Indonesia's Jene Field:

The reservoir pressure in Indonesia’s Jene ("Jenny") Field nosedived soon after production began three years ago. To prevent a decline below bubblepoint pressure, operator P.T. Stanvac Indonesia (an Exxon Corp./Mobil Corp. joint venture) immediately started a water injection program. The field pressure has since been stabilized. Attention is currently focused on development optimization using a second generation version of the simulation model that was used to design the water injection program. Now the same model looks set to guide field production for the next 20 years.

Oilfield Review looks at the history of this major field and at the rare opportunity it has provided to simulate a field development virtually from the start of production.

Alarm bells rang as soon as the Jene Field went on production in September 1986. For every 1,000 barrels of oil that were being produced, the reservoir pressure dropped by 1 pound per square inch (psi) (right). If the decline had not been halted, the reservoir pressure would have soon dropped below bubblepoint; it was feared that this might lead to loss of ultimate recovery and production difficulties similar to those already experienced in the nearby Krisna Field. Krisna, like Jene Field, produces from the prolific Batu Raja carbonate formation.¹

Designing the optimum pressure maintenance system for the Jene Field posed quite a problem for P. T. Stanvac. The field had been put on production a year after its discovery and the only detailed information about the oil-bearing formation was from logs taken in four wells, three of which had been drilled along the field crest and the fourth on the extreme southwest edge of the reef (page 6). Elsewhere, the lateral extent of the reservoir and the structure of its flanks had to be deduced solely from 260 miles [420 kilometers (km)] of surface seismic data (next page, right). Today, the information about the field is much more comprehensive as 38 wells have now been drilled.

A rapid decline in field pressure after the Jene discovery well went on production in 1986. The field would approach bubblepoint pressure (1,500 psi) within a year unless a water injection program was implemented. The question was, where to inject the water?
A Reservoir Simulation Case Study

However, in 1987, log and core data indicated that the 6,000-foot [1,800-meter] deep oil field was made up of a series of stratigraphic Miocene reef buildups with associated fore and back reef deposits.

Reef growth occurred in shoaling upwards cycles which terminated in sub-aerial exposure (probably due to a combination of basin subsidence and tectonics rather than eustatic sea level changes). Each growth cycle produced buildups a few kilometers long which were mainly elongated northwest to southeast, parallel to the paleo-shoreline. During

the exposure period, secondary porosity zones and permeability barriers developed in the vadose zone (water table zone) near the top of each buildup cycle.

Porosities near the crestal portions of the reefs typically range from 8 to 25 percent. In the phreatic zones, and the fore and back reef areas which were not subject to sub-aerial exposure, the early diagenesis and porosity destruction was preserved. This can be clearly seen on the microresistivity logs (right).

During a final period of sub-aerial exposure, the reef complex developed a laterally persistent vadose zone crosscutting individual cycles. Precipitation of dissolved carbonate from the vadose zone resulted in an almost field-wide permeability barrier which is also easily recognized on the microresistivity logs. According to Stanvac, recent tectonic movements rotated the entire reef structure 12 degrees to the southwest.

In 1987, all the evidence indicated that the oil-water contact had a similar dip and also coincided with the position of the main "tight streak." But where should Stanvac inject the water to maintain field pressure?

The company was faced with two options. The conventional approach would have been to place the injection wells on the flanks in an attempt to sweep the oil towards the crestal producers. However, the lack of geological information about the flanks made this kind of program risky. It would have been difficult to predict the quality of the aquifer rock (and hence the injectivity of the well) and there was always the possibility that water fingering would occur leaving major blocks of oil unswept.

Injection tests on Jene #4, which was the only well drilled off the crest, showed that it would be difficult to inject sufficient quantities of water economically.

The alternative was to inject water beneath the main tight streak from a series of injection wells placed along the long axis of the field crest. The theory behind this scenario was simple. If the tight zone were extensive, the injection water would spread out horizontally, creating a high-pressure zone that would effectively act as a piston.

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*Mark of Schlumberger*
pushing the oil slowly but uniformly toward the crestal wells.

However, this injection method also posed risks. If the tight zone turned out to be patchy, there would be the possibility of rapid water breakthrough into the oil zone which could have a serious impact on the potential oil recovery. But if this did happen, there was the possibility of completing the well in the oil zone thus converting the injection well into a producer. This option would not be possible if a flank water injection well found poor or no aquifer rock; such a well would be a total loss. On the other hand, if the main tight streak was highly impermeable, the bottom water drive would not work and other approaches would have to be considered.

Stanvac asked Schlumberger to build a reservoir model to predict the field’s response to a variety of injection scenarios. Because of the rapid pressure decline, it was important that the simulation runs be completed within four months to leave sufficient time to install an injection system and surface facilities before the reservoir pressure reached bubblepoint.

Obtaining data of sufficient quality to build and test a reservoir model in such a short time was the first challenge facing Schlumberger’s modeling team. The field had been on production for only about five months and less than 0.5 percent of the estimated oil in place had been produced. In addition, the reasonably fresh connate water (20,000 parts per million [ppm] dissolved solids) made it difficult to determine precisely water saturation values from log data and the exact position of the oil-water contact.

The model and its parameters had to be determined from log data and laboratory measurements of cores and oil samples acquired prior to the start of production. In addition, some pressure data had been obtained in producing wells. Initially, there was no significant water cut, so history matching was based on pressure alone. This created a major area of uncertainty for long range forecasting since the efficiency of the recovery mechanism was critically dependent on the control of produced water. As more data became available, they were compared with the model prediction, and modifications were made as necessary.

The Model Develops

Seven development wells of the Jene Field had been subjected to a thorough testing program by the time the model was built. This data, which included hundreds of Repeat Formation Tester (RFT) tool pressure measurements and full well tests, proved to be the key data upon which the initial model was built.

Fortunately, the discovery well, Jene #1, had been surveyed with an RFT tool before production started and three vital pieces of information were derived from this:

First, it provided the original vertical pressure distribution in the reservoir—an excellent baseline from which to observe the field’s reaction to the onset of production.

Second, the intercept of the water- and oil-pressure gradients indicates the precise position of the oil-water contact.

Third, the oil pressure gradient can be interpreted to give the in situ fluid density of the reservoir fluid.

The next step was to quantify the horizontal communication between wells. To obtain the average horizontal reservoir permeability, an interference test was conducted before field production started. During the test, oil was allowed to flow from Jene #1 and the pressure response in three neighboring wells (Jene #2, #3 and #4) was monitored using gauges run on slickline. Because the field was in its virgin state, the measured response at the three observation wells had to be due to the effect of oil being removed from Jene #1.

The interference test data were first interpreted assuming that the reservoir was infinite and homogeneous. The analysis was carried out by making a simple type-curve
However, the system compressibility derived using this simple analysis differed by a factor of three from the values obtained from laboratory pressure-volume-temperature (PVT) tests.

The reservoir was then modeled as a rectangular bounded system—basically as an enclosed box (below). The theoretical type-curve response for this kind of reservoir geometry proved to be a close match with the pressure response from the three observation wells. The system compressibility derived from the interference test analysis closely matched laboratory measured values.

The interference test proved that there was communication in the oil zone between all wells. This was a significant revelation as the surface seismic data had indicated a possible fault running between Jene #1 and Jene #4 which, had it been a sealing fault, would have interrupted communication.

For each well, analysis of the buildup and drawdown tests enabled individual horizontal permeabilities to be calculated. For example, the interference test between Jene 1# and 2# revealed an average permeability of 675 millidarcies (md). But individual well tests on Jene #1 and Jene #2 gave permeabilities of 210 and 400 md, respectively. These individual permeability values served as a useful guide to field-wide permeability mapping.
Microresistivity logs were run in almost all the production wells. The logs were interpreted using LITHO*, an interpretation program which identifies electro-facies—formations which exhibit identical characteristics on logs. These electro-facies can be checked against a core description. Micrologs helped to identify tight streaks, comprising mainly siltolites, between several reservoir layers. Therefore, in addition to the average reservoir horizontal permeability, the modelers also needed an estimate of the horizontal permeability of each reservoir layer.

This was achieved by developing a transform that converted log-derived water saturation values into permeability values. These were then checked for each reservoir layer by comparing them with spot permeability values obtained from drawdown analysis of RFT tool pressure tests and core-derived permeabilities (cores were taken in only four wells and did not cover the total reservoir thickness). As a final check, the log-derived permeability values were compared with those obtained from full-scale well tests. The log transform was then used to calculate the horizontal permeability values of each reservoir layer.

Determining the number of layers necessary to model reservoir behavior was important for efficiency—the more layers in the model, the more computer time would be needed to complete a simulation. To minimize the number of layers that would accurately represent the reservoir, individual layers were grouped if they exhibited similar production characteristics across the field. These characteristics were determined using single-well models.

The first model incorporated every layer indicated by the highly sensitive microresistivity logs. The number of layers was then reduced until the simplification began to significantly affect the accuracy of the simulation. It was eventually decided that a nine-layer model would satisfactorily represent the reservoir system, each layer being assigned an individual horizontal permeability (below, left).

The next challenge was to quantify the vertical communication within the reservoir. This is needed to predict the efficiency of the essentially vertical water influx and requires an estimate of vertical permeability which is extremely difficult to measure. Core analysis provides vertical permeabilities only on a very small scale. Interference testing can be used to obtain average values for the reservoir, but the testing procedure is complex.

However, comparison of the baseline pressure gradient measured in Jene #1 with that taken several months later in Jene #7 indicated a change in the pressure gradient above the oil-water contact (above). This change could not be attributed to an increase in fluid density as this is practically constant above bubblepoint. The only possible explanation was that vertical fluid movement had produced an increase in the pressure gradient in the formation.

This provided the modelers with a relatively simple means of estimating the vertical permeability of each reservoir layer. Using single-well modeling, they adjusted the vertical permeabilities in each layer until the simulation results accurately matched the field data. From the results they deduced that the vertical permeability in the porous zone was 2.1 mD. Subsequent material balance calculations enabled them...

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to derive a value of 0.0015 md for the main tight streak in the reservoir—an extremely important parameter as it controlled the efficiency of the water injection scheme. Too low a value would mean high injection pump pressure requirements, low injectivity and probably inadequate support; too high a value would mean a rapid water encroachment. Finally, the RFT tool pressures measured in the aquifer below the extensive tight streak enabled the size and productively of the aquifer to be calculated from material balance equations.

Core and log data for each well were combined with surface seismic data and correlated on a Schlumberger reservoir description workstation to produce a static, three-dimensional, multi-layered, multi-well model. The dynamic analysis of the reservoir could then be carried out using the Eclipse 100 reservoir simulation software on a mainframe computer.3

Three months after the modeling work started, the full-scale model was almost ready for its first simulation run. In situ fluid properties data—formation volume factor, viscosity, compressibility, solution gas-oil ratio—necessary to initialize the model at its virgin equilibrium state, had been obtained from PVT analysis. Only one item of data remained to be found, namely, the formation capillary pressure. This was essential for computation of initial reservoir saturation values.

Capillary pressure had been obtained from core analysis but the results were poor; they indicated high water saturation in the oil zone. As one modeler put it, “Had we believed the core analysis we wouldn’t have had a reservoir.” With the core data discarded, the only option was to plot log-derived saturation values versus depth and use the Leverett “γ” function to derive an average capillary pressure.

Rock properties—capillary pressure as a function of saturation, porosity, absolute and relative permeability, anisotropy—were then assigned to every block in the multi-well, multi-layered model. The modeling process is relatively simple but numerically laborious. The model essentially solves a material balance for the entire oil field. During each time step of a simulation run, a specified amount of fluid is removed from each reservoir block containing a producing well, which is “completed” in this block. The program logic then calculates the remaining fluid volumes, pressure changes and resulting inter-block flows of oil and water. On average, a full-scale simulation of the Jene Field model takes several hours on a mainframe computer and produces a saturation and pressure value for every block of the reservoir over time.

History Matching

When the first modeling runs were carried out, the Jene Field had been on production for only six months and no significant water had been produced. The only way of checking that the model was working properly as they were given to us. The match was so good that a Stanvac manager commented that he would have accused us of cheating had it been any closer.”

By this time, the model had proved that it could simulate the behavior of the field and the long-term prediction phase was started in earnest. This allowed Stanvac to determine the amount of injection water needed to maintain the reservoir pressure above bubblepoint and reach the plateau production target set by the reservoir managers. The model also indicated that there should be no problem injecting water at the crest, under the extensive main tight streak. With this information, Stanvac achieved its primary objective of designing its injection system including wells, pipelines and associated facilities before the reservoir approached bubblepoint. The field water injection capacity was targeted at about 8,000 barrels per day of water, to be brought on stream as the injection wells were drilled.

Examination of the predicted performance showed that there were several ways recovery might be increased and simulations were performed to test the various options (next page, bottom).

The model showed it was possible to achieve a recovery of 37 percent of stock tank oil in place by adjusting the planned location of some injection and producing wells. Flank producing wells were moved upstructure to prevent early water breakthrough and improve sweep efficiency. All

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Predicting performance of the Jene Field. These typical simulation runs show the field water saturation and pressure at 392 and 850 days after the start of production. The oil sweep, generated by water injection, can be observed. Note how casing leaks in Jene #13 (injection well) significantly affect water saturation throughout the entire reservoir interval. The cross section is taken along plane 6 of the model (left).

Predicting productivity, Stanvac used the model to predict field performance until 1993. This simulation run shows that the target production rate set by Stanvac could not be maintained beyond 1991 and that production would have declined two-thirds by 1993.


5. Eclipse 100 is a trademark of Exploration Consultants Limited.
injection wells were repositioned along a line directly beneath the long axis of the reef, and the number of injectors was increased from five to seven. Fine-tuning of producing well locations was carried out by relocating poor performance wells to areas of predicted high residual oil saturation.

Simulation runs also revealed that too many producing wells would decrease the recovery in a given time frame, because of interference between producers and injectors and the loss of energy through production of injected water.

The Model Strikes Back
Besides performing prediction runs, the model also proved to be extremely useful for spotting anomalies in the field data. The first incident occurred soon after the water injection program had been put into operation in November 1987, 420 days after production began. The model had predicted a rise in reservoir pressure over the following months. This rise was initially seen in the field data. But by July 1988, the measured pressure started to drift progressively lower than that predicted by the model (above, left). "The first reaction when this kind of thing happens," Wittmann observed, "is to tweak the reservoir parameters to try and achieve an acceptable match between the real and modeled data. But in this case we would have had to adjust the parameters a ridiculous amount. After a frustrating time we concluded that the pressure data must be wrong and discussed this with the Stanvac reservoir engineers who were also wrestling with the same problem. They were trying to reconcile pressure measurements taken with their own Amerada gauges with the high-performance gauge measurements taken by a contractor. The

Water breakthrough or poor cement? A much higher-than-predicted water cut was observed in June #10. It was feared that water breakthrough had occurred on a major scale, maybe as the result of a patchy low-permeability layer between the aquifer and oil zone. The model indicated, however, that this was unlikely. The reason became obvious when radioactive tracers were injected. A gamma ray log was run in the well and showed there were major channels in the casing cement through which the injection water was able to pass. Remedial cementing has been carried out to cure the problem. All new injection wells are fitted with external casing packers as an added precaution against leaks.
model passed judgement: Stanvac’s humble Amerada gauges were right and the high-performance gauge was wrong! The contractor’s records showed that the gauge had been slightly damaged in June. Laboratory testing revealed that the gauge had subsequently started to suffer from temperature effects and was consistently giving too low readings.

Another worrying moment for the modeling team came when a high water cut was seen in some of the producing wells soon after injection had started (previous page, bottom). This seemed to indicate that the tight streak, which was being relied upon to distribute the injection water pressure evenly under the oil field, was not as extensive as was first thought. Serious water breakthrough problems seemed to be just over the horizon.

However, the simulation model indicated that such a high water cut would probably not be seen, even if the tight layer was patchy. This prompted Stanvac to look for leakage in the injection wells. Radioactive tracer surveys were run in wells with suspected leaks using a logging device that injects a very small amount of radioactive material into the injection water. It then follows the progress of the radioactive cloud with a gamma ray survey. The problem was immediately obvious. Poor casing cementing meant that the aquifer and oil zone were in communication along the borehole.

Remedial cementing was carried out to prevent leakage (below). As an added precaution, all the new injectors are fitted with external casing packers to prevent further water channeling problems.

The model and the field behavior also revealed that the reservoir must be bigger than indicated by the surface seismic data. As more oil was taken out, the rate of pressure decline began to decrease exponentially. Meanwhile, Stanvac had drilled a new well to the northwest, outside the original field boundary, to check what appeared to be a small local seismic high. When this struck oil, everyone realized that the surface seismic data needed to be reinterpreted.

A major revision of the seismic velocity data, using a Schlumberger reservoir description workstation was carried out (bottom, left). As Graham Bunn commented: “As a first pass, Stanvac had originally used a simplified velocity field to convert the seismic time to depth. We used a more rigorous, geostatistical approach, called Kriging, to derive what we believed to be a more realistic velocity field. The depth map derived in this way is very similar to the one that Stanvac had made, but has significant differences at the northwestern end of the field. Jene #36—which was thought to be situated in the saddle between the little seismic high and the main field—was accurately predicted by the geostatistical map and

529 days

Water Saturation

2,638 days

- Injection well
- Production well

Simulations showing the change in reservoir saturation by 1993. Note the effect that leaking injection wells would have on the final water saturation distribution if they were not repaired.

A typical workstation screen display of interwell correlation between the seismic and log data. The reservoir description workstation enabled surface seismic data to be correlated between wells and with well log information. From these log and seismic correlations, it was possible to deduce the structure of the Jene Field away from the crest. This was particularly useful as only one of the field’s 38 wells had been drilled on the flanks.
proved a significant extension of the Jene Field. On the other hand, a few weeks later, Jene #38 struck oil 30 feet lower than predicted—so much for statistics.”

Meanwhile, further analysis in several wells led to an improved correlation between core- and log-derived permeability data that was applied to all the wells in the field. The improved data sets were incorporated into a revised model which is the one in use today.

Another modification to the model became necessary when it was realized that injection in Jene #13, in the southeastern portion of the field, was felt almost instantly in a nearby well, Jene #6, and yet hardly seen in others, Jene #3, #4, #11, #16, and #30 (above). This can only be modeled by assuming that a zone of high permeability lies between the cluster of wells. Could this high permeability streak be following the line of the fault that was first seen on the surface seismic data? Stanvac is now carrying out interference testing to solve the puzzle.

The Future of Modeling
There is no doubt in the Stanvac reservoir engineers’ minds that reservoir modeling brings important benefits to oilfield development. Their experiences working for P.T. Stanvac Indonesia on the Jene Field model and on other modeling projects around the world have convinced them that reservoir simulation will continue to play an increasingly important role in the oil industry.

“Every time I have seen a model built, it has helped with field management and taught us things about the reservoir,” says one senior Stanvac engineer. “The question is: if you have a one- or two-million barrel field, is it worth the effort and cost of modeling? Jene was certainly worth the effort and cost—the field is Stanvac’s crown jewel.”

The senior engineer explains that the Jene Field model, designed to plan the water injection program, has helped in many other ways: “For example, the current model is helping us optimize production. We want to know how many wells to drill and whether we can defer the timing of drilling to save expenditure. We are currently investigating whether to produce the highest water cut wells to strip oil and defer production from the low water cut, ultimate drainage well.” Stanvac also plans to use modeling to help with the timing of artificial lift.

However, their engineers do not believe in placing too much reliance on modeling but say that it is better to use a model for planning well locations rather than simply drawing a matrix over a 40-acre area and drilling a well at every node point.

The company’s long-term aim is to develop a smaller model that will be directed at answering short-term problems in small areas of the field. Simulations with such a model would cost less in computer time yet provide the necessary short-term answers. Occasionally, the full-scale model would be run to keep a check on the performance of the entire field.

Stanvac has also turned its attention to the adjacent Plan Field. “This field has a gas cap and other problems,” says another senior reservoir engineer, “and we shall certainly be doing some radical modeling on this.”

—GC