The Giant Karachaganak Field, Unlocking Its Potential

Karachaganak, one of the world’s largest gas condensate reservoirs, requires an innovative team approach to maximize field potential. Its remoteness, complex carbonate structure and perplexing fluid behavior present both obstacles and opportunities for production optimization.

Land of the Giants

The Karachaganak field lies on the northern margin of the Pre-Caspian basin, the predecessor of the Caspian Sea, 150 km [93 miles] east of Uralsk, Kazakhstan (next page). The sediments in the 500,000-km² [193,000 sq-mile] basin are up to 22 km [14 miles] thick, with a salt layer dividing the volume into subsalt and suprasalt sections.

Hydrocarbon exploration has been active in the suprasalt section of the Pre-Caspian basin since the early 1900s: about 80 small, mainly oil fields were discovered, but are now almost depleted. Subsalt exploration began only in the 1970s. Since then, discovery of the giant fields such as Karachaganak, Tengiz and Astrakhan has placed the Pre-Caspian among the richest oil and gas basins in the world.
Quantifying reserves and optimizing recovery from these fields require an overall understanding of the basin and its architecture. Drilling into the subsalt has been confined mainly to the margins of the basin, and in some parts there exist seismic surveys. These and a knowledge of the regional geology have helped to construct a vision of the basin that is guiding exploration and production efforts.

Field History
Karachaganak itself was discovered in 1979 and began production in 1984 under the operatorship of Karachaganakgazprom, a subsidiary of Russia’s GazProm. Kazakhgas, the Kazakhstan state gas company, took over operatorship when Kazakhstan became a sovereign state in 1992. Agip and British Gas formed a contractor group after being awarded sole negotiating rights to the field in 1992. Texaco and Lukoil joined this group in March 1995 and signed a Production Sharing Agreement (PSA) with the Republic of Kazakhstan in November 1997. The PSA became effective in January 1998.

The field is located near the border between Kazakhstan and Russia in a lowlying, almost flat area noted for its arable farming but traditionally considered part of the steppes. The region is characterized by hot summers, cold winters and short springs. Currently, produced fluids are piped 130 km for processing and distribution to Orenburg, Russia. In the future, separated and stabilized oil will be sent, via a connector, to the Caspian Pipeline Consortium pipeline.
Karachaganak field operating conditions. A remote location and harsh conditions, including extreme variations in seasonal weather, make production operations difficult and challenging.

and autumns. The severe continental climate, with wind blowing constantly, makes operating conditions very difficult (above). From November to March, with temperatures regularly around –40°C (–40°F), the ground is frozen and travel is hazardous. Crews have to fly to Uralsk using a charter airline. During the spring thaw and after occasional rain showers, the soil turns to heavy, sticky mud and roads are regularly washed out, so roads in the field have to be built up onto banks several meters high. The summer months, by contrast, are noted for temperatures in excess of +40°C (140°F).

Currently, the operating team uses existing buildings for both accommodation and offices in the nearest support town, Aksai, over 30 km [19 miles] away. Plans are afoot to develop a new camp site to provide modern working and living facilities for a staff of 200 expatriates and 600 local residents.

The 1979 discovery of the field resulted from drilling to confirm a structural high detected during reinterpretation of 1970 to 1971 vintage 2D seismic data. Extensive appraisal drilling resulted in the identification of the huge Permian-Carboniferous reef complex measuring 30 by 15 km [19 by 9 miles] (next page). The crest of the structure is recognized at 3500 meters subsea (mss), the gas-oil contact at 4950 mss and the oil-water contact at 5150 mss. This provides a gas column of 1450 m [4757 ft] and an oil column of 200 m [656 ft], with hydrogen in place of 1.2 Tcm [42.4 Tcf] gas and 1 billion tonnes [0.1 billion tons] of liquids.

It is hardly surprising therefore that Karachaganak is ranked as one of the largest gas condensate fields in the world and is expected to produce far into the next century. The field consists of a carbonate massif, the structure and stratigraphy of which have been documented in several publications.1 The formations are heterogeneous, especially the uppermost reservoir in the Permian. The average reservoir permeability is 2 mD with 9% porosity, 40% net/gross ratio and a water saturation of only 10%. Initial reservoir pressure was 52,000 to 59,500 kPa [7547 to 8630 psi] and the field temperature ranged from 70 to 95°C [158 to 203°F].

Hydrocarbon production began in October 1984, initially from three wells penetrating the Permian. An oil and gas separation plant was installed to treat the oil and gas for transfer by pipeline to the Orenburg processing plant located 130 km [80 miles] north in Russia. In 1984 the pilot production plan limited production operations to partial separation and dewpoint control with all subsequent stages of processing at Orenburg. The condensate delivered is approximately 47 degrees API and contains a high mercaptan content of 1700 ppm.2 Also, the gas is difficult to handle as it is sour, averaging 3.5 to 5.0% hydrogen sulfide [H2S] and 5.5% carbon dioxide [CO2]. The hydrocarbon composition varies with depth.1

The previous development plan, created by VNII Gaz, called for full voidage gas reinjection to maintain the reservoir pressure above the dewpoint pressure. Since then, this dewpoint restriction policy on production wells has been maintained by the Kazakhstan Ministry of Geology and Protection of Natural Resources.

During the pilot production phase, production rose steadily as more wells were brought on-stream to reach a plateau rate of 155 Bcf/yr of gas and 100,000 B/D of liquid in 1990. The plateau lasted for two years until a gradual decline began in mid-1992. The field is expected to produce 2.0 Mt of liquids in 1998. There have been 252 vertical production wells drilled on the field, but the current maximum number of active wells on production is only 36. Because of technical difficul-


5. Mercaptans are pungent-smelling sulfur compounds that occur in natural gas and are sometimes used to add odor to refined gas.

Structural cross sections through the Karachaganak field showing the buildup associated with the Permo–Carboniferous reef complex. The flanks of the structure are overlain by salt so imaging them seismically is difficult. Consequently, the new 3D seismic acquisition program being planned for 1999 may lead to a different interpretation of the flanks.
Oilfield Review

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The first part of the pilot stimulation program involved using coiled tubing to clean out the wells and spot hydrochloric acid at a low rate (0.6 bbl/min) across the long pay interval. The matrix acid was then bullheaded into the formation at a rate of 5 bbl/min, and the first wells saw a substantial 400% increase in productivity index, although much of the surface production increase was tempered by current tubing restrictions (above). This success was very encouraging. However, the extremely large zones did cause a problem for conventional bull-headed acid jobs. As soon as the acid opened up a section of the damaged zone, that zone absorbed all the remaining acid. Also, high-permeability streaks within the pay zone inhibited total interval stimulation; the acid flowed preferentially into certain zones and did not open the entire interval.

Next the team focused on diversion techniques to achieve more effective acidization. In many of the Karachaganak wells, the quality of the cement bond behind the casing is unknown. Thus, diversion techniques would have to take into account the possibility of acid channeling behind the casing through the cement and not into the formation. The aggressiveness of the diversion program would then be a function of the connectivity of the reservoir. If the reservoir intervals are separate, then each interval would need to be stimulated individually to tap the oil. Ideally, the wells would be worked over and vertical conformance testing performed with packers to determine vertical permeability. Such tests would help determine reservoir connectivity. However, as workovers are expensive, the stimulation program was performed through tubing.

The first trial step in the diversion program involved the use of self-diverting acid pumped at a high rate—exceeding 30 bbl/min. This type of gelled acid etches wormholes into the carbonate formation, but as the acid is spent, pH increases, causing the fluids to crosslink and thicken. The acid’s viscosity increases, thereby temporarily shutting off the wormhole and diverting the fresh acid to other damaged areas in the formation.

Finally, the diversion program evaluated mechanical diverters, such as ball sealers or coiled tubing injection with through-tubing inflatable packers. Alternatively, a full workover may be necessary to run straddle packers or fullbore packers and bridge plugs to isolate zones.

The combination of mechanical and chemical diversion techniques has helped to improve the production stimulation program and achieve the desired production targets. Simulations using StimCADE well stimulation software are now being run to match the results of the damage removal from the pilot acidizing program with the modeled job designs. Mechanical and particulate diversion techniques are also being modeled to determine additional means of removing the skin from the wells.

Another option under consideration for the future is acid-etched fracturing. The acid fracs would bypass the deep-penetrating formation damage, which is difficult to remove by the radial flow of matrix acidizing. Acid fracs also allow stimulation of lower permeability intervals and can attain significant negative skins to improve production. These jobs are not perfect, however, and without mechanical diversion, the fractures tend to initiate in the high-permeability streaks, leading to suboptimal conformance.

Another potential problem is control of fracture height and placement. In order to prevent gas cusp—alogous to water coning—into the oil zone, the team will need to ensure that the fractures do not extend beyond 200 m [656 ft]. In fact, it may be technically less risky to drill horizontal drainholes because the risk of gas cusp is reduced as gas is injected or liquid is produced. Cusping may become an even greater problem as gas is reinjected.

Similarly, modern horizontal well technology could be used to optimize production from the 200-m thick Carboniferous oil rim. One approach would be to use existing vertical wells as starting points for horizontal drainholes. For this purpose it is important to know the condition of the wells, so another part of the Karachaganak project involves a study of the mechanical state of the wells. Initially, all well log data such as cement bond logs are being analyzed for rock mechanics information to characterize the rock properties. Also, all datum depths are being verified, because it is crucial to know the precise spatial extent of one well if another horizontal well is being drilled nearby.

Reservoir Characterization Challenges

Previous 2D mapping and detailed litho-stratigraphic and chronostratigraphic studies of the Karachaganak field by Agip and British Gas geologists in 1992 produced a layer-cake model. This was done by correlating “porosity packets” interpreted from wireline log data and using the original reservoir rock-type classification scheme based on five rock types. Since 1992, advances in sequence stratigraphy and 3D reservoir modeling techniques now enable a more realistic reservoir description incorporating all the available core, log, seismic and performance data.

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Optimizing Karachaganak Operations

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were cored early in the life of the field and approximately 1800 to 2500 m [5900 to 8200 ft] of core were collected. Unfortunately, the cores were not continuous, and core recovery was not consistent. Additionally, through the years, the cores have been divided and distributed to a number of institutions in Russia and Kazakhstan. The KIO reservoir team plans to recover the core to enable detailed interpretation of whole well cores. The team understands that much work has been completed in the past and plans to ensure that past studies are incorporated into the present work and that local experts in Kazakh institutes are closely involved in the field development.

The cores may also be useful for answering an important question about the role played by fractures and faulting in the production of hydrocarbons from Karachaganak. In the existing 2D seismic datasets, significant faults have not been identified in the Permian-Carboniferous reservoir, yet they are recognized in the Middle Devonian. The reservoir team has not seen compelling arguments for fracture support in the past production history of the field and can account for existing production rates through matrix support from the low-permeability, 1650-m [5414-ft] thick reservoir. However, until the cores have been studied in detail, the team is keeping an open mind on the issue. Local experts have indicated the possibility of fractures in their interpretations of well logs, but there are only limited borehole images available that could cast some light on the issue.

Currently, the largest contribution to the geological database for modeling the field comes from electric logs taken in 173 wells. In only one well, K818, have both “western-style” and “Russian-style” logs been run. Even so, this single occurrence of dual logging has enabled an algorithm to be created that relates western rock property measurements to Russian log values and ratios (see “Comparing Schlumberger and Russian Well Logs,” page 22). Consequently, the large quantity of older Russian log data was usable in producing rock property distributions and the present reservoir model for Karachaganak. In the well deepening that will occur with further development of the field, there will be a number of opportunities to run new sets of both Russian and western-style logs including borehole imaging tools.

Construction of a detailed digital 3D reservoir and visualization model will therefore consist of a number of stages:

- Collection, repatriation, description and interpretation of the cores
- Development of modern genetic sedimentary units within a sequence stratigraphic approach
- Integration of petrophysical, geological and seismic data
- Creation of a 3D stochastic geological model (above)
- Upscaling for reservoir simulation and development planning.
In order to make independent estimates of reserves, and to determine or predict how the Karachaganak reservoir might perform, Russian and Schlumberger logs were run in the same well, K818 (right). This operation allowed Russian logs to be calibrated against Schlumberger logs, which are in turn calibrated against known standards for rock and fluid properties.

In general, there is good agreement between the Russian and Schlumberger log curves. The exception is the neutron curve: in most intervals, the Russian logs read 2 to 5 porosity units higher than the Schlumberger curve, reflecting the algorithm used to convert Russian curve counts to porosity. Hole conditions are reported to be good, as revealed by an excellent caliper response.

Effective porosity curves from the neutron/sonic crossplots are presented in the far right-hand track. Despite the different ways in which Russian and western experts interpret the meaning of effective porosity, neutron/sonic crossplot porosities compare much more closely than do the raw neutron curves.1 Porosities from the Russian logs were then calibrated, using an algorithm developed from K818 relationships, against western logs.

As a result of this comparative study, and other ‘back-to-back’ well log evaluations,2 considerable confidence was gained in the Russian logs and logging contractors, to the extent that calibrated Russian logs from the remaining 170 wells in Karachaganak could be used to obtain valuable reservoir parameters for mapping, modeling and reserve estimation. In addition, these results showed that a substantial new log acquisition program was not required, and that operational cost-savings could be made by using local contractors.

The Fluid Model

The Karachaganak field is considered to have a range of fluids and fluid behavior that is uniquely complex, so a thorough understanding of these properties is essential to modeling the behavior of the field and planning its development in the future.4

The reservoir hosts a gas condensate fluid system grading from “rich” at the structural top of the reservoir to “extremely rich” and “black oil” at the bottom. The initial pressure and temperature of the system place it in the category of “retrograde gas condensate” behavior: when production causes the pressure to drop below the saturation pressure—a condition called the dewpoint—condensate liquid will condense from the gas phase. The properties of such a fluid, especially its mobility, and the effects on well productivity during production below the dewpoint, are under debate within the technical community. This will be discussed in more detail in the next section (see “Production Below the Dewpoint,” page 24).

The ratio of gas to liquid varies with depth throughout the reservoir. At the top of the Permian, for example, the gas/liquid ratio (GLR) is about 2000 sm3/scm, at the gas-oil contact (GOC) it is 800 sm3/scm and at the base of the oil leg in the Carboniferous the ratio has dropped to 200 sm3/scm. There is a continuous and steady compositional gradation between these points, as can be seen in the decreasing GLR (above right), the decreasing API of the product liquids (right) and by the variation in dew- and bubblepoint with depth (below right). In fact, there is no distinct boundary between the gas condensate and oil legs of Karachaganak, and at the gas-oil contact zone the reservoir fluid is close to the critical point. This means that the gas and oil have very similar compositions and there are no sudden changes in fluid properties as gas condensate becomes oil. In fact, the formation pressure would have to drop by 20% for a heterogeneous fluid system to appear.

A large amount of data on reservoir and surface liquids was available from earlier Soviet sources, which allowed Agip and BG to develop a robust fluid model for the reservoir. Field data available to the companies included: historical produced gas/liquid ratios; drillstem test (DST) data for exploration and production wells plus associated laboratory studies; and well test data on production wells. Karachaganakgasprom generated these data and the Agip-BG group was able, in addition, to conduct several “western

Historically, the industry has employed pressure maintenance techniques—cycling produced gas through the reservoir—to maintain reservoir pressure above the dewpoint. This was due to mobility concerns and other factors such as the lack of a gas market. A review of literature shows that as early as 1947 Standing et al presented a different view of the need to maintain pressure above the dewpoint. They stated, “The recovery of the heavier components from a gas cap or retrograde pool is shown to be the greatest when the sand is cycled with a dry gas at a low pressure. This conclusion is in direct opposition to the belief that the most efficient production program is pressure maintenance and cycling at or near the dewpoint.”

Weinaug and Cordell reported on revaporization studies in 1948. They stated, “A study of the behavior of retrograde condensation from gas mixtures was made in the presence and absence of sand in order to determine if the condensed liquid would revaporize in the presence of sand. The data obtained for this system also show that equilibrium is maintained at all times during the pressure decline. These results indicate that revaporization is aided rather than prevented by the fact that the condensate wets the sand.”

In 1967 Havlena et al reported on their study of cycling at declining pressures in the Windfall field. They addressed the issue of revaporization and concluded, “Cycling condensate reservoirs under conditions of declining pressure rather than constant pressure is advantageous both from a recovery and an economic standpoint. By operating at declining pressure, the wet gas displaced from the swept areas is recovered concurrently with wet gas recovered by expansion from the unswept portions of the reservoir. Any liquid condensed in the swept areas is revaporized by dry injection gas and recovered as an enriched gas.”

In 1983 Aziz gave a critique of gas cycling and in his discussion of factors affecting recovery efficiency he noted, “It is very important to closely define reservoir heterogeneity in order to predict the performance by cycling a gas-condensate reservoir.”

This applies especially to numerical modeling. Aziz discussed revaporization of condensate and reminded the reader of the work of Standing et al. He stated, “A popular concept prevailing until the sixties was that any liquid condensed in the reservoir by pressure reduction would be lost forever. Standing et al had presented an opposite concept in 1946. However, the possibility of revaporization of condensate with dry gas injection was ignored as a viable process.

The increasing price of gas forced operators to make a thorough study of the cycling process. As a result of these findings and the increased price of gas, the previous cycle of gas production, condensate stripping, gas reinjection with makeup gas followed by blowdown and gas sales only has been modified. Net present worth of a gas-condensate reservoir can now be maximized by an optimal amount of gas and condensate sales right from the start.” Essentially, Aziz emphasized the economic aspects of gas-condensate reservoir operations.

These quotations by leading reservoir engineers show that production below the dewpoint with gas injection does not cause the large-scale loss of condensate that was previously anticipated. The volume of gas injected will depend upon an optimization of technical and economic conditions relevant for that field.

The development strategy for Karachaganak is designed to efficiently recover hydrocarbons from each distinct producing horizon using state-of-the-art technologies such as 3D reservoir characterization and horizontal drilling. The dewpoint is only an issue in the Carboniferous, where gas reinjection is planned. Heterogeneities in the Permian will not support reinjection, while the volatile oil rim will be developed using horizontal wells. Staged reinjection is planned in the Carboniferous with extensive monitoring to detect mobility losses should they occur. This targeted development plan—along with technical arguments, field analogies and continual laboratory testing—will guide the reservoir development.

To investigate the phenomena of condensation and condensate mobility below the dewpoint, BG Technology performed several experiments at their London Research Station in England. Soon after, BG Technology relocated in 1994 to the purpose-built Gas Research and Technology Centre in Loughborough, England. BG Technology completed additional experiments to measure the interfacial tension (IFT) of the condensate at pressures below the dewpoint and measured the relative permeability of gas and condensate at various pressures below the dewpoint. An important benefit for the Karachaganak development is that the fluid is near-critical in the lower section of the gas leg. The fluid EOS model predicted low IFT in the near-critical fluid, which increases the pseudo-pressure, offsetting a reduction in relative permeability caused by liquid drop-out. The EOS model prediction of low IFT was confirmed by BG Technology’s laser IFT rig that measured IFT values at reservoir conditions as low as 0.08 m N/m at more than 6900 kPa.
The KIO reservoir team has received approval to add more wells to the dewpoint trial well stock during 1998 to drawdown the wells even further below the dewpoint and observe the effect on the CGR. Agip also conducted gas injection experiments on the oil leg to determine the alteration of the bubblepoint as lean gas is injected.

Based on the results of the experimental program, Agip and BG proposed a field experimental program to evaluate the laboratory phenomena under field conditions. In August 1995 Agip and BG signed a protocol with the Republic of Kazakhstan Ministry of Oil and Gas and Ministry of Geology and Protection of Natural Resources to allow six wells to be produced below the dewpoint to a pressure of 410 bar to test the laboratory results. These wells have been on production since, and no reduction in condensate/gas ratio (CGR) has been observed. It has been agreed with the Kazakh technical governing bodies that condensate mobility in the producing wells of the field trial is not adversely affected for drawdowns consistent with the pressure drops applied during the laboratory experimental program.

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Further laboratory experiments carried out under reservoir conditions involved depositing condensate onto core samples by reducing pressure below the dewpoint. Flowing equilibrium gas through the core and measuring gas and liquid flow rates demonstrated that liquid mobility continued well below the dewpoint with residual condensate saturation still at only 5% at 6900 kPa below the dewpoint. Agip also conducted gas injection experiments on the oil leg to determine the alteration of the bubblepoint as lean gas is injected.

3D Seismic Survey

To further understand the reservoir and petroleum system, the team is planning to conduct a large 3D seismic survey over the field in 1999. This survey will cover approximately 800 km² [308 sq miles], and will have three primary objectives. The first is to image the detailed internal structure and heterogeneities within the Permian and Carboniferous reservoirs to resolve the effects of faulting and fracturing. The second is to delineate the flanks of the Karachaganak Permian and Carboniferous reservoirs, which are overlain by thick salt. The third objective is to image deep Devonian strata to 7000 m [23,000 ft] to appraise its exploration and production potential.

Planning, designing and executing the survey will be particularly challenging in view of the multiple, and to a certain extent conflicting, objectives of the survey, the size of the study and the environment of the region. To assist in the 3D interpretation, the team is investigating the placement of geophones suspended down wells during the 3D acquisition. The 3D survey will require careful planning in order to obtain balanced results and optimize the trade-offs between cost and benefits.

Although imaging the Devonian may be the most difficult of the objectives, it is nevertheless vital for the team to obtain some information on the potential of this unit. The Production Sharing Agreement between the KIO and the Government of Kazakhstan was signed in November 1997; the team has only five years from that date to submit a development plan for the Devonian. The appraisal program will include workovers, DSTs and new wells drilled into the Devonian.

Looking Ahead

Karachaganak is a giant field with large commercial (gas marketing) and technical challenges caused by reservoir heterogeneity and the complex fluid system (left). Describing, monitoring and predicting reservoir performance will require the use of leading-edge technologies to optimize recovery from the field. The reservoir and operations teams of KIO will be closely watching the development of technologies and working with technology solution providers such as Schlumberger to address these challenges:

• planning and completing a large 3D seismic survey with both exploration and production objectives
• characterizing heterogeneity of the reservoir: can the heterogeneity be predicted?
• understanding the role of fractures and faults in field performance
• predicting the performance of the oil leg
• evaluating the potential of horizontal wells
• resolving the dewpoint issue: how far below the dewpoint can the field be produced? What is the best timing and quantity of gas reinjection?

The teamwork approach and application of appropriate technology promise to go a long way toward answering these questions, thus unlocking the full potential of Karachaganak.

—LS

9. For more on survey design:
Multi-objective surveys:
Subsalt surveys: