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Breaking the Barriers—The Integrated Asset Model

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Abstract

The objective of this paper is to highlight the necessary steps for the successful use of integrated asset modeling. It presents the full workflow for optimzing production and injection cycle times with the help of a simplified reservoir model (SRM) through the set up of an integrated asset model (IAM) to validate the SRM results and control the actual production performance.

A discusson of the theory of the IAM as well as the steps to set up a SRM and IAM are presented in this paper. The steps are described in context of an actual field operation. A WAG cycle optimization workflow for the Snorre field has been created to demonstrate the advantages of using the SRM and IAM technology. The optimization process is performed using a SRM able to run a simulation run in a matter of minutes and hence being suitable for sensitivity analysis and optimization. The optimized WAG injection and production cycle is then carried forward to an IAM in order to accurately determine the well performance and the reservoir production. The IAM couples the modeling results from reservoir and well model with the surface facility network and process plant model. The coupling and integration allows investigating the impact of changes in one model to all the other models and hence also handles the proper propagation of constraints throughout the system.

Introduction

Coupling a full field reservoir simulation model with a surface facility network model allows for more accurate computation of hydrocarbon recovery since both system imposed constraints (fluid flow from the reservoir and surface constraints), can be considered simultaneously.

The integrated asset model (IAM) comprises of a coupled system of reservoir simulation models with surface facility network models. The purpose of coupling is to balance a reservoir simulation model with the response of the surface facilities. The IAM consists of three distinct parts: The reservoir model, the well model and the surface facility model. These three models are coupled at coupling points, each passing the conditions at the coupling point on as a new boundary condition for the next model.

The reservoir simulation model as a starting point computes the fluid movement and pressure distribution in the reservoir model, passing the information about the pressure and fluid saturation at the subsurface coupling point (well locations in the reservoir model) to the well models (conditions at sandface). In the well model the information about the conditions at the coupling point (sandface) is used as a boundary condition in order to compute the fluid rates or the pressure at the surface coupling point (e.g. well head), where the well model is linked to the surface facility model. The well model surface boundary condition acts as sink or source term in a surface network, which has to be balanced to account for varying fluid flow and pressure conditions in every well in the system. Their interaction will ultimativley lead to a newly calculated backpressure of the production system for every well. The system backpressure is then conveyed all the way back through the well model back into the reservoir in order to account for the changed boundary condition imposed by the surface model in the reservoir.

This serial system is iterated in order to balance the full network obtaining stabilized solutions for fluid flow from the reservoirs into the well and from the well into the surface system and all the way to the system exit point (sales point).

The whole system is hence balanced and in contrast to conventional reservoir simulation the IAM is considering the response of the surface system in the calculation of fluid flow rates.

Integrated asset models are gaining popularity as they can be applied for a variety of different and computationally challenging tasks:

- Coupling of a full field reservoir simulation model with a surface network model, in order to obtain more accurate estimations of the well and field flow rates at the surface by considering the response of the surface system.(Litvak and Darlow 1995; Hepguler, Barua and Bard 1997; Trick 1998; Zapata et al. 2001)
- Evaluation of the impact of changes at the surface conditions on the fluid movement in the reservoir. This is especially interesting for EOR methods involving the injection of liquids and/or gas as the restrictions in injection volumes imposed by the surface equipment and by the reservoir will affect sweep efficiency significantly.
- Planning of new wells and their effect on surface rates and the resulting requirements for surface facilities
- Coupling the production and the injection from various reservoirs through a common surface network as often encountered in offshore assets. Several reservoir simulation models can be linked to one or more surface facility model to ensure that bottlenecks are considered appropriately throughout the production system.
- Applying general injection and production constraints to the whole system and allocate injection volumes more efficiently. (Haugen, Holmes and Selvig 1995)
- Using different PVT descriptions for the individual models. Since all models are generally considered as entity they can be set up with their own fluid formulation. Hence it is possible to link black oil and compositional reservoir simulation model through a common surface facility model, which could be set up in black oil or compositional mode as well. (Weisenborn and Schulte 2000)

Linking the Reservoir Model with the Surface facility model can be obtained in various ways. The coupling uses a similar approach as a reservoir simulation model would use if the surface model can be considered as an additional block. The reservoir-surface link can therefore be solved implicitly, iterative lagged or explicitly.

This paper presents how a coupled system is setup that can be used to find the optimization potential in the SnorreB oil field offshore Norway. Using a simplified reservoir model the WAG production and injection (P & I) cycles in the field can be optimized in order to maximize the Net Present Value of the Asset (NPV). The resulting P & I schedule is then used in an integrated asset model in order to identify bottlenecks and optimization potential.

Field Details

The Snorre field covers an area approximately 8 km wide and 20 km long (**Figure 1**). The reservoir consists of coastal plain sandstones of the Statfjord Formation and alluvial plain sandstones of the upper Lunde Formation. The complex reservoir geology and the resulting heterogeneity in reservoir properties have dictated a reservoir drainage strategy based on long horizontal producers with commingled production from several reservoir zones. Both up- and down-dip water alternating gas (WAG) injection is widely used. Due to the variation of permeabilities within the layers and due to the heterogeneities each of the layers needs its own optimum flooding strategy to obtain highest sweep efficiency. Based on the experience in Snorre A, the Snorre B plan of development included the use of downhole flow control devices (Kulkarni, Belsvik and Reme 2007).

Water & Alternating Gas (WAG) injection has been used on Snorre field since February 1994. The first WAG injection was performed on the Central Fault Block (CFB) in the Statfjord formation. The WAG injection strategy was later implemented in other parts of the field and is also planned as injection strategy in the development of Snorre North.

Snorre oil is highly undersaturated, and injecting gas may result in considerable swelling of the liquid hydrocarbons. The Snorre injection gas is quite rich and may develop miscibility with the oil. Laboratory measurements have estimated the minimum miscibility pressure (MMP) to be below the initial reservoir pressure, i.e., remaining oil saturations are expected to be small in the gas swept areas. However, gravity segregation may be strong for down-dip gas injection, resulting in low sweep by the injected gas.

Due to reservoir heterogeneities, the communication between the wells and formations are complicated and difficult to describe. Attempts have been made to analyse the communication throughout the wells and their sleeves and within each individual zone controlled by a common sleeve. Each well is tested at least once a month. When changes in the well behavior are observed, for example, a change in a certain pressure gauge, a multi-rate well test is performed to decide the new flow distribution (Kulkarni, Belsvik and Reme 2007). A well model is used to allocate the production to the respective sleeves. Once the well tests have been performed, the individual sleeve production is allocated to the individual zones based on formation *kh* (permeability×net height). During production, the voidage factor is continuously updated on the block and formation level. This information is used to plan the zonal production and injection (P & I) plan. During the monthly testing, the zonal production performance and all sampled temperatures and pressures are observed.

Optimization of a WAG treatment using a Simplified Reservoir Model and IAM

Snorre B was chosen as a pilot field to show how an integrated approach to field management and operations can increase oil recovery. The research program aimed to implement a series of workflows investigating the production optimization potential in the Snorre B field. The primary focus areas were:

- Online collaboration
- Real-time field monitoring
- Day to day field performance analysis
- Simplified Reservoir Model
- Advanced well control

The Simplified Reservoir Model (SRM) is used as a proxy to the detailed reservoir model in order to optimize the WAG cycle efficiently. Due to the SRM the simulation run times could be reduced to three minutes making the SRM an attractive option for optimization studies. The objective is to optimize the Net Present Value of the Asset (NPV) with an emphasis on increased oil production. The optimization control variables are the duration of the water and gas injection cycles as well as the amount of fluid to be injected. The optimization methodology will be presented in detail in the next section. The optimized P& I plan is then passed to the IAM for validation and for computation of the optimized production rates.

The optimized P & I schedule is applied in an Integrated Asset Model (IAM), through the application of asset management rules that dynamically vary the water and gas injection in the reservoir over time. The IAM comprises of four separate reservoir simulations mapped to a common surface network production facility model. The IAM computes the expected surface production rates of the wells and of the field in order to investigate well control optimization potential.

Integrated Asset Model Description

The validation step of the workflow makes use of an integrated asset modeling approach. The benefits of IAM have been widely discussed in the introduction of this paper and in the literature. Of primary concern in this study are back pressure effects from the surface network model, application of the optimized WAG schedule, and prediction and control of sand production.

The IAM used in the course of the validation is shown in **Figure 2**. It consists of four different reservoir simulation models coupled to a common production network model. The coupling point between the wells in the reservoir model and wells in the network model is the sandface. A network balancing scheme is employed to ensure pressure and rate convergence between the surface and subsurface models.

The IAM does not contain an injection network. Injection rates for the wells controlled by the optimization are applied to the reservoir simulation model through the application of asset management rules. The rules use tables of injected water and gas rates versus time produced by the optimization.

To address the issue of sand erosion, the surface network branches are monitored to ensure the branch maximum mixture velocity does not exceed 10 m/s. If the limit is exceeded, corrective action is taken by the simulator to choke the wells upstream of the offending branch.

Workflow to Create a Simplified Reservoir Model

Reservoir simulation models tend to grow directly proportional to the state of the art computational power. Additionally simulation models become more complex because of the fast growing amount of available information that has to be incorporated. Commercial software products support this development as it becomes easier and easier to create simulation models with a large number of grid cells. However, engineers are facing big challenges when it comes to history matching or incorporating uncertainty into these models. Typically these huge simulation models take a long time (e.g. twelve to eighteen hours) to run, making it tedious and time consuming to history match them. The high number of grid cells makes it hard and a timely – often an almost impossible - task to update the model regularly according to the latest status of information during the lifetime of a field. Consequently these models cannot be used in day to day field performance analysis or in any optimization process.

It is clear to see that such a huge simulation model would be the bottleneck in the optimization workflow of an integrated asset model. All other models of the workflow (the well model, the surface network model) usually run in such a short time that the effect of their CPU consumption on the overall optimization process cycle time can be either beared or neglected. Even using a smart optimizer a minimum number of 20 to 50 runs have to be performed. Therefore a simulation model has to be created that does not take longer than three to five minutes to run, so that the optimization workflow can be completed within a few hours.

One of the tasks of this research project was to create a simplified simulation model that runs very fast but does not lose too much resolution, so that it still can mimic all important physical processes of the dynamic reservoir behavior. As for each block of the SnorreB field a large simulation model existed, a workflow has been developed that simplified those complex models in a fast and simple way. Large emphasis was also put on the generalization and repeatability of his workflow.

Because of the intention to generalize the methodology, another consideration had to be taken into account. Not for every reservoir a simulation model is created. Economical reasons prevent usually modeling small marginal fields numerically. As integrated asset modeling can increase the performance of such fields as well, the newly developed workflow would ideally also handle these cases. Of course a limited amount of data has to be available, otherwise the uniqueness and predictability of the model cannot be guaranteed. In addition the creation of a model and the history match (HM) has to be performed within a short time. The target was that the setup and HM process should not take longer than a day.

The foundation of the workflow is a G&G software, which allows running predefined model-building steps automatically. This software permits also storing the workflow in a template, making it possible to apply the workflow very fast and efficiently. The learning curve for engineers is fast, which is a major requirement for the deployment of this workflow. As soon as all available data are imported, a step by step procedure leads the engineer through the model creation process in such a way that the base model is constructed in a few hours. The most time consuming part is definitely the history matching process. In order to reduce the time an engineer has to spend on this part, a procedure has been developed, which allows automating the majority of the HM part. For a flowchart of the whole workflow see **Figure 3**.

The first step of the SRM creation workflow is to import available data from wells (i.e. trajectory, logs, cores, completion, and production history, **Figure 4**) and the reservoir (i.e. structure, faults, fractures, 3D-porosity distribution – if available) in the case where no detailed reservoir model is available. If a detailed simulation model exists, all necessary information can be imported from this model.

As a next step a coarse grid has to be constructed. Model boundaries should be oriented on the structure of the reservoir or if existing, kept similar to the boundaries of the detailed simulation model. It is important to consider carefully all available information. Structural information and faults have to be included in this modeling step. The grid dimension can be three to seven times larger than the original grid size. First, the structure has to be upscaled. Special emphasis has to be put on the vertical coarsening of the structure into simulation layers. In order not to lose too much resolution by constructing such a coarse grid, in a second step a grid refinement has been introduced around the wells in an area of interest. Wells can be arbitrarily shaped, as long as their trajectory is known. Also multi-segmented wells can be incorporated easily. Usually a 3 x 3 refinement on areal level and a one to three layering refinement around wells are sufficient to guarantee a proper geological modeling.

After the grid construction task is finished, the model has to be populated with reservoir properties. As data of different origin and kind can be used and all of them bear a sort of uncertainty, a stochastic process has been chosen to generate the simulation model properties. Imported well logs are upscaled to the coarse grid dimensions, before they are used to populate the whole model. In the case of SnorreB porosity and permeabilities have been provided in log format. Therefore the porosity – permeability relationship was given and there was no need to establish a new model for this relationship. Once the well logs have been upscaled (**Figure 5**), a geostatistical method is applied to populate the simulation model with each parameter. The engineer can choose between different petrophysical modeling algorithms and tune each one to generate a list of most probable realizations (**Figure 6**).

All steps which have been described above can be designed in a workflow editor and automatically run for any number of times. That way a huge range of geological realizations and the according simulation files can be generated and calculated. The software automatically imports the simulation results and calculates the deviation to the measured data for each individual run (RMS-Error, **Figure 7**). In that way all realizations can be ranked easily and the best ones can be picked for the fine-tuning part of the HM process. Current technology limitations do not allow applying stochastic modeling to intergrated asset models. Even with a SRM, the optimization of the full production time would be too CPU expensive. Consequently, the best ranking realizations need to be reduced to a single best matching model. This workflow uses a gradient technique to evaluate parameter sensitivities combined with a regression algorithm to minimize a given objective function. With a limited amount of input required, this technique can find the best history match for each of the best ranking realizations. Engineering judgement is then required to choose the model for the production optimization workflow in IAM.

The SRM of the Snorre B field has been prepared according to the workflow described above. A comparision of the full field fine grid model with the SRM with grid refinement is depicted in **Figure 8**. It contains 3000 simulation grid blocks and needs 3 min on a standard desktop to predict 10 years of WAG injection. As can be seen for example in the comparison of Water cut of Well C06-AP in **Figure 9** the SRM satisfactorily matches the historic performance of the well and hence is considered a suitable representation of the reservoir as well as an acceptable simplification of the fine grid reservoir model.

Detailed Reservoir Models

The detailed reservoir simulation models for the Snorre Field consist of five separate simulation models which are connected using a reservoir coupling facility in reservoir simulator. Four out of the five models contain Snorre B wells. A corner-point geometry is used for all models. Individual models have the same lateral grid size (100m by 100m) and orientation corresponding to the geological grid. The NEFB model of the study area is built up of 76 layers and has 130,000 active grid cells. In total, the five models include 246 simulation layers and consist of 440,000 active grid cells.

The Snorre simulation models use a 3-phase, black oil PVT description. Gas is generally allowed to re-enter into oil phase when reservoir conditions permit. Gas resolution rate is controlled by a simulator keyword (DRSDT), which is to some extent used as a history match parameter. Miscibility effects are not accounted for.

In general, WAG injection with gas cycle lengths of 3 months is regarded as the best starting point for optimization. Historically, equipment limitations in some of the injectors have led to longer gas cycles in other injectors, which have caused re-cycling of gas between injectors and producers.

Surface Network Model

The detailed allocation of production and injection per sleeve is considered important in the history match process. DIACS (Downhole Instrumentation and Control Systems) wells are modeled as a network group with individual wells connected to that group. Each well in the group then represents a sleeve in the DIACS.

The surface facility model addresses the complexity of the Snorre B production system. The complexity arises from the DIACS production wells. The production from each layer in the DIACS wells is modeled by a source in the surface network model. The downhole tubing connecting the producing layers is also represented in the surface network model. This allows the integrated asset model to selectively control production into each layer using network choke models. Kosmala et al (2003) highlighted a previous application of this approach to modeling DIACS wells.

WAG Cycle Optimization using SRM

The optimization was performed using the simplified reservoir model to determine the most favourable P & I schedule according to an objective function.

Taking the baseline SRM model as the starting point, this step of the work involves a discrete optimization with an objective function, *F*, defined as a function of oil production and penalties for the production of non-hydrocarbons. Optimization was performed over a set of control variables describing the production and injection targets of the wells in the simulation (SCHEDULE section). Full details of this framework for optimization are described in Raghuraman et al. (2003) and Bailey, Couët and Wilkinson (2005). These articles both discuss the underlying optimization techniques and also provide examples. One important aspect from these papers is the concept of control variables and uncertainty. Control Variables (CV's) are the controls of the model that we can actually manipulate and adjust to obtain the optimum strategy. Uncertainties, on the other hand, are not controllable and are usually associated with physical uncertainties of the reservoir itself (porosity, permeability, and the like). Our optimization framework can correctly treat and accommodate realistic uncertainties and extract meaningful results to aid the decision makers. The approach presented in this paper shows a deterministic optimization, which – at the current stage – is not considering any uncertainties in the reservoir model.

The optimization procedure is to numerically obtain the optimal values of various operational (controllable) variables that generate either the maximum fraction of oil and/or the minimum water production, or the maximum NPV of the oil produced out of the field over a pre-determined time period. In this study, the control variables were a combination of gas and water injection rates, by reservoir layer, and also injection time and liquid production rates from the well C-06AP well and its neighbor C-05P. These control variables must also conform to various physical constraints (e.g., total injection limit) and some high-level economic constraints (e.g., injection and lift cost).

Formulation of the Objective Function

The main objective was to increase oil production. This is easily specified in the formulation of the objective function. However, injection capacity has a price and water treatment at the facilities is also costly. The definition of the objective function for this WAG optimization combines a demand for maximum oil recovery while maintaining the injection at the lowest possible level in order to reduce the costs. If we focused on maximizing oil production only then the conclusion would be to inject at the maximum rate at all time regardless of costs of injection.

This means that a blind adherence to total oil production for the wells specified (C-06AP and, to a lesser extent, C-05P) would most probably provide misleading WAG targets as injectors and facilities need to have some penalty imposed. Consequently, with an eye fixed firmly on maximizing production, an objective function, *F*, was defined that incorporated estimated costs for injection and water treatment alongside lift cost as well as promoting oil production by using appropriate oil price models. The resulting objective function could then respond in a manner that would account for over-production of water from the two production wells being studied and would respond to large increases in injection rates. The simple cost structures were estimates only and did not go into fine detail of costs nor did it consider any tax or other royalties. This is an acceptable simplification at this stage. In Bailey, Couët and Wilkinson (2005) some of the issues in defining sensible and expedient objective functions are discussed in detail.

A set of linear constraints were also defined in the optimizer to limit injection volumes as well as a set of saturation- and pressure-triggered simulation actions (ACTION statement) were declared in the simulation and were designed to prevent the simulator of violating some given saturation or bottom hole pressure threshold.

Optimization Model

It is important in any optimization study to manage the number of legitimate control variables (CV's) to a managable number. The CV's can essentially be any variable contained in the reservoir simulator input set. For this preliminary WAG optimization, each of the separate 28 time step segments specified in the SCHEDULE section (covering the complete 1250 day forecast) had the following CV's (sometimes the time step had less than these CV's due to periodic shut-in of injection zones and/or carry-over of production targets or injection rates from a previous time step):

- Water injection rates into layers 1 to 4 of well K-06 (= 4 CV's)
- Gas injection rates into layers 2 to 4 of K-06 (= 3 CV's, layer 1 was inactive)
- Injection duration (TSTEP) (= 1 CV)
- Liquid production rate targets (LRAT) for production wells C-06AP and also C-05P (= 2 CV's).

Producer C-05P was not initially considered in the analysis remit, however it was found from simulation analysis that it was impacted by K-06 injection and could be cannibalizing C-06AP production slightly and as such was added to the set of CV's in order to investigate the correct balance between injection and liquid rate. Bailey, Couët and Wilkinson (2005) demonstrate that a reasonable upper limit for number of control variables is around 30. The number of CV's has to be carefully chosen since a too high number would bias the optimization procedure in a way so that the global optimum solution is not likely to be found but rather only a local minimum of the objective function. Note that not all the CV's stated above were applied to each of the 28 separate time step segments, leading to a variation of the number of CV's considered in each step-wise segment.

The detailed WAG schedule was modestly simplified in structure to make it more amenable to identify primary control variables. However, for the forecast period (1250 days) there were still far too many legitimate CV's for declaration at one single time. Instead a sequential step-wise optimization was performed. This is a process where we optimize from the earliest (in chronological terms) CV's to the last. These optimized values are then fixed and we move forward to a new period involving a manageable number of CV's, until we reach the end of the study period. In this way, four separate sequential optimizations where performed, covering the 1250-day (~3-year) forecast period of interest. **Figure 10** also shows the number of CV's for each step-wise optimization and the duration of forecast attributable to each. This step-wise approach does, however, run the risk of locating a local optimum so, as a quality check, we revisited the "final" optimized schedule and randomly selected 30 CV's and re-ran for the full period. This test established that step-wise approach had indeed found a very good optimum and that no easily obtainable upside would be forthcoming from the given model. This exercise of "restarting" an optimization again but starting from the new "optimum values" is good standard practice and strongly recommended if time allows.

Application in the Detailed Model

The next step in the optimization workflow is to transfer the optimized WAG workflow developed using the SRM to the detailed simulation model in the IAM for validation. The validation step is performed using an integrated asset model to capture the interaction between the wells in the reservoir model and the surface network model. As discussed in the introduction to this paper the integrated surface/subsurface modeling has a critical impact on production operations optimization and the improvement of field development planning of production assets (Ghurayeb et al. 2007).

Conclusions

- An optimization workflow has been presented here as part of an ongoing collaborative research program between StatoilHydro and Schlumberger. The aim is to provide closed loop production optimization focusing on increasing recovery through monitoring, optimization and control of WAG injection wells.

- The workflow facilitates development of a production and injection plan designed to maximize oil production. The workflow utilized a phased approach. Firstly, a simplified reservoir model is optimized by adjusting the WAG injection rates and timings. Secondly, the WAG schedule resulting from the WAG is validated against an integrated asset model.

- The optimization example presented focuses on two multi-zonal production wells (C-06AP and C-05) and one multi-zonal DIACS WAG injection well in the north east fault block of the Snorre B reservoir.

- The omission of the surface facility model in the optimization will most probably result in a suboptimal P & I plan. Its inclusion in the optimization however is essential in obtaining a truly optimal solution. This is part of an ongoing research and development program.

Nomenclature

CV	Control Variable
WAG	Water Alternating Gas
WOPR	Well Oil Production Rate
DIACS	Downhole Instrumentation and Control Systems
IAM	Integrated Asset Model
LRAT	Liquid rate
P & I	Production and Injection
SRM	Simplified Reservoir Model

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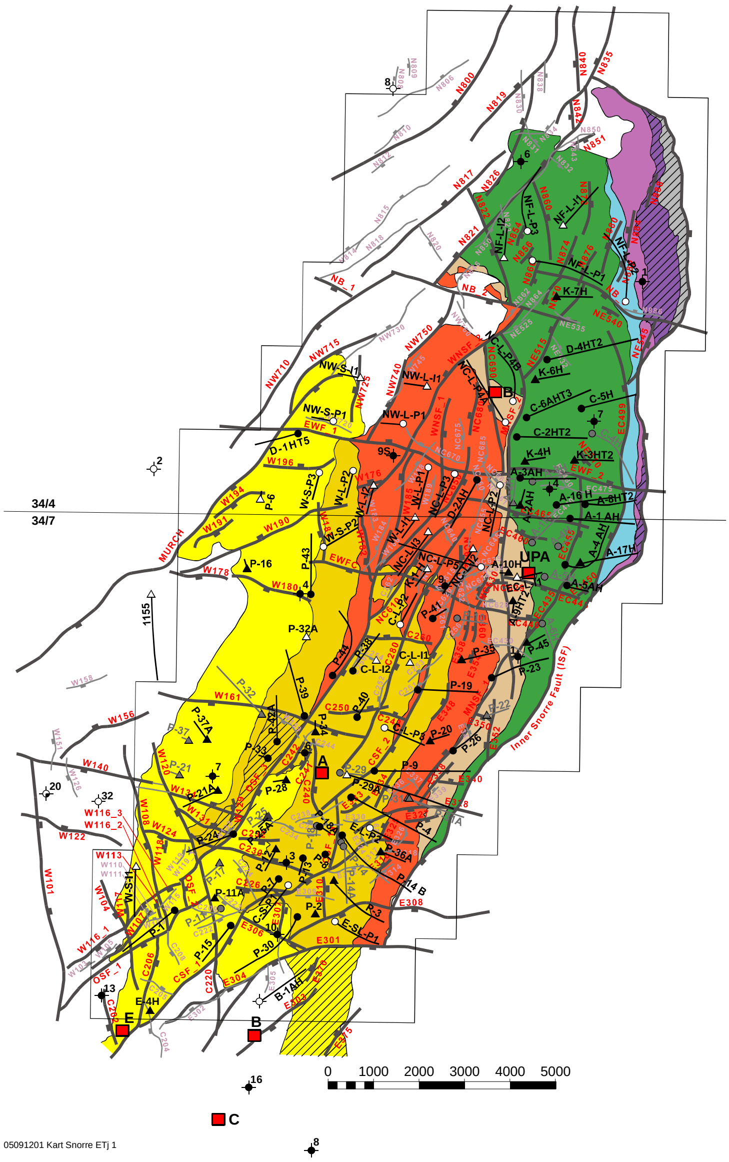

Figure 1: Map of Snorre B Field

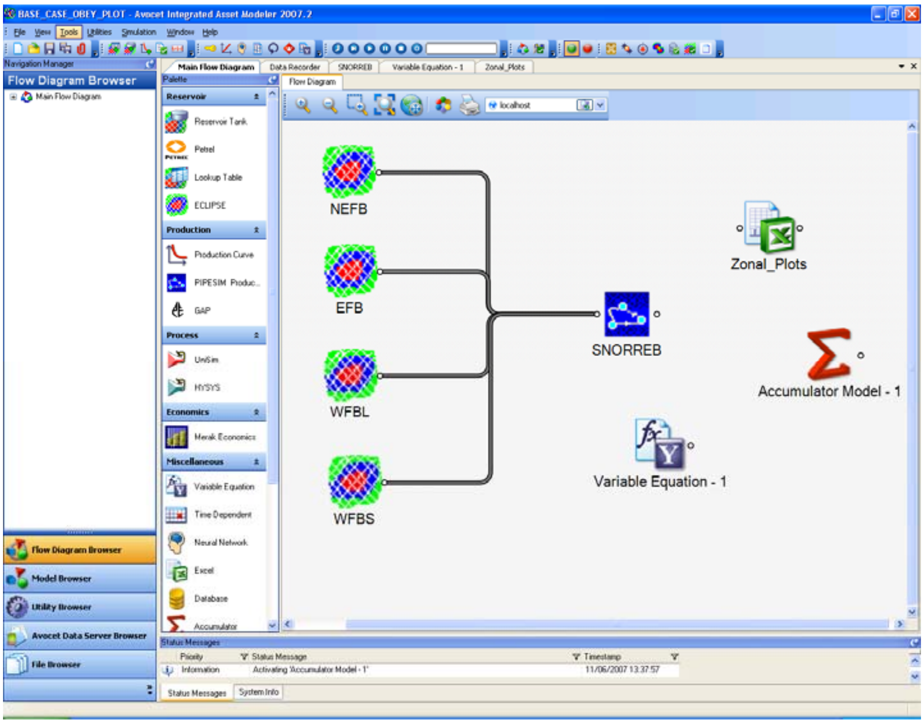

Figure 2: Configuration of the Integrated Asset Model

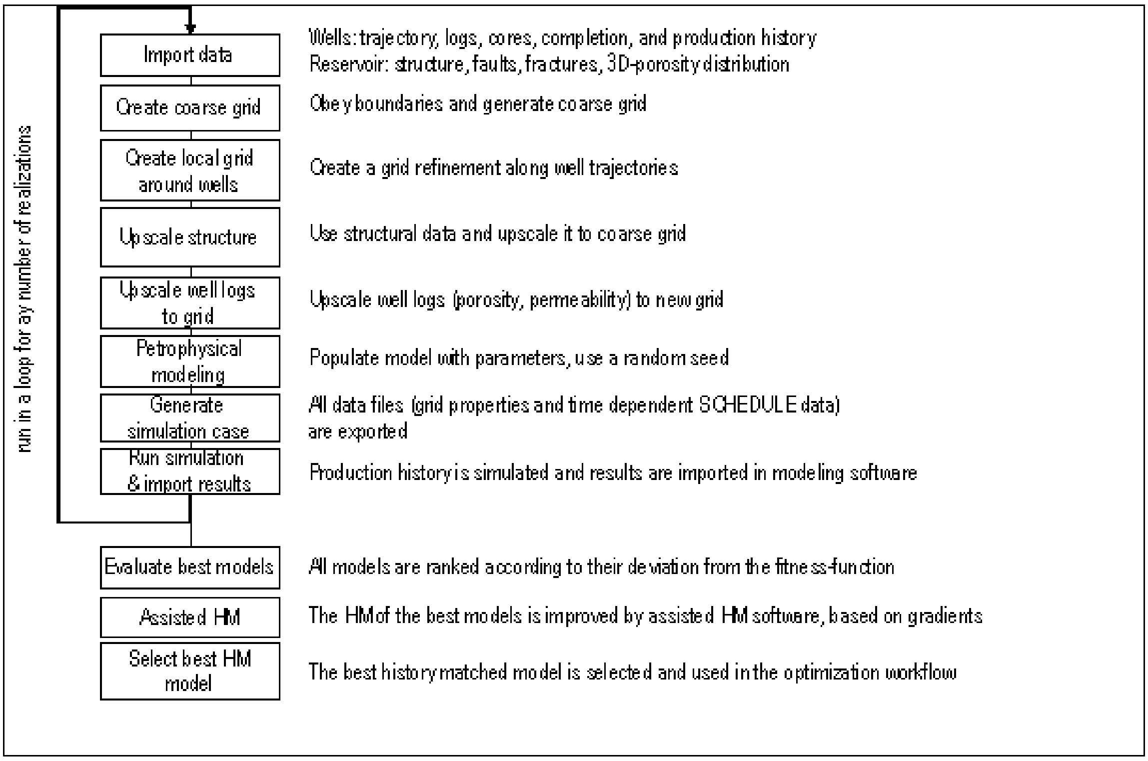

Figure 3: Model Building and History Matching Workflow

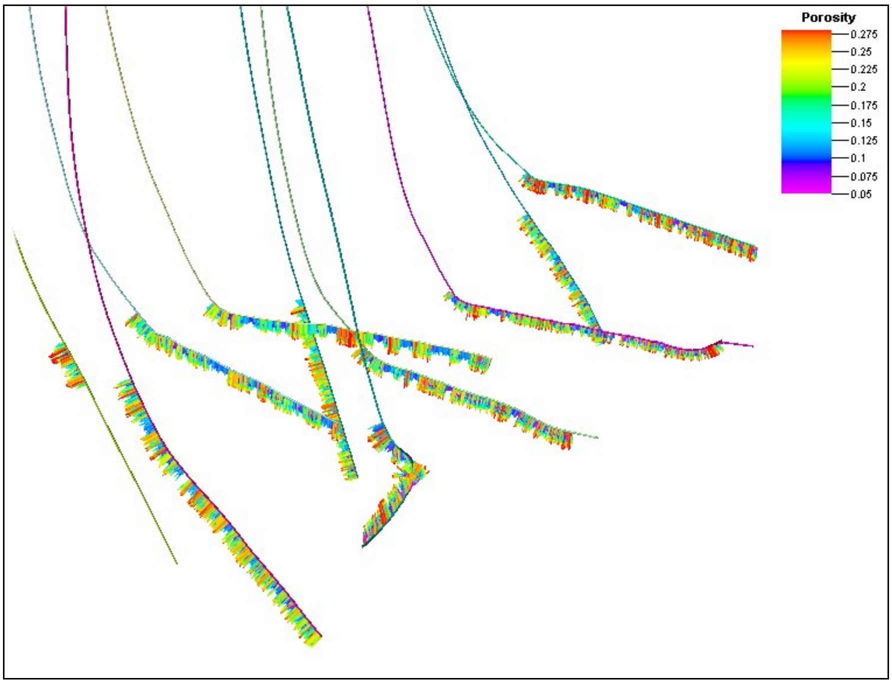

Figure 4: Well Logs

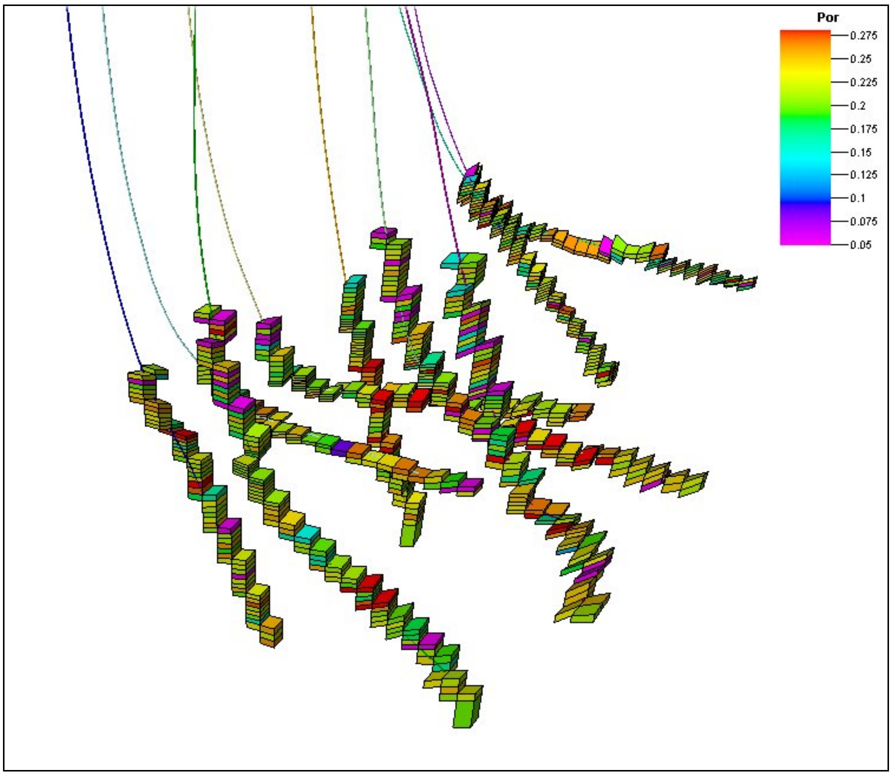

Figure 5: Upscaled Property (Porosity) along well path

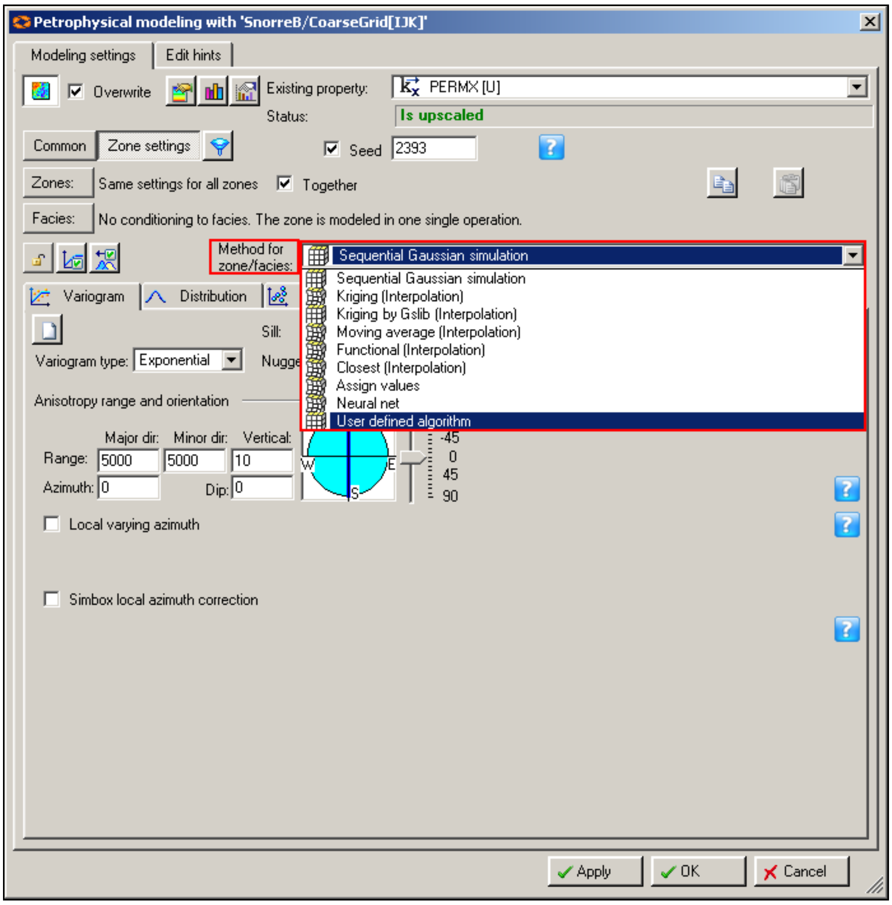

Figure 6: Petrophysical Modeling: Generation of multiple geological realizations

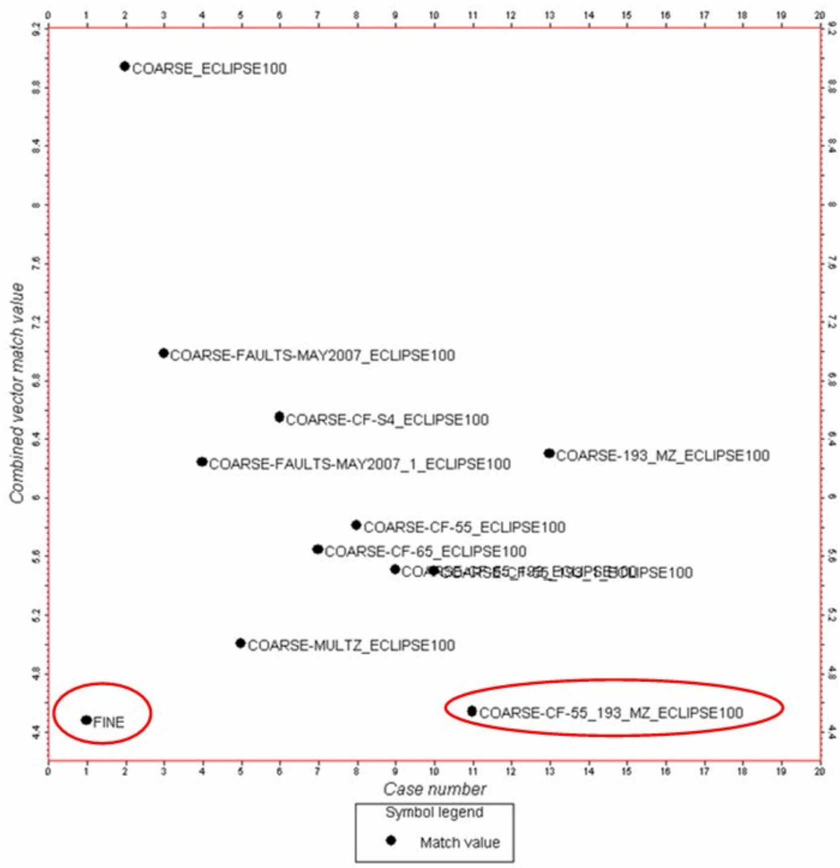

Figure 7: Evaluation of History Match runs; RMS Error vs. Simulation run shows realization that matches the fine model best

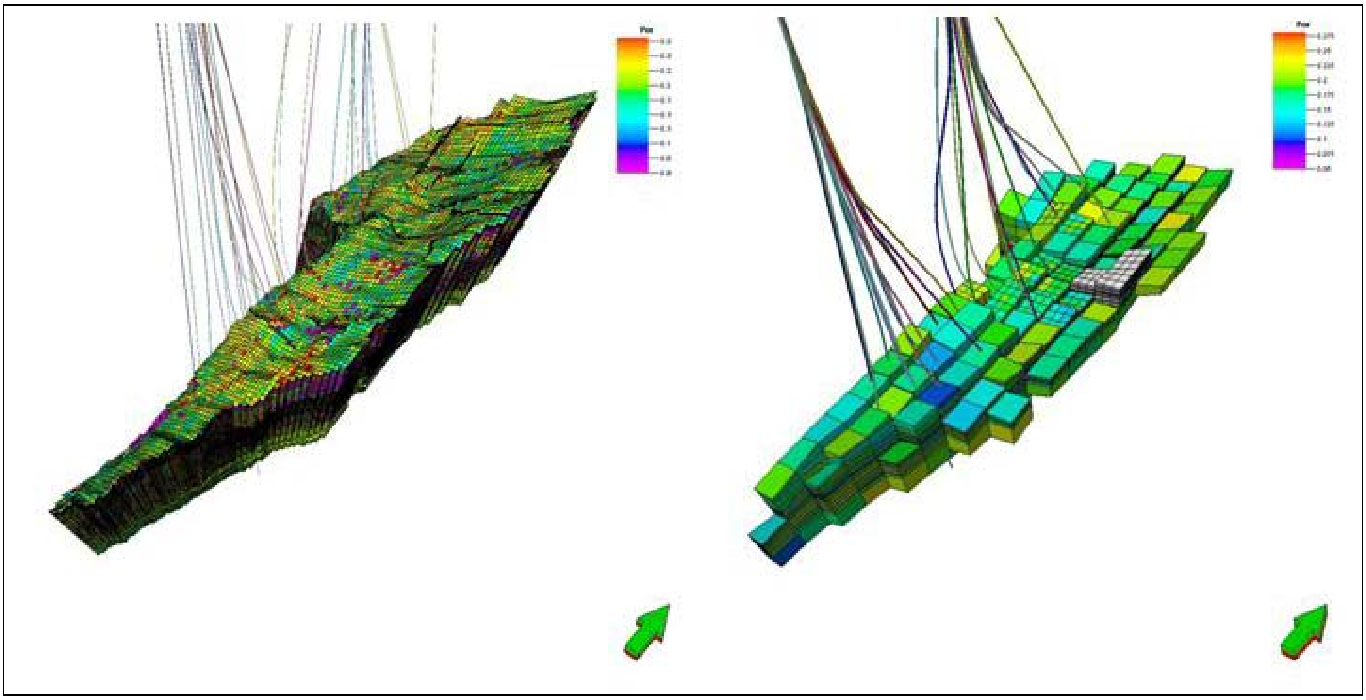

Figure 8: Comparision of fine grid model (left) and SRM with Grid Refinement (right)

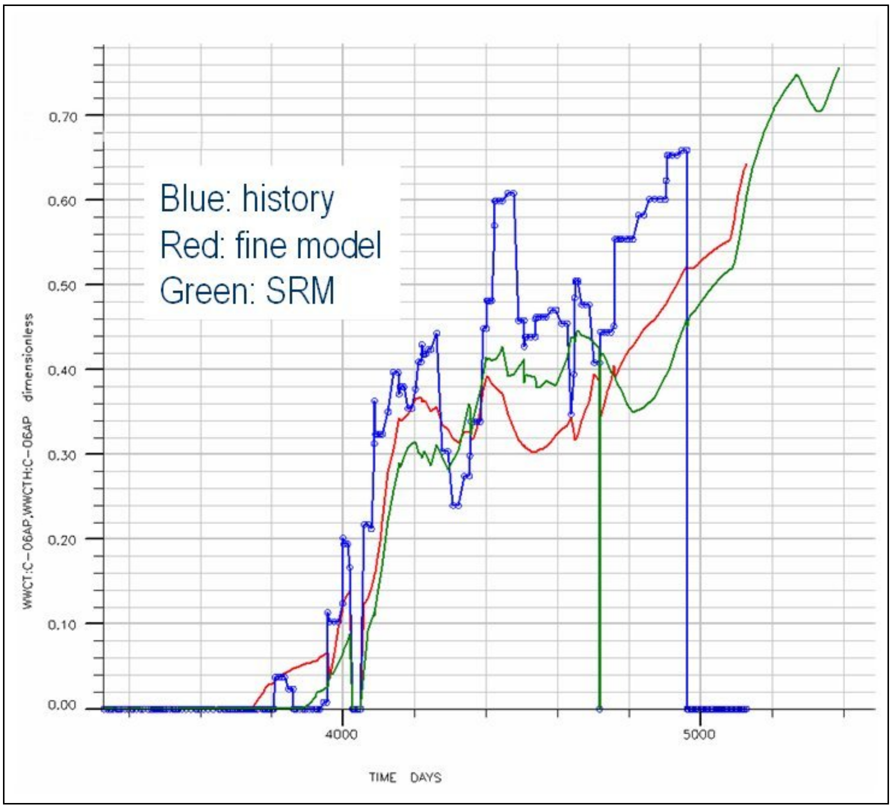

Figure 9: Water cut of C06-AP

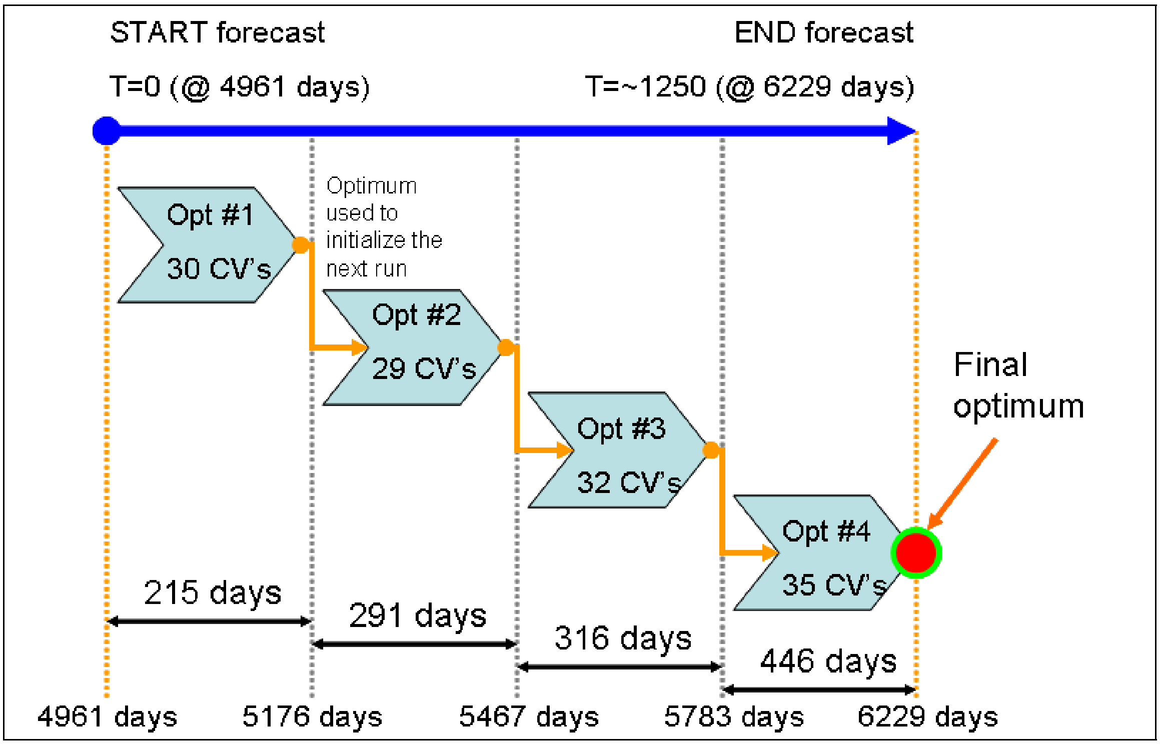

Figure 10: Schematic of step-wise sequential optimization