Reservoir simulation studies of the Snorre Field were initiated in 1985 for the purpose of formulating an optimum reservoir development strategy and predicting reservoir recovery and performance. The results formed the basis for the commerciality evaluation and the Field Development and Operating Plan.

The Snorre Field reservoirs are interpreted as fluvially deposited sandstones interbedded with shales. The reservoir simulation modelling of these complex reservoirs progressed from two-dimensional channel (single sand body) models and "panel" models (cross-sections with randomly distributed sand/shale sequences) to three-dimensional (3D) element models. The 3D element models were the primary prediction tools. They were based on stochastic, spatial sand/shale distributions which were gridded and input as grid block multipliers to porosities and transmissibilities. Relatively fine grid blocks were required to model adequately the reservoir discontinuities present in the geological model. The 3D element models were therefore quite large (up to 18000 active grid blocks).

The recovery and rate predictions from the element models were adjusted to account for intra-sandbody heterogeneities (based on channel model results) and other field heterogeneities that could not be represented directly owing to practical limitations of the model size. The element models covered approximately 44% of the field. The results were extrapolated to full-field production profiles by use of typical well performances and a well-summation routine. Pseudorelative permeabilities and well functions developed from the element models were used to build a full-field simulation model that confirmed the production profiles.

INTRODUCTION

This chapter contains a description of the reservoir simulation work performed on the Snorre Field in the period 1985–1987. This work formed the basis for the well location and reservoir management plans, as well as production-profile estimates used both in the commerciality evaluation and as a basis for the Field Development and Operating Plan.

The objectives of the reservoir simulation work were:

• to establish an optimum reservoir production strategy, including drive mechanism, number, location and sequence of wells, well completion strategy, injection and production rates; and
• to estimate recoverable reserves and production profiles for a number of different development scenarios for use in development planning and commerciality evaluation work.

The objectives were met through a simulation programme using both two-dimensional (2D) and three-dimensional (3D) simulation models. The simulation work programme was tailored to provide a timely input to several milestone reports that required the preparation of some interim models.

The basic strategy in the simulation programme was to incorporate as many details and inhomogeneities as possible in the simulation models (each of which covered a limited area, or element, of the field and contained relatively small grid blocks), rather than attempting to construct a full-field model where a high degree of data averaging would be necessary. The development of the models progressed from relatively simple 2D models describing a single sand body with a total thickness of 5–10 m to larger 2- and 3D models involving 2–12 wells. The final results were based on the 3D element models, which were 3–15 km² in areal extent and consisted of up to 18000 active grid blocks. Correction factors were applied to the element model results to reflect the heterogeneities that could not be adequately incorporated in them. The results from the element models were extrapolated to unmodelled areas of the field, on the basis of reservoir quality and considerations of structural geometry.

A key part of the input data was the transfer of the geological model of a complex, fluvially deposited reservoir into a 3D Cartesian simulation grid. The geological modelling is described in a companion paper by Stanley et al. (this volume). As discussed by Augedal et al. (1986), stochastic representations of the geological model were generated using the SISABOSA (SIMulation of SANDs for SAGa) programme. These representations were discretized, and input into the reservoir simulation models through the use of multipliers to porosity and transmissibilities.

Figure 1 shows an overview of the simulation programme in relation to the major development planning milestone reports.
ROCK AND FLUID DATA

The Snorre Field reservoir is interpreted as fluvially deposited sandstones interbedded with shales. A total of 11 exploration/appraisal wells has been drilled on the field. An overview of the data collected is given in Fig. 2. All of the wells have been tested, and fluid samples of the undersaturated low-viscosity Snorre oil have been collected. A total of 1635 m of cores has been cut, and porosity and permeability measurements have been made. Well tests and permeability measurements made on the cores have indicated average oil permeabilities at initial water saturations ranging from 200 to 2000 mD, while the porosity ranges from 21 to 26%.

Special core analysis has been performed on a large number of core plugs as described by Lien and Nysetvold (1988). It was concluded from an evaluation of wettability that the reservoir rocks are of an intermediate to oil-wet nature. Hysteresis scanning curves for use in the simulation models were generated according to a history-dependent model for saturation functions.

INTERFACING AND VERIFICATION OF GEOLOGICAL AND RESERVOIR SIMULATION MODELS

Stochastic sand/shale distributions generated by the SISABOSA modelling tool were transformed into discrete distributions suitable for direct input to the reservoir-simulation model. This was done by superimposing 3D grids onto the sand/shale distributions, and assigning representative values for sand content to each grid block. The grid block sand content values do not supply the model with information concerning where within the grid blocks the sand body “edges” exist. Two neighbouring grid blocks might both have non-zero sand content and still be intersected by a shale that would act as a barrier to flow. It was therefore necessary to supply the model with information about grid block connectedness as well. This was achieved by assigning transmissibility multipliers in all three directions to all grid blocks.

An example of how a vertical transmissibility multiplier is calculated is shown in Fig. 3. This figure shows a 3 x 1 x 2 grid block system superimposed on two sandbodies, and how a vertical transmissibility multiplier between the two central grid blocks is calculated. Nine horizontal planes intersect the grid blocks between the grid block centres, and the sand fraction found in each of these planes is recorded. Because the flow between the two grid blocks will be dominated by the smallest sand area, the transmissibility multiplier is taken as the harmonic average of the sand fractions from the planes. In the example, one plane with zero sand content was found, and hence a transmissibility multiplier of zero was calculated. The horizontal transmissibility multipliers are calculated in the same manner.

The sand content in a grid block is calculated as the arithmetic average of the sand content values of 10 vertical planes through the block, and is entered into the simulation model as a multiplier to porosity.

The treatment of wells penetrating grid blocks with a discontinuous sand/shale distribution has a significant impact on the reservoir-simulation results for some models. It is important to ensure that the model wells communicate with the sand bodies in accordance with the model’s actual location of the sand bodies so that:

- The simulation model should complete the well only in sand bodies that are intersected by the well. Sand bodies that go through the well grid block, but are not actually intersected by the well, should not be in direct communication with the well.