SUMMARY

As the number of the world's fractured reservoir assets has grown, it has become increasingly important to develop new approaches in fractured reservoir modeling and simulation upon which productivity predictions, economic forecasts, and business judgements may be based. An integrated study at ExxonMobil Upstream Research Company developed a fractured reservoir modeling and simulation workflow by incorporating fracture characterization, geologic modeling, and fractured reservoir simulation technologies developed internally and externally to ExxonMobil. A field study was conducted to validate the workflow. During the validation study, a common-scale framework was built for geologic and simulation models. Effective matrix permeabilities were derived using ExxonMobil proprietary technology (patent pending). Comprehensive fracture analysis was conducted based on the field structure, stratigraphic facies, core, FMI logs, outcrop, and prior study. A discrete fracture network (DFN) model was built to generate the directional equivalent fracture permeabilities, porosity, and matrix block dimensions. EMpower™ dual-porosity/dual-permeability models were then built using common-scale geometry, effective matrix properties, and DFN-generated fracture properties. Simulations were carried out against a long history of multiphase production, and the results show a better history match than the previous single-medium model, suggesting that a dual-porosity/dual-permeability model more accurately captures the impact of fractures on fluid flow than does a single-medium model. This study demonstrates that the fractured reservoir modeling and simulation workflow is practical and effective.

FRACTURED RESERVOIR MODELING AND SIMULATION WORKFLOW

Our integrated process incorporates fractured reservoir characterization and fluid-flow simulation, using both ExxonMobil proprietary and vendor software tools (Petrel, EPSIM, FRACA, FloGrid, and EMpower™). It generates effective matrix properties, directional fracture permeabilities, and equivalent matrix block dimensions, which are used to build dual-porosity/dual-permeability reservoir simulation models. The workflow is as follows:

- Build geologic framework based on seismic, well data, and geologic concepts
- Generate effective properties
- Conduct comprehensive fracture analysis
- Build discrete fracture network (DFN) models
- Calibrate DFN models to dynamic well test data and production logging tests
- Generate equivalent fracture permeabilities, porosity, and matrix block dimensions
- Build dual-porosity/dual-permeability simulation model
- Validate model based on agreement with production history

As a validation of this workflow, we present a successful application to a naturally fractured reservoir.

RESERVOIR SETTING

The field under study lies in a weakly deformed carbonate platform (Figure 1). Within the reservoir, a series of third order sequences has been recognized, with each reflecting transgressive-through-highstand systems tracts (Figure 2). Each transgressive-to-highstand couplet is interpreted to represent a single cycle of rapid accommodation.
increase followed by slowing in that increase. Transgressive systems tracts are defined by widespread shoal deposits, formed during rapid accommodation increase. Highstand systems tracts represent periods of slower accommodation increase and are characterized by well-defined platform-margin buildups and restricted platform interior (Muir et al., 1984; Yose et al., 2001a, b).

The dominant reservoir rock type is diagenetically recrystallized limestone with very fine-scale intercrystalline porosity. The best microporosity is developed in skeletal grain-prone facies; so, despite significant diagenesis, reservoir quality can be predicted effectively from depositional facies and stratigraphic framework. The transgressive-to-highstand systems tracts show significant lateral and vertical facies and textural variations. The platform-wide transgressive deposits are interpreted to have formed at 15 to 20 m water depth. Relatively uniform energy flux across the platform at these times produced continuous reservoir units with minor facies variation. Highstand units show greater lateral variation in facies. These units are interpreted to have formed at water depths ranging from 2 to 15 m as biota responded to slowing relative sea-level rise and build-ups began to exert more control on local energy flux. Mechanical differences in rocks produced in different depositional environments exert substantial control on fracture network characteristics, making the sequence stratigraphic model an important input to the fracture modeling work (Muir et al., 1984; Yose et al., 2001a,b).
Movement on a thrust fault down-section from the reservoir interval built a structural tilt that increases across the field from ~5° to ~10°, forming a combined structural and stratigraphic trap (Figure 3). Natural fractures associated with the same compressional event variably enhance reservoir permeability. Two nearly orthogonal regional fracture sets have been described consistently from core, through outcrop, to aerial photo scales. Orientations are consistent with expectation for the structural setting: one set is developed parallel to the maximum horizontal compressive stress inferred from the thrust sheet transport direction, and one set is parallel to the hinge on the fault-ramp-related fold. Relatively low rock matrix permeability is enhanced by these natural fractures, especially in the higher dip portion of the field (Muir et al., 1984; Yose et al., 2001a,b).

**MODELING AND RESULTS**

**Reservoir Modeling**

**3D geological modeling**

Because computed fracture network permeabilities may show scale and boundary condition dependencies (Couples, et al., 2003, Flodin, et al., 2004), we designed our 3D geological model to minimize the need for scale-up and to test the fracture network over the largest volume possible. Layer optimization (Stern and Dawson, 1999) yielded a 17-layer model. Areal dimensions of cells were set to 62.5 m x 62.5 m to insure that wells would be separated by a sufficient number of grid cells. Effective matrix properties dependent upon fine-scale lithologic variation were modeled using the proprietary ExxonMobil EPSIM technology (patent pending).

To capture the effects of depositional facies on reservoir response and development of natural fractures, facies assemblages were defined on the basis of reservoir quality. These assemblages are represented in the 3D geological model by a discrete Lithofacies property. Three transgressive and five highstand lithofacies were modeled (Yose et al., 2001a,b).

Development and hydraulic effectiveness of fractures within the reservoir are also strongly controlled by structural position relative to the ramp on the underlying thrust fault. Therefore, a discrete “Structural Domain” property was modeled, dividing the reservoir into regions of High, Moderate, and Low fracture impact. Well interference and tracer tests indicate strongest evidence for fracture-related flow in the region of High fracture impact. The Low-impact region shows little evidence of such flow, and the Moderate region shows an intermediate response (Yose et al., 2001a,b).

To reflect the controls imposed by both lithofacies and structural position, a composite discrete “Fracture Domain” property was built (Yose et al., 2001a,b) based on appropriate combinations of the “Structural Domain” and Lithofacies properties (Figure 4). These combinations were determined based on a calculated component of non-matrix permeability (obtained by taking the difference of well-test-derived permeability estimates and scaled-up core-plug permeabilities). Cumulative probability curves (Yose et al., 2001a,b) showing the range of non-matrix permeability values associated with each discrete “Fracture Domain” are shown in Figure 5. The “Fracture Domain” property was used to control the spatial variation in fracture network characteristics during the fracture modeling.
Figure 4. Views of the 3D geologic model showing the Lithofacies and Structural Domain properties, which were combined to produce the “Fracture Domain” property. Fracture properties in the Discrete Fracture Network model were keyed to “Fracture Domain” values.

Discrete Fracture Network modeling
In order to predict the hydraulic behavior of the fracture network, we built a discrete fracture network (DFN) model using Beicip, Inc.’s FRACA software. We then used FRACA to compute directional fracture permeabilities and equivalent non-matrix permeability (mD).

Figure 5. Cumulative probability curves for non-matrix permeability. Numbered curves correspond to values of the discrete “Fracture Domain” property. “Fracture Domains” for parasequence set 8 are shown in the inset map.

matrix block dimensions for use in the EMpower dual-porosity/dual-permeability simulation described below.

In a DFN model, a virtual rock volume is stochastically populated with planar objects to represent natural fractures. These objects are assigned properties from statistical distributions, defined through integration of outcrop and well fracture data, field production data, and theories of mechanical and hydraulic behavior.

An appropriate set of statistical distributions was defined for each value of the “Fracture Domain” property. This property was exported as a 3D grid to FRACA and used to control the spatial variability in fracture characteristics in our DFN model. Those characteristics were primarily

- fracture orientation
- bed-parallel fracture length
- bed-perpendicular fracture length
- fracture spacing
- fracture conductivity (permeability and aperture)

Fracture dips and dip directions are drawn from independent circular von Mises distributions. This distribution is fully described by a mean and a concentration parameter. Distribution parameters defining orientations for the two approximately orthogonal fracture sets in the DFN are listed in Table 1.

Fracture length scales are defined in terms of both bed-parallel and bed-perpendicular fracture extents. The length measured parallel to bedding is drawn from a log normal distribution (with parameters for sets 1 and 2 listed in Table 1). The bed-perpendicular length is related to the thickness of observed sedimentary bedding and to the tendency of fractures to terminate at or crosscut bedding surfaces. This tendency is specified as a probability that a given fracture should extend from one bed to the next. Average bedding thickness and crossing probabilities for sets 1 and 2 are given in Table 1.

Fracture density for each set is defined in terms of a mean fracture spacing. Local variation about this mean value is positively correlated with the thickness of sedimentary bedding. This relationship
Table 1. Discrete Fracture Network parameters

<table>
<thead>
<tr>
<th>Fracture Set:</th>
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<th>2</th>
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<tbody>
<tr>
<td>orientation</td>
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<td>180°</td>
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<tr>
<td>dip direction</td>
<td>2.0</td>
<td>1.5</td>
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<tr>
<td>dip</td>
<td>88°</td>
<td>75°</td>
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<td>conductivity</td>
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<tr>
<td>spacing</td>
<td>1.4 to 3.3 m</td>
<td>2.5 to 7.8 m</td>
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<tr>
<td>bed-parallel length</td>
<td>3.0 m</td>
<td>1.5 m</td>
</tr>
<tr>
<td>mean</td>
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<td>0.5</td>
</tr>
<tr>
<td>bed-perpendicular</td>
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<td>20 to 33</td>
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<td>length % crossing</td>
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<td>75 to 300</td>
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<tr>
<td>mean</td>
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<td></td>
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</table>

EM\textsuperscript{power} dual-porosity/dual-permeability simulation

Equivalent fracture network permeabilities, porosity, and matrix block dimensions were exported to Petrel for visualization, quality control, and shape factor calculation. Then the common-scale framework, effective matrix properties, equivalent fracture porosity and permeabilities, and shape factor were exported to FloGrid to build the simulation grid.

The common-scale approach applied in this study minimized upscaling the geologic model. The simulation grid honored the 3D geological model layering exactly (with 17 layers). The 62.5 m x 62.5 m cells were preserved for most areas, except in the aquifer and the thin, fracture-poor shoal-extension area where a coarse hexagonal grid was used to reduce the size of the simulation model. Figure 7 shows the full field simulation grid.

Three flow systems exist in a dual medium reservoir: flow in fractures, flow through matrix, and fluid transfer between matrix and fractures. Driving forces for fluid transfer between matrix and fractures include: pressure gradient, capillary pressure, gravity drainage, convection within the fractures, diffusion, and thermodynamics (expansion, vaporization). Among these, pressure gradient, capillary pressure, and gravity drainage are the most important. Since a matrix node and its corresponding fracture node are at the same elevation in a dual-medium simulation model, it is impossible to simulate gravity driven exchange between matrix and fractures directly. Therefore, a pseudo-capillary pressure term is used to represent both capillary pressure and gravity drainage effects (Rossen and Shen, 1987).

Pseudo-capillary-pressure curves were generated with fine-grid simulations of typical matrix blocks surrounded by fractures. Four fine-grid models were built for four displacement regions with different fracture spacing and matrix block size. Both gas-displacing-oil and water-displacing-oil scenarios were modeled (see Figure 8).

EM\textsuperscript{power} dual-porosity/dual-permeability results

Simulation results were compared to the 59-year field production history and to the prior history-
Figure 6. Directional effective fracture network permeabilities computed from the DFN and used for EMpower™ dual-porosity/dual-permeability simulation.

Figure 7. Full field simulation model (81,512 total active nodes). Color Scale represents depth. Blue is high, red is low.

Figure 8. Water saturation computed for fine-grid simulation of a single block of reservoir rock matrix bound by fractures on all sides.

matched single-porosity/single-permeability results. In this single-porosity model, total permeability was derived by adding the non-matrix permeability component (described above) to matrix permeability values.
Because full-field dual-porosity/dual-permeability simulation was time-consuming, a partial-field model (with 28,359 total active nodes) was used to accelerate the validation process. The partial-field model covers the more fractured, updip part of the field (Figure 9).

Neither matrix nor fracture permeabilities were modified during EMpower™ simulation. Results shown represent a “first-pass” model rather than a “history-matched” solution.

Total liquid (oil + water) rate was specified.

The EMpower™ results match the field oil and water rates well, showing an improvement over the history-matched single-porosity results. The match for the gas rate also shows improvement, but less dramatic. We suggest that the artificial boundary imposed in the EMpower™ partial-field model produced unrealistically high reservoir pressure predictions and, therefore, unrealistically low free gas production.

Due to the age of most wells, few down-hole pressure gauges have been placed in the field, and flowing bottom-hole pressure (FBHP) data are unavailable for most wells. Calculated FBHP based on wellhead pressure were available for some wells, but proved inadequate to support any comparison with predicted pressures.

Figure 11 gives the EMpower™ simulation results for a group of 16 producers from one terminal. Again, the EMpower™ results give a better match with the field oil and water rates than do the single-porosity results. The gas rate computed for these 16 producers gives a better match than was obtained in the preceding example, possibly because these 16 wells are farther from the artificial boundary.

Figure 12 presents the simulation results and field data for a single well. Also in this case, the partial-field EMpower™ dual-porosity/dual-permeability model matches the field data better than does the full-field single-porosity model.

**CONCLUSIONS**

Capturing the effects of fracture-related flow with the dual-porosity/dual-permeability approach implemented in ExxonMobil’s proprietary EMpower™ simulator produces a significantly better match to field performance data than was achieved with a single-porosity/single-permeability simulation strategy. Success of field validation demonstrates that the fractured reservoir modeling and simulation workflow is practical and effective.
Figure 10. Simulation results and comparison for a group of 40 producers from four terminals.

Figure 11. Simulation results and comparison for a group of 16 producers from one terminal.
REFERENCES


