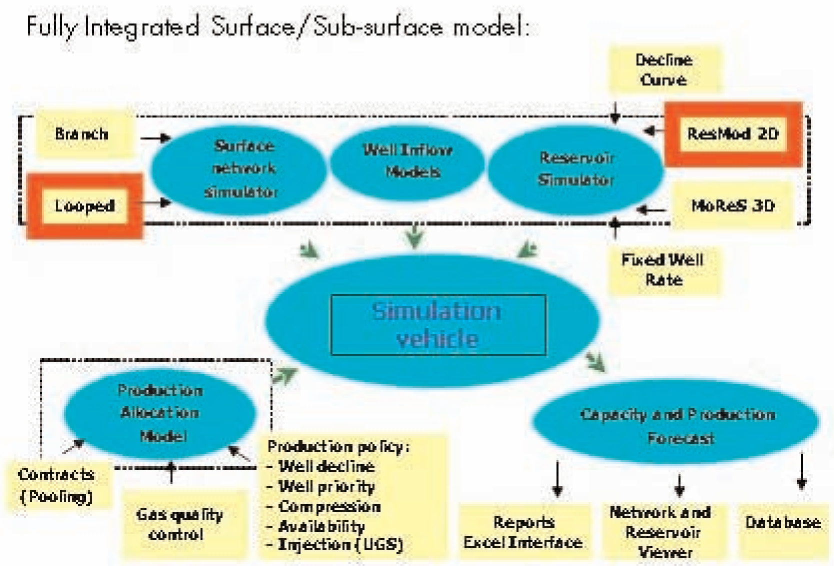
Short-term capacity planning - II



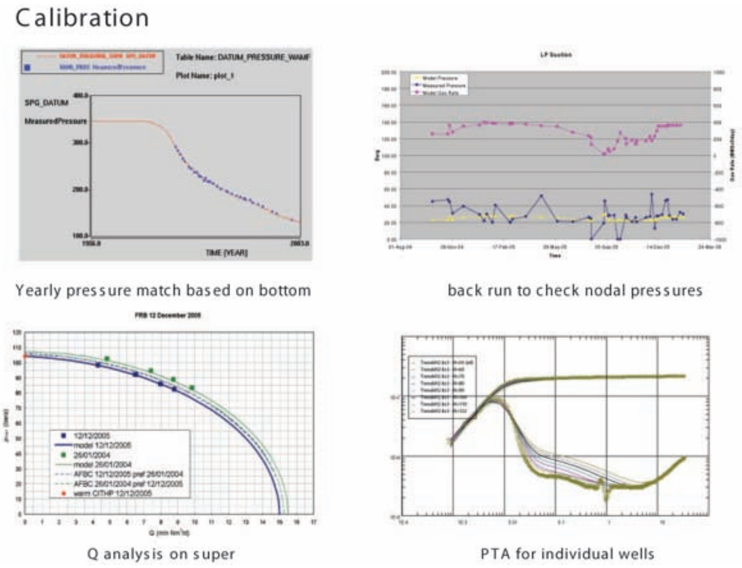
Long-term capacity planning



Long-term capacity planning - I



Long-term capacity planning - II

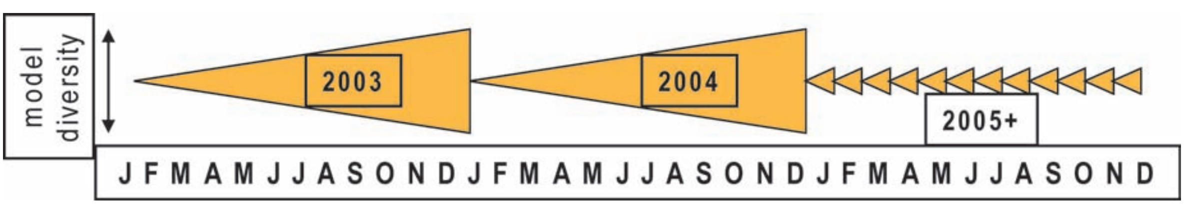


Long term capacity planning - III

Change Management process

Red thread deck.

- Auditable basis with latest insights reflected in the deck.
- Keep track of technical, commercial and software changes.
- Frequent updates: limited model diversity.



Example 16: EOR forecasting

Production forecasting for thermal and chemical projects

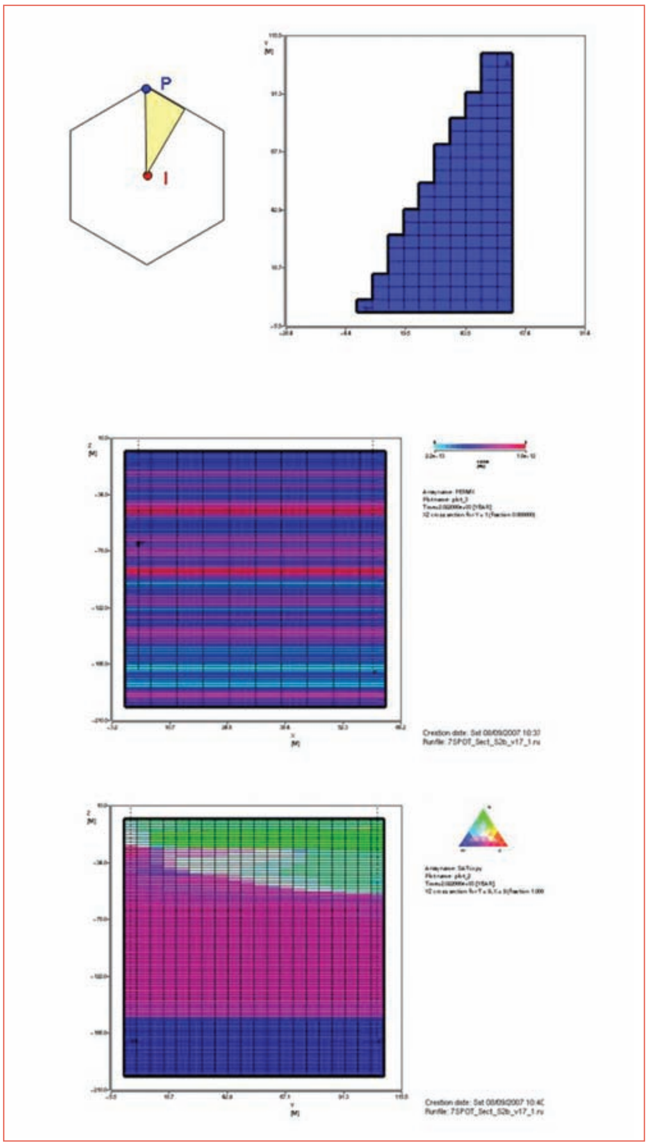
Meaningful simulator generated EOR forecasts for thermal and chemical projects require detailed oil bank resolution.

In general, full-field models can not achieve the required resolution EOR project forecasting has been based on pragmatic approach.

1. High-resolution simulation of few (steam/chemical injection) patterns at various locations in the reservoir to arrive at representative forecasts for oil, gas, water, steam, heat, etc.
2. Generating analytical functions from these individual pattern responses by including physical principles. These functions have relevant reservoir and process parameters as input.
3. Upscaling to full-field through fit-for-purpose aggregation of individual analytical pattern forecasts.

Numerical modelling

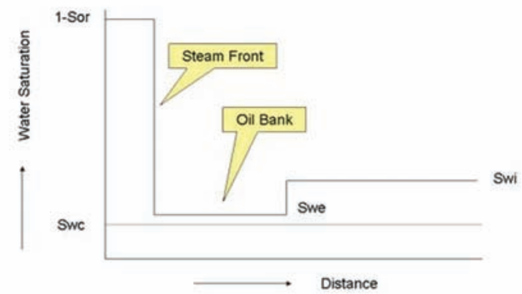
- Symmetry element modelling.
- Sector modelling based on detailed geological model.



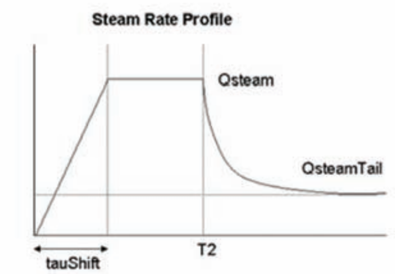
Generic Analytical Profile

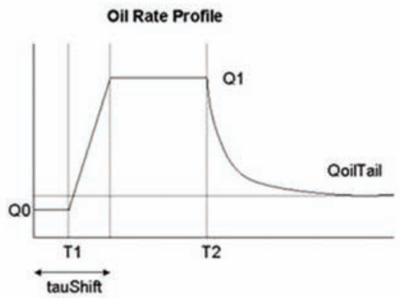
Below are examples of a Saturation Profile and a Injection and Production Profile.

Saturation Profile

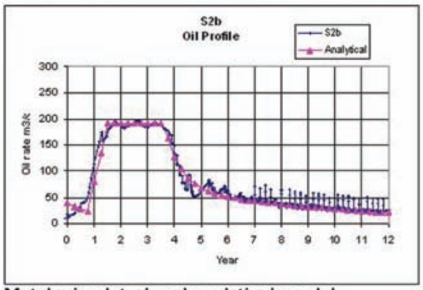


Injection and Production Profile

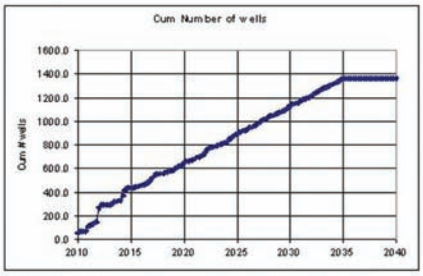




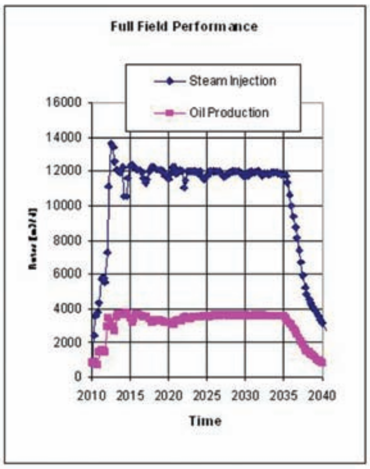
Upscaling results



Match simulated and analytical model.



Cumulative number of wells with time



Full field steam injection and oil production forecast

Example 17: Corporate forecast using HFPT

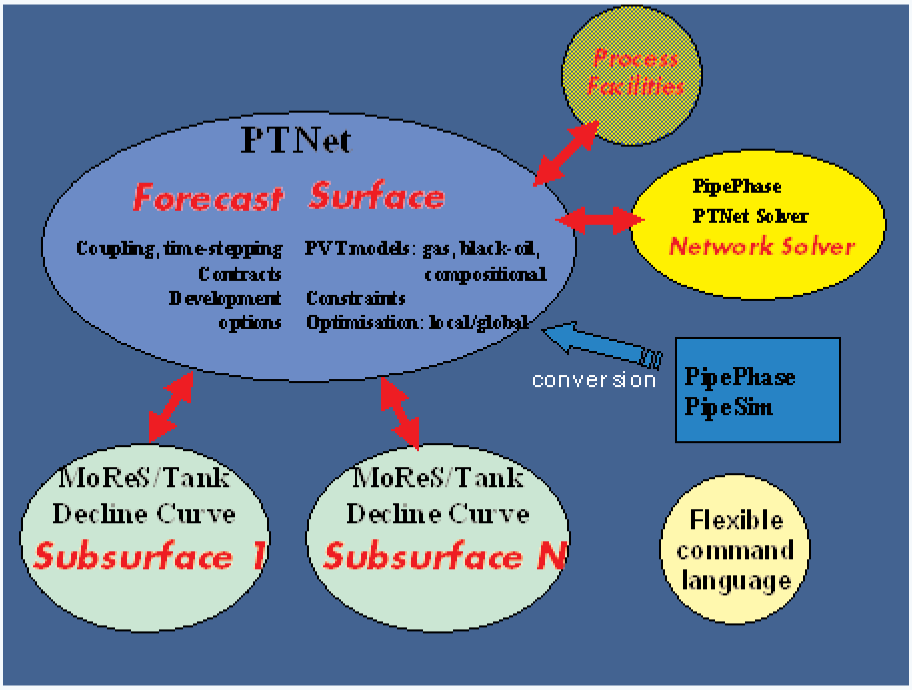
Why use an integrated model?

- No gas production without gas contract.
- No gas production without AGG Facility (after flares down).
- AGG availability/deferment affects oil production.
- AG is produced through gas network.
- Condensate is produced through oil network.
- Planned downtime of oil Facility may free ullage in AGG Facility.
- Constraints in oil pipelines reduces AG production into contract.
- Networks are connected, shortage in DOMGAS can be levelled out by NLNG production and vv.

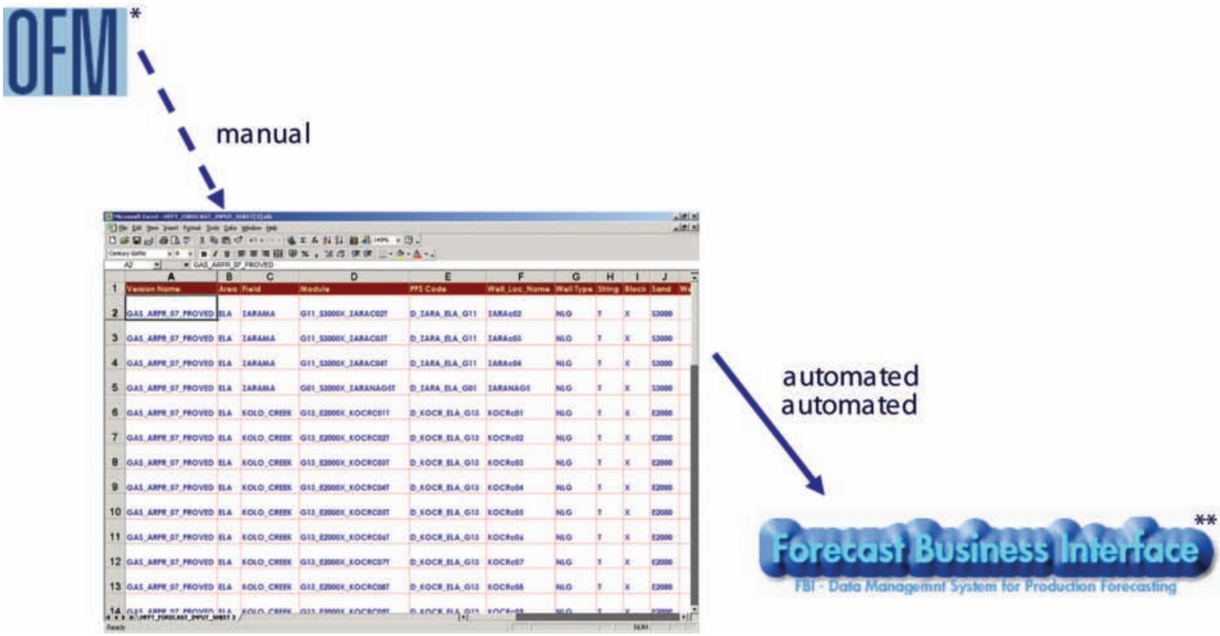
For future application (proof of concept already given during FOD Gas project):

- AG gas may enhance gas quality
- condensate may enhance oil quality
- full C1 – C7+, CO_2, H_2S, N_2 modelling will help production planning for future contracts
- pressure balanced calculations will optimise compressor planning.

General: HFPT architecture integration platform



AR/BP production forecasting - workflow



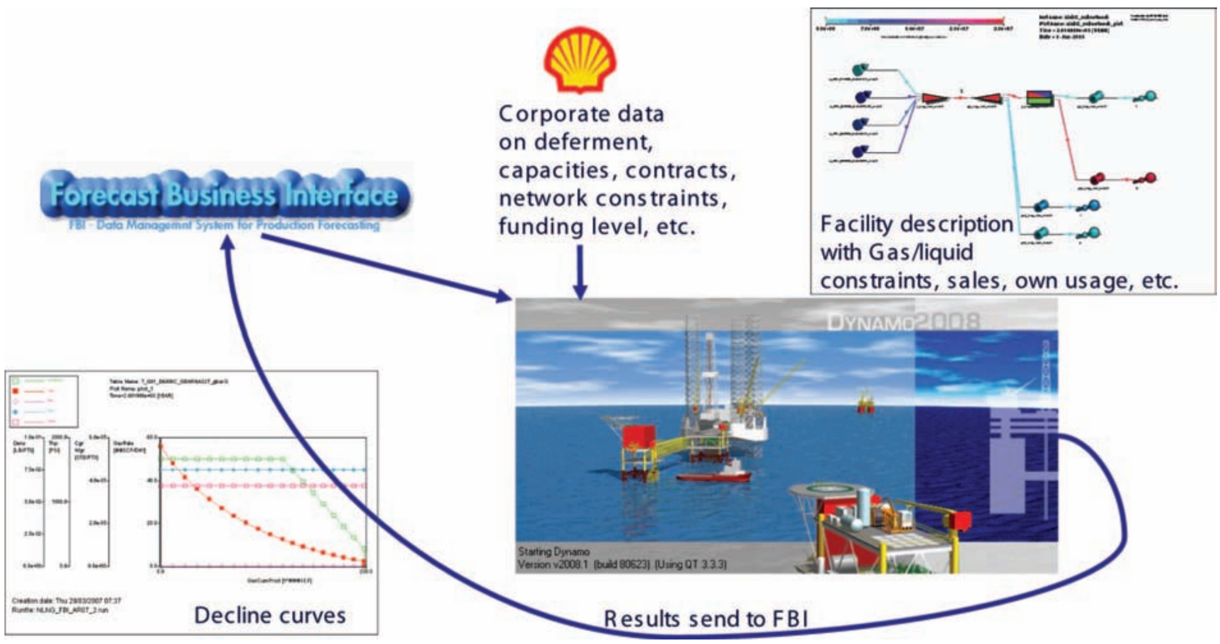
OFM production data is used by the field RE to determine decline curve parameters for each drainage point.

Decline data is entered into FBI database through automated Excel sheet upload.

* OFM - Production Surveillance, Analysis and Forecasting (Schlumberger).

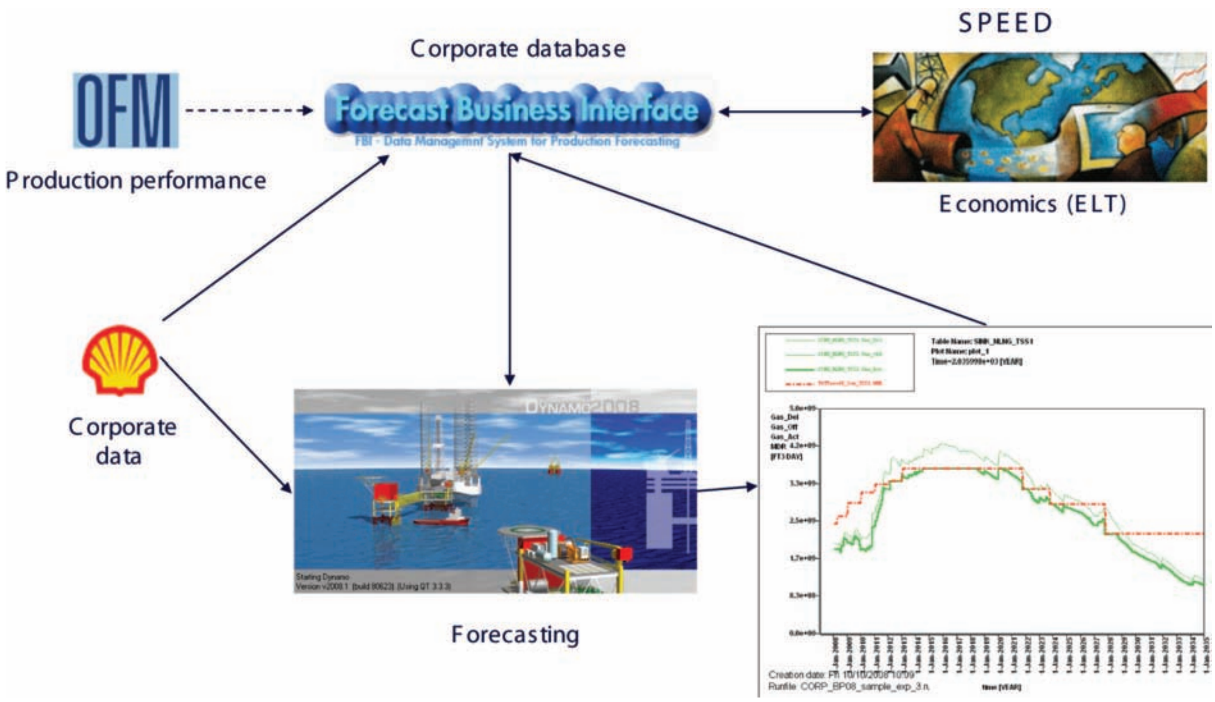
** FBI is an internal SPDC developed Oracle database with a web-based user interface.

Examples

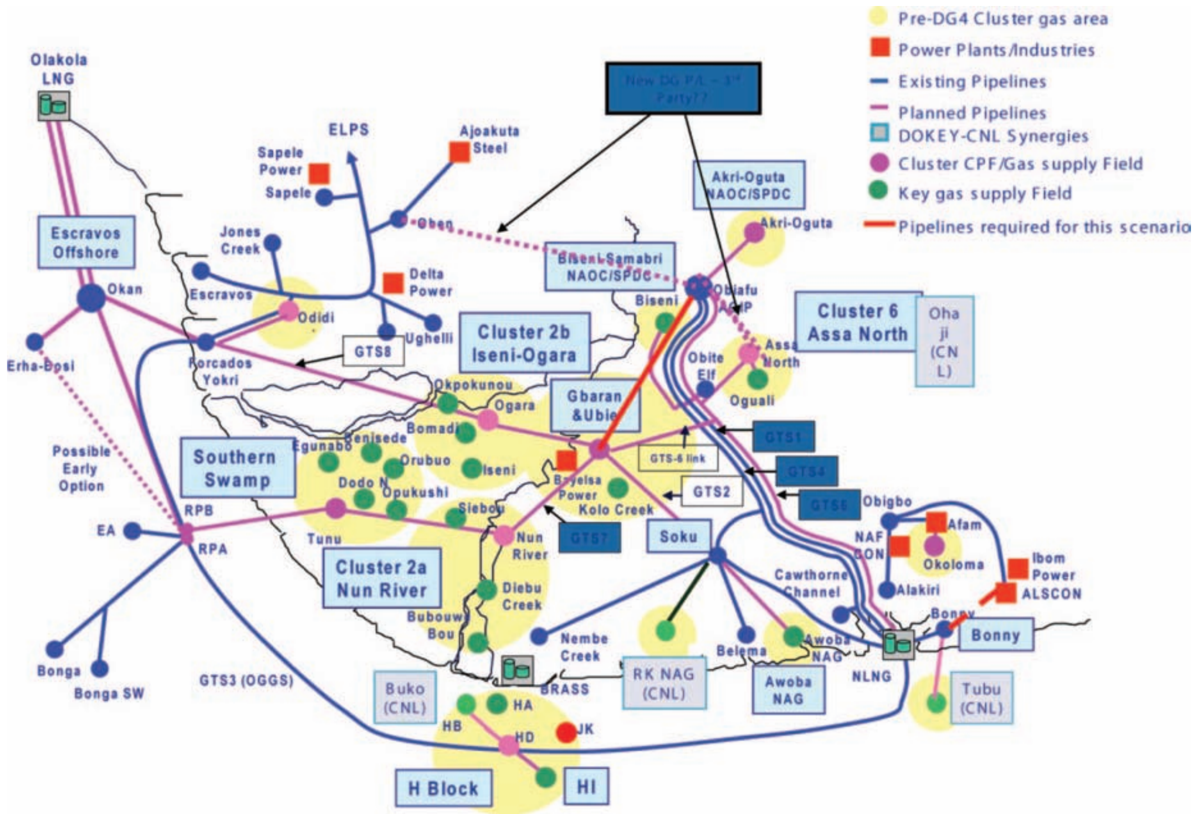

Forecast Business Interface
FBI - Data Management System for Production Forecasting
Corporate data
on deferment,
capacities, contracts,
network constraints,
funding level, etc.
Facility description
with Gas/liquid
constraints, sales, own usage, etc.
DYNAMO2008
Starting Dynamo
Version v2008.1 (build 80623) (Using QT 3.3.3)
Decline curves
Results send to FBI

- HFPT loads the corporate data on Facility capacity, Scheduled/Unscheduled/3rd party deferment, own use.
- Drilling sequence, funding level, as well as network connection and constraint data.
- Corporate data also contains availability of (shared) AG facilities and their capacities.
- HFPT downloads the decline curves from FBI and automatically generates the surface network.
- All drainage points (Oil, AG and Gas) are integrated in one model.
- Gas contracts are preferably filled with AG to maximise oil production.
- Forecast results are automatically fed back into FBI database after simulation run.

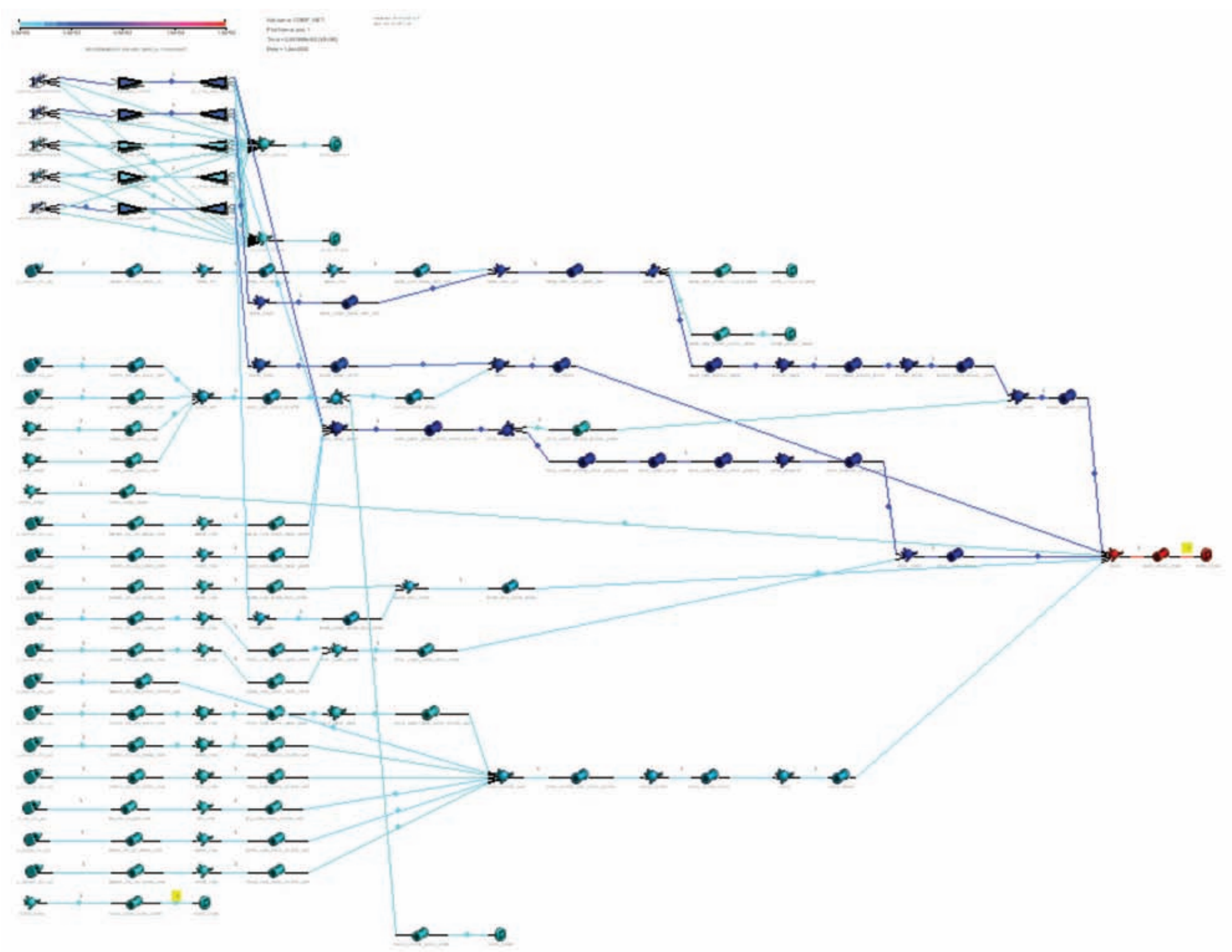
AR/BP production forecasting - workflow overview



Transmission system

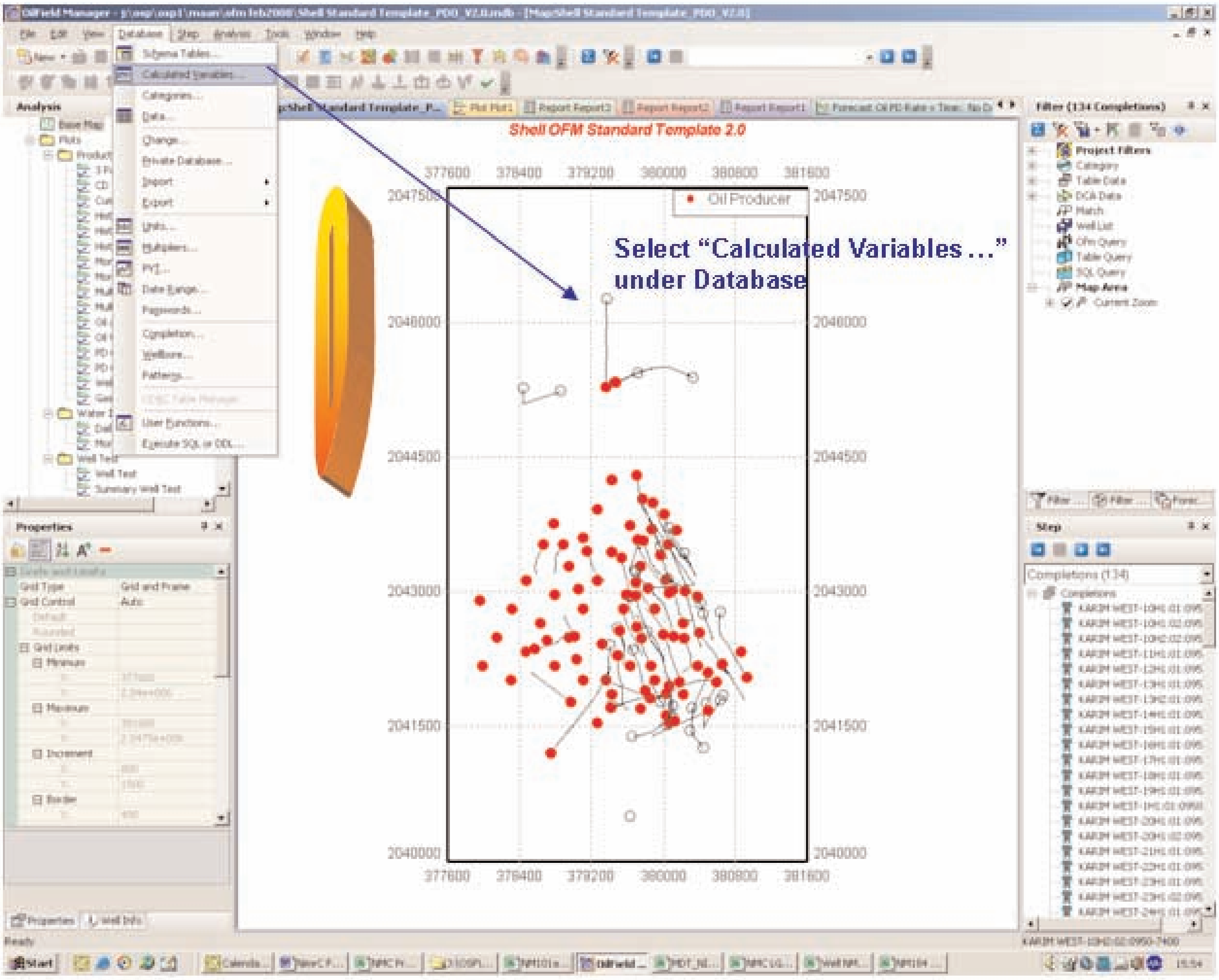


NLNG supply network



Example 18: OFM workflow for making decline curve forecast

General: HFPT architecture integration platform



Comparing forecasts

OFM allows for storage and comparison of expectation forecasts between two consecutive years and between the proved and the expectation forecast.

Using variables Variable Edition Box and write "OilFcstARPR07_E" instead of "OilFcstARPR08_E"

Select the system function "@Forecast" and fill up its arguments.

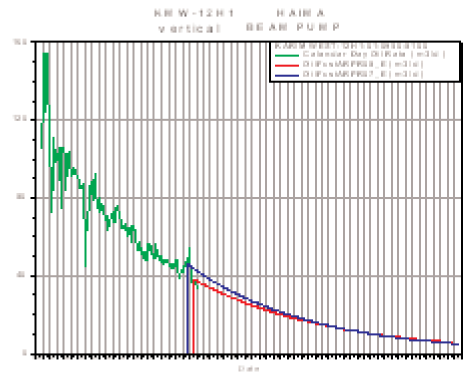
Pay attention to the syntax described as you pick the respective function.

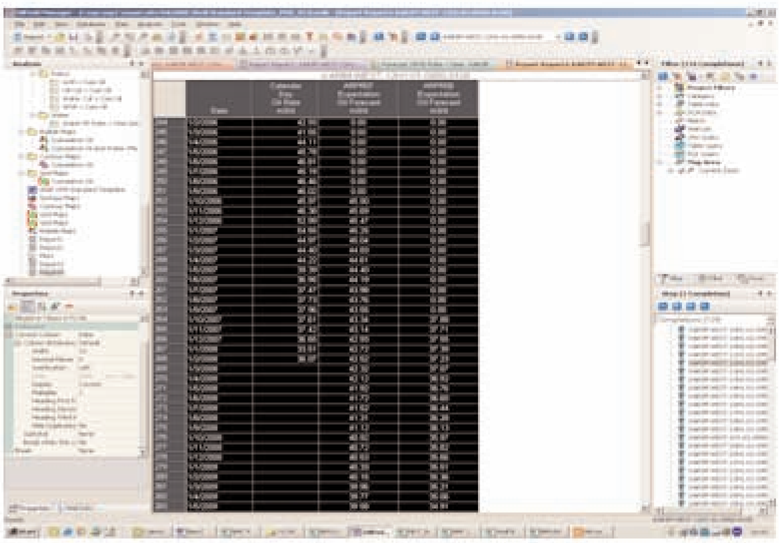
Note that a forecast for water and gas is still required.

Report

- Write the following variables to create the report e.g. Date, OilCD, OilFcstARPR07_E, OilFcstARPR08_E

Comparative plot





5. References

#	Title	Number
1.	Production Forecasting Standard	EP Standard
2.	Principles of Production Forecasting	EP 2003-5500
3.	Operational Excellence Volume 4	On Wiki
4.	Petroleum Resource Volume Guidelines Resource Classification & Value Realisation	EP 200x-1100
5.	Control Framework for Discovered SFR and Expectation Resource Volumes	EP 2008-5126
6.	DCAF	On Wiki
7.	Practical Guidelines for Long Term Production Forecasting in Field Development Plans	PDO GU-557
8.	Production Forecasting Guidelines	SPDC 2007
9.	Production Forecasting Code of Practice	PDO CP- 153
10.	IRM guidelines http://sww.wiki.shell.com/wiki/index.php/IRM_guidelines	On Wiki
11.	Risk Management in Projects	EP Standard
12.	Simplified modelling of turbidite channel reservoirs	EP 2007-3145
13.	The Application of Risk Factors in Assessing Scope-For-Recovery Volumes	Reserves Portal
14.	Production System Optimisation Process Guide	EP 2008-9012
15.	HSSE Performance, Monitoring and Reporting (PMR) – 2 January 2008 interim version	sww.shell.com/hse/
16.	Event Driven Manual https://sww-knowledgeepe.shell.com/teamsiep/livelink.exe?func=ll&objid=2693740&objAction=browse&sort=name	EP Finance Business Planning (see URL)

Glossary

Acronym/Abbreviation	Definition
A	
ADL	Asset Development Leader
AFPR	Annual Field Performance Review
AoO	Area of Operation
ARP	Asset Reference Plan
ARPR	Annual Review of Petroleum Resources
B	
BP	Business Plan
C	
CFR	Concept Feasibility Report
D	
DCAF	Discipline Control and Assurance Framework
DG	Decision Gate
DR	Developed Reserves
E	
EOFL	End of field life
EP	Exploration & Production
EPT-D	EPT Petroleum Engineering Department
F	
FDP	Field Development Plan
G	
GES	Group Equity Share – Shell's entitlement to reserves
GIP	Group Investment Proposal
H	
HCRV	Hydrocarbon Resource Volume
HCM HC	Hydrocarbon Maturation Health Check
HRVMS	Hydrocarbon Resource Volume Management System
L	
LIO	Locked in Oil
M	
MMboe	Million barrels of oil equivalent
MoM	Minutes of meeting
N	
NFI	No Further Investment
NFA	No Further Activity
NOV	Non-Operated Venture

Aconym/Abbreviation	Definition
O	
ORP	Opportunity Realisation Process
P	
PIN	Project Initiation Note
P-masters	Project Masters (project descriptions for programme build)
PRA	Proved Reserves Addition
PSO	Production System Optimisation
PUR	Proved Ultimate Recovery
Q	
QA/QC	Quality Assurance/ Quality Control
R	
RC	Reserves Committee
RE	Reservoir Engineer
RRVM	Regional Resource Volume Manager
S	
SIA	Shell Internal Audit
SEC	Securities and Exchange Commission
SFR	Scope For Recovery
SFR UA	Scope For Recovery Under Appraisal
SFR IP	Scope For Recovery In Planning
SS	Shell Share (see also GES above)
T	
TLVC	Technical Limit Value Creation assist
U	
UDR	Un-Developed Reserves
UTC	Unit Technical Cost
V	
VAR	Value Assurance Review
W	
WRM	Well and Reservoir Management

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