Let's Get the Most Out of Existing Wells

Closing the gaps between current output and productive capacity is one of today's best opportunities to quickly enhance production and improve recovery. A unique service initiative and focused engineering well reviews help tap into potential productivity and increase oil and gas asset value.

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Established fields are the most likely places to find additional oil and gas output. Improving the performance of wells that are already producing is a cost-effective way to offset natural decline, extend field life and improve hydrocarbon recovery. Production enhancement (PE) efforts are aimed at evaluating wells and recommending ways to increase productivity. Effective well interventions and recompletions, therefore, are essential elements of this endeavor.

But how can oil companies and service providers work together to identify suitable candidates for production enhancement from among thousands of wells? One method is by prospecting—searching in well files for opportunities to get more oil and gas from existing wells. And modern computers combined with new oilfield technology, tools and services are facilitating this effort.

In daily operations, E&P companies often require specific production and reservoir engineering recommendations. Service companies can meet this need by helping to identify underperforming wells and then assist by providing customized solutions to improve production. Within Schlumberger, there are two approaches to production enhancement: candidate recognition and field support (above). Schlumberger Wireline & Testing, Dowell and Anadrill solve field operational problems, and perform well construction and single-service candidate recognition (CR) through field support. Requests for integrated solutions, optimized well designs, specialized well construction services and production engineering assistance are addressed by ad hoc teams that are tailored for each situation.

Generally, candidate recognition is a means of identifying opportunities as they arise, not merely solving problems in the field. But rather than wait for opportunities to present themselves, proactive candidate recognition (PCR) actively seeks out production and value beyond what normally results from customers calling service companies to perform work, and is the top priority for the Schlumberger Production Enhancement Group (PEG).

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ClientLink, DESC (Design and Evaluation Services for Clients), Dual-Burst, ELAN (Elemental Log Analysis), Enerjet, FoamMAT, NODAL, Pivot Gun, RAPID (Reentry and Production Improvement Drilling), SPAN (Schlumberger Perforating Analysis), TDT (Thermal Decay Time) and WellWatcher are marks of Schlumberger.
Specifically, the PEG mission is to optimize well productivity and increase oil and gas output at a pace that exceeds historic industry trends. As prospectors, PEG engineers do not stop to make “jewelry” from the “gold” that is found. Instead, they keep looking for new “nuggets” of opportunity. Design and implementation of specific services are turned over to one of the Oilfield Services companies or an integrated solutions group. This article discusses this focused and aggressive initiative to improve production from client wells.

How PEG Works
Candidate recognition began in the late 1980s in response to customer needs and requests. In 1990, the first co-located Dowell engineers were placed in oil company offices along with the necessary computer and communications tools to fulfill client requirements. At the same time, an integrated PEG was formed in Houston, Texas. These were among the first steps toward building new business and working relationships in the oil industry. With more than 200 engineers posted in client offices, the DESC Design and Evaluation Services for Clients program continues to grow, facilitating cooperation and providing intimate contact with daily operations. Today, there are also more than 20 PEG locations in key markets worldwide, some with multiple teams in place (below). More are planned for 1998 and beyond.

The Production Enhancement Group works outside of traditional transactions, interactions and work flow between operators and service companies. With permission and cooperation from clients, production specialists look at well files and identify opportunities to increase production—they recognize candidates—acting and moving forward instead of reacting and waiting to fill phone-in orders or direct requests. This approach achieves production rates beyond levels that the industry traditionally expects and that result from clients initiating a call to a service company.

The PEG engineers evaluate well and production histories using the latest computer software, applying openhole, cased-hole and production logs or interpretation as needed. Current well performance is analyzed. Pressure, net pay, permeability and skin, or formation damage, are determined. Potential well output is calculated and the best services are recommended. Results of these well interventions are then systematically evaluated after implementation.

Experts from Schlumberger Wireline & Testing, Dowell, Anadrl and, when required, GeoQuest Reservoir Technologies make up a typical PEG. As a team, they cooperate with operating company asset managers to develop well intervention strategies that increase production. In addition, through the ClientLink initiative, the extensive Schlumberger intranet provides direct access to research, technology and innovative solutions tailored to meet specific client, field and well requirements.

Proactive candidate recognition does not involve extensive field studies or exhaustive reservoir evaluations. The heart of these efforts is an engineering calculation and innovative methodology based on single-well NODAL production system analysis from outer reservoir boundaries to the wellbore sandface, across the perforations and up the production tubing (see “Production System Analysis,” next page). Any restrictions, such as safety valves, chokes, surface facilities and flowlines, can be included in this type of analysis.

The PEG engineers perform detailed technical and economic analyses of single wells, groups of wells or fields, and recommend actions with input and support from internal and client experts. There is no charge for this well review, evaluation and engineering function. Compensation for production enhancement recommendations comes from providing customized solutions and performing value-priced services for clients (see “Turning Cost into Revenue,” page 20). In some cases, recommendations to optimize well output involve simply modifying the wellbore flow conduit—tubulars or artificial lift. Except for coiled tubing completions and scale removal, recommendations to change wellbore mechanical configurations—replacing tubing, resizing chokes and adding or modifying artificial-lift methods—are considered an extra benefit of the candidate recognition process.


PEG Locations

The PEG teams. At this time, there are PEG offices located in key markets around the world and more are planned. Some of these areas, like Venezuela with six in place, have multiple teams. Proactive integrated efforts by PEG specialists recommend actions to improve client production without regard to specific company or individual service considerations within the Schlumberger Oilfield Services group.
Production System Analysis

NODAL analysis is used to optimize well production systems (below). This technique couples the capability of reservoirs to produce fluids into a wellbore with the capacity of tubulars to conduct the flow to surface, including facility piping if applicable. The name of this technique reflects discrete locations—nodes—where independent equations describe inflow and outflow from reservoirs to stock tanks by relating pressure losses and fluid rates. This engineering methodology allows calculation of the rate that a well is capable of delivering and helps determine the effects of perforations, stimulations, wellhead or separator pressure and tubing or choke sizes. Future production can also be estimated based on anticipated reservoir and wellbore parameters.¹

Computer software based on NODAL analysis is often used to diagnose and identify system bottlenecks—completion, perforation and piping limitations or formation damage—that restrict production or injection. These calculations are also used to quantify the production increases that can be expected if restrictions are removed. The estimated production can then be used in economic models.

The reservoir section is described by inflow performance relationship (IPR) curves. Wellbore tubulars and surface pipes—the flow-conduit section—are described by vertical or inclined multiphase flow correlations for tubing outflow, or intake, performance. The most common approach is to start at one end of the system, the reservoir node for example. Subtracting all the pressure losses at various rates from the reservoir pressure defines an IPR curve for fluids flowing into the wellbore. Pressure at the wellbore node facing the reservoir bottomhole pressure declines as production rates increase.

Starting from the separator and adding pressure losses encountered in surface pipes and wellbore tubing gives the pressure for various rates at the IPR reservoir node. This calculation results in a tubing intake, or flow-conduit, curve with bottomhole pressure increasing as production rate increases. The equilibrium point where IPR and flow-conduit curves have the same pressure and rate—intersection of the two curves—represents anticipated production and downhole pressure for the specific conditions being modeled. Output from NODAL analysis can be two curves or a set of curves for sensitivity analysis.

For example, this type of plot can be used to determine the effect of increasing choke and tubing sizes. A larger flow diameter moves tubing curves down and to the right, increasing the flow rate. In production enhancement, IPR curves are most often used to evaluate the impact of increasing effective borehole radius by perforating, acidizing, fracturing or drilling horizontal or lateral drainholes (above). These remedial well interventions move IPR curves up and to the right.

When operators allow a local PEG to diagnose production gaps and initiate design, execution and evaluation of services, both parties focus on production and results. This unique interaction ensures optimal recommendations to close productivity gaps and application of the right services. Focusing on production generates more revenue for both clients and the service company. In today’s new business relationships, operators are agreeing to share some of this added value, and service companies are accepting some downside risk. Having a vested interest in the outcome of remedial actions helps the service provider better understand and meet customer needs and expectations.

**Producing Wells**

Existing assets have several distinguishing characteristics, both positive and negative, in the context of production enhancement. On the upside, because established fields have wells and facilities in place, production increases can generate cash flow without adding infrastructure, which reduces lead and cycle times. There are also fewer unknowns. Fluid properties, reservoir drive and recoverable reserves are, in most cases, well understood. On the downside, available information is older, perhaps out of date; data were gathered using possibly obsolete technology, tools and techniques; and completion strategies may be outdated. But these negatives also present potential opportunities to increase production.

Single-well production enhancement involves moving reservoir inflow performance relationship (IPR) curves up and to the right, or moving flow-conduit performance curves down and to the right (below). The objective is to recommend solutions and services that move identified gaps between current well output and potential production. To achieve this goal, the components that contribute to a production gap must be identified and understood (see “Production Gaps: Well Performance Components,” right). The total production system includes reservoir, completion, flow-conduit and artificial-lift components plus surface flowlines and facilities, which are assumed to be a constant in most individual oil and gas well analyses.

Based on what is known about a field, well files and data can be examined with an eye for likely opportunities from among these components. A model of the well production system is then developed using this information and, if required, confirmed by well tests or additional wireline logs to determine net pay, reservoir pressure, permeability, skin and saturations—oil, gas or water. Once a model is validated, wells are chosen for further evaluation using the PEG methodology. Remedial interventions are recommended, costs are estimated and viable options are compared based on estimated well productivity and operator economic constraints.

**Production Gaps: Well Performance Components**

Engineering optimum production rates requires that reservoir deliverability, well stimulation, recovery efficiency, wellbore hydraulics and surface constraints be addressed. Elements of the well production system are interrelated, and performance of the entire system is often a function of the weakest links. During the production enhancement process, various screening methods and well-analysis techniques are used to examine reservoir, completion, flow-conduit—wellbore tubulars or plumbing—and artificial-lift system performance (next page).

**Reservoir performance**—A production gap exists if reservoirs do not effectively deliver hydrocarbons into a wellbore. The result is low flow rates at high-drawdown pressures. This problem may be overcome by increasing effective borehole radius—fracturing, acidizing or high-performance perforating. Lateral or horizontal drainholes are another solution. Nearby injectors or producers may also affect the region around a well. A possible solution might be to squeeze off zones in injectors using cement. Controlling water influx and mitigating the production of formation fines are also alternatives.

Single-well inflow performance relationships (IPR) are a function of time and original oil in place. Near-wellbore effects and mechanical physical description, Darcy’s law and pressure-volume-temperature (PVT) behavior affect an IPR. Diagnostics, including transient testing, artificial-lift or permanent monitoring, saturation logging, production logging, sonic imaging and economic analysis, can be performed to obtain needed information. Remedial actions include high-performance perforating, stimulations, drilling laterals, squeeze cementing, water control and fines mitigation.

**Completion performance**—The completion, which includes perforations, liner slots, the cement-by-borehole annulus, sand-control screens, gravel packs and any zone of formation damage, dictates fluid movement from reservoirs to wellbores. Pressure drawdown at the completion is a function of flow rate. Factors that influ-

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ence completion performance are perforation entrance-hole diameter and depth of penetration into a formation, sand control, stimulation, zonal isolation and damage, or partial formation penetration. Drawdown through a completion is reduced by reperforating or acidizing and by perforating a larger interval to reduce classical skin, resulting from a limited perforation interval. If not in place, a gravel pack or other sand-control method may be required. A cement squeeze may be needed if some zones produce unwanted water and gas, or take fluids that crossflow from another zone. Poor cement may also allow communication behind casing.

Tools used for evaluation include perforation-analysis programs, saturation logs, ultrasonic imaging tools, production logs and economic analysis. Services that improve completion performance include high-performance reperforating, sand control—gravel or fracture-packing sand control jobs, squeeze cementing and acidizing.

**Flow-conduit performance**—Wellbore hydraulics may also limit flow if tubulars are improperly sized, and if there are unnecessary mechanical restrictions like tapered strings and profile nipples, or scale buildups inside the tubing and casing. Flow efficiency is a function of restrictions or leaks in wellbore tubulars. Tubing type, traps, restrictions, erosional velocity and crossflow can also limit performance efficiency. Required information may be obtained from calipers, ultrasonic imaging tools, production logs, water-flow logs and economic analysis. Solutions include acidizing, scale removal with coiled tubing, coiled tubing completions and early production systems.

**Artificial-lift performance**—Since flowing bottomhole well pressure is a function of artificial-lift efficiency, lifting system problems can impact well performance. Data useful for performance evaluation may be obtained from production logs, artificial-lift monitoring and economic analysis. Services to pull and replace or redesign rod pumps, gas-lift valves or electric submersible pumps can remediate performance problems.

The components of well performance.
Production Enhancement

Opportunities to enhance production—untapped primary, secondary and tertiary recovery—are abundant. On average, less than 35% of original hydrocarbons in place are recovered from millions of wells worldwide. These remaining reserves represent one of the best opportunities for operators to improve production. And this potential oil and gas output is fertile ground for prospecting (above). The PE portion of this prize, realizing an incremental 5% increase nominally from just one out of ten wells for example, could yield billions of barrels in additional production and reserves.

Because porous formations act as filters, most wells become damaged, or develop a significant “skin,” at some time during the drilling and production life cycle. Skin is a zone of reduced permeability around the wellbore that causes an excessive pressure drop across the completion face and limits fluid flow from the reservoir. Formation damage is a natural consequence of well drilling, completion activities and production flow. Drilling mud, completion fluids, crude oil, gas and formation water deposit clay particles, formation fines, asphaltenes, paraffin and scales that can block rock pore spaces and reduce matrix permeability. Damage can also result from mechanical crushing and compaction of the near-wellbore region as a result of pressure drawdown.5


Unlike our automobiles, however, most wells do not have their filters checked regularly. Recall any number of stories, from the mid-1980s until today, about oil companies that sold mature fields to other operators who then significantly improved production from these supposedly unprofitable, marginal or poor assets. Situations like these—success for one company, disappointment for another—are not unique.

Untapped reserves, formation damage and wells that need modern, full-service tune-ups are the factors that combine to make many assets, some with significant remaining reserves, ripe for auction blocks or abandonment (see “New Life for a North Sea Field,” page 10). There are even more wells and reservoirs that still produce economically which have additional potential waiting to be identified. These opportunities prompt operators and service providers alike to ask such questions as: In any theater of petroleum operations, from the Permian Basin of west Texas with over 100,000 wells to the North Sea with more than 2000, how many wells have skin effects that can be eliminated; or could oil and gas output be improved using new technology, modern techniques, improved tools and better fluid systems? Answers to these questions are the basis for production enhancement.

Because of this industry’s preoccupation with drilling and production operations, the many recent improvements in well services, and today’s powerful computers and modern software, operators can now take full advantage of PE opportunities for the first time. Recently as well as in the past, the industry concentrated primarily on exploration, drilling, well construction and field operations, assigning lower priorities to production engineering and well performance optimization. Initial flush production, limited production quotas and government-regulated allowables meant that many wells were produced at rates far below their true potential.

The PE opportunity. One way to increase production is by looking where oil and gas have already been found. Existing wells with gaps in performance are the target of a focused and aggressive initiative to enhance production. The prize—more stock tank barrels of oil and greater volumes of natural gas.
Completions did not have to be optimized if wells were producing their allocated volumes. The only way to obtain higher allowables and increase production was to drill more wells. As a result, optimal completions were not always a priority. With few exceptions, however, the days of drilling into giant, prolific, near-darcy-permeability reservoirs are gone. Allowables, quotas and production limits are becoming a thing of the past; target reservoirs are more complex, smaller and tighter—lower permeability; many existing fields, large and small, are in mature stages of their production life cycle; and older fields need more attention to maintain output and identify overlooked opportunities.

It Begins With “Where are the Files?”

A unique new interaction between operator and service provider begins when PEG representatives are allowed access to relevant well files by an oil and gas company. The goal is to collect and analyze data quickly so that additional information needs can be determined or specific service proposals can be made (previous page, bottom). This phased approach with short cycle times—look at well files, recommend and execute services, evaluate results, then re-analyze and make improvements based on new data—reduces operator exposure to risk while providing timely feedback about the effectiveness of production enhancement. When proprietary client information and well data are being used by a local PEG, complete confidentiality is maintained at all times.

Proactive candidate recognition using the prospecting methodology and PEG analysis function is an iterative cycle (right). Data on a given field, reservoir or well are collected, cataloged and evaluated; and any production anomalies are noted. The best screening techniques and software are then used to thoroughly diagnose and assess well productivity in order to identify prospective candidates for remedial actions. The PEG software tool box—Production Enhancement Analysis Kit (PEAK)—includes Schlumberger and available industry programs, but PEG engineers are not limited to any particular software. They can use software that is preferred by a client or other programs with which they are familiar.

A minimum amount of information is needed to perform PCR; and there are usu-
New Life for a North Sea Field

Decline-curve projections indicated that production from the Amoco N.W. Hutton field would fall below the break-even economic limit of 6000 BOPD [950 m³/d] in 1996, and signal the beginning of decommissioning for 1997 (right). This would have been the first North Sea field to be completely abandoned, not a comforting prospect in light of environmental controversy surrounding other field abandonments and proposed disposal of their platforms.1

Reservoir studies, however, indicated that factors other than natural decline could have caused the poor performance of this field. Most wells demonstrated significant declines within the first year of production. Although declines were initially believed to be the result of reservoir complexity, further investigation indicated that formation damage and scale in the immediate wellbore region of productive zones might be a more likely cause. Productivity also declined after well or field shutdowns. There was no flush production from recharging when wells were brought back online; productivity losses were permanent; and gas/oil ratios (GOR) remained constant during the initial decline phase, which was not consistent with structural compartments. Production below bubblepoint pressure should cause the GOR to increase, so drastic declines could not be attributed to pressure depletion of small drainage areas.

The field production platform was designed to handle 120,000 BOPD [19,070 m³/d], but actual production peaked at 83,000 BOPD [13,190 m³/d] for only a short time. The initial 280 million bbl [44.5 million m³] estimate of recoverable reserves had been reduced over the life of the field and production averaged 7000 BOPD [1112 m³/d] in 1996. Only about 120 million bbl [19 million m³], or 24% of the 487 million STBO [77 million m³] estimated to be in place originally, had been recovered. Most of the area’s Brent fields have recovery factors of at least 40%. Amoco wanted to determine if the suspected damage mechanisms could be successfully treated and if new technology—sidetracks, conformance control, injection management or stimulation—might improve oil recovery.

GeoQuest Reservoir Technologies for reservoir technical expertise, Schlumberger IPM for project coordination and the PEG Production Enhancement Group located in Aberdeen, Scotland, conducted a technical review of the field. This evaluation indicated a high probability of significant additional mobile oil, possibly 20 to 50 million bbl [3 to 8 million m³], remaining to be exploited. The operator was willing to share incremental value in return for engineering and services that would address limited resources, reduce uncertainty and risk, and facilitate project implementation.

An action plan and commercial proposal were presented to Amoco and the field partners. Schlumberger would risk intervention and engineering revenue to enhance field production, manage production and development operations, and optimize reservoir performance. In return, as the integrated service provider, Schlumberger would recover costs plus a gain-share compensation component from incremental oil. For each dollar invested, an agreed-upon multiple would be paid back. After the gain-share cap is reached, all revenue reverts to the N.W. Hutton field owners. This proposal was accepted and the project was initiated in the fall of 1996. The scope of work includes coiled tubing operations, matrix acidizing, water shutoff, fracturing, scale management, wireline logging, testing, perforating, lateral drilling and reservoir modeling. IPM manages the project, which is now generating incremental oil revenue.

A three-phase redevelopment plan was proposed with each phase dependent on the success of the previous work. Investments were staggered and to some degree self-funding. The first phase involved rate maintenance and data acquisition. Scale inhibition was initiated, up-time improvements were made and a production logging program was performed. Phase two involved fracture and diagnostic matrix stimulations to address skin damage. Conformance and gas-lift optimization were also initiated. The goal of the third phase is to generate high-risk, high-reward opportunities to add reserves through a full reservoir study.

The first and second phases of this project are under way. Production enhancement stimulations were undertaken to generate positive cash flow, demonstrate the potential to produce this field economically and instill confidence in the project’s future. These efforts are also providing data to supplement reservoir studies that are targeting options for extending the productive life of the N.W. Hutton field.

Skin, reservoir description, reserves, pressure and water chemistry data were used to generate intervention proposals—candidate recognition. Four intervention techniques to remove or bypass near-wellbore damage have been proposed:
scale dissolver treatments to address barium sulfate deposition in the rock matrix, diverted acid stimulations to treat calcium-carbonate scale and fines migration, tip screenout hydraulic fracturing and short coiled tubing drilled laterals to bypass skin damage.

Three of the four proposed well interventions to remove or bypass skin—scale inhibitor, acid and fracturing—have been applied, resulting in significant improvement in well productivity. Prior to fracturing, one candidate well produced at a rate of 700 BOPD [111 m³/d]. Three weeks after the stimulation treatment, the well was producing about 3200 BOPD [510 m³/d]. Scale dissolver and acid treatments have also been successful. More than 500 BOPD [80 m³/d] of additional oil production were realized from one well. The criterion to begin phase three, a goal of 6000 BOPD incremental production, was achieved and surpassed.

The Amoco and GeoQuest Reservoir Technologies team is revising N.W. Hutton reservoir descriptions and evaluating development scenarios that will increase the value of this field by improving productivity. The proposed redevelopment includes production enhancement, well construction and project management efforts aimed at improving production and increasing reserves through application of leading-edge technologies. It will be managed and coordinated by IPM working in conjunction with the Schlumberger Oilfield Services companies.

The organization and process were developed jointly by Amoco and Schlumberger to create an alliance structure and contractual provisions that are equitable and beneficial to all parties. The alliance approves budgets and proposals consistent with the strategies of both the operator and the service company. Sharing financial risks and rewards through equity pricing results in a high degree of alignment between companies and refocuses efforts and resources on achieving common goals.


ally enough data in the well files. Ideally, available data should include formation evaluation logs, buildup or production tests, and a well history. In addition to well logs, or if logs are not available, field net-porosity and net-hydrocarbon-thickness maps may be used. Ideally, both logs and maps should be used, and in some cases, seismic data may be helpful. New wireline formation evaluation logs may be needed to verify production potential. When there are no production or well-test data, new pressure buildup or production well testing are often recommended. If well data are incomplete, it may be possible to “back into” well and reservoir unknowns by iterating through a NODAL analysis until a good fit with known parameters is obtained. This type of analysis can best be described as reverse, or inverse, engineering. Typically, relevant data are gathered and compiled in a spreadsheet or database.

Candidate recognition may include calculating skin and damage effects, determining production potential at a reduced skin, quantifying available reserves, running economic evaluation and making recommendations based on risk versus return or cost versus benefit. Current well output is analyzed along with production history and the effects of various PE options. Additional formation evaluation logs may help verify productivity before economic and risk analyses are performed.

Analyzing current performance using the best available data establishes the most likely reservoir parameters for a well. If build-up or drawdown tests are available, transient-pressure-analysis programs help calculate pressure, permeability, skin and reservoir boundaries. Four-point and backpressure tests can be used to determine initial reservoir pressure. Iterative NODAL analysis can also be used to match pressure and permeability, and obtain skin at a given time. The most useful skin information comes from recent time. “Snapshots” of a well production system can be obtained at the start of production, before a well is put on gas lift or rod pump, after a well is put on artificial lift, and at current rates. These reference points include reservoir pressure, wellhead pressure, production rates—oil, gas and water—skin and cumulative production.

Since the objective is to predict future output, only production rates at the present skin value are important. This means that cumulative production since the last significant event that altered the skin is all that needs to be examined. Data are normalized by selecting this event as the initial time. Cumulative time and oil, gas and water production can be calculated from this point. Initial pressure—reservoir pressure at the time of that event—is derived from material balance programs.

Production history analysis is used to verify the current performance analysis. General material balance programs with single-layer model solutions for homogeneous reservoirs quickly evaluate reservoir performance and obtain reliable initial pressure estimates, pore volume and average aquifer-water influx rate. Sensitivity analysis can be performed with these models to evaluate drainage area, initial pore pressure and the influence of water influx on reservoir pressure history. Once a satisfactory production history match is obtained and unknown parameters are determined, these models can help forecast future well performance and recovery by extrapolating from previous production to an average reservoir pressure or time using conventional rate-decline relationships.

Other programs and production-history analysis are also used to model wells and check values obtained using NODAL analysis and material balance programs. Programs that give a continuous production picture, rather than just a few snapshots over time, can be particularly helpful. NODAL analysis software is used to match production at several times during the productive life of a well, and these reference points are used to verify the production history model. Excellent matches between estimates and real data provide confidence in well model validity and the accuracy of their predictions.

At this stage, it may be evident that more data or full reservoir simulation are needed to determine candidate economic viability. Not all production gaps can be addressed through candidate recognition with the prospecting methodology. Some problems do take weeks or months to solve, and PEG engineers must recognize these problems and refer them to reservoir study groups for evaluation.

Once required well data are compiled, the next step is to study enhancement options, which establishes viable PE alternatives, and the production increases and economic benefits associated with them. After all of these steps are applied to the wells being considered, PE candidates are prioritized in terms of risk versus net-present-value (NPV) economics, and appropriate recommendations and well interventions are selected, designed and executed. The final step in this process is...
to compare actual results to predicted outcomes and carefully analyze the details of this feedback. Results—successes and failures—are evaluated, reviewed with the client and then used as additional input in another cycle of the PEG analysis process. Out of 100 wells, for example, a PEG evaluation might find as many as 10 potential candidates. Successful interventions on these wells may then generate additional PE opportunities.

The PEG process, which is always applied one well at a time, is used for individual single-well evaluations, but is perhaps most successful when employed to analyze groups of wells or a field. This allows engineers to look at a statistically significant number of wells, which can compensate for some unsuccessful jobs and help ensure overall project success. Wellbore mechanical modifications on some of the wells being evaluated may also improve production and contribute to overall production enhancement success.

**Why Proactive?**

Candidate recognition performed proactively is the antithesis of chance occurrence—waiting until wells go off line or drop below economic limits before initiating action. Another reason to take advantage of PCR is synergy, those actions taken jointly to increase overall effectiveness beyond the sum of their individual effects. Production enhancement efforts create a partnership, or team, often based on a handshake agreement, consisting of the client and a local PEG organization working together with Schlumberger Oilfield Services companies (above right). Cooperation between these groups, in concert with advanced technologies and well servicing methods, can be effectively employed to improve production from existing wells.

With the exception of tubulars, downhole equipment and other stock warehouse parts, Schlumberger provides services from discovery to depletion, including seismic surveying, data processing and interpretation, drilling, well logging, perforating, well testing, cementing, acidizing, fracturing, and coiled tubing or abandonment services. And many of these applications—cleaning out fill, perforating or reperforating, logging, interpreting and evaluating data to find more pay, acidizing to remove damage, fracturing to create conductive flow paths, water and gas control, and infill, directional, horizontal or lateral drilling—are directly related to moving IPR curves and increasing productivity.

The style of proactive PEG evaluations is quick—hours and days, not weeks and months—and action oriented, generating specific recommendations to be implemented. Reports or studies to be read and reviewed. In most cases, these “action” plans are a simple list of wells, or sometimes a single spreadsheet page, with recommendations to gather more data or apply a specific solution, technology, service or integrated application (next page).

Among the short-term benefits of production enhancement, PCR generates candidates for well interventions, demonstrates production potential for added confidence in well or field viability and provides additional cash flow for funding further production enhancement. The long-term upside potential includes maintaining profitability, increasing asset value and extending well or field productive life.

But why are operators allowing PEG representatives access to their prized well files? One answer lies in leveraging the best mix of knowledge, experience and technical resources to address production engineering. Another reason is that E&P company personnel have a limited amount of time, which can often be taken up by higher priorities like drilling new wells and maintaining their more prolific producing properties. It can be difficult to consistently maintain effective surveillance, perform production engineering and identify opportunities across an entire asset portfolio, and still keep up with the latest techniques and technological advances. In addition, it is helpful to have input from experts who look at production enhancement opportunities and potential well productivity from different points of view.

Unlike the period following oil price collapses in the 1980s, experienced service personnel are now available to undertake PE projects. Over the past several years, service companies, including Schlumberger and Halliburton, have been among the top recruiters of petroleum engineers. In addition to filling entry-level technical positions, these companies are also adding mid-career professionals, many with oil company and consulting backgrounds, that expand the service sector experience base.

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**Integrated Services**

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Cooperation and integrated services. Production enhancement involves a partnership, or team, made up of the client and a local PEG organization plus applicable Oilfield Services companies. When coupled with integrated service company advanced technologies, joint actions taken by these groups can significantly improve production from existing wells.
### Proactive Candidate Recognition Screening: West Texas

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<th>Inadequate stimulation</th>
<th>Injecting above fracture pressure</th>
<th>Poor artificial-lift performance</th>
<th>Fill across pay zone</th>
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### Phase 1 Candidate Recognition: Gulf of Mexico Acid Treatments

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<tr>
<th>Well</th>
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<th>Current production</th>
<th>PEG prediction</th>
<th>Comments and recommendations</th>
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<td>Based on well production history</td>
<td>40 117 — —</td>
<td>120 — — —</td>
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**Incremental enhanced production total**: 700

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**Action plans. The final product of a PEG analysis is often a simple, one-page list of wells, sometimes in spreadsheet format, with specific solutions and recommendations about actions, services or integrated applications that need to be performed to enhance production.**
Current PEG teams include the talents, expertise and experience of petroleum engineers with PhD degrees, and some top experts and specialists in key production engineering disciplines. Schlumberger Oilfield Services also recently acquired S. A. Holditch & Associates, Inc., College Station, Texas, a worldwide petroleum engineering company that offers consulting services in well stimulation, completion design and reservoir analysis. This acquisition broadens the range of production enhancement activities and reservoir engineering services that can be provided to operators.

Proactive candidate recognition can be performed solely by PEG specialists, but perhaps works best as an operator-Schlumberger team approach. Oil company personnel are most familiar with the overall production history and reservoir view, but integrated service providers invest time and money for research to commercialize new technology and, therefore, are knowledgeable about specific applications of the tools, methods and services that are developed. As a result, PEG engineers review well files and data from a fresh perspective and may recognize opportunities to apply specific techniques, unique combinations of technologies or an integrated solutions approach that might otherwise be overlooked.

Result-Based Experience

Typical well interventions for production enhancement include jobs that address the full range of performance-gap components. Reservoir- and completion-related interventions, however, usually represent most of the jobs and dominate the mix (above right). The remaining well productivity gaps are the result of artificial lift and tubing performance. Reservoir IPR curves can be moved and productivity gaps can be closed by:

- finding bypassed pay
- perforating
- acidizing
- fracturing
- drilling laterals.

Since being established in 1990, the PEG organization has worked to improve production and increase reserves for clients through PCR and the production enhancement process using these types of well interventions.6

Recompleting older wells using new methods may be what is needed to improve productivity. Oil and gas technology has improved by orders of magnitude over the past 15 years, and many of today’s producing wells were drilled and completed before these newer techniques were in full use. Just ten years ago, completion and stimulation practices were not as effective as they are today. Research and development have provided innovative new technologies that, on a well-by-well basis, can greatly increase production and improve recovery.

Finding additional pay—For example, reinterpreting existing logs, pressure-buildup and production well testing, and new technologies for evaluating formations, including deep-investigating logs, azimuthal borehole imaging logs, multiprobe formation testers, cased-hole logs and modern transient tests, are critical for analyzing and diagnosing wells. Early production facilities can also be used to get first oil and gas sooner, and improve initial field development economics.8 Advanced perforating, acidizing and fracturing methods, and coiled tubing services are key techniques to increase production, along with horizontal or multilateral reentry drilling. Modern computer capabilities also play a vital role, facilitating and supporting these oilfield service improvements and developments.

Several PE activities help identify additional pay or bypassed productive intervals. Surveillance methods, like net-porosity mapping and hydrocarbon indexing, can be used to locate behind-pipe production potential in existing fields (next page, top). Older logs can be reevaluated or interpreted using new techniques, or modern wireline logs can be run to acquire more information. Recompletions can tap bypassed hydrocarbons. In one case, an old electric log was reviewed to identify possible zones of interest. Through-casing potential was determined by running a Dual-Burst TDT Thermal Decay Time log and performing an ELAN Elemental Log Analysis evaluation. A previously undiscovered gas zone was perforated with a through-tubing Enerjet gun. The new zone produced 770 Mscf/D [22 Mscm/d] and paid out in eight days (next page, bottom).

Reservoir surveillance. Methods like porosity mapping and hydrocarbon indexing help locate behind-pipe production potential in existing fields.

Finding new pay zones. New formation evaluation techniques—logs and processing software—also locate bypassed oil and gas. A previously undetected zone produced 770 Mscf/D [22Mscm/d] and paid out in eight days.
Adding perforations. Additional perforations improved production from this offshore Louisiana well. Increased gas production also improved flow-conduit lifting performance. The 12-day payout for this PE job was less than the initial estimate, resulting in a 30% price premium.


SPAN Schlumberger Perforating Analysis version 5.0, Schlumberger Perforating & Testing documentation, Rosharon, Texas, USA (1997).


Perforating—Modern perforating gun charges make bigger holes in casing and penetrate deeper than older versions. Wells completed with charges that penetrated 12 in. can now be reperforated with guns that create tunnels more than 26 in. into formations. Entry-hole diameters larger than ¾ in. can be obtained compared to less than ½ in. in the past. Perforating charge performance can also be designed and predicted with greater accuracy and confidence. In addition, new techniques like extreme overbalance perforating (EOP) offer innovative and unique ways to enhance well productivity.

Adding perforations using a through-tubing expendable Enerjet gun increased reservoir inflow performance and the additional produced gas improved flow-conduit lift performance. NODAL analysis indicated that well output could potentially be close to 300 BOPD [48 m³/d]. Production from this offshore Louisiana well was enhanced from 22 to 260 BOPD [3.5 to 41 m³/d]. The client accepted a value-pricing arrangement and agreed to pay a percentage over existing contract prices if this PE well intervention broke even sooner than the estimated payout. Schlumberger agreed to share some risk by agreeing to receive market price less 20% if the job took longer to payout. Total job costs were recouped in just 12 days and the operator paid a 30% value-price premium (left).

In another example, reperforating with high-performance charges can increase production and realize the predicted production potential of wells. Deep-penetrating perforations or larger entry holes reduce drawdown across the completion. Analysis of a well in a dolomite oil reservoir in Texas indicated a 6-in. damage zone with a 0.85-mD permeability. The 1.6-mD dolomite reservoir was 20 ft [6 m] thick with an 8500-psi reservoir pressure. The well was completed by perforating with a casing gun and tested at 55 BOPD [8.7 m³/d] rate. When reperforated using an expendable through-tubing gun, the well produced 148 BOPD [23.5 m³/d]. NODAL analysis predicted that this well should be capable of making 270 BOPD [43 m³/d] (next page, top). A recommendation to shoot the well with a Pivot Gun perforator resulted in a rate of 277 BOPD [44 m³/d].
Acidizing—Stimulation technologies have been improved as well. Today’s acid systems remove damage more effectively, and these matrix treatments can be designed, placed and diverted with greater efficiency.  

Matrix acid jobs reduce skin and improve well productivity. In south Texas, a matrix acidizing treatment was used to stimulate an Edwards Lime well with 40 ft [12 m] of 1-mD gas pay and 2200-psi bottomhole pressure. Gas production before acidizing was 750 Mscf/D [21 Mscm/d], but NODAL analysis predicted that production potential from this well was 1270 Mscf/D [35 Mscm/d] (right). Actual production after a FoamMat acid treatment was 1400 Mscf/D [40 Mscm/d], almost a two-fold increase.

Reperforating. NODAL analysis predicted that this well could produce 270 BOPD. After perforating with a Pivot Gun perforator the well tested at a 277-BOPD rate.

Acidizing. A south Texas gas well produced 1400 Mscf/D after a FoamMat acid treatment. Before acidizing, production was 750 Mscf/D. NODAL analysis estimated potential production at 1270 Mscf/D.
Drilling lateral drainholes. A well in Lake Maracaibo, Venezuela, had not produced since 1986 because of mechanical wellbore problems—junk in the hole. NODAL analysis predicted 275 BOPD from a 70-ft lateral sidetrack. The well actually produced 250 BOPD and paid out in 13 months.

Fracturing. A low-permeability gas well was shut in. NODAL calculations estimated post-fracture stimulation potential to be 550 Mscf/D. After fracturing the well produced 600 Mscf/D.
Fracturing—Today’s fracture stimulations use cleaner fluids and more effective props to provide the most conductive path possible from the formation to the wellbore. In Lake Maracaibo, Venezuela, NODAL analysis forecast that a 70-ft [21 m] sidetrack would produce 275 BOPD (44 m³/d) (previous page, bottom and below). This well had been shut in since 1986 because of mechanical wellbeing problems—a lost fish or junk in the hole. After the sidetrack was drilled, this well produced 250 BOPD (40 m³/d). The payout for this production enhancement intervention was 13 months.

Computer and communications capabilities have advanced as well. A little more than 10 years ago, personal computers were used almost exclusively for word processing. Today, these computers provide the computational horsepower for engineering programs that help select, design and evaluate well interventions. Previously, reservoir and production calculations were time consuming, made by hand or on massive mainframe computers. Now, service company representatives can quickly forecast the effects of completion and stimulation actions with portable laptop computers while sitting across the desk from clients in their offices.

Reservoir surveillance capabilities, data management and information technology have also improved.

In most PEG evaluations, the overall reservoir development plan is fixed, but production enhancement may be an integral part of more extensive reservoir management projects that are directed at optimizing field, production and reservoir performance. Data and results from the PE process also provide insights and input for further detailed reservoir studies and simulation. On larger, complex projects, like the Amoco N.W. Hutton field, production enhancement during early stages can jump-start oil and gas production and boost income to help generate funds for initial remedial efforts. Efforts to improve productivity should not be directed solely at marginal wells, completions on the structural flanks of fields or areas with limited pay or potential. Like fracture stimulation well candidates, the best producers often make the best PE prospects. Each well should be evaluated to determine if it is producing at its full potential.

Turning Cost into Revenue

An important aspect of production enhancement and the PEG function, in addition to actively prospecting for well candidates, is undertaking projects on a contingency, risk-reward or value-price basis. Until recently, charges for well services were usually based on service cost or prevailing market rates. But compensation for integrated, solution-based services that deliver an incrementally greater return can also be based on performance, benefits or the extra value generated—value pricing (right). Value pricing makes sense when customized solutions result in measurable savings or increased income that is quantifiable and differentiated from other products, services or methods.

Helping clients meet incremental production targets is the foundation for customized solutions and contingency payments or result-based rewards (below right). For risking some service revenue down to a lower cost limit, Schlumberger receives a fair share of the added value generated by PEG recommendations. Operators share this additional value, up to a reward cap, in return for reduced financial exposure, technology and service resources, and a mutual working arrangement that helps overcome risk and technical obstacles, resistance to applying new technology and pricing fixations that are left over from the low-bid days and industry downturns of the past decade. This approach focuses on generating, measuring and sharing greater value.

Payment for PEG recommendations could, for instance, be calculated based on incremental production. The operator might share 50% of incremental production, after paying taxes and royalties, for a mutually agreeable period of time. In short, to the extent that services provide two dollars of extra value, the client shares some amount less than a dollar. Compensation can also be based on job success using a sliding scale. Payments for services can be determined by multiplying market or alliance price rates by a predetermined percentage (next page, top left). The operator could agree to pay market rates or less for services that are unsuccessful or for marginal production increases. Successful jobs that return large increases in production would be invoiced at higher percentages.

Cost and market-driven pricing

Costs versus solutions. Value pricing moves customers and solutions forward in the service process. Customized solutions emphasize production not low-bid jobs and can generate greater value for both operators and an integrated service provider like Schlumberger.

Sharing risk and value. In value-pricing arrangements, operators share the rewards, up to a cap, from projects that enhance production, add reserves, improve efficiency or increase service quality. For risking some service revenue, down to a limit, Schlumberger gets a fair share of this value. Value pricing makes sense if customized solutions, differentiated from other products and services, deliver measurable savings or increased revenue.
Value-based pricing and contingent payment philosophies help buyers and service providers think, act and make decisions in terms of value rather than price, and therefore concentrate on optimum solutions and results instead of the lowest price tools and services. When Schlumberger as an integrated service company is given the task of helping operators achieve a target incremental production, NPV or return-on-investment (ROI) in exchange for a fair share of incremental production, costs are more effectively turned into revenue. The result is a new focus on the outcome, production to be generated and value that is provided instead of the cost, or expense, of services. Focusing on production generates more revenue and, as a result, additional value for both the client and the integrated service company.

The service sector, now more than ever, is able to assume more responsibility for production operations. A complete range of Schlumberger service capabilities is available to deliver customized solutions, and manage well construction, production enhancement interventions, field operations, major projects and reservoir performance (above right). But the blurring of traditional boundaries between clients and service providers can be complicated. Schlumberger believes that service companies should be independent, maintaining consistent relationships with all clients. Actions that might result in overlap, confusion and potential conflicts of interest are avoided even when sharing risks and rewards.

Integrated service providers should be compensated for service quality, performance and the value that is delivered, but without taking an equity position in oil and gas assets. Value-pricing ensures that the service provider is fairly compensated for integrated skills and services, such as production enhancement, project management and reservoir optimization, and ensures that the extra value generated by customized solutions is distributed equitably.

What Does the Future Hold?
In the arsenal of services available to oil companies, production enhancement is rapidly gaining acceptance. The future for PEG includes expansion into more markets and continuing advances in computer capabilities and data management. Candidate recognition, including well monitoring and evaluation, will become more automated. Real-time data measurement, communication and management tools—like the WellWatcher system—will help track surface and subsurface parameters, such as temperature, pressure, flow rate and fluid densities, and then transmit this information to operator offices continuously or on command.

The Production Enhancement Analysis Kit (PEAK) will be further developed into a tightly integrated reservoir and production engineering software support package. And finally, production enhancement efforts will be further integrated with future well construction, project management, reservoir enhancement, field study and reservoir management processes.

Increasingly, efforts by PEG teams may also be an integral element in larger projects. As a logical next step in new business relationships between clients and service companies, production enhancement can be a starting point to further expand integrated production management and customized service solutions. Operators benefit from improved production, reduced risk and more effective use of service sector knowledge and experience. As the integrated service provider, Schlumberger gets an improved return for services rendered and an expanded market for solutions, services and tools, in addition to more opportunities to prove new technologies and ideas, demonstrate integrated services concepts and gain experience.

On a daily basis, oil and gas operating companies must deal with many existing wells and reservoirs while trying to improve or maintain output from an increasing number of new wells. Proactive efforts to optimize the productivity of client-operated wells through production enhancement are helping to get the most value out of existing wells. This engineering methodology breaks down traditional barriers between petroleum disciplines as well as producers and integrated service companies, providing a more open exchange of information that results in additional production, increased recoveries and the sharing of value. —MET