Reservoir Management at Dunlin

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Summary

Dunlin field in the U.K. North Sea has been developed using reservoir simulation as a valuable tool in optimizing its exploitation. Simulation studies have been applied routinely to evaluate alternate development plans as well as to help understand the complex fluid movements in the reservoir. The paper presents examples of these applications.

Introduction

The Dunlin field, located in the northern North Sea, is owned jointly by Shell U.K. Exploration & Production, Esso Exploration & Production U.K., British Natl. Oil Corp., Gulf Oil Corp., and Conoco (U.K.) Ltd., and is operated by Shell. Since discovery in 1973, the field has been the subject of a flexible and continuously adaptable development plan. The initial plan was based on limited reservoir description from only a few wells and relatively widespread seismic data. Recognizing the limitations of the data, the development plan called for updating and improving the reservoir description as part of the initial steps of field development. The data from this early development needed rigorous evaluation to produce a final plan near optimum. One of the tools that has been very useful both in the data evaluation phase and the optimization phase of reservoir management is reservoir simulation. This paper includes major results of some of Esso E&P U.K. simulation studies of the Dunlin reservoir.

Water encroachment into the highly stratified Brent (Middle Jurassic) reservoir can be understood best in terms of simulation studies. The extent and effect of restrictions to vertical flow in the reservoir are difficult to predict from geological studies, but use of history matching by reservoir simulation can quantify the hydraulic effect of these restrictions. The model then can become a useful tool on which to base management decisions for field development. The Esso reservoir simulation program has been used successfully to match the pressure and watercut performance at Dunlin. The cross-sectional model developed for the Main Fault Block at Dunlin has been used to understand how to manage the field effectively.

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Background

Reservoir simulation has proved a valuable tool in management of the Dunlin reservoir. Dunlin, like other North Sea Viking Graben fields, presents a challenge to the reservoir manager trying to optimize field development and operation. The fields are, without exception, highly faulted and geologically complex. They require very large initial capital investment, which must be optimized relative to the development of the reservoir.

Reservoir simulation enables the engineer to try out various development schemes before commitment to install a platform. It also can assess the sensitivity of the ultimate recovery to various unknowns in the early reservoir description. Ultimately, the simulation model can become an operational tool, regularly updated, to help understand the complexities of fluid movement within the reservoir.

This paper addresses Esso's experience in evaluations of the Dunlin field development as an example of the use of reservoir simulation both for development planning and as a working tool in reservoir management. These studies have been undertaken by Esso to assist in decisions regarding the Dunlin Unit.

Specific problems addressed using reservoir simulation include: (1) evaluation of alternative development plans, (2) estimation of ultimate recovery, (3) analyses of the nature of water encroachment into the reservoir,

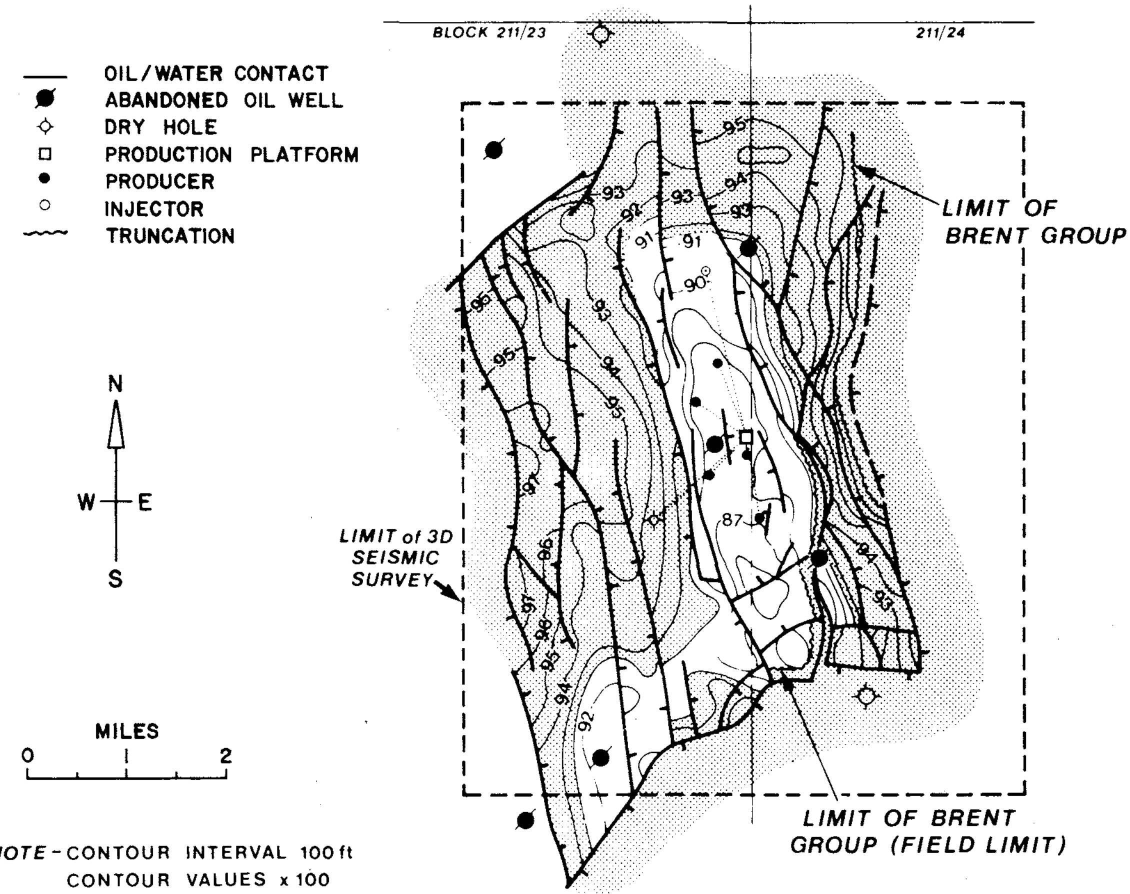

Fig. 1—Dunlin field structure map on top of Brent formation.

(4) evaluation of reservoir fluid flow both horizontally and vertically through the various strata within the formation, (5) estimation of aquifer size and performance, and (6) need for and timing of injection programs.

Reservoir History and Description

The Dunlin field was discovered in 1973 by Well 211-23/1. This well was drilled by Shell as a joint well on behalf of Shell/Esso, the licensees of Block 211/23, and Conoco, British Natl. Coal Board (license later assigned to British Natl. Oil Corp.), and Gulf, the licensees of Block 211/24. The well, drilled near the crest of what is now identified as the Dunlin field, found the entire Brent section to be oil-bearing. Fig. 1 shows a current interpretation of the structure at Dunlin as well as the location of the discovery and appraisal wells.[1]

In 1974 and 1975, initial field development decisions were based on data from six wells in the Dunlin area. These wells left many questions unanswered about the structural position of some unappraised fault blocks and suggested relatively high reserves. More importantly, these wells effectively had proved sufficient reserves to justify the development. Van Rijswijk *et al.*[2] have reported the early history of Dunlin in detail.

Development drilling started after the platform was installed in 1977. Also in 1977, before platform installation, a three-dimensional (3D) seismic grid was shot over the central part of the Dunlin field on an experimental basis. The sophistication of the 3D processing and migration of the seismic data developed a reservoir description that was much more refined than that available at the time of the initial development evaluations.[1]

The main block in Dunlin field is now described as a northwest-southeast-trending horst. This block has much subsidiary faulting both within the main block and even more to the west and east of the main horst section. Appraisal wells both to the southwest and to the southeast of the main block have identified separate oil/water contacts, establishing effective separation of these blocks from the main fault block.

Stratification

A more difficult problem to identify by conventional seismic and geologic evaluation is the problem of stratification and communication within the reservoir itself. Typically these properties can be estimated only by log correlation. With only one well in a fault block prior to development, correlation within the block can only be inferred. It is very important, however, to realize that recovery efficiency from the field depends on communication within the reservoir and to a lesser extent from the aquifer into the reservoir.

At Dunlin, the Brent section has been correlated into five zones using nomenclature as proposed by Deegan and Scull.[3] Fig. 2 shows a stratigraphic section in the

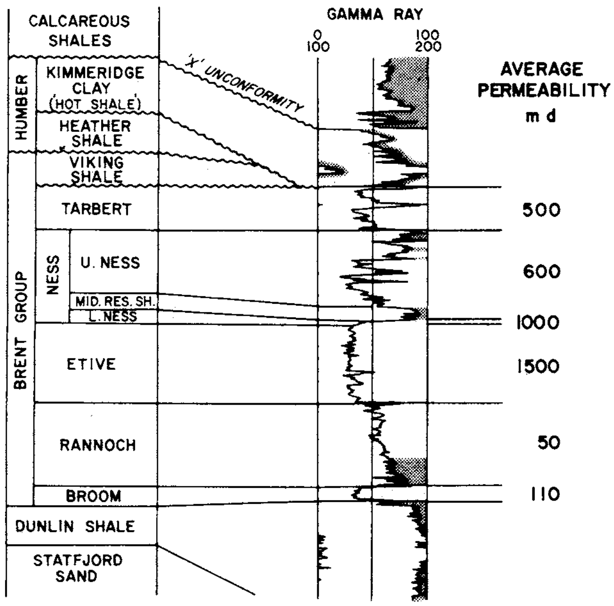

Fig. 2—Dunlin field type log.

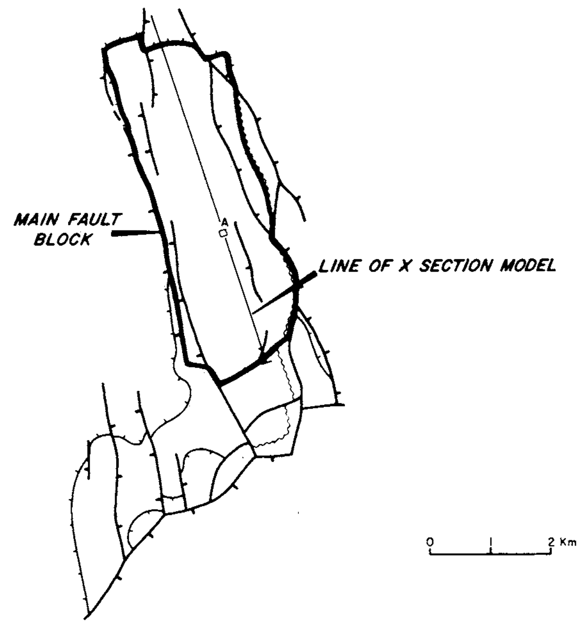

Fig. 3—Location of Dunlin cross-sectional model.

Jurassic, and illustrates the five productive intervals in the Brent Group: Tarbert, Ness, Etive, Rannoch, and Broom.

Pressure measurements in development wells indicate that the midreservoir shale within the Ness forms an effective barrier to vertical flow. It is present throughout the field. The gamma ray log is a good indicator of shaliness, and shows many shaly intervals within the Ness and Rannoch zones. The Etive, Tarbert, and Broom, by contrast, are relatively clean but have widely varying permeabilities. Average permeabilities, as shown in Fig. 2, are generally good, but the overall permeability variation within zones is from a few to several thousand millidarcies.

Early Simulation

Esso first conducted studies of Dunlin in 1975 to evaluate development plans. These studies included considerable use of reservoir simulation, although this early simulation was, of necessity, based on very limited well data. It used a simplified 3D model, being essentially an areal grid with two layers in the vertical direction, segregated by the midreservoir shale. This model had 40 by 46 grid blocks in each of the two layers. Its primary purpose was to estimate the potential recovery of oil under different, technically possible development plans. Further uses were to check the sensitivities of recovery to the many unknowns in reservoir description, and to estimate both the need for injection and the sensitivities of recovery to the timing of injection.

A further application of simulation was a study of the impact of reinjection of produced casinghead gas into the reservoir. This problem was addressed first by Shell, the field operator, in 1974 as part of simulation studies. The means of gas disposal had to be faced in light of both conservation of the natural gas and also conservation of the reservoir energy. Unfortunately, the structure was not sufficiently steep at Dunlin for gas to be injected successfully into a crestal area to form an effective secondary gas cap. Rather, the model work indicated that gas injection greater than the critical rate of about 5×10^3 Mcf/D would channel rapidly through the very low structural relief at Dunlin and result in impaired recovery of oil. Gas injection, therefore, was not desirable at Dunlin.

The initial development plan chosen by the owners was to inject water downstructure in the north and to sweep oil north to south. Producers and injectors would be completed separately in zones: Tarbert and Upper Ness, Lower Ness and Etive, and Rannoch and Broom. Early development wells indicated no separation between the Rannoch and Etive intervals, so subsequent lower-zone wells were commingled in Lower Ness, Etive, and Rannoch. With this modification, the initial general plan was followed for about the first three years of Dunlin development. More recently, as discussed later, wells have been completed selectively to minimize water production, but the same general sweep pattern still is being followed.

Recent Simulation

In 1979 and 1980, Esso began a second phase of Dunlin simulation to incorporate the reservoir performance data to date, and to refine the development plans based on the impact of the improved reservoir description. The specific objectives of this simulation were to evaluate the influence of the reservoir stratification on ultimate recovery. It became clear early in the development that there were very high-permeability streaks in the Upper Ness and Etive. The problems in producing oil through all the intervals could well result in reduced ultimate recovery from some strata. At Dunlin the specific options available in the development plan were (1) to produce all the intervals in all the wells or (2) selectively produce and inject in the individual wells.

TABLE 1—DUNLIN FIELD, PRESSURES IN BROOM ZONE

	Well A-16	Well A-37
Depth, true vertical subsea, ft	9,531	8,974
Date of RFT survey	Oct. 11, 1979	Feb. 17, 1980
Measured pressure, psig	6,095	5,061
Calculated pressure, Model A*, psig	5,858	5,726
Calculated pressure, Model B**, psig	6,042	5,096

*Model A incorporates uniform, restricted vertical permeability in lower Rannoch interval equivalent to 0.0003 md.
**Model B incorporates restricted vertical permeability at southern end of lower Rannoch equivalent to 0.017 md X two blocks; nil vertical permeability elsewhere.

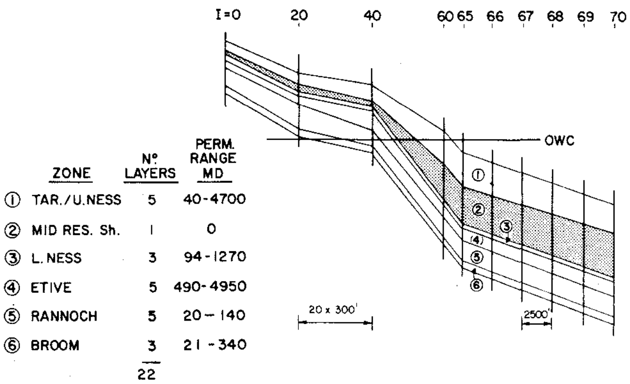

Fig. 4—Dunlin field—Esso reservoir simulator cross section.

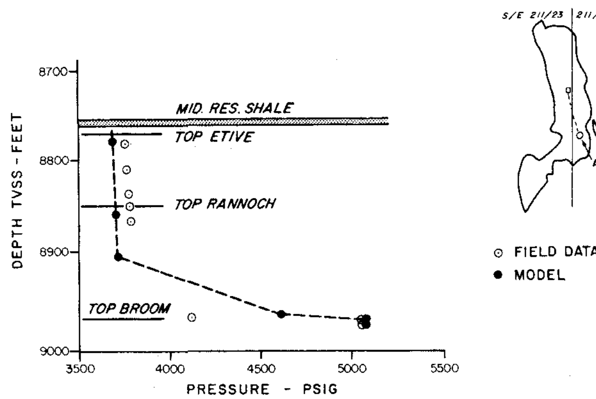

Fig. 5—Dunlin Well A-37, simulator vs. actual pressures.

Another unresolved question involved production from the Broom. Here the options were either to produce Broom along with the Etive/Rannoch or defer Broom production. Estimates of total OIP for the Broom were only 4% of the field total, so both options were viable. Low Broom productivity would not justify segregated development of only this interval.

Cross-Sectional Model

The reservoir model best suited to answer vertical flow and stratification questions at Dunlin was a cross section down the axis of the main fault block. Fig. 3 shows the location of this axis relative to the platform and the major faults. Depths of each zone as well as net thicknesses were assigned to each grid block according to the actual data found at the grid points along this line on the geologic maps of the field.

The cross section uses 22 layers, each 70 blocks long, to represent the field. In the oil zone, each block is 300 ft along the axis and 5,600 ft in width (across the fault block). Fig. 4 shows the actual cross section as well as the wide range of permeabilities assigned within each zone.

Horizontal permeabilities were assigned to the various strata according to core-measured permeabilities. Relative permeability to oil and water were assigned to each layer according to laboratory measurements on Dunlin cores from the same zone with similar permeability. These values then were checked by history matching to actual field data. During the history matching, the aquifer size and vertical and horizontal permeabilities were varied to match the field pressure performance. In all, a total of 25 trial runs were made to match the field pressures adequately.

History Match

The accuracy and utility of a reservoir simulation are improved greatly by matching the calculated reservoir performance to the actual field data. In addition, some reservoir parameters, such as vertical permeability and long-range communication, can be quantified effectively only by history matching. For example, core analyses are used routinely to estimate vertical permeability at the particular spot penetrated by the wellbore. However, the applicability of the core-measured permeabilities to large areas is questionable. A shale zone, for example, may have nil permeability at the well, but if it extends only a few feet into the reservoir it will have little effect on overall vertical flow.

As shown on the type log in Fig. 2, the shale sequence at the lower portion of the Rannoch should restrict vertical flow in this interval. How much restriction, though important to the development plan, could not be estimated from either logs or cores. Obviously the degree of communication in the vertical direction will have a major impact in the ultimate recovery from the lower intervals. Quantifying this communication was important in evaluating development both in the Broom and in lower strata in the Rannoch. Since no wells had been completed in the Broom at this time, quantification

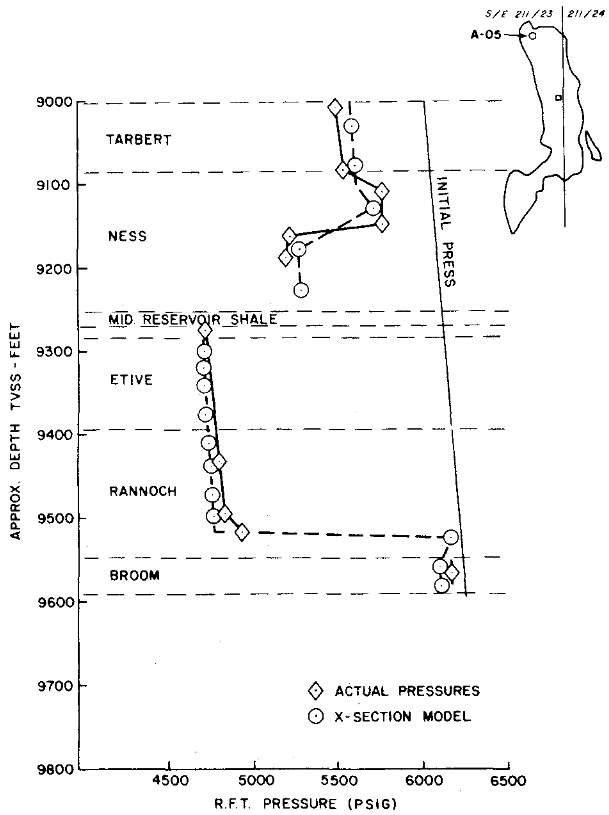

Fig. 6—Dunlin Well A-05, simulator vs. actual pressures.

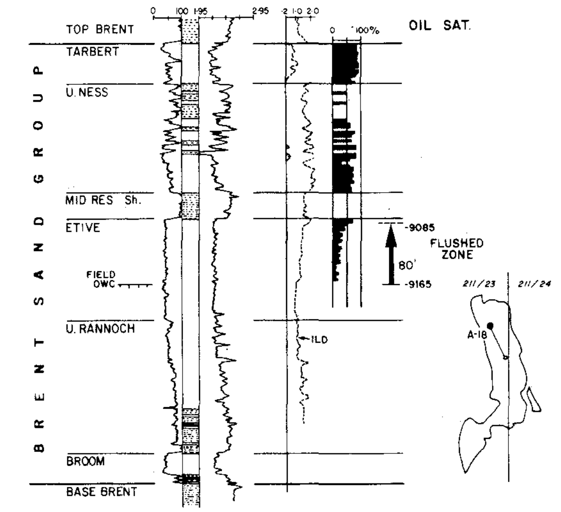

Fig. 7—Dunlin Well A-18, oil saturations calculated from logs.

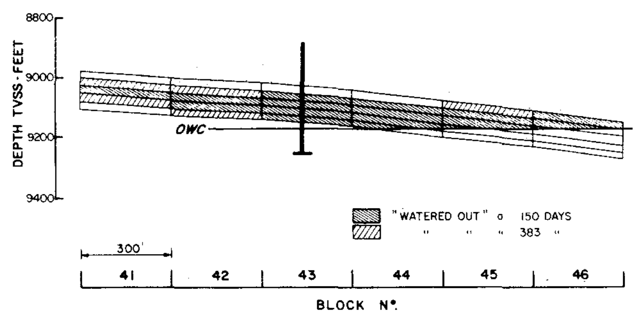

Fig. 8—Dunlin field cross-sectional model, water encroachment at Well A-18.

would have been difficult without the use of reservoir simulation.

The simulation model for the early trials assumed a finite but highly restricted vertical permeability throughout the Lower Rannoch interval. This model could match early data from the field adequately, all of which were from wells in the north and central parts of the field. The model, however, did not present a unique solution to the question of vertical permeability.

When Dunlin A-37 was drilled in 1980, Broom pressure measurements indicated a pressure gradient in the Broom from north to south. The model used in early history matching runs (Model A) was proved invalid and was revised to incorporate the new data. A satisfactory history match is obtained using a model with restricted vertical permeability in the lower Rannoch in the faulted area at the south end of the field (Model B). Vertical permeability elsewhere in the lower Rannoch appears to be nil. Table 1 compares the actual pressures in A-16 and the later A-37 with the pressures calculated using the different permeability models. Fig. 5 illustrates the pressure match in the lower zones using Model B.

The exact nature of vertical encroachment at the south end, either up a fault or through relatively poor shale development, is immaterial to the actual field performance. The important point is that the area of communication has been identified. This knowledge is important in our studies of possible completion schemes for the Broom interval. In fact, the model predicts a recovery of about 10% OOIP in the Broom through this natural communication, even with no wells specifically completed in the Broom zone. A rerun of the cross-sectional model with Broom perforations added to the lower-zone wells shows that the recovery would be improved to about 30% OOIP. Significantly, the model results at this stage show no detrimental effect from the Broom completions. Subsequent well completions at Dunlin have incorporated this knowledge, and Broom production started in late 1980.

The vertical permeability in the Upper Ness also was estimated by history matching. Permeability was found to be restricted in parts of the Upper Ness, but was relatively good elsewhere. A pressure match in the upper zones is illustrated in Fig. 6.

Simulation runs then were made for producing wells either completed throughout the Brent formation or completed only above or below the midreservoir shale. All wells were produced until reaching 90% watercut and then were shut in. The ultimate recoveries from both schemes were virtually the same, although there were some variations in recoveries in individual zones.

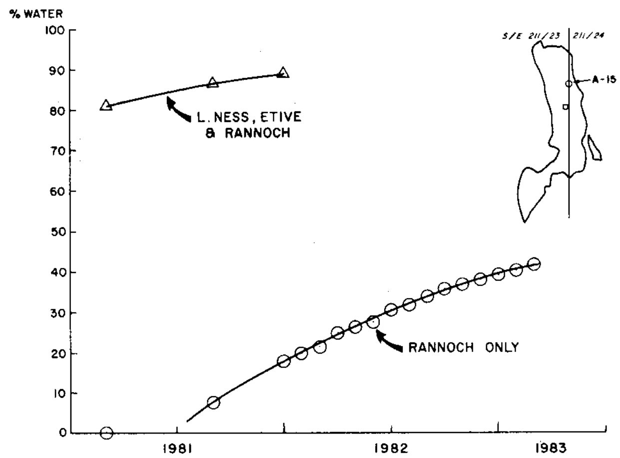

Fig. 9—Dunlin Well A-15, watercuts predicted by simulator.

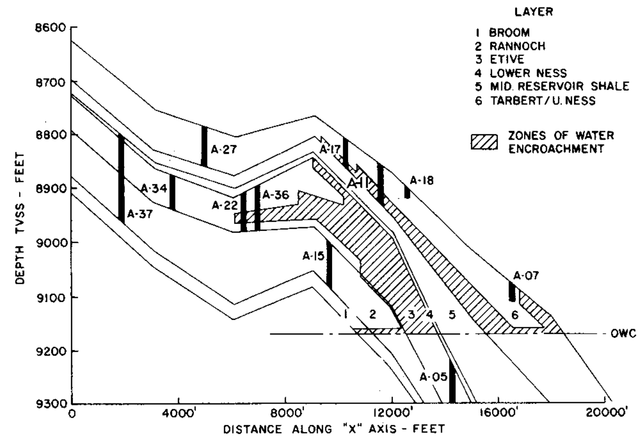

Fig. 10—Esso cross-sectional model study, water encroachment by March 1981.

Initial Results

The significant conclusions from this simulation work were as follows.

1. There is no advantage to commingling zones above and below the midreservoir shale.

2. Broom perforations should be added to lower zone wells.

Water Encroachment

Another use of models is in quantifying the nature and magnitude of water encroachment into the oil zone. Water tends to flow best through high-permeability streaks or sections within the individual substrata of the reservoir. However, early in the life of the field it is difficult to tell by the field performance whether the water is coming through a continuous high-permeability streak or indeed is encroaching uniformly from the bottom updip. The first Dunlin well to identify movement from the original oil/water contact was Dunlin A-18. Fig. 7 shows log-measured water saturations in this well with a transition zone and swept interval in the Etive some 80 ft above the original oil/water contact at 9,165 feet subsea. The oil could have been swept through this interval either by a uniform bottomwater encroachment or by sweeping in from the side, with the water sweeping fastest through the high-permeability strata within the Etive. The model predicted that this indeed was an uneven encroachment through the high-permeability streaks, as shown in Fig. 8. Later performance data from the Dunlin field have confirmed the model's prediction of water encroachment up the high-permeability streaks.

Recovery From Highly Stratified Section

The cross-sectional model has proved very effective in evaluating the recovery from the highly stratified Brent section found in many North Sea reservoirs such as Dunlin. Fig. 9, for example, shows the expected production from a well planned in the northern part of the main fault block, Well A-15. The possible completions for this well were to open all the interval below midreservoir shale or to complete only in the Rannoch section, which, per model prediction, had not yet been swept by water at the time of drilling (early 1981). The model predicted that a well completed in Rannoch only should recover oil from this interval, some of which might otherwise not be swept to other producing wells in the south. However, completion of the well in all intervals would be clearly uneconomical and would result in early abandonment of the well because of high watercut. These data were considered in planning the ultimate completion for the well. Well A-15 was drilled as planned, and the lower portion of the Etive essentially was watered out with a very low residual oil saturation. Fig. 10 shows the location of the flood front predicted by the simulator for early 1981. This figure shows the actual structural cross section used in the model. Grid blocks into which water has encroached are crosshatched on the figure. Note that the flood front has passed the Well A-15 location in the Etive but not in the Rannoch.

Routine Reservoir Management

Simulation has proved useful in monitoring reservoir management decisions. An example involved the possible recompletion of Well A-07, a northern, lower-zone injection well. Reservoir management requirements at the time dictated diverting some of the available injection capacity from Well A-07 to the Tarbert/Upper Ness. The possible uses for wellbore A-07 were Tarbert and Upper Ness injection, or Tarbert production if the water encroachment into the Tarbert had not passed this location. The model indicated a likelihood of Tarbert production, and the interval was completed as a 10,000-BOPD producer. Fig. 11 compares the predicted watercut with actual for this well. The simulator prediction supported the decision to preinstall production equipment, as well as to make alternate plans for Tarbert/Upper Ness injection.

Outlook and Plans

The development plan for Dunlin will remain flexible to incorporate new reservoir data continuously as they become available. Simulation will continue to provide guidelines to this plan as it evolves. The current plan is to continue drilling producing wells to provide good

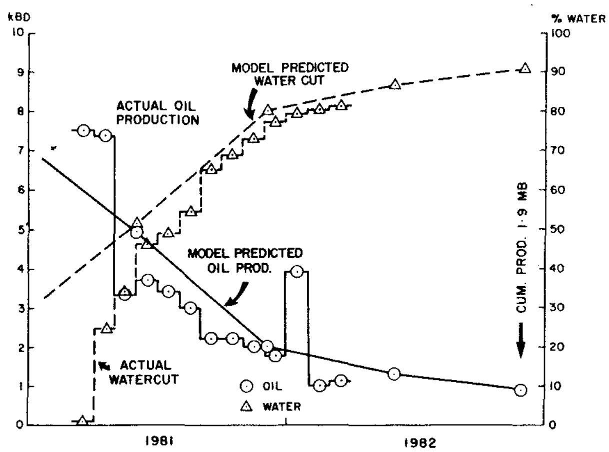

Fig. 11—Dunlin Well A-07, production predicted by model vs. actual results.

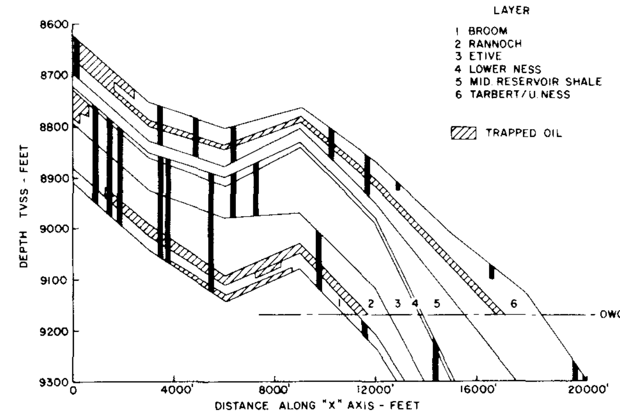

Fig. 12—Esso cross-sectional model study, predicted ultimate swept volumes if no wells were recompleted.

areal coverage in zones both above and below the midreservoir shale. Selectively completing wells to avoid watered-out intervals will be useful in reducing water production, but the highly stratified reservoir nevertheless should result in large volumes of water production. These data were considered by operating management, among other factors, in making a commitment to increase water-injection capacity.

The ultimate recovery from the field, however, is predicted to be relatively good. Depletion will require producing many years at high water cut, but most of the low-permeability strata eventually will be swept. Fig. 12 shows the ultimate swept volumes to include virtually all the Brent section. Areas of low recovery in the Upper Ness ultimately can be reduced by recompleting additional lower-zone wells into this interval following water out in the lower zones.

Small amounts of oil in the low-permeability zones in lower sections of the Rannoch will be relatively difficult to sweep. The operator currently is attempting selective completion into the Rannoch only in two Dunlin wells. Results of these tests will be incorporated in the future plans for Rannoch production.

Overall, the model, allowing for areal inefficiencies not accounted for in the cross section, predicts a recovery efficiency of about 44%. This value is remarkably similar to the 45% figure estimated by early simulation before any field development. These simulation studies have confirmed the viability of the current operation and plans for the Dunlin Unit.

Conclusions

1. Reservoir simulation using a cross-sectional model has proved valuable as a routine reservoir management aid at Dunlin. Results of this work have supported depletion plans to commingle production from the Broom sands with lower zone completions and to attempt to produce the Rannoch sand separately from the Etive zone.

2. History matching by simulation has quantified the vertical permeability in the Dunlin field. Field pressure performance and simulation matching show that vertical communication is good except across the midreservoir shale, across much of the lower Rannoch, and parts of the Upper Ness.

3. Water encroachment into the stratified Dunlin reservoir will result in high-water-cut production over the life of the field. Reservoir simulation has indicated that no loss in ultimate recovery results. Simulation will help in managing depletion plans to maximize recovery.

4. Esso's cross-sectional simulation studies of the Dunlin Unit indicate that current depletion plans are based on a sound reservoir management approach and will result in recovery of 44% OOIP.

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	= m^3
cu ft	× 2.831 685	E−02	= m^3
ft	× 3.048	E−01	= m
mile	× 1.609 344*	E+00	= km
psi	× 6.894 757	E+00	= kPa

*Conversion factor is exact.

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