RUSSIAN VENTURES—1

Evaluating oil, gas opportunities in western Siberia—log and core data

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Wells drilled in Russia are broadly classified as "research" wells and "production" wells.

Research wells are drilled by the local geologic institutes, known as geologia, and include exploration and delineation wells. Production wells are drilled by the local production institutes, called neft, for the purpose of developing and producing delineated fields.

Oil and gas prospects usually are identified through seismic prospecting and hydrocarbons are confirmed by drilling and testing exploratory research wells by the geologic institutes.

After hydrocarbons are discovered, fields are delineated with additional research wells. These wells are extensively evaluated and provide data for preparing the Russian geologic TEO—not to be confused with the joint venture TEO—which includes:

1. Estimating original hydrocarbons in place and reserves.
2. Designing a development plan.
3. Estimating development economics.

Reserve estimates are submitted to the Central Geologic Group in Moscow (presently being shifted to the Area Geologic Committees) for certification.

Fields are offered for competitive bid only after their reserves are certified. Once certified, the responsibility for a field historically has been transferred to the local production company (neft), which drills production wells, constructs intrastructure, installs production facilities, and produces the field.

Depending upon the level of development, fields may be partly or fully delineated or may be at varying stages of development and/or production when a new joint venture is formed. The data available for evaluating a property are different for each of these situations.

Most research wells are evaluated with open hole logs, cores, and flow tests. The typical suite of logs for wells drilled since about 1985 includes the spontaneous potential (SP), lateral, conductivity, microlog, caliper, and acoustic logs.

Some logging suites also include a gamma ray and neutron log. In addition to the open hole logs, prospective formations may be conventionally cored, open hole drillstem tested, and/or flow tested through casing.

In contrast to the relatively complete data package gathered from research wells, production wells generally are evaluated with an SP in combination with a lateral or conductivity log and are not cored or flow tested. The most useful logs

Series to assist westerners analyzing Russian oil, gas deals, data

Western Siberia oil and gas data have many idiosyncracies that can cause delays for western geologists and engineers in their evaluation of properties.

The authors and their associates have made numerous trips to Russia to review data for the purpose of preparing feasibility studies, drafting Technical Economic Basis of Organization (TEO), and negotiating agreements. Based on this experience, this series of articles will provide geologists and engineers a quicker start in their evaluation of Russian ventures.

The series assumes readers are seasoned at evaluating oil and gas properties with western-type data. The intent is to provide insights into the database, economics, and agreements in Russia.

The five articles will take the reader through the data, discuss geologic and engineering approach to evaluating projects, and review joint venture structure options and their effect on project economics.

This first article deals with log and core data.

Later articles will take in reservoir description; flow rates and production forecasts; feasibility studies: development plan, costs, and economics; and finally deal agreements and licenses.

GLOSSARY OF RUSSIAN RESISTIVITY LOGS, TERMS AND LOG ABBREVIATIONS

Russian	Western equivalent
A0.5M0.1N	Lateral 0.55 m
M0.5A0.1B	Lateral 0.55 m
A1.0 M 0.1N	Lateral 1.05 m
M1.0A0.1B	Lateral 1.05 m
A2M0.5N	Lateral 2.25 m
M2A 0.5B	Lateral 2.25 m
N0.5M2A	Inverted lateral 2.25 m
B0.5A2M	Inverted lateral 2.25 m
A2.5M0.25M	Lateral 2.625 m
M2.5A0.25B	Lateral 2.625 m
A4M0.5N	Lateral 4.25 m
M4A0.5B	Lateral 4.25 m
N0.5A4M	Inverted Lateral 4.25 m
B0.5A4M	Inverted Lateral 4.25 m
A5.28M0.82N	Lateral 5.69 m
A5.70M0.40N	Lateral 5.9 m
M8A 0.5B	Lateral 8.25 m
A8M1.0N	Lateral 8.50 m
M8A1.0B	Lateral 8.50 m
M9A0.5B	Lateral 9.25 m
B2.5A0.25M	Normal 0.25 m
N5.70M0.40A	Normal 0.4 m
N6M0.5A	Normal 0.5 m
N8M0.5A	Normal 0.5 m
N2M0.5A	Normal 0.5 m
B2A0.5M	Normal 0.5 m
N4.48M1.62A	Normal 1.62 m
A0.025M0.025N	Microlateral 0.0375 m, 1×1 in.
A0.05M	Micronormal 0.05 m, 2 in.
СКВ	well
каротаж	well log
высота, or alt.rot	altitude, or KB
сопротивление	resistivity
кавернограмма	caliper
глубина	depth
$\rho_в$	Rw
ρ_c	Rm
$\rho_п$	Rt
К$_п$ лористостъ	ф.porosity
К$_н$	So, oil saturation

Russian	Western equivalent
$\alpha_{пс}$	SP coefficient
ПС	Spontaneous potential
БК	Laterolog
БК-3	Three-electrode laterolog
БК$_з$	Deep laterolog
БК$_c$	Medium depth laterolog
БК$_ч$	Shallow laterolog
ИК (6Ф1)	Induction log (6FF40)
ИК$_з$	Deep induction log
ИК$_c$	Medium depth induction log
ИК$_ч$	Shallow induction log
МБК	Microlaterolog
МЗ (МКЗ)	Microlog
ΔT	Acoustic (delta-T)
ГК	Gamma ray log
НГК	Neutron log
Common logging units	
ед	unit
мксек	microsecond
сек	second
мин	minute
час	hour
сут	day
год	year
см	centimeter
м	meter
г	gram
кг	kilogram
г/см^3	g/cc
ΔT	delta-T
дБ	decibel
Дж	joule
имп/мин	impulse/min
мкР/час	μ Roentgens/hr
В	volt
ма	milliamp
ом-м	ohm-meter
мСим/м, or мСм/м	milliSiemen/meter (equivalent to millimho/m

for formation evaluation are the SP, conductivity, microlog, and acoustic logs.

Russian logs typically are recorded with the mechanical stylus equipment and the multiple log traces and are not confined to specific tracts or standard scales common to western logs. Depending on the zone being logged, the curves may overlay each other and make them difficult to read.

Fortunately, many log traces are color coded, which makes them more legible. However, even color coded, their presentation makes them difficult to quickly interpret and inherent to scale errors. The following three sections—log data, core data, and saturation calculations, review open hole logs and core data as they pertain to estimating net pay thickness, porosity, and hydrocarbon saturations.

Log data

Lateral/conductivity logs

The available suite of Russian lateral logs is summarized along with common logging units and abbreviations (see table).

Western oilmen use lateral logs primarily for correlation and for comparison with older logs. Laterals were the primary resisitivity logs run in Siberia before the early 1980s but are being superseded by induction-conductivity logs, which are more accurate and easier to use.

Spacings on lateral logs range from .25 to 9.25 m with the 2.25 m spacing (A2M0.5N tool) being the most common.

Fig. 1 is a sample of the 2.25 m lateral log in combination with the SP across a Jurassic formation in Tomsk oblast; the lateral is recorded in ohm-meters and the SP in millivolts.

This SP-lateral log combination is referred to as the electric log and is an excellent correlation log. Lateral logs use linear scales with multiple 5X backup and resemble those run in America in the 1950s and early 1960s.

Laterals are plagued by thinbed effects, lack of calibration, and deep invasion of relatively fresh mud filtrate. A full suite of lateral logs is run in many research wells, and the resulting resistivities are manually plotted on a complex series of cyclone charts to correct for invasion and estimate the true formation resistivity.

This procedure is time intensive and renders questionable results. Many Russian petrophysicists prefer using the newer induction-conductivity devices to estimate deep resistivity. Conductivity derived resistivity varies significantly from lateral log resistivity.

The "6ф1" induction-conductivity log is the most popular of several conductivity tools and is equivalent to the 6FF40 resistivity tool. Conductivity measurements are converted to skin-effect corrected resistivity using the nomogram shown in Fig. 2. Although not borehole corrected, these resistivity measurements are the most reliable and consistent for making saturation calculations.

SP logs

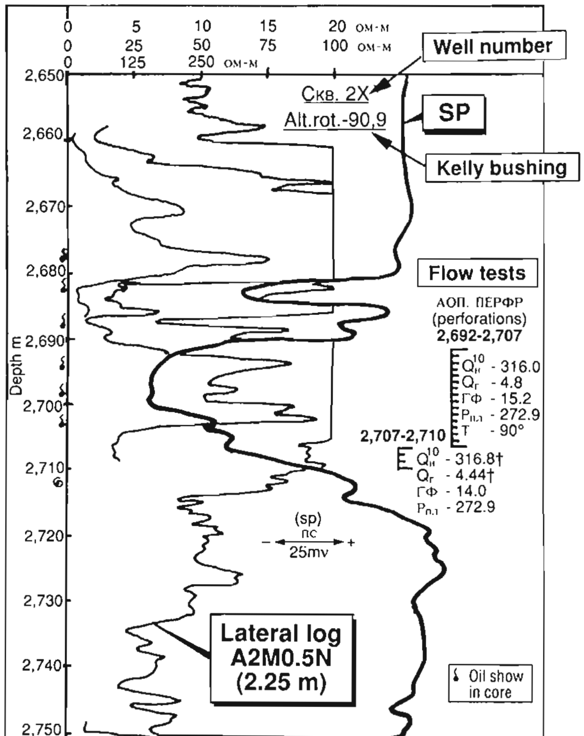
Westerners use the SP log for correlations, estimating Rw, and sometimes for estimating sand and porosity thicknesses.

In addition to these applications, Russian petrophysicists often use SP to estimate porosity used in saturation calculations and pore volume estimates.

Core data are preferred over the SP for porosity estimates, but core analyses commonly are not available for three years after drilling of a well. Since reserve estimates are required much sooner, the research facilities

Fig. 1

Russian electric log*



*Over a Jurassic sand and shale sequence in Tomsk oblast. Left curve is the A2M0.5N (2.25 m) lateral log. Right curve is the spontaneous potential. †Daily oil, gas rates on 10 mm choke.

Courtesy Wavetech Geophysical Inc., Denver

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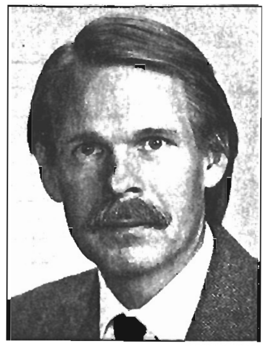
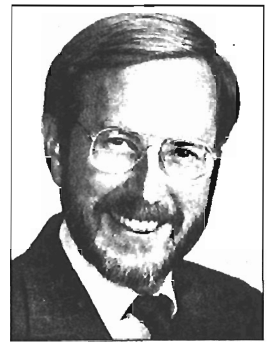
The Authors



Connelly



Krug

William Connelly is chief geologist and founder of Pangea International Inc. He focuses on projects in Russia and is active with domestic property and acquisition evaluations. He has studied oil and gas data in Tyumen, Tomsk, Irkutsk, and Komi oblasts during several extended trips to Russia and helped prepare feasibility studies and TEO agreements for those properties. Before Pangea, he was employed a combined 15 years by Nerco Oil & Gas Inc., Rock Oil Corp., Davis Oil Co., and Amoco Production Co. He has managed exploration and development programs in the Rocky Mountains, Gulf Coast, and Alaska. He has a PhD in geology from the University of California at Santa Cruz and a BS in earth sciences from California State University at Hayward.

Jack A. Krug has traveled extensively through Russia and other C.I.S. republics, collecting data and performing economic feasibility and TEO studies of oil and gas exploration and development projects. He has been project manager on studies in Timan-Pechora, Tomsk, Komi, and Irkutsk. His other international consulting experience includes project management for Danish Oil & Natural Gas, developing resources and alternative energy sources for Denmark, studies of strategic energy supply for Swisspetrol and the Australian government; design and supervision of drilling, completing, and testing deep exploratory wells (U.S. and Europe), asset management, expert witness testimony, and acquisition evaluation.

He has professional, MS, and PhD degrees in petroleum engineering from the Colorado School of Mines. In the U.S. he worked in Alaska with Chevron and British Petroleum in Prudhoe Bay and North Slope exploratory wells and with Anschutz, Petro-Lewis, and Nerco Oil & Gas in the Gulf Coast, Midcontinent, Appalachian, and Rocky Mountain regions.

have derived a series of empirical linear equations to calculate porosity based on the relative deflection of SP.

These equations are updated periodically based on new core data and are provided to district offices by-field, by-formation.

Where micrologs are not available, sand and porosity thicknesses are estimated using the SP in conjunction with conductivity. With beds exceeding 2 m, this approach is acceptable. However, for beds less than about 2 m, the SP estimated thicknesses are anomalously large.

Micrologs

The microlog is a very important log in the Russian suite.

It provides the best indication of permeable and porous formations and is used to construct porosity isopach and net pay maps. There are two common micrologs in use, the A0.025M0.025N and the A0.05M.

These tools correspond to approximately 1-in. and 2-in. electrode spacing. Microlog separation correlates with caliper log mud-cake buildup (Fig. 3) and indicates permeable zones. There is good agreement between microlog permeable zones and flow test results.

Acoustic logs

Second to core data, the acoustic log provides the best estimates of porosity. However, the tool is an uncompensated, single-receiver, dual-transmitter device that has inherent problems with hole rugosity and alignment.

There are different sonde spacings available, so one needs to be careful when calculating delta-T from T1 and T2; data are recorded in microseconds per meter.

If used carefully, the sonic porosity can be used for qualitative water saturation calculations. However it is first necessary to determine the matrix velocities by crossplotting delta-T with core porosities from several key wells.

Special core analysis may be available that calibrate the sonic travel time with core porosity at various laboratory and reservoir conditions.

GR, neutron logs

The gamma ray log is used for correlations and estimating shale content in sandstones. It is run in combination with a single detector neutron log in many research wells.

Gamma ray logs are reported in impulses per minute (conventional units) using linear scales; they are not calibrated to a standard API count basis. Westerners use the gamma ray with limited success to determine shale volumes in water saturation calculations; the erratic nature of the curve sometimes renders it unusable.

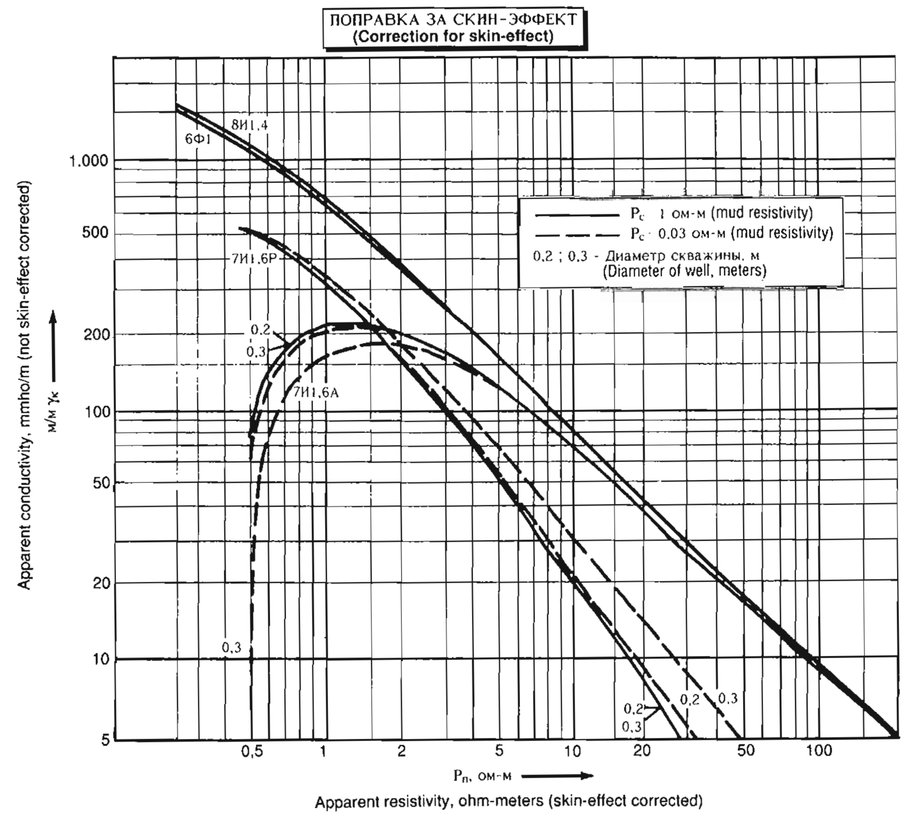
The scale on some gamma ray logs needs to be estimated based on lithologic "standards" in the wellbore because their printed scales indicate responses significantly different from offset wells.

The virtue of the single detector neutron log is not apparent to the authors. Russian petrophysicists indicated they use it only to identify gas caps.

A neutron log is run prior to running casing. Normally at this time the mud filtrate invasion is deeper than the neutron log radius of investigation, so the log does not record beyond the wet in-

Fig. 2

Nomogram converting Russian conductivity to resistivity*



*Use to convert 6Ф1, 7И1, and 8И1 from conductivity (mmho/meter) to skin-corrected resistivity (ohm-meters)

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vaded zone.

A second neutron log is run through casing three months later. If there is a significant shift in the cased hole curve compared with the open hole curve, it is interpreted to indicate gas moving back into the zone of investigation, hence the zone is gas bearing.

Digitizing log data

Before starting log analysis, the authors recommend digitizing the required logs across zones of interest.

Scales on logs are linear, and it often is difficult to determine which curves are backup and which are not. There may be as many as four backup curves over some zones. Our best results occur when a log analyst color-codes each curve and corresponding scale before digitizing.

Russian log curves are not confined to specific tracts; therefore several curves can migrate over each other and make it difficult to follow traces unless they are color-coded. Fig. 4 illustrates the resulting three tract log of the example logs.

In addition to the digitizing difficulties, the authors have encountered significant depth shifts on some logs. Depth correcting log traces is tedious but critical to obtaining usable log calculations. Depth shifts in excess of 10 m are not uncommon. The authors recommend inputting core data with the digitized logs and insuring it, too, is depth corrected.

Core data

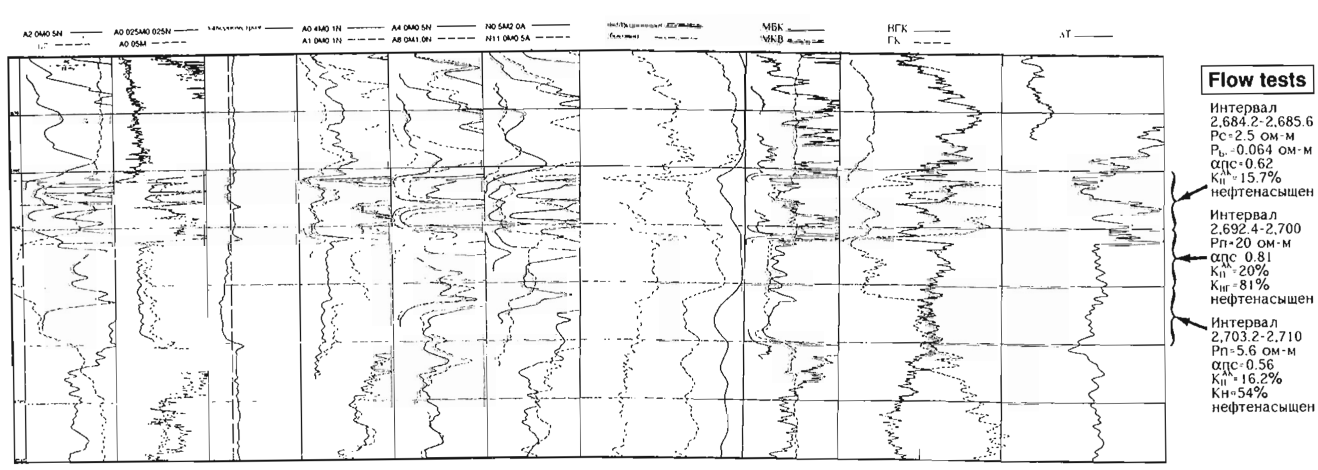
Core data are by far the best measure of porosity.

It cannot be overemphasized how critical it is to gather and analyze core data during feasibility reviews of projects. These data are used for log calculations, calibration of sonic data, and most importantly for pore volume estimates of original hydrocarbons in place.

In addition to reviewing the core analyses, the authors recommend an inspection of cores to determine the extent of fracturing, the depositional environment, and the core sampling method and frequency. If time

Fig. 3

Composite display of Russian suite of logs



Courtesy Wavetech Geophysical Inc., Denver

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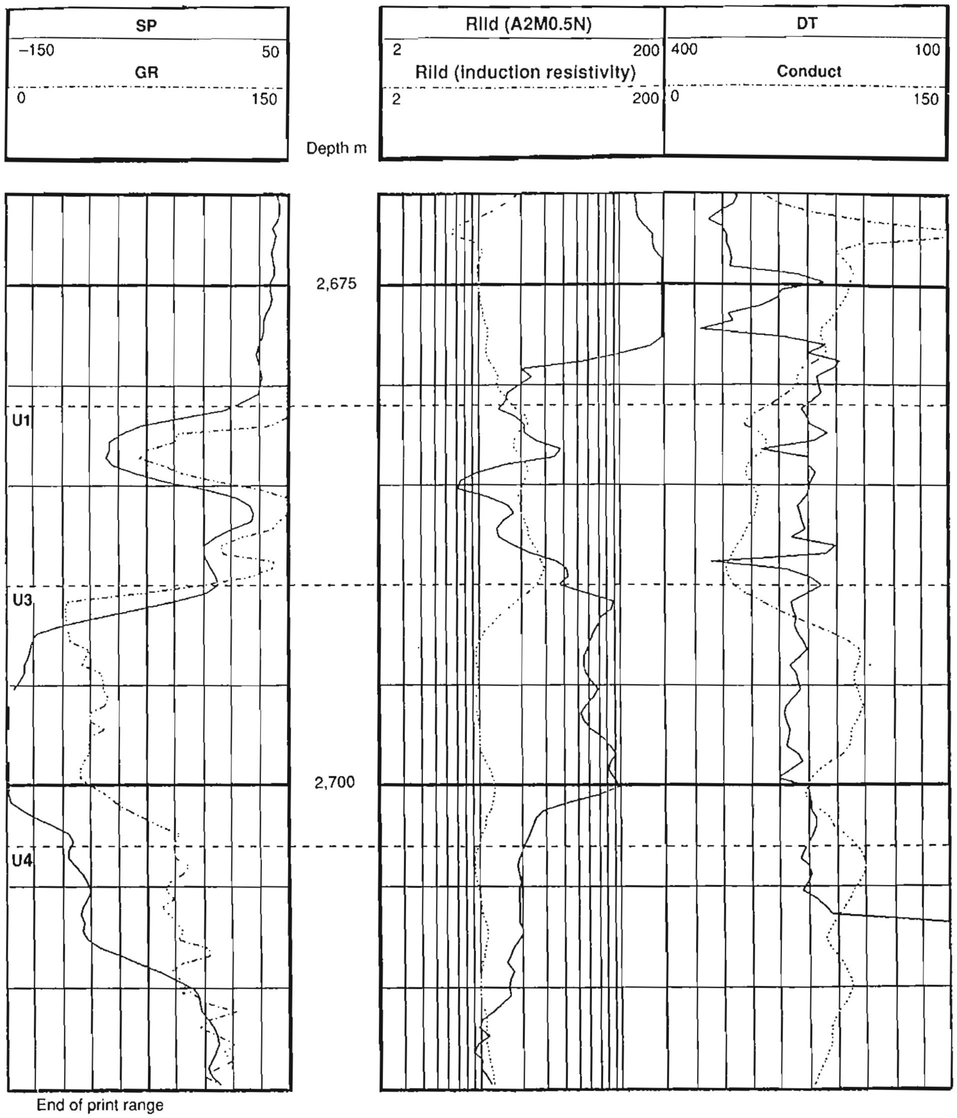
Fig. 4

DIGITIZED RUSSIAN LOG DATA*



*Displayed in a conventional three-tract format using software by Hydrocarbon Data Systems, Houston.

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allows (and it usually does not), it is preferable to study the cores in detail.

Russian petrophysicists generally report core analyses in a fashion similar to western core reports. Sampling of cores for analyses tends to be greater in porous sands than in tight sands. Because the porosities used in volumetric calculations will be weighted-average core porosities, it is important to understand the sampling technique.

In addition to conventional core analyses, special core analyses sometimes are available. Special core analyses provide mineralogical components, saturation indices, formation factors, grain-densities, and acoustic travel times. From these studies the tortuosity constant (a), cementation exponent (m), saturation index (n), and matrix travel time are obtained and provide input data for the log calculations.

Lengthy petrographic descriptions are available on many cores. The authors recommend translating these core descriptions from Russian to English because they contain a wealth of information about reservoir quality, depositional environment, and explain log responses in some pay zones.

Saturation calculations

Since Russian logs lack modern sophistication, an analyst quickly reaches a point of diminishing returns during analysis of the data.

Problems with the data include lack of calibration, no borehole corrections, no depth corrections, no deep invasion correction, lack of Rmf control, and the fact there is only one useful porosity tool.

In the western Siberia basin, the problems are compounded by multi-mineralogic sands that include conductive minerals such as glauconite, micas, and pyrite, in addition to the presence of thin-laminated beds and shaly sand sequences.

Nevertheless, some log calculations are reliable if the analyst is careful. The following methodology has proven efficient in western Siberia:

1. Digitize the SP, conductivity, gamma ray, and sonic curves over zones of interest.
2. Depth correct all curves.
3. Convert conductivity to resistivity with appropriate tool correction chart(s).
4. Determine Rw from fluid analyses, SP, and Hingle and/or Pickett plots.
5. Correlate core data to acoustic travel time and determine matrix velocity.
6. Calculate sonic porosity for the zones of interest.
7. Create a pseudo calibration for the gamma ray log using wellbore lithologic control points to estimate shale volume. Use the SP log as an alternative shale indicator.
8. Assume "a," "m," and "n" are 1, 2, and 2, respectively, for a first pass calculation. If special core analyses are available, consider recalculating the logs with these data.
9. Compute water saturations using Archie, modified-Archie, and Simandeaux equations.
10. Compare saturation calculations with flow-test results to determine the reliability of the calculations. Calculated water saturations do not always agree with reported test results.

Fluid contacts often are recognizable based on conductivity and lateral logs. However, test data are the most reliable data for determining fluid levels.

The second part of this series deals with fluid levels and other subjects pertaining to reservoir description and volumetric estimates of original hydrocarbons in place. ▪

TEXAS

West

Fina Oil & Chemical Co. has completed a discovery in Pecos County.

The 2602-A Longfellow West, 4 miles southeast of five well Bitterweed field, flowed 2.785 MMcfd of gas through a one half in. choke with 1,226 psi flowing tubing pressure from Mississippian-Devonian Caballos Novaculite perforations at 6,223-319 ft and 6,380-6,518 ft. CAOF is 3.891 MMcfd.

Shell Western E&P Inc., Houston, will rework two Thistle field wells in the Marathon-Ouachita area of Pecos County.

Shell will try to establish production from Mississippian-Devonian Caballos novaculite at 2,295 ft at the 2-5 Downie Ranch, 25 miles north of Sanderson, Petroleum Information reports.

The company completed the well in 1984 flowing 213 b/d of oil from Caballos perforations at 1,690-1,810 ft. Old total depth is 7,085 ft.

Shell will try for Caballos B production at 2,400 ft at the 4L Downie Ranch, completed in 1986 pumping 323 b/d of oil, 45 Mcfd of gas, and 86 b/d of water from Caballos perforations at 1,797-1,910 ft.

Union Pacific Resources Co. has staked a wildcat in Val Verde County.

The 1 Rose-Lea, 30 miles southwest of Sonora, is projected to 13,500 ft. It is about 1 mile west-northwest of Vinegarone field, which produces gas from Pennsylvanian Strawn at about 10,000 ft, PI reported.

A deep wildcat planned in Cottle County that could threaten a drilling depth record in the area.

Gunn Oil Co., Wichita Falls, has staked 1 Brooks, 9 miles southeast of Paducah, to 15,000 ft.

The location lies between the Palo Duro and Hardeman basins, PI points out. It is 1¼ miles south of Broken Bone field, which produces gas from Pennsylvanian Conglomerate at about 8,000 ft.

It is also 1¼ miles southeast of Gunn's 1 Majors, drilled to 13,600 ft in 1991. Completion at that well was for 42 Mcfd of gas from Conglomerate at 11,078-13,225 ft. The drilling depth record for Texas Dist. 8A is 14,201 ft.

North

Staley Oil Co., Wichita Falls, has staked a remote wildcat in Foard County.

The 1 Burgess, 23 miles southwest of Crowell, is projected to 6,300 ft. The location is more than 5 miles south of nearest production, PI reported.

Mitchell Energy & Development Corp. has completed four more gas wells from Mississippian Barnett shale in the East Newark field area ofe Wise County.

The 1 Ted Morris flowed 5 MMcfd of gas through an 18/64 in. choke with 2,380 psi flowing tubing pressure from perforations at 7,754-8,040 ft.

The 1 Spain Gas Unit, 3 miles northwest of Rhome, flowed 4.7 MMcfd from perforations at 7,508-7,608 ft.

The 1-A Pavillard, 2 miles northeast of Boyd, flowed 4.5 MMcfd from perforations at 6,906-7,110 ft, and the nearby 2-A Pavillard flowed 3.4 MMcfd of gas from 6,968-7,160 ft.

MEC Development Ltd., a partnership in which Mitchell is operator and general partner, holds 100% of the working interest in the wells.

East

Texaco Exploration & Production Co. has completed a second dual lateral horizontal well in Brookeland field of Newton County.

The 5-H Texaco Fee Brookeland, 6 miles northwest of Mayflower, flowed a combined 1,122 b/d of 49.2° gravity oil, 7.326 MMcfd of gas, and 1,178 b/d of water from Upper Cretaceous Austin chalk, Petroleum Information reported.

The well produces from open hole at 10,450-13,888 ft measured depth in a northwesterly drilled lateral and open hole at 10,450-13,461 ft MD in a southeasterly lateral.

United Oil & Minerals, Austin, has permitted the first horizontal well in Leon County.

The well, to be in Hilltop Resort field, is 1 Wildman, 7 miles northwest of Normangee. Objective is Upper Cretaceous Austin chalk at 6,500 ft true vertical depth. Proposed horizontal displacement of 3,633 ft, Petroleum Information reported.

Saratoga Resources, Austin, completed the first horizontal well in Hemphill field of Sabine County.

The 40-A TI-G, a reentry, flowed 192 b/d of 48.8° gravity oil and 690 Mcfd of gas natural through a 10/64 in. choke with 1,700 psi flowing tubing pressure from Upper Cretaceous Saratoga chalk at 5,512-5,860 ft.

Three other horizontal wells are permitted in the field, but no activity has been reported at them, PI reported.

Gulf Coast

Esenjay Petroleum Corp., Corpus Christi, has staked the first horizontal well in Tyler County.

It will reenter the 1 W.T. Carter & Bros., 10 miles northwest of Woodville, is projected to Upper Cretaceous Austin chalk at 13,008 ft true vertical depth. Enserch completed the vertical well in 1978, and it has produced 31,310 bbl of oil and 92.8 MMcf of gas, and 5,679 bbl of water from Austin chalk, PI reported. It is one of Woodville field's three completed wells, one of which is an Upper Cretaceous Woodbine gas well.

OKLAHOMA

Operators developing the Ames hole structural feature near the town of Ames in Major County, Okla., have completed 21 Cambro-Ordovician Arbuckle producing wells since the first completion in August 1990, Petroleum Information reports.

Oil and gas production records that represent wells currently active through July 1992 indicate that 471,321 bbl of liquids and 2.56 bcf of gas have been recovered.

Bligh Petroleum, Dallas, has asked the state to force pool mineral interests for a possible Cambro-Ordovician Arbuckle wildcat in western Pittsburg County.

The company sought to pool interests in 26 formations from Pennsylvanian Senora through Arbuckle in 33-6n-12e, about 1 mile north of shallow gas production in South Pine Hollow field, PI reported.

The tract is 2 miles northwest of a well drilled in 1973 that topped Arbuckle at 8,802 ft.

ARCO Oil & Gas Co. has sought to pool mineral interests near a deep wildcat it is drilling in Atoka County.

The area sought for pooling in numerous zones through Cambro-Ordovician Arbuckle is in 18-1n-13e, just north of ARCO's 1 Ingersoll, in 19-1n-13e.

ARCO is below 19,375 ft deepening the well to Arbuckle at about 21,500 ft. The area is 2½ miles southwest of West Wesley gas field, PI reported.

RUSSIAN VENTURES—2

Evaluating oil, gas opportunities in western Siberia—reservoir description

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Part one of this five part series discussed core and log data used for evaluating oil and gas properties in western Siberia.[1] In this article, we discuss how to use the subsurface data to describe hydrocarbon reservoirs and estimate the original oil in place (OOIP).

Initially the evaluation should use only the "research" wells because they include relatively complete data sets and are adequately located over the structures (4-8 sq km spacing). These preliminary reservoir models can be refined later by using data from "production" wells.

The methodology for describing a reservoir and estimating the OOIP in western Siberia is similar to the approach for most reservoirs:

1. Establish stratigraphic correlations across the field;
2. Construct structure maps on key horizons;
3. Construct porosity isopach maps for significant reservoirs;
4. Construct net pay maps;
5. Determine reservoir parameters; and
6. Calculate pore-volume estimates of OOIP.

Table 1

MESOZOIC STRATIGRAPHIC NOMENCLATURE*

	Vartov	BV 0-9	Вартовская	БВ 0-9
Cretaceous	Megion	BV 10-12	Мегионская	БВ 10-12
(Меловой)	Achimov	Ach 1-4	Ачимовские	АЧ 1-4
	Bezhenov	—	Беженовская	—
Jurassic	Vasyugan	UV 1	Васюганская	ЮВ 1
(Юрский)	Tyumen	—	Тюменская	—

Stratigraphy

Most production in western Siberia comes from the thick sequence of sandstone and shale deposited during the Jurassic-Cretaceous subsidence of the Western Siberia basin.[2] These clastic sediments often contain glauconite and marine fauna evidencing deposition under shallow marine conditions.

Occasional coals and root tubules evidence periods of emergence. Porosity isopach maps of these sand bodies usually contour as prograding deltas, estuaries, marine bar sands, and occasional channels.

The first step in describing a reservoir is to correlate strata in all "research" wells and identify any faults. The "electric log" (SP and lateral log displayed at 1:500 scale) is an excellent correlation log. The known productive zones have distinct characteristics and are easily recognized throughout the basin.

Once the logs are correlated, construct a series of restored (fault corrected) stratigraphic cross-sections hung from reliable regional shale markers. The Bezhenov shale is an excellent hang-horizon for Jurassic objectives (Table 1). These cross-sections are used repeatedly to study reservoir continuity and paleoenvironments and to construct isopach maps.

Structure maps

Most western Siberia fields are located on gently dipping four-way seismic closures. Seismic data quality varies but usually is adequate to define the gentle structural closures typical of the region.

Seismic data are multi-fold and common-depth-point (CDP); most seismic data acquired since the mid-1980s are digitally recorded. In some instances, reprocessing is beneficial. Because most Siberian ventures available to western companies involve fields already delineated with subsurface control, seismic interpretation is much less important than subsurface data.

Before mapping can begin, suitable base-maps must be located or constructed. This task is complicated by the absence of any grids or x-y coordinates for wells. Occasionally the latitude and longitude of wells are available, but often it is necessary to trust the wells are accurately posted on the Russian maps. We recommend digitizing the base-maps and creating an x-y coordinate system for each project. This x-y coordinate system is necessary for a simulation study and thus has a dual purpose.

The Bezhenov shale is an excellent seismic reflector and overlies several productive Jurassic sands, therefore the first structure map should be on this horizon. Russians usually construct seismic structure maps on this horizon.

Because the Bezhenov seismic structure maps commonly have not been updated to honor subsequently drilled delineation wells, we update these maps with the newer subsurface control. Russians are good structural mappers, and it is unlikely you will make significant changes to their interpretations.

Subsurface structure maps of shallower horizons are made as needed. Many structures are syndepositional, therefore it is wise to map several horizons and study growth history (graphing a series of isopach thicknesses versus datums will establish periods of growth; alternatively, construct interval isopach maps). Differential compaction structures are also common and will show no evidence of stratigraphic thinning over structure.

Porosity isopach maps

The preferred measure of porosity thickness used on isopach maps is microlog separation. If the suite of logs does not include a microlog, then the SP in combination with an induction-conductivity log can be used to estimate the porosity thickness. A third alternative for picking porosity thickness values is the caliper log. In permeable zones, the caliper shows mud cake build-up and generally agrees with microlog separation.

Russian geologists conventionally core many "research" wells and annotate the logs with brief core descriptions. While picking isopach values from logs, it is important to study these core descriptions and/or the log character for indications of depositional environments.

The map should be extended beyond the area defined by productive wells in order to develop regional depositional models. Flow test data also is commonly posted on logs and is the best source of information about fluid contacts.

Net pay map

Construction of the net pay map is the integration of structural, fault, and fluid level information from the structure map in combination with the sand distribution information from the porosity isopach map.

Table 2

Reserve categories compared

RUSSIA

Reserves				Resources		
Explored			Preliminary	Prospective	Prognostic	
A	B	C_1	C_2	C_3	D_1	D_2

U.S.G.S.

Identified			Undiscovered	
Demonstrated				
Measured	Indicated	Inferred	Hypothetical	Speculative

S.P.E.

Proven				
PDP	PDNP	PUD	Probable	Possible

RUSSIAN RESERVE CATEGORIES*

- A – Pool reserves under production.
- B – Pool reserves that yielded commercial flows of oil and gas from wells at different depth levels.
- C_1 – Pool reserves characterized by commercial flows of oil or gas from some wells and positive results of geological and geophysical investigations in untested wells.
- C_2 – Pool reserves in untested zones adjacent to reserves of higher categories; reserves in untested beds occurring within and above the producing section of a field.
- C_3 – Prospective resources of oil and gas in traps prepared for deep drilling and situated within an oil and gas region, and in developed fields in horizons untested by drilling but proved to be productive in other fields.
- D_1 – Prognostic resources of oil and gas in lithostratigraphic units evaluated within major regional structures with proved oil and gas commercial potential.
- D_2 – Prognostic resources of oil and gas in lithostratigraphic units evaluated within major regional structures without proved commercial potential.

* After Geologiya Neft i Gaza, Moskva, 1985, p. 43, compliments of Wavetech Geophysical Inc., Denver. This comparison of reserve categories is intended to provide general guidelines and is not to be interpreted literally.

Carefully review flow tests, core descriptions, and log analyses for oil/water contacts (OWC), gas/water contacts (GWC), and gas/oil contacts (GOC). When a fluid contact is established, post the contact datum on all logs in the "control area" to be certain there are no contradictions ("control area" refers to each reservoir in pressure communication). Many reservoirs contain stratigraphic barriers, so there may be multiple fluid levels in what appears to be a continuous sand. Planimeter each reservoir control area to determine the bulk reservoir volume. If suitable core data are available, construct a "porosity times net pay" map in addition to the net pay map.

Reservoir properties

The following reservoir properties are used in the volumetric calculations: formation volume factor (Bo), porosity (ϕ), oil saturation (So), and recovery factor (RF). Reservoir fluid properties are obtained from PVT analyses of fluid samples and from measurements taken during flow tests.

Typically oil, water, and gas samples are collected during testing operations and field measurements are made of oil density, gas-oil ratio, and salinity of produced water. Other samples are sent to laboratories where the bubble-point pressure, density, viscosity, and bulk modulus are measured at reservoir temperature and pressure, and oil density, gas density, gas-oil ratio, and relative volume factor are measured for flashed and differential conditions.

These data are analyzed and average values calculated which provide the fluid properties for volumetric calculations, flow test analyses, and material balance calculations.

In addition to these single condition measurements, the oil density and viscosity are also measured at 1) reservoir pressure for decreasing temperatures beginning at reservoir temperature and ending at 20° C., and 2) reservoir temperature for decreasing pressures beginning at reservoir pressure and ending at 0.1 Mpa. It is recommended a comparison of the analytical results with Vasquez and Beggs correlations be made of the measured data.[3] Using the oil density, gas-oil ratio, and reservoir pressure and temperature, the formation volume factor and bubble point may also be determined using the correlations. If there is a large difference between the reported formation volume factor and the calculated value, the reason for of the difference must be identified. Normally this is not a difficulty; however inconsistencies do occur, so the data should be checked and independent calculations made.

Original oil in place

The original oil in place (OOIP) and recoverable reserves are determined using volumetric calculations. The oil volume is reported by Russians in tons rather than barrels so the volumetric calculation includes oil density (γ_o).

$$\text{OOIP} = \frac{\Phi * h * A * S_o * \gamma_o}{B_o}$$

$$\text{Recoverable reserves} = \text{OOIP} * \text{RF}$$

The reservoir volume terms ϕ, h, and A, can be estimated through mapping or through a combination of map, core, and log data. The mapping approach is recommended because it averages the data across the entire reservoir.

The most difficult item to estimate is the oil saturation. We recommend selecting several key wells with complete log, core, and test data located at least several meters above the OWC for rigorous oil-saturation calculations.

Russians classify OOIP in a fashion similar to our own. Table 2 summarizes the classifications used in Russia and compares it to Society of

Table 3

Russian reserve calculation example*

Stratum Пласт	Category Категория	Area 1,000 m^2 площадь тыс.$м^2$	Net pay, m вффек. толщина	Porosity $К_п$	So $К_н$	Oil density, g/cc плотность, г/$см^3$	1/Bo персч.
		Parameters Параметры					
Ю1	C_1	150,000	6.0	0.16	0.60	0.800	0.69
Б10	C_1	130,000	6.5	0.19	0.60	0.810	0.72

Recovery factor КНО	Oil Reserves, 1,000 tons Запасы нефти, тыс.т: OOIP балансовые	Oil Reserves, 1,000 tons Запасы нефти, тыс.т: Recoverable извлекаемые	Gas factor Газовый фактор, m^3/T	Solution gas, million m^3 Запасы Растворенного газа, млн.$м^3$: In place балансовые	Solution gas, million m^3 Запасы Растворенного газа, млн.$м^3$: Recoverable извлекаемые
0.400	47,693	19,077	190	9,062	3,625
0.350	56,180	19,663	180	10,112	3,539

*Example of Russian computation of pore-volume reserves. Parameters are multiplied horizontally to determine oil and solution gas reserves.

Table 4

Common Russian geologic, volumetric terms

Geologic terms	
oil	нефть
gas	газ
water	вода
mud	раствор
oil/water contact	ВНК
gas/water contact	ГВК
gas/oil contact	ГНК
map	карта
depth	глубина
interval	интервал
core	керн
formation	формация
layer, stratum	пласт
field, deposit	месторождение
reservoir	коллектор
sandstone	песчаник
coal	уголь
smell	запах
no show	без признаков
dry, tight	сухо
Volumetric, analytical terms	
reserves in place	балансовые запасы
recoverable reserves	извлекаемые запасы
recovery factor	КНО
area	площадь
thickness (m)	Н (м)
porosity	пористость
permeability	проницаемость
gas/oil ratio	газовый фактор ($м^3$/т or $м^3$/$м^3$)
pressure	давление
pascal	па
formation volume factor	объемный коэффициент нефти
oil density (g/cc)	плотность нефти (г/$см^3$)
parameters	параметры
coefficient	коэффициент
results	результаты
table	таблица
category	категория
1,000	тыс
1,000,000	млн

Petroleum Engineers and U.S. Geological Survey classifications. OOIP and recoverable reserve pore-volume estimates are reported by reservoir, by category, and/ or by well. These estimates periodically are updated and provide the basis for reserve certification.

Table 3 is an example of an OOIP and recoverable reserve computation as it might appear in a table on a Russian net pay map. Metric tons of oil are calculated from the table by horizontally multiplying all of the parameters in the columns.

To convert from thousands of metric tons (MT) to thousands of barrels of oil, divide MT by the oil density (= thousands of cubic meters) and multiply by 6.29.

Table 4 summarizes common Russian terms and abbreviations dealing with reservoir descriptions and volumetric calculations.

To calculate recoverable reserves, the recovery factor must be estimated. Sands in the Western Siberia basin respond well to pressure maintenance through waterflooding because most are moderately permeable volumetric reservoirs rather than extensive reservoirs with active water drives. Pressure maintenance generally is started two to five years after production begins.

Ultimate recovery factors range from 14-35% for mature waterflooded fields; thus waterflood sweep efficiencies range from ineffective to excellent. From our experience, recovery factors range from 9% for primary recovery (thin discontinuous sands) to 35% for floods with good sweep efficiency. Average recovery factors for well-managed waterfloods are expected to range between 20-27%.

Part three of this series is a discussion of well tests and production forecasts.

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1. Connelly, William, and Krug, J.A., Evaluating oil, gas opportunities in western Siberia—log and core data OGJ, Nov. 23, 1992, p. 97.
2. Peterson, J.A., and Clark, J.W., Geology and hydrocarbon habitat of the West Siberia Basin, AAPG Studies in Geology No. 32, 1991, 96 pp.
3. Vasquez, M., and Beggs, H.D., Correlations for fluid physical property predictions, JPT, 1980, pp. 986-970.

W. AUSTRALIA

A well drilled by a group led by small Australian explorer Anzoil NL has gauged a record gas flow for the Canning basin.

The 1 Point Torment flowed 4.3 MMcfd of dry gas at 685 psi stabilized flowing pressure from 2,085.8-96.5 m. More work is needed to determine commercial potential.

The well site is 25 km from the coastal town of Derby and 50 km west of the Blina and Sundown group of onshore oil fields.

The well was projected to 1,765 m to evaluate a sand that produced oil in the nearby 1 West Kora well, which Esso drilled in the early 1980s and Anzoil reentered earlier this year.

That formation was dry in the 1 Point Torment. Two participants, Stirling Petroleum and Basin Oil, alone elected to fund the deeper drilling.

Besides Anzoil with a 32% interest, the group included Oil Co. of Australia 20%, Stirling and Basin a combined 20%, First Australian Resources and Austin Oil each 8%, Indigo Oil 5.4%, International Minerals and Portman Resources each 2.3%, and Gulliver Productions 2%.

S. AUSTRALIA

BHP Petroleum Pty. Ltd.'s four well offshore Otway basin program started with the 1 Troas wildcat in the South Australian sector. Target is the Cretaceous Pretty Hills formation, which has shown promise at onshore locations in the region.

The succeeding three wells are planned off Victoria. All four are being drilled by the Byford Dolphin semisubmersible brought from the North Sea for the program.

THAILAND

Operators plan to evaluate a Gulf of Thailand oil discovery described by one as encouraging.

The well produced waxy crude oil from two intervals at rates of 228 b/d and 126 b/d. The well is on Block 5/27 shared by British Gas Thailand and the Thai state company PTT Exploration and Production (OGJ, Sept. 23, 1991, p. 12).

The well site is 55 nautical miles southwest of Sattahip and 200 km south of Bangkok, a Bangkok newspaper reported.

TURKEY

Coplex Resources NL, Hobart, Tasmania, is to spud the 1 Maras well in the North Arabian basin to probe untested anticlines.

The company believes the postulated target reservoir might hold 800 million bbl of reserves.

Coplex recently increased its interests in the Maras licenses to 67.5% from 50%.

NORTH SEA

BP Exploration Operating Co. Ltd. is preparing to spud its second Hyde field production well, which will have the longest horizontal section in a North Sea well at a planned 6,240 ft. The well will be drilled by the Glomar Baltic I rig in a 132 day program.

PUBLICATIONS

The East Continent Rift Basin: A New Discovery, has been published by the Kentucky and Indiana Geological Surveys and the Ohio Department of Natural Resources, Division of Geological Survey.

The report describes a recently confirmed sedimentary basin that lies largely beneath the well known but younger Cincinnati arch. It is thought that the basin is a major southeastern extension of the Midcontinent rift system and may be filled with as much as 25,000 ft of lithic arenites and basalts.

Like the Midcontinent rift, the basin is Middle Proterozoic in age and is of continental rift origin. The Grenville Province apparently was thrust over the eastern part of the basin.

Only a few wells have tested the East Continent rift basin, and none has penetrated its full thickness. The basin is scientifically significant because of its importance to understanding the geological evolution of the North American craton.

The illustrated 25 page report is available for $4 plus shipping from the three participating geological surveys (OGJ, Nov. 12, 1990, p. 128).

TEXAS

Gulf Coast

Alexander Energy Corp., Oklahoma City, has identified three locations for drilling that offset a horizontal Cretaceous Austin chalk producing well it completed in Giddings field of Fayette County.

The 2H Dusek, a reentry 6 miles north of LaGrange, flowed 2,225 b/d of oil and 4.47 MMcfd of gas through a ½ in. choke with 1,475 psi flowing tubing pressure. The state allowable is 1,476 b/d of oil and 2.95 MMcfd of gas.

The wellbore was drilled about 1,500 ft horizontally from the existing vertical well.

AEJH 1989 LP, a partnership between John Hancock Mutual Life Insurance Co. and Alexander, owns a 64% working interest shared equally.

East

Mitchell Energy & Development Corp., Houston, is drilling an offset to a well it said is a significant northwesterly extension of North Personville field in Limestone County.

The 3 Engram flowed 4.7 MMcfd of gas through a 16/64 in. choke with 3,100 psi flowing tubing pressure from Jurassic Cotton Valley lime at 10,792-954 ft.

Mitchell also completed 3 the Browder Gas Unit, 4 P. Rothermel, 3 Quinn, 3 Raines, and 4 Miles, from Cotton Valley. Flow rates ranged from 1.8-4 MMcfd of gas.

West Central

Throckmorton Oil Co., Throckmorton, Tex., has staked three rank wildcats in a sparsely drilled area of Throckmorton County about 20 miles northwest of Albany.

The 1 Sloan XS B-4 Unit, 2 Sloan XS B-4 Unit, and 1 Sloan XS F-5 Unit, are projected to 5,500 ft, PI reported. The area is 4 miles west of Y-L field, which produces gas from Pennsylvanian Caddo at 4,725 ft.

Enron Oil & Gas Co., Midland, has staked a wildcat in Sutton County near abandoned Jo Nell gas field.

The 1 Cauthorn, 16 miles southwest of Sonora and more than 1 mile northeast of previous Canyon production, is projected to Canyon at 9,800 ft, PI reported.

The location is also 2 miles south of Shurley Ranch (Canyon) gas field.

ARKANSAS

Seeco Inc., Oklahoma City, appears to have a discovery in Crawford County about 6 miles northeast of Alma.

The company staked the 1 Cotten, in 33-11n-30w, for 3,400 ft or Ordovician Everton.

Seeco drilled 1 Gilker, in 32-11n-30w, about 6 miles north of Alma gas field, to 3,340 ft in Ordovician St. Peter sand and tested Pennsylvanian Hale sand perforations at 2,213-20 ft, Petroleum Information reported.

The discovery, waiting on pipeline connection, has been named Frog Bayou.

CALIFORNIA

Tri-Valley Corp., Bakersfield, has entered a coventure with Texaco USA Inc. to generate prospects in the San Joaquin Valley.

The coventure provided Tri-Valley with a proprietary data base covering 1.5 million acres in the province. Tri-Valley will interpret the data to generate prospects that Texaco may elect to join.

COLORADO

Coastal Oil & Gas Corp. plans two offsets to a Upper Cretaceous Mesaverde (Almond) gas discovery in Moffat County.

The locations are in 18- and 19-11n-94w, 35 miles northwest of Craig. Projected total depths are 9,900 ft, Petroleum Information reported.

The sites are 1 mile west and northwest of Coastal's 1 Federal, in 20-11n-94w, which flowed 3 MMcfd of gas through a 16/64 in. choke with 2,600 psi flowing tubing pressure from perforations at 9,529-9,600 ft.

The area is about 6 miles northwest of Big Hole gas field.

Meridian Oil Inc. and Barrett Resources Inc. are drilling a horizontal test for gas in Upper Cretaceous Mesaverde (Cozzette) in Rulison field.

The 43-33H Quarter Circle, in 33-6s-94w, is to test Cozzette at about 7,947 ft true vertical depth, PI reported.

The drill site offsets to the west the CER Corp.-U.S. Department of Energy 1 SHCT-Superior, a high angle/horizontal well that was completed during January 1992 for 3.048 MMcfd of gas from open hole at 8,578-9,407 ft.

RUSSIAN VENTURES–3

Here are considerations in evaluating Russian flow tests, reservoir performance

Jack A. Krug *Questa Engineering Corp. Golden, Colo.*
William Connelly *Pangea International Inc. Golden, Colo.*

Flow test data contain some of the most important information for evaluation of a field. As part of the Russian evaluation process, research wells are extensively tested.

Three types of well tests are conducted: 1) drillstem tests, 2) production flow test (if the well flows to the surface), and 3) rising head test (if the well will not flow to the surface).

Drillstem tests are run in the open hole across potential pay zones. After casing is run, wells are flow tested with multiple-rate tests, and

Table 1

DST SUMMARY

Test No.1	**I ОБЪЕКТ**
Test interval, 2,150-2,210 m	ИНТ 2,150-2,210m
Drawdown, 17.5 MPa	ΔP = 17,5 МПА
Open time, 100 min	T = 100 МИН
Shut-in time, 120 min	КВД = 120 МИН

the bottom hole pressures are recorded during the build-up periods.

Results of the tests are summarized in test reports, on net pay maps, and on logs. The results from these tests include reservoir pressure, reservoir temperature, formation permeability, productivity index, and damage ratio. This information provides the basis for estimating production capacities and future reservoir performance.

Drillstem tests

Russian drillstem tests are conducted in a similar manner to western methods and with very similar tools. Bottom hole and straddle tests are conducted. The open and closed times and sequences depend upon the zones being tested and the test objective.

Table 1 is a typical drillstem test summary as it might appear on a net pay map or annotated on a well log.

Russian analysis of the pressure build-up data uses the "Horner method" for calculating permeability and estimating the original reservoir pressure. The production rate during the flow period is estimated based on 1) the produced liquid volumes, or 2) the change in fluid level determined from

Table 2

FLOW TEST SUMMARY WELL NO. 29, TEST NO. 4

Formation:U3-4
Test date: 10.01.86 Test interval: 2,844-2,850 Gauge depth: 2,840

No. п	Работа на штуцере: Д штуцера мм	время общее час	устан овив режим час	Дебит в м. куб/сут.: общий	нефти	вода	газа тыс. куб. м.	Газовый фактор куб.м ф/м	Давлене в атм: пластовое	статическ: буфер	затруб-ное	забойное	трубное	затрубное	Температура T°C
Test no.	**Choke size, mm**	**Flow time: total hr**	**Stabil-ized hr**	**Total fluid**	**Production rate, cu m/day: Oil**	**Water**	**Gas 1,000 cu m/d**	**Gas/oil ratio cu m/cu m**	**Pressure, atmospheres: Formation pressure**	**Static (surface): tubing**	**casing**	**Bottom-hole**	**tubing**	**Casing**	**Reservoir temp. °C.**
1	4	24	18	16.0	16.0	—	2.370	148.5	—	—	—	193.6	17.5	24.5	98°
2	6	34	12	26.4	26.4	—	4.170	158.0	—	—	—	157.2	11.5	16.0	—
3	0	150	—	—	—	—	—	—	283.5	60.0	70.0	—	—	—	—
4	6	46	12	24.0	24.0	—	3.845	160.2	—	—	—	169.5	9.0	15.5	—
5	4	24	10	17.6	17.6	—	2.659	151.0	—	—	—	196.0	12.0	17.5	—
6	2	24	8	8.8	8.8	—	1.394	158.3	—	—	—	242.0	17.2	30.0	—

Quality Tubing Inc., Houston, Tex., has named David L. Daniel president. Previously Daniel was president of Baker Hughes Tubular Services, Inc.

Daniel

Daniel has over 17 years experience in the oil field service and supply industry where he has held key management positions with Baker Hughes and NL Industries.

Quality Tubing, Inc. is a manufacturer of coiled tubing for use in drilling, production, workover and pipeline operations. In addition, Quality Tubing supplies coiled tubing for subsea flow lines, umbilicals and service lines.

Landmark Graphics Corp., Houston, Tex., has announced that C. Eugene Ennis has resigned as chairman and chief executive officer to found a Houston oil company that will generate and develop prospects with his former firm's 3D computer-aided exploration technology.

The yet-unnamed company will seek nonoperating working interests as a partner with land owners and other oil companies. Landmark Graphics is contributing $100,000 cash and $200,000 in hardware and technology for a 35% nonvoting equity interest. Peter Duncan and Doug Nester, of former Landmark Graphics subsidiary Concurrent Solutions, will join Ennis in the new company.

Replacing Ennis as Landmark Graphics chief executive officer is Pres. Robert P. Peebler. Sam K. Smith, a director, becomes chairman.

Weatherford International, Houston, Tex., has acquired the Gemoco Div. of Sequa Engineered Services, Inc.

Gemoco, located in Houma, La., manufactures and sells cementation products used in oil and gas wells. It also supplies replacement parts for process industry control valves.

Weatherford is a diversified international energy service and manufacturing company that provides tubular running and fishing services, rents specialized equipment and fishing tools and sells products and equipment, including cementation products, to the oil and gas industry.

Pipe Rehab International, Inc., Dallas, Tex., has announced the assignment of James D. (Andy) Anderson and Jerry Dunlap to the Midland, Texas sales office. Stanley Bull has been assigned to the Houston sales office with responsibility for the Houston-Gulf Coast.

Mid-Continent Oil and Gas Association, Jackson, Miss., a regional petroleum trade group, has elected officers for 1993: Chairman, William R. James, Pruet Oil Co.; vice chairman, James D. Abercrombie, Mobil Exploration & Producing U.S. Inc.; president, Joseph K. Sims, Mid-Continent Oil and Gas Assoc.; and secretary-treasurer, Thomas E. McMillian, Jr., Smackco, Ltd.

The Association awarded the prestigious 1993 Bill and Emmett Vaughey Wildcat Award to Harry Spooner, Spooner Energy, of Jackson, an independent oil and gas producer. The award is given annually by the Association to individuals or companies with distinguished records in the Alabama or Mississippi oil and gas industry.

Peerless Pump Co., Montebello, Calif., has named Ron McCurry president.

McCurry previously was director of operations at Goulds Pumps, where he headed a number of operating divisions, including their slurry, California vertical, Texas vertical and West Virginia pump units.

In addition, McCurry has held manufacturing, industrial engineering, systems, sales and general management positions at Dresser Industries and Joy Technologies.

Peerless Pump Co. designs, engineers and manufactures a full line of pumps and packaged pumping systems for most any industrial need including: pulp and paper, chemcial processing, offshore, fire protection, power generation, HVAC, municipal/industrial water and waste, irrigation, agricultural, construction, pollution control and general service.

Peerless Pump Co. configurations and designs for these markets include: vertical turbine, ANSI standard, heavy duty process, self-priming, horizontal split case, general service end suction, vertical fire pumps, horizontal fire pumps and a variety of special products including engineered packaged systems.

The MH Koomey Companies, Houston, Tex., has announced that their parent company, The Maritime Group, has reorganized the five Koomey locations into a single entity with centralized management.

David Ellis, The Koomey Companies president, is based in Houston. Ellis has thirteen years service with Koomey in the U.S.A., Scotland and Norway.

Iain Duncan, who joined Koomey ten years ago, holds the position of general manager in Aberdeen.

Eddie Khoo, also with ten years service, holds the general manager position in Singapore.

The Singapore office is further strengthened by the recent addition of Glen Baker, formerly located in the Houston headquarters. Baker, with twelve years service with Koomey, will add valuable technical support to the active Southeast Asia area.

Maritime Group has announced that MH Koomey's sister company, Maritime Hydraulics, has established its Houston base, Maritime Hydraulics U.S. Inc. The newly appointed president of MH U.S. is Ray Atchley, whose experience includes thirty-six years with Continental Emsco.

Energy Ventures, Inc., Houston, Tex., has announced that John A. Wenck has joined Grant TFW, Inc., its wholly owned tubular manufacturing subsidiary, as director of international sales, reporting to Peter H. Nielsen, president. Wenck has extensive international management experience with U.S. Steel and Hydril. Wenck will be responsible for international sales and marketing of Grant's proprietary lines of Atlas Bradford premium threaded tubulars.

Mallard Bay Drilling, Energy Ventures' marine contracting subsidiary, has named Robert P. Dunn vice president international operations, reporting to William C. Langford, president. Dunn's previous experience included international management assignments with Zapata Offshore Co. Dunn will assume control of foreign operations and be involved in marketing and sales efforts for Mallard Bay's international contracting businesses.

Energy Ventures, Inc. is an oilfield service and equipment company which manufactures high performace tubulars and artificial lift equipment and provides drilling workover services.

Fig. 1

FLOW TEST SUMMARY

Formation: U3 & U4

Test date: 12.09.88-01.10.88

Well No. 2a, build-up 1

Test interval: 2712-2729 m

Gauge depth: 2700 m

Pressure data

Shut-in time min.	BHP psi
0	3,933
30	4,059
120	4,072
240	4,083
360	4,090
480	4,096
780	4,099
1,140	4,102

Flow rate B/d	Flow time min.	Flowing pressure psi
96.9	17,280	3,933

Net pay ft	Porosity	Wellbore radius ft
32.8	0.128	0.35

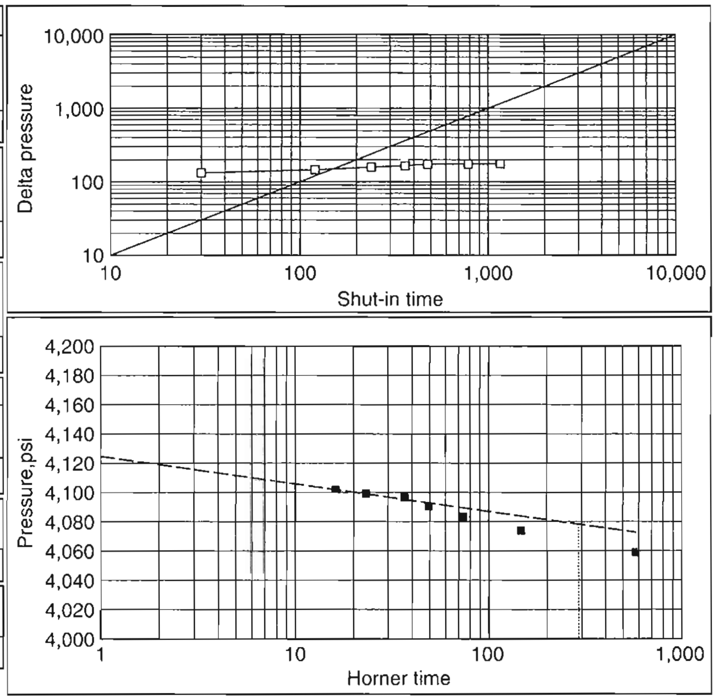
Ct 1/psi	Oil viscosity cps	Formation volume factor
8.72E-06	1.868	1.11

Calculation results

kh/u md ft/cps	k md	Slope psi/cycle
930	53	18.81

p* psi	skin	P1 hr
4124	3.03	4078

PI actual B/d/psi	PI ideal B/d/psi	Flow efficiency
0.506	0.684	0.74



OGJ

the initial and final bottom hole flowing pressures. For the latter case, the production rate calculation uses the following equation:

$$Q = \frac{(P_K - P_H) * S * 1440}{\gamma * T * 1000} \quad (M^3/cyt)$$

where P_H and P_K are, respectively, the final and initial flowing pressures, atm; S is drillpipe inside area, cm^2; γ is fluid specific gravity, gm/cm^3; and T is flow time, minutes. The denominator constant of "1,000" should be "967.6."

The permeability and initial reservoir pressure are calculated from the slope and intercept of the Horner graph. The shut-in pressures are plotted versus the log [(T + ti)/ti], where ti is the shut-in time. Base-10 logarithms are used.

The slope of the straight line passing through the last pressure points is "i" and the intercept is the estimated original reservoir pressure, $P_{\pi л}$. In western Siberia, original reservoir pressures tend to be normally or slightly overpressured.

The actual coefficient of productivity is calculated with the estimated flow rate and the drawdown pressure using the following equation:

$$\Pi\phi = \frac{Q}{\Delta P} = \frac{Q}{P_{\pi л} - \frac{(P_K + P_H)}{2}} \quad (M^3/cyt*atm)$$

The flow capacity is referred to as the "hydrodynamic permeability" and is calculated with the following equation:

$$\frac{Kh}{\mu} = \frac{0.1832\ Q}{i} \quad (Darcy\ cm/cp)$$

Note that in this calculation the units of Q are cm^3/sec.

The formation permeability, called the "strata-permeability," is calculated with the following equation:

$$K = \frac{0.183\ Q\mu}{h * i} \quad (Darcy)$$

The undamaged (or potential) coefficient of productivity is calculated using the flow capacity term:

$$\Pi_\pi = \frac{0.086\ Kh}{\mu} \quad (M^3/cyt*atm)$$

The damage ratio is the ratio of the two productivities:

$$\Pi = \frac{\Pi_\pi}{\Pi_\phi}$$

Typically for drillstem tests, the damage ratio is greater than one, which indicates the formation is damaged.

The theoretical natural flow rate of a well is calculated using the following calculations:

$$Q_\Phi = \Pi_\pi (P_{\pi л} - 0.1\ \gamma H_{\pi л}) \quad (M^3/cyt)$$

where $H_{\Pi\pi}$ is the formation depth in meters and γ is the flowing fluid specific gravity.

Production tests

After casing is run and cemented, long term production tests are conducted beginning at the bottom of the wellbore. After a zone is tested in research wells, it is plugged off with cement and the next shallower zone is tested.

Testing of flowing oil wells can be a multirate test or an isochronal test sequence. Most flow tests we have reviewed are multirate tests with a prolonged final flow followed with a long term pressure build-up.

Production flow test data are summarized in a format similar to Table 2. This table reports the test interval, test times, choke size, production rates, and final pressures at the surface and bottomhole.

The test sequence shown in Table 2 consists of two flow periods followed by a 150 hr shut-in period followed by three additional flow periods. The reservoir pressure is measured and reported for each shut-in period and each build-up is analyzed and reported in the test report. The pressures are measured with a bottom hole pressure gauge similar to the Amerada RPG-3.

The wellbore configuration during many tests consists of tubing suspended from the wellhead. The flow rate is controlled at the surface and the tubing does not have a packer to isolate the annular volume from the tubing volume. Therefore the shut-in periods have extended wellbore storage times compared to a well tested with a downhole packer and downhole shut-in valves.

The shut-in pressure data are plotted on three different graphs that provide the input to determine permeability, productivity, and flow efficiency calculations.

From a graph of log [t/(t+T)] vs. ΔP, the reservoir pressure $P_{\pi л}$ is estimated from the final flowing pressure $P_{заб}$ and the estimated maximum build-up pressure at infinite shut-in time.

$$P_{пл} = P_{заб} + \Delta P_o$$

The reservoir flow capacity is calculated using the slope of the straight-line portion of the last pressure data points and the following equation:

$$\left(\frac{Kh}{\mu}\right)_{\pi л} = \frac{0.183\ QB\ 11.57}{\alpha}$$

The ΔP_o is the ultimate drawdown pressure for the flow test and is used to calculate the productivity index for the zone:

$$K_{\pi р} = \frac{Q}{\Delta P_o}$$

The slope and intercept (α and A respectively) and the slope (B) of t vs. ln (dΔP) ÷ dt provide the input data for the near wellbore flow capacity calculation:

$$\left(\frac{Kh}{\mu}\right)_{\pi э} = \frac{11.57\ K_{\pi р}\ B_o \ln\left(\frac{R_k}{r_c}\right)}{2\pi}$$

where:

$$\ln\left(\frac{R_k}{r_c}\right) = \frac{1}{2}\left\{\frac{2.3A}{\alpha} - \ln\beta + 0.945\right\}$$

R_k = drainage radius, m; r_c = wellbore radius, m; and B_o = formation volume factor.

With the permeability calculated near the wellbore and for the reservoir, the damage ratio is calculated with the following equation:

$$\Gamma = \frac{k_{\pi л}}{K_{Пз}}$$

We review the calculations and independently graph and calculate the reservoir characteristics using a modified Horner method. Many of the research wells are flow tested following acid stimulation treatments.

After treating, the damage ratio normally is about 1.0 or greater.

Some severely damaged wells do not respond to treatments. Fig. 1 illustrates our calculations for test data from a flow test similar to the one in Table 2.

It is important to review microlog separation over a tested interval to determine the net meters of permeability in the interval. The independent calculations usually have different final flow capacity values because of different net pay estimates and fluid property assumptions.

Non-flowing wells are tested using the "rising-head" method which is very similar to the method used to test water wells. It has the same limitations and analytical problems as a "slug test." Because the wells do not have packers, high pressure air can be pumped down the annulus to displace wellbore fluid from the tubing and the annulus.

The depth to which fluid may be displaced is limited by the available air pressure and/or by the tubing setting depth.

After the air pressure and liquid levels stabilize, the air pressure is released from the annulus, thus allowing the fluid level to U-tube and stabilize below the static level. In this condition the wellbore is at a pressure below reservoir pressure, so the well begins to flow into the wellbore until it once again stabilizes.

The increase in fluid level is measured versus time and is related to the build-up of pressure in the wellbore.

In the west, slug tests generally are analyzed using type curves. However, Russians use a graphical method of analysis. A typical graph of time versus natural log of the increasing fluid head is prepared. Using the slope ($t_g{}^{\alpha}$) and the area of the wellbore in square centimeters (F), the productivity of the zone is calculated:

$$K_{Пр} = 0.024\ \frac{t_g\alpha F}{\gamma_o}$$

The productivity and permeability of the zones are estimated from these tests and are used to calculate the theoretical performance of the wells and the fields. Often the wells initially will flow, but generally after about two months they cease flowing and are placed on pump.

About 20% of the wells are produced with downhole submersible pumps and the rest are rod pumped.

The fourth article in this five part series discusses feasibility studies, including the development plan, costs, and economic analysis of the venture. ▪

Table 3

COMMON RUSSIAN FLOW TEST TERMS

F	Wellbore area, rising head test, sq cm
H(t)	Fluid level at t, rising head test, m
ИНТ	Interval, m
Кпл	Coefficient of reservoir permeability, darcy
(Кh/μ)пл	Reservoir flow capacity, darcy-cm atm
$(Kh/\mu)_{\pi 3}$	Near wellbore flow capacity, darcy-cm atm
ГФ	Gas factor, cu m/cu m
Г	Damage ratio, production test
П	Damage ratio, drillstem test
Пп	Undamaged productivity coefficient, cu m/day-atm
Пф	Actual productivity coefficent, cu m/day-atm
Q	Measured flow rate
$Q_{ф}$	Ideal flow rate
$P_{н}$	Initial DST flow ing pressure, atm
$P_{к}$	Final DST flowing pressure, atm
Рпл	Original DST reservoir pressure, atm
$P_{заб}$	Final flowing pressure, atm
ΔP	Drawdown pressure, atm
ΔPo	Intercept of log (t/t+т) vs ΔP, atm
r_c	Well bore diameter, m
Rк	Reservoir drainage bound ary, m
S	Drillpipe inside area, sq cm
Bo	Formation volume factor
Flow test units	
ат	Atmosphere
спз	Centipoise
Д	Darcy
МПа	MPa
A	Intercept of log (t) vs. ΔP
∝	Slope of log (t) vs. ΔP
β	Slope of t vs. ln (d ΔP/dt)
tg∝	Slope of t vs. ln (H(t))

RUSSIAN VENTURES—4

Evaluating oil, gas ventures in W. Siberia: feasibility studies

Jack A. Krug *Questa Engineering Corp. Golden, Colo.*
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This article discusses the methodology and calculations used in performing the economic evaluations for a typical western Siberia oil project venture. The discussion of taxes, funds, depreciation, and costs assumes the venture is a stock company and that economics are calculated on a project basis.

Venture structure, bidding procedures, and requirements for registration are discussed in the next article. Most ventures available to western companies are delineated oil fields that are not yet developed or producing. We focus on this type of property.

The required elements for an economic evaluation include original-oil-in-place (OOIP) and recoverable reserves; development plan and associated production forecast; and capital requirements and operating costs. The level of evaluation—i.e., screening, preliminary feasibility study, Technical Efficiency of Organization (TEO), or full feasibility study—determines the detail needed for each of these elements. Several economic analyses of a venture should be made to evaluate the sensitivity of alternative development plans, joint venture deal terms, capital requirements, operating costs, product prices, and taxation variables.

The first three parts of this five part series dealt with (1) log and core data, (2) reservoir description and (3) flow tests and reservoir performance, and provided a technical foundation for the evaluation of oil and gas ventures in western Siberia.[1 2 3]

Recoverable reserves, production forecasts

The OOIP, reservoir drive mechanism (i.e., depletion drive, waterflood, or gas injection), and recovery factor (RF) determine the production forecast. Computation of OOIP was discussed in part two of this series and is based on geophysical, log, core, and map data.

The production mechanism for western Siberia oil fields typically is depletion drive and/or waterflood. Two extremes of recoverable reserves and associated production forecasts are used to calculate the possible range of economics. The minimum case assumes a depletion drive mechanism with low production rates and RF. The maximum case assumes improved production rates and RF through a secondary recovery pressure maintenance development program.

For the minimum case, the primary recovery forecast is estimated using the Tracy method of material balance. This method assumes fluid expansion is the dominant drive mechanism.

The material balance approach provides an acceptable forecast of primary recoveries only if the reservoir pressure gradients are not too large and the reservoir does not have an active water drive or large gas cap.

The pressure gradients typical of Siberia reservoirs are not too large because permeability is sufficiently high to allow uniform drainage throughout the reservoir. Tracy material balance calculations generally indicate expected primary recoveries range between 7% and 15% of the OOIP.

With a depletion drive reservoir, the production rate rapidly declines exponentially with time. The resulting cash flow estimates have the lowest value.

For secondary recovery development programs using waterflood, the RF is lower for thin sands than for thick sands because sweep efficiency is better in thicker sands. The RF for a reservoir is not consistent across a structure because of stratigraphic inhomogeneities, structural boundaries (e.g., faults) and transition zones, all of which cause variations in flood efficiency across a field.

Oil companies use general guidelines for minimum pay thickness considered economically productive or likely to respond to waterflood. The first step in estimating recoverable oil is partitioning the bulk reservoir volume according to pay thickness; for example, net pay intervals that are less than 3 m thick and those greater than 3 m thick.

Thin pay zones in a reservoir are considered nonfloodable and are assigned an RF range from zero to 10%. Recovery from these thin zones is assumed to result only from fluid expansion (depletion drive). To justify development of thin pay zones, they must be economic on their own merit or they must be developed in conjunction with thicker pay zones elsewhere in the wellbore.

If a thin zone will be penetrated while drilling to a

The Dresser-Rand Co., Corning, N.Y., through its Turbo Products Div., and European Gas Turbines Limited—Industrial Products, U.K., have signed a memorandum of understanding covering their intention to jointly develop, engineer, and distribute gas turbine-driven compressor packages for the oil and gas industries.

The alliance will draw on the individual strengths of the two companies—Dresser-Rand's industry-leading turbocompressors and EGT's extensive gas turbine product line—and will combine them to provide oil and gas customers with the most efficient, technologically advanced, cost-effective gas turbine-compressor packages available.

The combination of each company's products and technologies into the resulting unique packages should allow Dresser-Rand and EGT, working together, to respectively provide a broader range of gas turbine-compressor offerings, and to better and more competitively service customers in North and South American and European markets. Each company will continue to market, sell, and service their respective indivdual products.

European Gas Turbines Limited—Industrial Products is a subsidiary of GEC ALSTHOM's European Gas Turbines, the leading manufacturer of gas turbines in Europe. The company is a major designer and manufacturer of industrial gas turbines from 2 to 50 MW, supplying the oil, gas, and power generation industries, with its main manufacturing plant in Lincoln, England, and service support facilities around the world.

Dresser-Rand, a partnership between Dresser Industries, Inc., and Ingersoll-Rand Co., is a supplier of turbocompressors, steam turbines, power turbines, hot gas expanders, motors, generators, reciprocating compressors, control systems, generator sets, operating and maintenance support, total module engineering, and construction services to the petroleum, gas, chemical, petrochemical, and electric power industries. D-R and its international affiliates have 12 manufacturing and test facilities and 31 service centers worldwide. Dresser-Rand Turbo Products Div. is headquartered in Olean, N.Y. with turbomachinery manufacturing facilities in Olean; Lethbridge, Canada; Le Havre, France; and Kongsberg, Norway; and has a manufacturing affiliate in Hiroshima, Japan.

Applied Subsea Technology and Engineering [UK] Limited, the independent subsea engineering consultancy, and Binnie & Partners, one of the UK's largest maritime and civil engineering consultancies, have announced the formation of a new subsea engineering and construction management company called Aquation (UK) Limited.

Aquation, which is jointly owned by ASTE and Binnie & Partners, will be based in Redhill Surrey, close to London and Gatwick. The new company will offer the subsea design and construction experience of ASTE together with the wide expertise, manpower resources and international organization of Binnie & Partners.

Aquation's services will range from studies and investigations, research and develoment, engineering design, through to project and construction management covering such areas as offshore and onshore pipelines, subsea production facilities, testing and precommissioning together with all aspects of decommissioning and abandonment. Aquation will offer innovative, economic and above all practical answers to the problems of subsea development together with expert assessment of all projects for safety, loss prevention, environmental protection and impact assessment, using the latest forecasting and analytical techniques.

American Norit Co., Inc., Jacksonville, Fla., has named Lowell E. Howard manager western region in the company's new A.C.E.S. (Activated Carbon Engineering and Services) division. His responsibilities will include commercial and technical management of activated carbon adsorption systems and services business in the western U.S., Canada and Mexico.


Howard

Howard has over twenty years of engineering experience in the design of purification systems for food, waste and petrochemical processing. Howard has special expertise in the design and fabrication of FRP systems to handle corrosive gases and liquids.

American Norit is a supplier of activated carbon offering a wide selection of carbon grades.

Stone & Webster Engineering Corp., Boston, Mass., has announced that its president, Ben Charlson, will assume the additional title of chief executive officer.

The company's board of directors also elected Warner I. Clifford and Brian D. Dunfield, directors; Richard B. Kelly and S.F. Koseoglu, executive vice presidents; Frederick B. Baldwin, Lenox P. Garrity and Frederick Pastor, Jr., vice presidents; and Stephen A. Quattrocchi, treasurer.

Stone & Webster Engineering Corp. is an international, multidisciplinary engineering and construction organization specializing in technologically advanced projects in such areas as environmental restoration, power generation and refining and petrochemical work. The company also undertakes transportation, pulp and paper, and other industrial projects. Stone & Webster Engineering Corp. is a subsidiary of Stone & Webster, Inc., New York City.

Catalytica, Mountain View, Calif., has named W. Robert Epperly vice president, engineering. Al A. Jecminek has been named general counsel.

Epperly has over 20 years of management experience. He was previously chief executive officer and managing director of Fuel Tech N.V., where he was responsible for worldwide operations and for commercializing low-emission, petroleum combustion technology. He led the development and commercialization of the NOxOUT technology that resulted in the Nalco Fuel Tech, Inc. joint venture.

From 1957 to 1986, Epperly was with Exxon Research and Engineering Co. His last position there was as general manager, corporate research, where he managed programs to commercialize new catalytic processes for chemicals and high-octane gasoline production. Epperly also held managerial positions in petroleum and synthetic fuels research, coal liquefaction, project development and planning, and worldwide marketing.

Jecminek is responsible for corporate intellectual property matters, and he will participate in strategic business planning and in the formation of Catalytica's worldwide partnerships.

Jecminek was with Shell Oil Co. for over 25 years, where he was responsible for patent and licensing matters, including litigation, in the areas of base chemicals, catalysts, detergents, agrichemicals, and oil processes. In 1983, Jecminek cofounded Triton Biosciences Inc. (a wholly owned Shell Oil subsidiary), where, as vice president and chief legal counsel, he managed the acquisition of a patent portfolio, generated multimillion dollar partnership and development agreements, and advised on the sale of the company to Schering A.G. in 1990.

Catalytica develops economic and environmentally advantageous catalytic technologies for the energy generation, petroleum refining, and chemical industries.

deeper objective, for economic calculations, the zone is assumed to be perforated and produced; however, the waterflood efficiency will be very poor in this area so an RF of 7% to 10% is used.

An alternative to water injection is gas injection for pressure maintenance. While gas injection has many advantages over water (especially in cold environments), generally there are not suitable gas supply and/or infrastructure to transport gas to the field for injection. Therefore gas injection is not considered a viable alternative for preliminary feasibility evaluations.

Waterflood efficiency for thicker pay zones is a function of reservoir continuity, injection rates, well spacing, and mobility ratios. Reservoir continuity needs to be studied carefully on stratigraphic cross-sections.

However for preliminary evaluations, there generally is insufficient time and/or data to adequately evaluate the continuity of sands. Based on our experience, Megion sands often have some of the best continuity, Achimov sands have the worst, and Vasyugan sands range from good to poor.

The waterflood efficiency can be estimated by (1) empirical Siberia correlations,[4] (2) analogy with mature producing fields, or (3) reservoir simulation studies.

The empirical method is used for screening studies and estimates a waterflood RF as a function of oil and water viscosities, permeability, well spacing, porosity, permeability variation, and net pay thickness. This method is based on multivariate analyses of the actual performance of waterflooded Siberia fields (though not necessarily optimized).

The preferred method for preliminary studies is the analogy method. While reviewing and gathering data for the field evaluation, it is important to identify analogous fields proximal to the property being evaluated.

Production and injection histories, flood patterns, well counts, reservoir rock, and fluid characteristics provide valuable information for estimating production performance and ultimate recovery factors in undeveloped fields.

These data are used to calculate the moveable and recoverable oil as a function of the injected water volume.

In our experience, the older developed producing fields in western Siberia were placed on waterflood early in their lives. The production and injection histories, fluid properties, saturations, well spacing, and flood pattern can be used effectively as an analogy for an offset field. The following summarizes some of the results of evaluating multiple mature waterfloods:

- Producibility: 6-11 b/d/ft of net pay
- Injectivity: 25-32 b/d/ft of net pay
- Moveable oil: 40-50% of OOIP
- Ultimate recovery factor: 14-34% of OOIP

From these performance correlations, the future oil production rates are estimated for various production and injection development scenarios. The production forecast calculations use the method of Chesnut, Cox, and Lasaki.[5]

The analogy method provides the best estimate for expected performance of undevelopment nonproducing fields assuming similar reservoir management. Production and injection for mature fields typically indicate they are overinjected; thus by using the analogy method, a degree of conservatism is included in the RF and production forecast. With improved reservoir monitoring and management, recovery factors should improve.

Recoverable reserves may also be estimated through reservoir simulation studies. Simulation studies tend to have better application for fields with significant production histories because these models are constrained by matching theoretical and actual oil and water production histories. We recommend simulation studies for fields with production histories, but not for fields that are delineated but not yet producing.

Recovery factors are 20-27% for reasonably well-managed mature Siberia waterfloods with good reservoir continuity. The better-managed floods have RFs ranging as high as 35%. In our experience, Russians generally make reasonable estimates of OOIP, but due to unreasonably high recovery factors, their estimates of recoverable oil often are too high.

Development plan

The two extreme case development plans are formulated for a delineated field assuming two reservoir management strategies:

(1) Primary production with only depletion drive recovery mechanism; and

(2) Secondary production using pressure maintenance from waterflooding.

The development plan and scheduling for the two extreme cases are approached from a relatively conservative viewpoint.

The drilling time required for a well is estimated based on local Russian experience with time added to account for mechanical breakdowns, lack of supplies, etc. In western Siberia, Russians report a deviated 2,700 m TVD (2,950 m MD) well requires about 15 days to drill, core, log, and drillstem test.

Most wells are directionally drilled from pads. After a pad is fully developed (eight to 12 wells), the rig is moved to the next pad.

Rig moves between wells on the same pad require less than one day. Moves between pads require three to four weeks. Using these times as a guide, a development drilling schedule is created.

The time required for building infrastructure (such as interfield and intrafield roads, pipelines, oil and water processing facilities, power lines, and housing) typically is less than the time required for development drilling and completion of all wells in the field; therefore, the critical path to first production is controlled by drilling and completion rather than infrastructure.

Any time required to mobilize western equipment and supplies to the field before drilling begins must be incorporated into the development time estimates. Most of the fields we have reviewed in Siberia are not near existing roads. Transportation of heavy equipment and supplies to fields must occur in winter when rivers and wet lands are frozen.

During summer months, transportation is mainly with aircraft. Optimizing the delivery of equipment and supplies has a major impact on the development schedule, and the econommics.

The more proximal a field is to existing cities, supplies, roads, railways, pipelines, airports, and rivers, the sooner it may go on production. For remote fields, it generally is assumed all wells are drilled before production begins. If a "temporary" pipeline can be laid and made operational early in a field's development, project economics will be improved because of oil sales acceleration.

Economic analysis

Costs

Cost estimates for development and operation of oil fields in Siberia are a moving target due to the changing tax laws, import restrictions, duties, and inflation.

For evaluation purposes we use Western exploration, development, and operating costs to calculate the economics of a field. Typically Russian costs are less than Western costs, so economics will improve if a ruble contribution is included.

The following are guidelines we use for estimating costs in western Siberia; depending upon field and development constraints, costs are adjusted accordingly.

- Drilling cost: Dry hole

Western Siberia project economics

Input data line drive

Well information	
Total producing wells	143
Total injection wells	111

Oil price
$20/bbl

Year	Wells drilled	Capital costs: Facilities pipeline (Million$)	Roads/ infra- structure (Million$)	Environ- mental (Million$)	Total (Million$)
1	0	2.63	2.61	0.52	5.77
2	19	3.29	1.23	0.45	4.98
3	52	3.04	0.00	0.30	3.35
Other	183	1.32	0.00	0.13	1.45
Total	**254**	**10.29**	**3.84**	**1.40**	**15.54**
Tangible %		0	0	0	
Intangible %		100	100	100	

	Well cost	Facil. & equip.	Completion cost
Million $/well	0.750	0.100	0.250
Tangible %	28%	60%	17%
Intangible %	72%	40%	83%

Note: Year 1 begins on Jan. 1, 1993

Operating costs	
Start-up expense, million $	1.00
Venture fixed cost, million $/yr	1.50
Western fixed cost, million $/yr	1.00
Lifting cost, $/bbl	1.75
Injection cost, $/bbl	0.05
Pipeline tariff, $/bbl	1.00

Other data	
Production begins in year	2
Revenue tax holiday, years	0

Interest ownership	Working	Rev.
BPO western partner	100%	75%
APO western partner	50%	50%

Year	Total well count: Prod. wells	Inj. wells	Revenue calculations: Gross oil rate (Million bbl)	Gross oil cum (Million bbl)	Oil price $bbl	Western gross revenue Million $	Cost calculations: Revenue tax 10% (Million $)	Oper. cost (Million $)	Intang. (Million $)	Year deprec. (Million $)	Funds (Million $)
1	0	0	0.00	0.00	20.00	0.00	0.00	3.50	5.77	0.00	0.00
2	19	0	1.52	1.52	20.00	22.80	2.28	6.68	19.94	1.08	0.00
3	45	26	5.13	6.65	20.00	76.95	7.70	16.82	44.30	7.40	0.11
4	69	54	8.52	15.17	20.00	127.80	12.78	26.41	41.67	12.81	4.87
5	99	76	10.78	25.95	20.00	161.70	16.17	32.85	41.67	16.25	7.81
6	130	98	11.90	37.85	20.00	178.58	17.86	36.08	41.74	16.35	9.49
7	143	111	10.78	48.03	20.00	161.54	16.15	33.00	20.47	13.65	11.18
8	143	111	9.51	58.14	20.00	142.65	14.27	29.52	0.00	8.23	12.93
9	143	111	8.42	66.56	20.00	110.55	11.05	21.74	0.00	2.71	10.70
10	143	111	7.53	74.09	20.00	75.27	7.53	12.53	0.00	0.00	7.87
11	143	111	6.74	8.83	20.00	67.42	6.74	11.45	0.00	0.00	7.02
12	143	111	6.04	86.87	20.00	60.39	6.04	10.49	0.00	0.00	6.26
13	143	111	5.41	92.28	20.00	54.07	5.41	9.62	0.00	0.00	5.57
14	143	111	4.90	97.18	20.00	48.97	4.90	8.92	0.00	0.00	5.01
15	143	111	4.48	101.65	20.00	44.79	4.48	8.34	0.00	0.00	4.56
16	143	111	4.12	105.78	20.00	41.21	4.12	7.85	0.00	0.00	4.17
17	143	111	3.82	109.59	20.00	38.15	3.82	7.43	0.00	0.00	3.84
18	143	111	3.56	113.15	20.00	35.60	3.56	7.08	0.00	0.00	3.56
19	143	111	3.32	116.47	20.00	33.16	3.32	6.74	0.00	0.00	3.29
20	143	111	3.08	119.55	20.00	30.83	3.08	6.54	0.00	0.00	3.04
Totals			**119.55**			**1,513**	**151**	**303**	**215**	**79**	**111**

costs range from $700,000 to $1.1 million for a 2,700 m (MD) deviated well with a 2,500 ft departure.

- Completion cost: Costs range from $250,000-350,000/well. Completion cost varies depending upon whether wells are completed with sucker rod pumps or electric submersible pumps. Most wells are placed on sucker rod pumps early in their lives. About 20% of Siberia wells are high volume and use electric submersible pumps.
- Intrafield and interfield roads: Costs are estimated at $75,000/mile.
- Pipelines: Intrafield and interfield costs are estimated based upon U.S. average costs and range from $40,000-200,000/mile, depending upon size and terrane.
- Camps and housing: All housing is assumed to be portable camps that are moved from pad to pad with the drilling and completion rigs.
- Western staff: Western personnel are maintained at a minimal number and are in supervisory positions. For start-up, additional Western staff are budgeted for training and equipment operation. After about one year, the number is decreased.
- Operating costs: Estimated production costs range from $2.50-4.50/bbl depending upon the method of operation. Transportation costs (i.e., pipeline tariffs) range from 80¢-$2.50/bbl depending on the region and the distance to market. Pipeline losses are estimated between 5-12%, also depending upon the region, transportation distance, and the blending of the various crudes in the pipeline.
- Capital cost of equipment: Equipment such as casing, tubing, wellheads, pumps are cost estimated at Western prices.

Economic calculations

The economics assume all revenues generated by the project result from oil sales. Additional revenues may be realized from the processing of associated gas produced with the oil.

The dry gas can provide fuel for electric generation (including cogeneration projects) in the field and/or can be used for gas lift operations if there is sufficient supply. Excess gas can be reinjected into the reservoir for pressure maintenance.

The hydrocarbon liquids recovered through gas processing can be mixed and sold with the oil. The value of these liquids is not included in the oil revenue calculation, therefore, these volumes may provide an upside to project economics.

Oil price is held constant throughout the project and ranges between $18-22/bbl depending upon the investor's philosophy.

The table shows a sequence of calculations for a

$20/bbl oil price, nonescalated prices and costs
10.0% revenue tax

Waterflood development summary results

20 year recovery	120 million bbl	Investment per barrel	$295 million $2.47 bbl
Cum net cash flow	$112 million	Payout	8.5 years
P/I ratio	0.4	Rate of return	13.3%/year

Present value profile

Disc. rate %/year	Disc. NCF million $	Disc. rate %/year	Disc. NCF million $
0	112	20	−15
5	47	25	−20
8	24	30	−23
10	13	35	−24
12	4	40	−25
15	−5	50	−24
18	−12	100	−17

Tax calculations			Cash flow calculations			
Taxable profit	Cum. profit	Total taxes	Net cash flow	Cum. cash flow	10% Disc. NCF	Cum. disc. CF @ 10%
			Million $			
−9.27	−9.27	0.00	−9.27	−9.27	−8.84	−8.84
−8.08	−17.85	4.79	−16.83	−25.09	−14.59	−23.42
0.63	−16.71	16.35	−24.58	−50.68	−19.37	−42.79
29.26	12.54	36.20	−10.38	−61.06	−7.44	−50.23
46.94	59.49	48.98	−2.08	−63.09	−1.33	−51.55
57.05	116.53	55.81	1.03	−62.06	0.61	−50.94
57.18	183.71	55.97	16.73	−45.33	9.00	−41.94
77.71	261.42	55.85	30.09	−15.25	14.72	−27.22
64.34	325.76	44.73	22.32	7.07	9.93	−17.29
47.34	373.10	31.69	15.64	22.72	6.33	−10.97
42.20	415.30	28.32	13.89	36.60	5.10	−5.86
37.61	452.91	25.30	12.31	48.92	4.11	−1.75
33.48	486.30	22.58	10.90	59.81	3.31	1.56
30.14	518.53	20.39	9.75	69.57	2.69	4.26
27.41	543.94	18.59	8.82	78.38	2.21	6.47
25.07	509.01	17.05	8.02	86.40	1.83	8.30
23.07	592.08	15.74	7.33	93.73	1.52	9.82
21.40	613.48	14.64	6.76	100.49	1.28	11.10
19.81	633.29	13.59	6.21	106.70	1.07	12.16
18.28	651.57	12.59	5.69	112.39	0.89	13.05
652	**652**	**539**	**112**	**112**	**13**	**13**

typical western Siberia project. Some of the costs in the calculation are summarized below.

Taxes

• Royalty tax. Royalty tax (or use tax) typically ranges between 8-16% depending on negotiations or bidding. This tax is based on the gross revenue from the oil sales and is identical to royalty calculations in the U.S.

• Profits tax. The Russian federation has levied a tax on taxable "profit." Taxable profit is the amount remaining after subtracting royalty, funds, capital cost, depreciation, and operating expenses from the gross revenue. A 32% profits tax is calculated from the taxable profit. Previous years' tax credits are carried forward until used.

• Excise tax. Government Decree 847 established an excise tax that limits the profitability of a project to about 20%. This is a negotiable tax rate based upon the project. For calculation purposes, the excise tax is included in the Profit Tax.

• Export Tax. Export tax, also referred to as the "value added tax," is 21 European currency units (ECUs) per ton of oil and condensate (which is equivalent to about $5/bbl). This tax is calculated based on the world price of oil and therefore fluctuates. This tax has previously been negotiated to a lesser amount for some joint ventures.

• Repatriation tax and/or fee. Repatriation tax is assessed on the currency repatriated from Russia to the Western investor. This tax ranges from 4½% to 15% depending on the country from which the foreign partner's company originates.

Cyprus currently has a favorable treaty with Russia, and the repatriation tax rate is 4½%. The fifth article in this series will discuss this further as it relates to the current U.S.-Russia Tax Treaty status.

Funds

The following are typical funds created in the joint venture documents. The Reserve Fund is the only mandatory fund.

• Research and exploration fund. Typically 5% of the income after deduction of the revenue tax, operating costs, intangible investment, and depreciation is designated for the Research and Exploration Fund. This fund is used for further investigative costs necessary to explore for and develop additional reserves.

• Reserve fund. Five percent of the income remaining after the research fund deduction is designated for the Reserve Fund. This fund is designed to mitigate the variability of revenue and to assist in paying fixed costs and is used to cover losses if insufficient revenue is generated by the project. It is required the reserve fund be maintained at a minimum of 25% of the charter fund (additional discussions of the charter fund will be in the final article).

• Social fund. Typically 5% of the remaining income after the reserve fund deduction is designated for the social fund. This fund pays for food and housing, pension and social benefits, camps, medical, equipment, schools, and other costs related to maintaining the infrastructure and improving the lifestyle of the workers. The "infrastructure cost" expended during the development phase is characterized as part of the social fund.

Other

• Bonus. A bonus payment made the first year is customary and is a means for the autonomous republics, oblasts, okrug, or krays to receive cash prior to the project having a cash flow or generating a profit.

• Land rental. Land rental, also called lease rental, is paid for the surface use of the land, and use of gravel, timber, and water for camp and field operations.

• Depreciation. All capital tangible items are depreciated on a three-year, straight-line schedule. All intangible items are expensed the year they are incurred.

• Tax holiday. Joint ventures approved in 1992 do not qualify for tax holidays because of the tax law changes; however many joint ventures are requesting a holiday (based on the old laws) in order to improve the project economics.

• Environmental. Costs may need to be included in the cash flow calculations to account for environmental studies and also for environmental work in the fields and/or the area of the joint venture.

The cash flow calculation sequence in the table is for a waterflood development project. Development of the field is estimated to take seven years to drill. Production begins in year two and continues for about 36 years, at which time the field reaches an economic limit for the assumed taxes and costs.

The table only shows the cash flow calculations for the first 20 years. These calculations are for the western partner on an after-tax basis and assume all the required capital is provided by the western partner.

For this example, during a 20 year life, approximately 120 million bbl of crude are produced. This results in a gross revenue to the western partner of $1.513 billion, assuming a constant oil price of $20/bbl. After the deductions for revenue tax, operating costs, funds, and total taxes, the project returns to the investor an estimated undiscounted $112 million.

The project has a payout of about 8.6 years and has an internal rate of return of 13.3%. These calculations assume all of the beforementioned taxes and funds are deducted from the revenues. The table shows the western partner has gross revenues of $1.513 billion, pays $801 million in taxes and funds, about $300 million in operating costs, and nets a cash flow of about $112 million.

The current taxes and taxation rates have a significant effect upon the economics for these projects. Sensitivity analyses of the taxation rates shows project economics can be greatly improved by small changes in current tax rates.

Tentative joint venture structures bidding procedures, registration procedures, and tax treaties will be discussed in the final article in this series.

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Berg

Berg named Powers recipient

Robert W. Berg, a professor at Texas A&M University, has been named 1993 recipient of the Sidney Powers Award by the American Association of Petroleum Geologists. Berg served as a geologist and geophysicist with Standard Oil Co. of California (now Chevron Corp.), Cosden Petroleum, and as a partner in a geological consulting firm before joining Texas A&M in 1972 as head of the geology department. He has remained active as a consultant for several major oil companies.

LIBYA

International Petroleum Corp., Dubai, tentatively plans to spud a well in Libya in second half 1993.

Processing of 500 km of land seismic acquired in second half 1992 is well under way. The well is likely to test a pinnacle reef prospect on Block NC176, where IPC has a 100% working interest.

Spud date depends on progress of seismic processing and interpretation.

RAS AL KHAIMAH

International Petroleum Corp., Dubai, expects final clearance from the government of Ras al Khaimah to resume land drilling shortly.

The company will move to secure a rig to drill the 1X West Jiri well, in which IPC will have a 45.15% interest.

A border dispute has resulted in a three year lull in operations.

SUDAN-ERITREA

International Petroleum Corp., Dubai, plans to appraise the Suakin structure on its 100% owned Delta Tokar block in the Red Sea off Sudan.

Interpretation of 1,000 km of new offshore seismic data acquired last year over the structure indicates that the 1 Suakin gas/condensate discovery well Chevron Corp. drilled in 1976 was located downdip from the structure's crest.

This indicates that the feature extends significantly to the southeast and is much more pronounced than initially thought, IPC said (OGJ, Dec. 7, 1992, p. 46).

The appraisal well will be drilled in second half 1993 on the crest 5 km southeast of the discovery well.

Also in the Red Sea, IPC established contact with the interim government of Eritrea with a view to resume operations on the Danakil block awarded IPC by the Ethiopian government.

A civil war for which IPC suspended operations has ended. The IPC group will drill at least one exploratory well on the concession, subject to results of the talks.

NEVADA

A well in Nevada's Railroad Valley produced 121,651 bbl of oil during three months in late 1992.

Balcron Oil Division of Equitable Resources Corp., Pittsburgh, produced the oil at 23-17 Balcron-Bacon Flat, in 17-7n-57e, Nye County, just northeast of the abandoned Bacon Flat field discovery well.

Balcron completed the well last August flowing at the rate of 225 bbl/hr on a short test of Devonian Guilmette perforations at 5,164-5,240 ft.

Petroleum Information reports the well averaged 996 b/d during part of September, 1,084 b/d in October, and 1,972 b/d in November.

PI notes that the Bacon Flat field discovery well produced about 300,000 bbl of oil from Guilmette before abandonment.

Endrex Corp., Salt Lake City, has staked two remote wildcats in nonproducing Lander County.

The 1 and 2 Battle Mountain, in 9-32n-45e, are projected to 3,500 ft. The locations are in Reese River Valley 1½ miles northeast of Battle Mountain and 45 miles west-northwest of Tomera Ranch oil field, PI reported.