Integrated Technology Streamlines Exploitation

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Amoco Canada Petroleum Company Ltd. has been organised in multidisciplinary teams for five years. But team members have typically worked in separate offices and lacked significant computing technologies to link their individual efforts. What was needed was a means of working together to make quicker, more reliable interpretations in order to pick optimum drilling locations and increase revenues.

Last year, the company investigated various ways of reducing cycle time and improving efficiency. The decision was made to conduct a pilot study using a common work environment and an integrated suite of Landmark software applications that share a common Oracle database. An asset team responsible for exploiting a small oil field in western Saskatchewan was selected for the project.

The core team for the Landmark Integration Project (LIP) consisted of a geophysicist with experience in seismic and mapping software (Brooks), a reservoir geologist with no prior workstation experience (Beaudoin), a reservoir-engineering technologist with PC experience (Froehiich), and a data manager

To facilitate the integrated process, Amoco Canada created a workroom (Figure 1) with three networked workstations — two Sun Spare 20s, and a Silicon Graphics High Impact —running a suite of applications for project data management, 3D seismic interpretation and visualization, synthetic seismograms, velocity modeling, geological interpretation, petrophysical analysis, mapping, reserve attribute analysis, and 3D geocellular modeling.

In addition, the LIP team contracted two Landmark technical consultants' to help the completely redesign their workflow and learn the applications "on the job".

Integrated Work Process

In less than two months, the LIP team completed the first three phases of its project: Database Assembly, Reservoir Delineation, and Reservoir Characterization of the field under study. A fourth phase, dubbed "Interpretation While Drilling" or "IWD," took place in. real time as new data came in during the drilling program

Database Assembly Data for the Landmark Integration Project consisted of a 3D seismic survey and a comprehensive well database. We information from 47 wells (21 within the seismic area of interest) included headers, raw log curves, formation tops, cross sections, petrophysically derived curves, zone attributes, structure and isochore grids and pointsets, synthetics, time-depth tables, and production data.

Fig 1: [wide shoot of team room with three people at workstation]. A common work environment facilitated teamwork. Team members are Darcy Brooks, geophysicist(front); Bill Beaudoin, geologist (center); and Warner Froehlich, reservoir engineering technologist(back).

Building a clean, integrated database required considerable effort to redundancies and reconcile nomenclature from different sources. Once all the data was loaded, however, the system provided powerful ways of accessing a wide variety of project information quickly — from tops and oil/water contacts to KB elevations, DSTs, or longitude and latitude. Interactive tools helped locate wells with particular log suites, customize cross section displays on the fly, and establish a common stratigraphic column for the project.

Reservoir Delineation. In the second phase, the team's unified approach enabled them to delineate the primary reservoir container with greater accuracy than ever before. They interpreted four key surfaces and three geologic units: the reservoir sand, the underlying shale, and the overlying carbonate. With integrated geological interpretation software, correlating logs, building and updating cross sections and maps were done much more rapidly than on paper.

Integrated applications also allowed the geologist and geophysicist to work more efficiently (Figure 2). First, they constructed a velocity model from time-depth tables in the database. Well log picks made onscreen were passed through the velocity model, and displayed instantly on seismic sections to guide interpretations in ambiguous places. Once the key horizons were interpreted, seismic time grids were run through the velocity model again, converting them back to depth.

Then the depth grids were residually surface corrected and tied to well control for final mapping of reservoir structure. Since few sonic logs and no checkshot surveys were available, the velocity model was later revised many times as new information came in during the drilling program

At this point in the workfiow, the team built a 3D geocellular model of the reservoir in depth. Because of extreme structural variations in the reservoir, the ability to visualize the structure in three dimensions was vital to quality control of interpretations and placement of wells (Figure 3).

Reservoir Characterization. In the third phase of the project, each cell of the 3D geocellular model was populated with over 50 rock and reservoir attributes. Zone attributes for the 3D model were derived from petrophysical and geological software, as well as historical production data. The team generated up to 14 petrophysical curves for each of the 21 wells

Fig 2: [Two monitors with data onscreen] Software applications that share a common database enabled better integration. A geologic cross section with depth-converted seismic backdrop (left) and a seismic section with time converted well log picks(right) aids correlation.

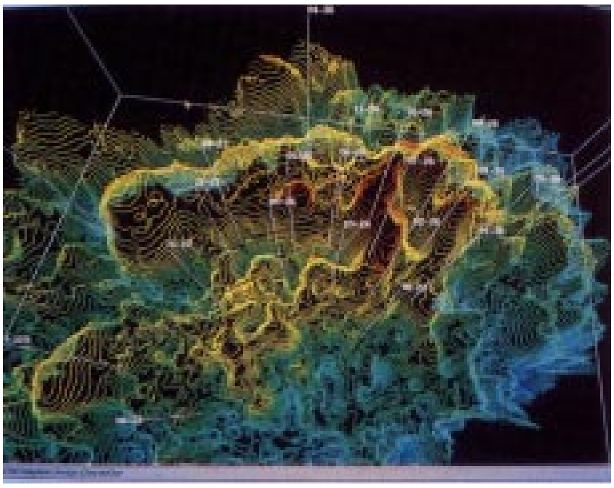

Fig 3: [single screen shot]3D visualtization of 3 D seismic data was vital to success in this field , due to extreme structural variations associated with the target reservoir.

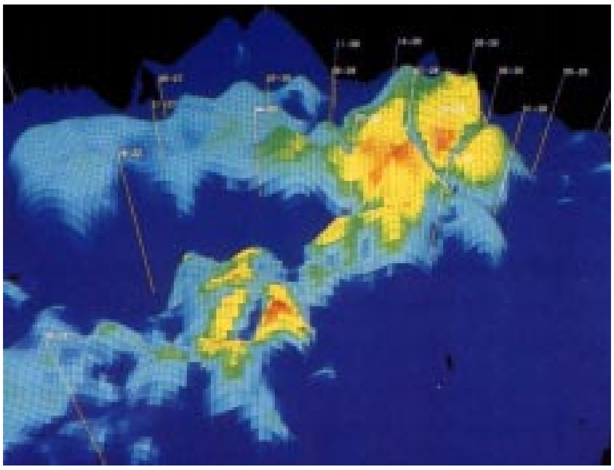

Fig 4: [single screen shot] 3D geocellular modeling enabled the team to calculate net oil pay and identify potential drilling locations. Dark blue outline approximately oil/water contact. Pay thickness indicated by lighter colors, from light blue to orange red.

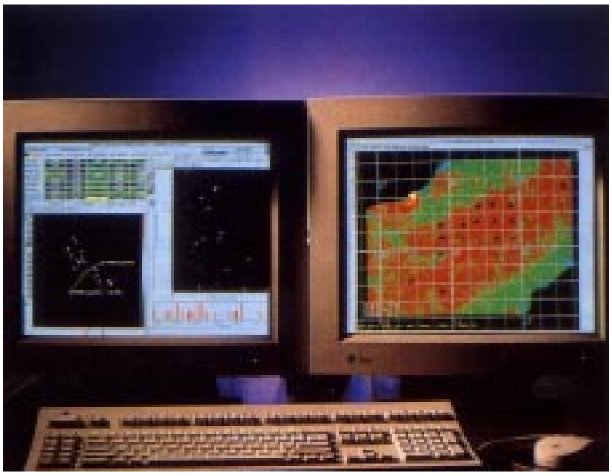

Fig 5: [two monitors with data onscreen] Sesimic attributes analysis helped the team highgrade proposed well locations selected in the 3D reservoir model. Two structurally high locations were deemed too risky and moved because they fell in a low quality sand area (green) on the attribute map at right

within the 3D survey area. In part of the field, there were several structures thought to be prospective based on elevation and porosity trends. But water saturation values were overly pessimistic, due to insufficient well control. To correct for this, porosity and water saturation were cross-plotted and a linear regression performed over the producing wells, generating an equation that further biased the model.

Then, using three known oil/water contacts and the modified water saturation and porosity cutoffs, the reservoir technologist calculated total oil in place for each reservoir compartment within the geocellular model (Figure 4). The team picked prospective drilling locations and isolated potential production from each well by selecting all the cells within a specified drainage radius. Then final net oil volumes were calculated. But several well locations were subsequently modified by seismic attribute analysis.

A variety of target interval attributes were extracted from the seismic data using both Landmark and Amoco software. Then the geophysicist embarked on an intensive analysis, looking for meaningful correlations between seismic and well attributes. Eventually three attributes were found that seemed to correlate with good reser voir quality: average instantaneous phase, slope instantaneous frequency, and coherency. Displaying these attributes in map view, a “quality sand” trend was observed that actually crosscut the structure in some areas (Figure 5).

Based on this analysis, two well locations identified in the 3D geocellular model appeared too risky. Those locations were dropped, and replaced by two others with a higher chance of success. However, due to time constraints and geological uncertainties, the team decided to postpone drilling the two replacement wells until after the first round of drilling. Amoco Canada’s management approved the team’s final recommendation to drill six wells in the field.

Benefits of Integrated Workflow. Once they completed the pre-drilling interpretation, the team attempted to quantify how the new integrated work process had benefitted them most. One of the most obvious benefits was reduction of overall cycle time by an estimated percent, based on a pure task-by-task comparison, before and after the project. For example, building and displaying a scaled cross section with ten wells using previous methods would have taken about two hours. With integrated technology, it took eight minutes.

Another example: In the past, making a good net pay map required the geologist to sit at a light table for perhaps four days. Finally, a map with a particular porosity cutoff would be handed off to a reservoir engineer. But if the engineer requested another map, at a different cutoff, the geologist would have to go back to the light table for four more days. With the integrated system, new maps were created in minutes.

Another, perhaps even more important benefit of integration was a dramatic decrease in time wasted on data manipulation and a corresponding increase in time spent on higher value interpretation. By storing well and production data in a single Oracle repository, the team estimates they cut data management from 70 percent of total project time to only 30 percent, boosting interpretation time from 30 to 70 percent.

Having experienced workflow consultants onsite provided additional value. The consultants facilitated better overall project planning, conducted on-the-job software and database training, streamlined the team's existing work processes, and provided detailed documentation of the new integrated workflows. When the project was done, the entire workflow document was put on the company's internal Web server, so any E&P professional in Amoco worldwide could benefit from the LIP team's learning.

Interpretation While Drilling

After completion of the initial field study, the integrated working environment enabled the team to make fast, on-the-spot decisions during drilling with a level of confidence and accuracy they would never have achieved in the past. The new process was dubbed "Interpretation While Drilling" (IWD). It was particularly important because the team was targeting thin oil zones between uneconomic gas and water. Also, working at the eastern edge of the Western Canada basin, targets were shallow enough to reach in a few days, so the drilling rig was not released between wells. Speed was vital. With new sonic logs and other well data coming in frequently, the team needed to continually update the velocity model and the most important depth maps as quickly as possible.

The first well encountered an unexpected gas cap. When the faxed log came in about 7:00 pm on a Saturday night, the geologist and geophysicist met in the team workroom. Using the integrated system, a solution was found in less than 30 minutes. New tops were picked, entered into the common database, and tied with the 3D seismic interpretation onscreen. The velocity model was quickly revised, and the seismic map reconverted to depth. Overlaying the porosity map on the seismic onscreen, new x,y coordinates were picked within the same porosity contour interval. Then they called the rig and instructed the drillers to sidetrack the well downdip. By doing this, they decreased the gas cap to one meter and increased oil pay to almost seven meters, which is economic in this play.

A checkshot survey was ordered on that first well, to verify the velocity model. But the data did not arrive until just after the third well spudded. Staying late one night, the geophysicist looked at the checkshot data and realized the new time-depth relationship had altered the previous interpretation. When the velocity model was further revised, it appeared that the current well would be structurally low and wet. After a quick teleconference with the geologist and business engineer, the team made an unusual decision.

The well had been drilled to a depth of 40 meters, and the engineers were about to set surface casing. The team phoned the rig and told them to stop drilling and move on to the next location. The drillers were understandably surprised. But when the rig came back at the end of the drilling program and kicked off 300 meters from the original surface location, they encountered nine meters of oil, with no gas. In this case, changing drilling plans on the fly probably saved the company about $100,000.

Conclusion

All told, the team drilled six oil wells out of six attempts in the first phase of drilling in the field. At least one dry hole was averted in the process, and production rates are excellent. Also, three professionals learned a whole new technology, and got up a steep learning curve in record time.

Since completing this study, a number of workflow presentations on this project have been given to Amoco colleagues and other industry professionals Amoco Canada is currently planning several other integrated field studies. Further analysis of the data set, including geostatistics and reservoir simulation, is also being planned.

Working in an integrated way means team members spend a great deal of time in the same room, right next to each other. In this case, it helped the team become more cohesive. Cross-discipline training was an unexpected bonus. Each team member became familiar with the other disciplines' tools and techniques, Once in fact, when the geophysicist was out of town, some seismic data came in. The data was loaded on the Landmark system, and the engineering technologist and geologist actually correlated the traces, auto-tracked the key horizon, and came up with a proposed drilling location. That kind of cross-training - and trust — usually does not occur without integration.

Asset teams today are under increasing pressure to get production online faster and boost revenues sooner than ever before. Having integrated technology can help them make smarter business decisions, even under that kind of pressure.