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Contents

PETROBRAS' OIL PRODUCTION IN BRAZIL UP 8.3% IN OCTOBER 6
By Petrobras Press Office

MATUR...
BGAN is now in Brazil. So you can call HQ, chase suppliers, send data, imagery and video. Right from the middle of nowhere. Simultaneously and affordably. Your competitors won’t like that.

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Petrobras' oil production in Brazil up 8.3% in October

Petrobras’ average oil production, in Brazil, reached the mark of 1,872,970 barrels in October, an 8.3% increase over a year ago. The natural gas production, also in the domestic fields, topped-out at 53.711 million cubic meters/day, 26% more than the 42.589 million cubic meters produced in October 2007.

By Petrobras Press Office

Adding the volumes of oil and natural gas, the average production, in October, in Brazil, totaled 2,210,830 barrels of oil equivalent (boe) per day, 6.9% more than a year ago (1,887,366 boe per day) and stable compared to the previous month’s mark.

The average oil production in October was 1.3% lower (1,897,563 barrels/day) than in September. This slight variation resulted both from operating problems, which have already been resolved, at platforms P-52 and FPSO-Brasil (Roncador Field), and at P-48 (Caratinga field), and from the decreased production at the Furado Oil Treatment Station, in Alagoas, on account of the accident which took place there on September 23. Gas production in October, meanwhile, was 2.3% higher than in September 2008.

Considering Petrobras’ fields in Brazil and abroad, the total oil and natural gas production last October reached the daily average of 2,440,367 barrels of oil equivalent (boe), 9.4% more than a year ago and stable compared to September.

International production

The volume of oil and natural gas produced by Petrobras in the eight countries where it has E&P operations, in barrels of oil equivalent, closed at 229,528 barrels per day in October, 3% more than in September. New wells going online in the Agbami field, in Nigeria, helped boost the volumes produced abroad compared to the previous month’s total.
## PETROBRAS’ OIL & NATURAL GAS PRODUCTION
### OCTOBER 2008 PER STATE AND COUNTRY

<table>
<thead>
<tr>
<th>STATE/COUNTRY</th>
<th>OIL PRODUCTION</th>
<th>GAS PRODUCTION</th>
<th>OIL/GAS in barrel equivalents/day (boe)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>barrels/day</td>
<td>thousand cubic meters/day</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>ONSHORE</th>
<th>OFFSHORE</th>
<th>TOTAL</th>
<th>ONSHORE</th>
<th>OFFSHORE</th>
<th>TOTAL</th>
<th>TOTAL – BOE/DAY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rio de Janeiro</td>
<td>---</td>
<td>1,527,734</td>
<td>1,527,734</td>
<td>---</td>
<td>23,080</td>
<td>23,080</td>
</tr>
<tr>
<td>Espírito Santo</td>
<td>18,408</td>
<td>90,507</td>
<td>108,915</td>
<td>742</td>
<td>8,325</td>
<td>9,067</td>
</tr>
<tr>
<td>Amazonas</td>
<td>50,705</td>
<td>...</td>
<td>50,705</td>
<td>9,555</td>
<td>...</td>
<td>9,555</td>
</tr>
<tr>
<td>Bahia</td>
<td>47,710</td>
<td>218</td>
<td>47,928</td>
<td>3,251</td>
<td>2,377</td>
<td>5,629</td>
</tr>
<tr>
<td>R.G.Norte</td>
<td>56,068</td>
<td>10,756</td>
<td>66,823</td>
<td>801</td>
<td>1,066</td>
<td>1,867</td>
</tr>
<tr>
<td>Sergipe</td>
<td>37,395</td>
<td>13,546</td>
<td>50,941</td>
<td>256</td>
<td>2,467</td>
<td>2,723</td>
</tr>
<tr>
<td>Alagoas</td>
<td>4,674</td>
<td>167</td>
<td>4,841</td>
<td>1,191</td>
<td>204</td>
<td>1,395</td>
</tr>
<tr>
<td>Ceará</td>
<td>2,351</td>
<td>8,037</td>
<td>10,388</td>
<td>2</td>
<td>175</td>
<td>177</td>
</tr>
<tr>
<td>Paraná (schist)</td>
<td>4,276</td>
<td>...</td>
<td>4,276</td>
<td>127</td>
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<td>127</td>
</tr>
<tr>
<td>São Paulo</td>
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<td>---</td>
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<td>91</td>
</tr>
<tr>
<td>Paraná</td>
<td>...</td>
<td>288</td>
<td>288</td>
<td>...</td>
<td>6</td>
<td>6</td>
</tr>
</tbody>
</table>

Total Brazil | 221,586 | 1,651,383 | 1,872,970 | 15,925 | 37,792 | 53,717 | 2,210,839 |

<table>
<thead>
<tr>
<th>Country</th>
<th>OIL PRODUCTION</th>
<th>GAS PRODUCTION</th>
<th>OIL/GAS in barrel equivalents/day (boe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argentina</td>
<td>53,093</td>
<td>---</td>
<td>53,093</td>
</tr>
<tr>
<td>Bolivia</td>
<td>8,296</td>
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<td>8,296</td>
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<tr>
<td>Peru</td>
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<td>13,614</td>
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<tr>
<td>Colombia</td>
<td>15,353</td>
<td>...</td>
<td>15,353</td>
</tr>
<tr>
<td>Venezuela</td>
<td>12,433</td>
<td>...</td>
<td>12,433</td>
</tr>
<tr>
<td>Nigeria</td>
<td>...</td>
<td>13,755</td>
<td>13,755</td>
</tr>
<tr>
<td>Ecuador</td>
<td>11,061</td>
<td>...</td>
<td>11,061</td>
</tr>
<tr>
<td>Angola</td>
<td>...</td>
<td>2,382</td>
<td>2,382</td>
</tr>
<tr>
<td>United States</td>
<td>...</td>
<td>14</td>
<td>14</td>
</tr>
</tbody>
</table>

Total Abroad | 113,850 | 16,151 | 130,001 | 16,798 | 112 | 16,910 | 229,528 |

Total Petrobras | 335,436 | 1,667,534 | 2,002,971 | 32,723 | 37,904 | 70,627 | 2,440,367 |

Source: Petrobras
Mature Fields

The revitalization of fields already past their production peak gives them a new life and steps up Petrobras’ oil production.

Until very recently, the Exploration and Production area of Petrobras had no corporate program focused on the revitalization of its mature fields, i.e. those fields that have already passed the production peak foreseen in their original exploitation scheme and in general have been in production for 10 years or more. However, the setting up of RECAGE - the Mature Fields Recovery Enhancement Program, changed this situation as of 2004. Today, thanks to this program, fields such as Carmópolis, Canto do Amaro, Camorim, Dourado, Bonito, and Albacora that have already passed their peak production, have acquired new vitality and in some cases total production is greater than it was in their prime.

RECAGE is a corporate management program that structures the support and the accompanying systematic incentives that, in Petrobras’ Exploration and Production Business Units, increase production levels of fields that have experienced a high level of exploitation. It achieves this by optimizing extraction costs and by the generation and management of production development projects. Besides this, the purpose is to extend the life of these fields, increasing their recuperation factor. This is carried out by using solutions such as increasing water injection levels and injecting steam in the case of heavy oil recuperation. Other solutions are the centralization and rationalization of installations for injection, production, and treatment deployed, and the introduction of new technology such as the underwater injection of seawater in wells and the use of horizontal wells with long multi-fractured stretches.

"We want RECAGE to bring better management to our projects and processes, to increase production, to optimize costs, and to help the Exploration and Production area overcome its major challenges, namely to reduce production decline, to increase reserves, and to improve the recuperation factor of fields that have experienced a high level of exploitation. The program is of major importance for us, since mature fields represent 70% of the concession blocks held by Petrobras (205 of a total of 288), 40% of the proven reserves of the company, and 60% of Petrobras’ total oil production. In addition, the 13 production development projects that are being accompanied by this program add around 850 million barrels of oil to Petrobras’ proven reserves, which is equivalent to the discovery of a giant field,” explains Carlos Roberto de Carvalho Holleben, general coordinator of RECAGE.

Revitalization in the Northeast

The anticipated results are encouraging. The Carmópolis field, discovered in 1963, in the onshore basin of Ser-
The offshore fields of Camorim and Dourado, located along the Sergipe coast in shallow water at depths of between 25 and 145m and of 30m, respectively, where light oil of excellent quality is produced, will also be revitalized.

The Camorim offshore field, located in the deep waters off the coast of Sergipe, will be revitalized.

The offshore fields of Camorim and Dourado, located along the Sergipe coast in shallow water at depths of between 25 and 145m and of 30m, respectively, where light oil of excellent quality is produced, will also be revitalized. With investments of US$ 600 million, Petrobras intends to increase productivity of these fields by 600% in five years. The project will involve the drilling of 27 new wells and the re-completion of 65 other wells. In addition, 73.8 kilometers of new pipelines will be laid for water injection in the two fields, and there will be two new platforms of the Caisson type, with a deep draft, one in each field, as well as a new platform in Dourado. In Camorim, the second-largest field in Sergipe, a new Caisson will be launched and the deck of the PCM-11 platform will be restored.

The Dom João Mar field, in Todos os Santos Bay near Salvador in Bahia, is old and has low production but holds considerable reserves, of almost 600 million barrels. It will be extensively revitalized, with environmental care redoubled. "Since it is a field located in an environmentally sensitive area, for part of it is in shallow water and part in a mangrove swamp area, Petrobras will create artificial islands from which directional wells will be drilled to reach the reservoirs. This initiative will reduce the number of wells and platforms in the area," explains Holleben.

Another differentiated and corrective environmental project foreseen in RECAGE is the injection of carbon dioxide (CO2), a type of greenhouse gas, into wells. "Thanks to a joint incentive of the Exploration & Pro-
duction and Supply areas, a pipeline will be constructed to transport the gas produced at the Landulfo Alves Refinery (RLAM) in Mataripe (Bahia) to the Miranga field in Bahia so that after water injection in the wells, the gas will be injected, aiming at an increase in the internal pressure of the reservoirs and a greater recovery of oil from the Miranda field”, adds the general coordinator of RECAGE.

**Revitalization of the Southeast**

In the Campos Basin, three RECAGE projects will revitalize the Bonito, Badejo, and Albacora fields. In the Bonito field, an area with carbonate formations of low permeability, unique solutions will be tested by Petrobras - horizontal wells with long multi-fractured stretches and water injection. The intention is to increase the recuperation factor of the wells in this type of formation from 8% to 30%. In Siri, a reservoir in shallow water within the Badejo field, solutions such as a horizontal well and technology for specific production of heavy oil will be used. On the other hand, in the Albacora field, it will be possible to use technology developed by CENPES, Petrobras’ R&D center, which is innovative to the company namely the subsea injection of sea water known as Subsea Raw Water Injection. The technology consists of underwater pumps and filters installed on the seabed. Seawater is pumped into the reservoir through an injection well, which allows an increase of injection capacity without altering the structure of surface installations.

Also in the Campos Basin, projects for the revitalization of the Congro and Marlim offshore fields are another RECAGE priority, in terms of production increase. The Marlim field will probably be revitalized using an innovative process of subsea separation of oil and water.

In the Espírito Santo Basin, in the onshore field of Fazenda Alegre, a project to inject steam will be set up for the recuperation of heavy oil, while in the North of Brazil, in the Solimões Basin, two projects have been planned – one intended to develop the gas production in the Rio Urucu region and the other to optimize the production of the Leste do Rio Urucu field.
Cost Optimization

As each well of a revitalized field can cost from 50% to 70% of the total cost of the project, the optimization of the well cost is essential in RECAGE. The use of small pneumatic rotary rigs is a solution that has been foreseen with this aim in mind. This equipment is being used in the first phase of drilling wells in projects in Rio Grande do Norte and in Ceará. Subsequently, a conventional drill rig, the rental of which is considerably more expensive, will complete the service, with the advantage of carrying out the work in less time, which will result in significant savings for Petrobras. Another measure to optimize costs will be operations such as the hydraulic factoring of reservoirs without the use of rigs, which are expensive to rent.

At any rate, it is advantageous to invest in mature fields, since, according to Holleben, there are fewer uncertainties in relation to the presence of oil. “We set up simple projects and obtain the largest output possible in exchange. Furthermore, the expectation concerning RECAGE is that it will contribute with 25% of the present production for Petrobras in 2011, which will mean something around 550,000 bpd,” he reveals. The prospects could not be more promising.

The technology of subsea injection of seawater consists of pumping the seawater into the reservoir, through an injection well, which increases the injection capacity without affecting the surface installations.

In the Bonito field, a new solution for Petrobras will be tested – horizontal wells with long multi-fractured stretches and water injection.
The Carmópolis field in Sergipe is presently serving as a base for technological tests that could bring a final solution to one of the main problems during the production of heavy oils - the presence of oily sludge, a sub-product until now characterized as an environmental liability and discarded in sanitary landfills or given to cement industries. The technology, unprecedented in the world and recently patented by CENPES in the United States and in Europe, reduces both the volume of oily sludge generated and the cost to discard it, almost totally eliminating the problem. It is a matter of thermal treatment of multiphase residues and materials plus (TTRMM+).

"Petrobras' environmental liability is on the order of 300,000 tons of oily residues, stored in various units. This number has been increasing, since the cement companies that have agreements with Petrobras have ceased to accept donations of residues. With the setting up of TTRMM+ technology, this scenario is changing. In two or three years, Petrobras will save around US$ 40 million per year in the transport and storage of these rejects," explained Luis Fernando Gallo, an equipment engineer at CENPES.

A TTRMM+ technology prototype on a semi-industrial scale, the Telab K500 was set up at the end of January in the field. Developed through a technology partnership between CENPES and the industrial equipment company Albrecht, it was assembled within a large cylinder and placed on a trailer that can be transported to various Petrobras units. This prototype has the capacity to process 500 kilos of oily sludge per hour. Its system includes a series of processes in which the residues generated during the extraction of oil are submitted to temperatures that reach 700°C. Within this closed cycle process, 99% of the oil in the sludge is recovered, obtaining a quality oil that is sent to a refinery; water that is sent to treatment stations or reinjected; gas that is treated or reutilized; and the solid content that is transformed into an inert matter can be discarded into nature without any environmental damage and without added co-responsibility.

According to the coordinator of the TTRMM+ project, Arilza Pickler, a chemical technician in the area of Biotechnology and Environmental Treatments at CENPES, the high temperatures of the process guarantee that the solid fraction remaining is 100% free of hydrocarbons, which means total utilization of the oil. "As research goes on, new uses will be found for each sub-product," he adds.

The uses of TTRMM+ could bring benefits to the Exploration & Production, Transport, and Refinery areas of the company, since oily residues often accumulate at the bottom of reservoirs and oil tanks over time. During regular maintenance stops this sludge is removed and, since there was no appropriate use for it, it became an environmental liability. Now, thanks to the diffusion of TTRMM+ technology in Petrobras, the elimination of oily sludge is no longer a cause of concern.

While the Telab K500 tests go ahead in Sergipe, researchers at CENPES are installing equipment with a smaller processing capacity, around 200 kilos per hour, in the Nativo Oeste field in Espírito Santo. The objective is to test another innovation made possible by the TTRMM+ technology – the production of solvents for injection from residues of oily sludge. The light oil extracted from the residues will be reinjected into the reservoir, to be mixed with the heavy oil to revitalize the production which was stopped because it was uneconomical. The process is unprecedented and is protected by international patents. ✅
Corrosão é o principal fator que afeta a durabilidade e compromete a disponibilidade de linhas de dutos de óleo e gás, terrestres ou submersos em água do mar (sub-sea).

Como resultado, as linhas de dutos são projetadas e construídas com sistemas de proteção contra corrosão na superfície externa, protegidos simultaneamente com sistemas de proteção cátodica.

Nos últimos 40 anos, tubulações de óleo e gás são protegidas com uma larga gama de sistemas de proteção contra corrosão, como: coal tar, polyolefin tapes, polietileno extrudado dupla camada, simples ou dupla camada de fusion bonded epoxy coatings FBE, triplo camada polyolefina (polietileno ou polipropileno), tintas ricas em zinco entre outros.

Cada sistema de proteção tem sua eficiência com variados graus de sucesso e atendem à indústria de óleo e gás. Com maiores demandas de confiabilidade nas linhas de dutos, novos revestimentos são sempre testados.

A Durotec fornece para as refinarias da Petrobras, E & P (Extração e Produção) e unidades da Transpetro, novas alternativas de proteção contra corrosão para linhas de dutos de óleo bruto, água de processo, tubulações de combate a incêndios terrestres e enterrados, tubulações do flare, módulos das plataformas de produção. Estas alternativas contam com sistema de proteção com camada metálica de zinco e alumínio aplicados poraspersão Térmica que atuam como barreira e proteção cátodica, promovendo proteção efetiva mesmo com danos mecânicos na superfície do revestimento.

Discussidos sempre previamente com o CENPES e através do Contrato Compartilhado 4800185370, a Durotec fornece diretamente aplicações de revestimentos em campo (on-site) para Petrobras em todo o Brasil ou em suas próprias instalações.

A Durotec participou da II Edição da Santos Offshore que foi um absoluto sucesso! Certamente, negócios promissores foram fechados neste evento que teve como objetivo fomentar um mercado extremamente promissor na Baixada Santista e região. Participamos também do SENA - Seminário Nacional de Fornecedores e a Rodada e Encontro de Negócios - com a palestra Aspersão Térmica na Proteção Contra Corrosão no Setor Óleo e Gás. Se você não pode assistir, entre em contato conosco. Teremos prazer em apresentá-la em sua empresa.
The pipeline network from North to South

By Petrobras Press Office

In addition to the investments made in generating electric energy and in increasing natural gas supply, Petrobras also works to increase the product transportation infrastructure. The gas pipeline network will grow, from nearly 6,500 kilometers, in 2007, to more than 10,000 kilometers, in 2010.

One of the main projects is the Southeast Northeast Gas Pipeline (Gasene), an integral part of the Federal government’s Growth Acceleration Program (GAP), and 1,387 km long. The first two sections, Cacimbas-Vitória (131 km) and Cabiúnas-Vitória (303 km), are already in operation.

The remaining section is expected to be completed in the first quarter of 2010. The Gasene is the biggest pipeline construction engineering and assembly project in Brazil since the completion of the Bolivia-Brazil Gas Pipeline, in 1999. The project is an infrastructure milestone in Brazil, and will allow the existing networks in Southeastern and Northeastern Brazil to be interconnected and will be capable of transporting 20 million cubic meters per day.

In addition to the Gasene, work is being done to reinforce the Northeast network, which currently totals 1,700 km of gas pipelines. The Southeast will also get new gas pipelines which, among other functions, will allow production to be transported from the Santos, Campos, and Espírito Santo basins, supplying these markets with gas. The Northeastern Region, meanwhile, will count on the Urucu-Coari-Manaus pipeline to supply the capital of the State of Amazonas to generate power by means of thermoelectric plants, reducing local dependency on fuel oil or diesel fuel.
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We are all aware that new technologies development may take a while before giving birth to innovations. It is quite natural that problems will constantly rise and be solved until the product becomes marketable. In most of the human knowledge fields, technology and equipment users are spared from the need to cope and interact with typical development processes since they can be run at specific facilities or in basic reserved laboratories. New equipment are released to users after gaining all necessary approvals.

In the case of the pipeline industry basic labs may become quite limited for certain more evolved trial stage applications, but given the highly significant costs involved in the construction of full scale testing centers, most of the companies test new equipment and procedures in the field, facing operational risks while the customers witness a continuous trial and failure cycle. Such an open process gives rise to consequences that extend beyond financial losses, as they may tarnish the image and the reliability of a supplier in front of its customers.

Training activities for new operators are subject to other categories of constraints, as the huge responsibilities and risks of accidents require newly-qualified workers to spend additional lengthy periods of time under the sponsorship of their senior colleagues until they are sufficiently trained to handle the job by themselves. This training structure increases costs, slows the entry of new skilled workers into effective work, and does not ensure risk-free training.

Undesirable from every standpoint, these situations are consequences of high costs and, ultimately, low usage rates of testing and training facilities that makes it unfeasible or unattractive for a single user to build such an installation alone. In such a scenario it is quite unlikely that the outcome of a cost x benefit analysis will recommend the construction of individual installations.

CTDUT’s concept as a shared laboratory that is open to the entire pipeline industry eliminates the unfavorable cost x benefit result. Its Pipeline Test Loop 14 is available for equipment testing and crew training purposes at no risk to the environment nor to the operators’ distribution and transporting activities.

The Pipeline Test Loop 14 is a 100m by 14” diameter loop circuit assembled with several flanged spools that can be easily interchanged or removed. These spools have damages which were deliberately and carefully inserted and mapped, making it easier to assess new pipeline integrity inspection tools. New spools can be produced and included in the circuit in order to attend customer’s requests for new developments. This Pipeline Test Loop counts with its own pumping system and PIG launcher and receiver located close to each other.

Since it works with water or inert gas, the Pipeline Test Loop 14 facilitates training, as it offers no environmental risks, even if a trainee operator performs a procedure
mistake. This characteristic also allows real leaks to be caused, assessing the actual capacity to detect or repair them, with the pipeline under load.

Another extremely important aspect is the capacity of the Pipeline Test Loop 14 to be used as a definite tool for calibrating pipeline integrity assessment devices. Routine inspections of pipelines with PIGs or other inspection tools are vital for lessening the probability of leaks. However, these inspections are extremely expensive, and always involve a certain amount of operational risks.

We know that inspection tools are not able to achieve 100% accuracy when searching pipelines for damages or when assessing such damages. However, it is necessary to be aware of the actual capacity of such tools to locate and categorize these potential risks for the benefit of the pipeline and the society that lies around it.

Although most of the technologies employed in PIGs production are wide spread, due to its unique manufacturing characteristics, each unit produced is separately assessed in order to measure the effectiveness of each produced PIG, which may differ from that of some other unit produced by the same manufacturer using the same technology. This is a type of calibration that only a pipeline with mapped defects can provide.

For all the reasons presented above, the benefits offered by the Pipeline Test Loop 14 for testing and training activities will certainly make this a major ally of companies that act in the pipeline industry, while reducing the risks of accidents, which are not always easily quantifiable.

CTDUT is open to respond to new demands presented by the pipeline community.
Pipeway Integrity:

Piping is one of the most important sources of static equipment’ failure in the Oil and Gas Industry\(^1\). People have spent much time to establish an effective system to manage the integrity of such equipment. We can divide piping into two main classes.

On-site piping is inside the process units and its lines have in common the possibility to be liberated and repaired at the same event, the maintenance turnaround.

Off-site piping serves to connect the units among each other and with storage tanks and clients outside the plant. These off-site pipes are further divided in two more types: ducts or, in common language, pipelines which pass through third-owned areas, and will not be studied here; our interest in this article are the off-site pipes inside the limits of a complex, like a refinery or a petrochemical facility, but outside the battery limits of the units. The typical code adopted to design these pipelines is the same as on-site piping, ASME B31.3\(^2\), called “Process Piping”.

Why is off-site piping so critical? Although these lines are essential to the operational continuity, normally they cannot be treated like on-site piping. It is because those equipment often connect units whose operating periods are not the same. For example, a crude atmospheric and vacuum unit produces, among others, diesel oil, vacuum gasoil and residue. Diesel is sent to a hydrodesulphurization unit to be specified and gasoil may be sent to a catalytic cracking unit to produce lighter products. The residue can go to a delayed coking unit, where it will be thermally cracked. All these units cannot, for many organizations, have an integrated maintenance shutdown. So, it is necessary to deal with the fact that there will be units in maintenance among others in full operation. Some auxiliary and relief systems, like steam and flare piping, are also frequently unavailable to maintenance together with others, because they serve the complex as a whole.

Off-site pipelines are usually built in three kinds of arrangement: pipe-racks, pipeways and buried lines.

Pipe-racks lie on supports that keep them elevated high enough to make people need platforms, scaffolding or rigging machines to access them. That is the common solution to on-sites, where there are many equipment to be arranged in a relatively small space. However, some refinery, chemical or petrochemical facilities have more limited areas, which makes the designers follow this option to the off-sites too.

By Mario Jordao, Project Management – Duque de Caxias Refinery – PETROBRAS
A Huge Challenge

Why is off-site piping so critical? Although these lines are essential to the operational continuity, normally they cannot be treated like on-site piping. It is because those equipment often connect units whose operating periods are not the same.

Pipeways are piping systems erected in trenches below the level of the facility’s grade. It permits the traffic through the complex, for people, vehicles and machines (e.g.: cranes). Major problems arise from this “negative” elevation, because it allows rain water and other liquids to accumulate in the trench, increasing local humidity and sometimes flooding the place. This water easily absorbs sour gases present in the industrial atmosphere, increasing environment corrosivity. Pipeways often are damaged in the pipe-support interface by mechanisms like crevice and microbiological corrosion. Wet insulation causes energy losses and corrosion under insulation (CUI). So, for on-site piping and off-site pipe-racks the inspector must essentially pay attention to the interaction between the fluid conducted and the material; pipeways, however, often deteriorate faster for external reasons, associated with the trench microclimate: warm, moist and biologically and chemically aggressive.

Buried piping will not be treated in this article either, because they have specific and well established inspection programs. The common solution to protect buried pipelines is the cathodic protection (CP). However, some pipes usually have small buried sections, like when passing through a tank farm’s dike. In this case, the strategies applied to the pipeways include these parts, because there are soil-to-air interfaces and buried pieces not protected.

API 570 “Piping Inspection Code” indicates the inspection organization must evaluate, for each piping system, the likelihood of failure associated with its consequence. This approach is called “Risk-Based Inspection” (RBI), and is more detailed in the documents API RP 580 and API RP 581. The API Piping Inspection Code is very useful for on-site piping, but does not give more details to deal with pipeways. It means we need to develop specific strategies to guarantee pipeways integrity.

There are a number of good practices, involving inspection, operating, safety and other procedures applied to pipelines which could be adapted to pipeways. Other procedures come from on-site criteria. The goal is to create an integrity-management system for these lines comparable to the best monitored piping. Unfortunately, the main actions adopted to protect pipelines — CP and pigging — are in general not applicable to pipeways.

Leadership
Changing a philosophy or, at least, a culture requires a leadership committed to the change. The following recommendations will not take place without managers’ decisions. Many barriers to the changes are built on dogmas and myths, and many times the directors are specially vulnerable to the “conservative” approaches, rejecting some important alterations. The necessary partnership among all stakeholders (operational, inspection, maintenance and industrial safety sectors) is dependent to the leaders’ attitude.

Personnel
The most important step to reach the full reliability of pipeways is to prepare personnel to be able to establish the pipeway integrity program. People must be trained at least in qualitative RBI and be updated on inspection technology. In addition, the organization must give pipeway inspectors their deserved status, because these work-
ers are commonly treated as second-category technicians, usually remembered only when a sinister situation occurs. It is similar to taking care of the heart and spurning the circulatory system. The operational team is important to communicate all abnormality to the qualified personnel. Workers from maintenance specialties (welding, rigging, painting, etc.) must be well involved to plan and execute the repairs and other interventions at the correct moment.

**Supporting Structure**

The pipeway system’s reliability is not limited to piping inspection. There are many desirable devices useful to protect the lines.

A good leak-detection system permits rapid actions to localize and stop leakages. Pay attention to the fact that an “inoffensive” release (like steam) can be harmful to an adjacent pipe. The first leak-detection system is the “patrol” made by operators or other plant workers. A closed TV circuit is also useful as the pipeway is big. Night illumination is important not only to detect leaks, but to avoid accidents and operational errors. Pumping control is an indirect way to detect leaks, when a product is sent to a tank. The correct flow and level measures allow the controllers calculate if there is some missing fluid.

The trenches must, if flooded, be quickly and easily drained. If it is not possible to drain the trench by gravity, because it is the lower part of the plant, mechanical or jet pumps can be used to extract the liquids from the pipeway to a safe location.

**Inspection Planning and Technology**

The traditional approach treats these lines by geographic areas, including a basic qualitative (sometimes too subjective) RBI analysis. The inspection programs are essentially based on visual and conventional ultrasonic (UT) inspections, and the maintenance programmed close to the end of remaining life. Unfortunately, often the line can’t be liberated on the predicted date, which brings the need for alternative repair solutions like mechanical connectors, patches or plug welds. These emergency actions are valid but tend to become “normal” and early forgotten.

We propose a hybrid approach, where the visual inspection may be conducted by geographic areas and the non-destructive tests (NDT) must be submitted to a rigorous RBI program. The geographic and NDT inspection have to be analyzed in an integrated system, because a failure at a low-risk line (for example, a pipe with low pressure steam) may cause damages in higher-risk neighborhood lines (like LPG piping).

The inspection program must consider if the pipe operates continuously or not, because it changes the state of the internal corrosive medium and, if the pipe is insulated, can cause CUI.

It is out of the scope of this article to describe all inspection techniques. However, we need to consider the adoption of methods and technologies compatible to operating lines, minimizing the need to shut-off the line to make the inspection. As pigging is not a possible option for pipeways, we suggest the application of ultrasonic guided waves (UTGW)\(^{10}\) combined to digital radiography (DXR) to have a good notion of piping integrity. The shape of external coating (painting, insulation) must be well monitored too, with visual or instrumented techniques. The UTGW and DXR data, with visual and UT results and the equally important historical records and piping data sheets can feed a strong RBI program, ensuring a satisfactory reliability level to the pipeway system.

We propose a hybrid approach, where the visual inspection may be conducted by geographic areas and the non-destructive tests (NDT) must be submitted to a rigorous RBI program.
Design & Management of Change and Documentation

In general, industrial projects are carefully conducted when dealing with on-site design and construction. On the other hand, the off-site facilities are many times neglected. The licensors often deal only with the on-site, leaving the off-site design to the client or third-part contractors. So, the owner must control all projects in an integrated data base, to avoid undesirable interferences and other design errors.

The lack of attention to the off-sites, in addition, usually generates delays and late design changes, which are too expensive and can bring hidden new problems. When new lines are erected in an old pipeway, special attention must be given to the foundations and supports existents, because there is a trend to use them to bear the new lines without a deep study. All changes have to be well studied and recorded.

The piping documentation could ask for a special chapter. Even for on-site facilities, piping rarely receives the attention that, for example, pressure vessels do. It would be naturally difficult to do because the number of lines is many times bigger than the number of pressure vessels. Hence, it is necessary to simplify the forms, reports and other documents to keep the knowledge about the piping systems updated. But the organization can never think this database has little importance. We’ve already piping has a regrettably high position in the industrial accidents ranking, so more care is needed. The RBI techniques are very useful to guide the inspection team to the more critical lines, enhancing the effectiveness of the inspection program. But, if the database is weak, it will be unsuccessful.

References


Apolo Tubulars recently upgraded its industrial plant located in the City of Lorena, in São Paulo State. A special event was held November 13 at Apolo’s plant, and was attended by Carlos Eduardo de Sá Baptista, Apolo Tubulars CEO and President.

The investments in cutting-edge manufacturing in association with the strategic location of facilities result today in the company’s competitive advantage which has started to market a range of finished tubing (OCTG) for the exploration and production of oil and gas with diameters from 2. 3/8” to 9.5/8”. Those pipes are classified, depending on their applications, as Tubing - with diameters from 2. 3/8” to 4.1/2” and steel degree of up to P110 - and as Casing - with diameters of up to 9.5/8” and steel degree of up to P110.

Upon the start of this new business, Apolo Tubulars intends to direct its output to the manufacturing of high quality Oil Country Tubular Goods (OCTG) and Pipeline to service its customers needs. The company’s short term goal is to support its customers globally as well as emphasizing support for the rapidly expanding Brazilian Energy Industry. Apolo’s plant has an installed capacity of 120 thousand tons of pipes.

The company’s plan to upgrade its manufacturing plant started in 2003 and required investments of approximately R$ 62 million, 110 thousand man-hours during the implementation stage, and 48,840 man-hours during the technical training and technology transfer stages. The plan is strategically in line with Brazilian oil industry’s accelerated development and growth trend due to ongoing growth in global energy input demand.

“At that time, it was clear that in order for Brazil to succeed in its search for oil great technological improvement and qualification was required. Today, we see that our decision to prepare ourselves for this moment was extremely wise and enables us to participate actively in the new market challenges of the oil and gas industry”, states Carlos Eduardo.
The plant development project comprised the acquisition of national and foreign equipment of highly improved technology used for inductive heating up-set operations and for mechanical pressure wall width growth, and pipe heat treatment equipment based on computer-assisted inductive process control, and a dedicated pipe straightening software.

The plant development further enables the performance of non-destructive tests in all process stages utilizing ultrasound technique and hydrostatics tests up to a pressure of 20 thousand psi. For the threading stages, four data control centers utilizing dedicated Round, Buttress and Premium thread programs and sleeve torque equipment with mapping, are provided.

The expertise in connection with the new manufacturing processes incorporated during the equipment commissioning and start-up stages was possible due to the support of United States Steel Corporation, which was the provider of technology and tubular products, and partner holding a 50% interest in Apolo Tubulars in Brazil. The remaining 50% is controlled by Apolo Tubos e Equipamentos, a Peixoto de Castro Group subsidiary.

It is a company focused on high quality steel pipe manufacturing, welded with high frequency induction welding (HFIW), for the oil and gas industry and other segments within the energy sector.

**New Capacity**

Presently, Apolo Tubulars’ industrial plant has an installed capacity for manufacturing 120 thousand tons of pipes, 80% of which is directed to the manufacturing of exploration and production pipes (OCTG) and 20% for Line Pipe.

Based on the technical cooperation with U. S. Steel and the development of its industrial plant, the new company will attend a wide variety of clients with its large and well-developed global distribution network.

For more information about the company, please visit the following website: www.apolotubulars.com.br
This article discusses the PLT-correlated results of two test wells completed during 2006; one in sandstone and one in a carbonate reservoir, with the new completion technology of nozzle-based passive inflow control devices (ICD) which improves performance of wells with reservoir challenges as described: 1. In highly productive sandstone reservoirs, horizontal wells suffer from uneven flow profile and subsequent premature cresting/coning effects. In general, there is a tendency to produce more at the heel than at the toe of horizontal wells, which contributes to poor well cleanup at the toe. Additionally, excessively increasing the rate and/or horizontal well length can increase the risk of limiting sweep efficiency, resulting in bypassed reserves. 2. In carbonate reservoirs, permeability variations and fractures can cause uneven inflow profile and accelerate water and gas breakthroughs. Wells with early gas or water breakthrough have to be shut-in until remedial plans are decided and implemented, resulting in deferred production.

The main reservoir objectives for applying passive ICD technology in the two test wells are:

a. Sandstone: Decrease the influence of heel-toe effects and high permeability zones; thereby deferring water/gas breakthrough, improving well cleanup and sweep efficiency.

b. Carbonate: Control flow rates from high permeability intervals and to limit production from each compartment based on lateral offset from the gas-oil contact to prevent premature gas breakthrough.

The test well PLT-logs were correlated to static reservoir simulations. Analyses of the well performances show that the objectives of both completions were achieved. By having proper matches of the completions with ICD, the value over standard completions can be evaluated.

Post-evaluation of the completion designs based on the PLT-log results has increased our understanding of the nozzle-based ICD performance. As a result several approaches for completing wells in both sandstone and carbonate reservoirs with ICD have been recommended in order to achieve optimized inflow performance.

Introduction

Two trial wells with nozzle-based passive ICD systems were designed and completed in 2006; one for sandstone and one for carbonate reservoirs. To evaluate and approve the new ICD completion, these wells were production logged and the results were carefully analyzed.

The most important feature of the ICD completion is the self-adjusting effect of flow variations anywhere along the well trajectory and whenever they occur during entire well life. The key benefits are:

1) Increased well life and reserves due to improved sweep efficiency.
2) Delayed gas and water breakthrough.
3) Decreased water/gas rates after breakthrough when water/gas mobility is higher than oil.
4) Improved well cleanup.

The pressure drop through the ICD unit is generated by the flowing fluid through the nozzles (Figure 1a), described by a part of the Bernoulli equation:

\[ \Delta p = \rho \frac{v^2}{2} \quad \wedge \quad v = \frac{q}{A} \]  

(Eq. 1)

Where: \( p \)= pressure, \( \rho \)= density of fluid, \( v \)= velocity, \( q \)= rate and \( A \)= total cross section area of the nozzles.
This article discusses the PLT-correlated results of two test wells completed during 2006; one in sandstone and one in a carbonate reservoir, with the new completion technology of nozzle-based passive inflow control devices (ICD) which improves performance of wells with reservoir challenges.

The ICD unit is equipped with at least 2 or more nozzles and the pressure drop across the unit is designed based on the reservoir characteristics and flow rates in order to achieve the objectives of the well. An advantage with these nozzles is that at least one or more of the nozzles will be exposed to inflow of fluid, making the system reliable for cleaning up the well even if the well has been left with solids-laden fluids down hole for a longer period before the well is put on production.

Figure 1b shows a schematic of a well with packers to divide the lateral into compartments of permeability variations. The benefits of having packers supporting the ICD completion are:

- Permeability variations are captured and segmented.
- High productivity (high permeability) intervals are controlled by lower number of ICD units run in those segments, preventing cresting/coning in those segments.
- Inflow of gas or water through fractured zones can be isolated or highly restricted.
- Annular flow between compartments is prevented.
- Potential wet zones can be isolated while the rest of the well can produce dry oil.

Figure 1 - a) ICD unit integrated in a sand control screen. Screen ensures a solids-managed flow (allow particles < 45 μm to be produced), length 12m=one joint. b) An ICD completion example with packers for every ICD joint in a naturally fractured reservoir.

Figure 2 - Principle of improved wellbore cleanup:
- a) Barefoot
- b) Conventional Completion
- c) Passive ICD completion
When a barefoot or a conventional horizontal well is put on production, the filter cake is preferentially lifted at the heel of the well as a function of the heel to toe pressure gradient (Figure 2a and b). This leads to poor inflow performance due to higher completion skins at the toe. Usually as the horizontal well length increases, the inflow profile and corresponding recovery degrades because of insufficient well cleanup and lesser contribution from the toe.

For a horizontal well with ICD completion, flow rate per compartment is restricted (Figure 2c). At higher rates, a higher differential pressure is created and transmitted along the completion to other compartments and eventually to the toe. This differential pressure created lifts the filter cake off the formation face and additionally cleans the near wellbore damage, resulting in:

a) Skin reduction
b) Higher well PI
c) Enhanced sweep efficiency

Once ICD units are introduced into the completion, an additional pressure drop is created in the system. It is therefore very important to design the ICD unit pressure drop in accordance with the reservoir properties to achieve a design with the lowest possible ICD pressure drop and still achieve the objectives.

Figure 3 shows the principle of a standard screen completion compared to an ICD completion in a reservoir with 1 Darcy and 2 Darcy zones simulated in a static reservoir model. The two zones are supposed to be completed with a packer separating the annular flow between the zones. For a conventional completion the draw-down into the completion is shown as the $\Delta P_F$.

With an ICD completion the total draw-down into the completion is described as the $\Delta P_{ICD}$, and we observe that the draw-down pressure $\Delta P_F$ of the original horizontal well is now being re-distributed between the two zones when completed with an ICD completion.

The high permeability zone of 2 Darcy is having less draw-down ($\Delta P_{F2}$) while the low permeability zone of 1 Darcy is having a higher draw-down ($\Delta P_{F1}$), and the relationship is as follows:

$$\Delta P_{ICD} = \Delta P_{F1} + \Delta P_{NI} - \Delta P_{F2} + \Delta P_{E2}$$  \hspace{1cm} (Eq.2)

Where: $\Delta P_{Fi}$ is the pressure from the reservoir into the annulus and $\Delta P_{Ni}$ is the pressure from the annulus to the tubing = pressure across the ICD unit.

Simulating the two different completion types at the same rates, the flow rates for the zones are re-distributed (Figure 3a) and as a consequence the ICD completion will be able to defer gas or water breakthrough in high permeability layers. In addition, over time this will assure a much better sweep efficiency of the reservoir, because it is less likely that oil will be left behind in low permeability intervals.

Using the principle of Figure 3, the well PI for an ICD completion at the sandface (annulus) can be estimated and because when the flow rate per segment is known from the PLT-logging, we can calculate the pressure drop across the nozzle-based ICD units per segment from Eq. 1. To compare the results with the actual PI potential for the well, it is assumed that a perfect horizontal well is performing according to:

$$J = \mu B \ln \left( \frac{2 \pi k_i h_i}{\ln \left( \frac{2 r_o}{L_e / 2} \right) + \beta \frac{h}{L_e} \ln \left( \frac{\beta h}{2 \pi r_i} \right) \right)} \hspace{1cm} (Eq.3)$$

It should be noted that an estimate of the $P_{wf}$ (flowing bottom hole pressure) from this equation is not including friction loss along the horizontal well length. The $P_{wf}$ may therefore be slightly more optimistic than the actual measurement.

The evaluation of the well PI for both actual and theoretical has been completed for the two trial wells in order to measure and understand their performance.

**Sandstone Reservoir Trial Well**

The sandstone ICD well was completed in November 2006 (Figure 4). The objectives of the ICD completion were to reduce the heel-toe effect, deferring gas and water breakthrough.
2) The production profile changed in the time it took to log the two rates.

The results of the sandstone trial test in Figure 5 indicate that unloading at high rate can result in rapid wellbore cleanup; therefore, the latter condition 2), i.e. production profile changes due to wellbore cleanup, are evident. When this occurs, the utility of the lower rate PLT dataset is greatly diminished; therefore when logging a passive ICD well, it is recommended to log the high rate first, preferably for as long as possible, then log the lower rate afterwards.

Calculating the well PI at the sandface (annulus) based on the PLT-log results indicate clearly that the well performance improved during PLT-logging (Table 1) and that the actual well PI is approaching the theoretical well PI estimated from Eq. 3. The numbers for the Pwf from PLT are here marked with blue and are the same number for the rate variations during the PLT, because of uncertainty during the stationary readings.

This effect has also been inferentially observed in other wells. When a well is logged at two different PLT rates, occasionally when correlating a static simulation model to actual PLT results, the simulations will not match both rate curves. This can occur for one of two obvious reasons:

1) Either the simulation is simply invalid due to insufficient or invalid inputs, or

2) The production profile changed in the time it took to log the two rates.
The well PI estimated from the static reservoir model is assuming a skin of 0 along the entire wellbore and the performance according to the Pwf is in good agreement with the actual measured Pwf; however the well PI at sandface shows that the static reservoir modeling is over predicting the PI for the low rate, which is not that odd, since the initial low rate PLT log did not perform very well. At the high rate the static model is under predicting with about 100-200 STB/D/psi, which we will look into in further detail below.

Calculating the inflow per segment reveals that the toe part at the high rate has some problems (Figure 6a) because comparing actual PLT results with the static reservoir model with 0 skin along the entire wellbore, shows that segment 18 to 25 has less inflow than expected.

Reviewing the permeability log for the well, there is no clear explanation for this low rate from these segments, so instead of extensive permeability changes, the skin was changed from 0 to 30 for these segments.

For segments 5 to 7 the static reservoir model predicted too low inflow (Figure 6a), so in these three segments the skin was adjusted to between -5 to -10 and the permeability slightly increased. By doing these adjustments, the static model achieved a much better representation of the actual PLT log (Figure 6b).

Once the static reservoir model with the ICD completion matches the actual PLT-log performance at the high rate with less than 5% difference, then standard procedure is to simulate how the well would have performed if the well was completed with a screen completion instead.

The simulation of the screen is assuming a perfectly performing conventional screen completion, and does not take into consideration the risk of improper well cleanup of the toe as we saw from the PLT-log, and which we cannot predict if the well was only having screens.

The static reservoir simulations of the ICD well match PLT-log results as shown in Figure 7b, where the heel has a negative skin and the lower part of the well has high skin due to improper well cleanup. Comparing this case with a standard screen completion, the well is very fortunate to have an ICD completion. (Please note the remarkable change in the scaling.) The well has increased contribution from the high skin compartments 18 to 25 by about 2/3rd, meaning that the ICD completion is able to help high skin areas too, just as ICD completions can help on increasing contribution from low permeability layers. The well will therefore not suffer remarkably from the skin and the ICD completion will ensure good sweep efficiency of all layers.

**Carbonate Reservoir Trial Well**

The carbonate well was completed during June 2006 and put on production in May 2007 (Figure 8). The objectives of the ICD completion in the carbonate reservoir...
were to restrict inflow from the three last compartments, due to expected higher reservoir pressure towards the toe. Additionally, the toe part of the well was close to the gas-oil contact. The PLT-logging did not indicate a significant pressure gradient or free gas. Furthermore, there was no loss of circulation during drilling, which usually indicates severe fracture zones.

The PLT loggings were first performed at the high choke and then at a lower choke size (Figure 9a), to ensure that the well had been properly cleaned up before the logging.

Since the three last compartments have fewer ICD units, the well has an artificial heel-toe inflow profile. Also there was measured crossflow of 1000 RB/D during shut-in of the well which indicated a pressure gradient of about 2 psi decreasing towards the heel.

The high rate was then matched in the static reservoir model (Figure 9b) and required a manipulation of the permeability data. The well was initially designed based on an average permeability of 500 mD however the average permeability had to be increased to about 590 mD. Also the well had a higher GOR than expected, which was accounted for in the matching process.

The well PI at the annulus was predicted to be 250 STB/D/psi, however according to actual well performance the PI is approximately 500 STB/D/psi, right on target according to the perfect horizontal well PI calculated from Eq. 3. This means that there are no indications of formation damage due to skin effects. This is also a remarkable result, since the well was shut-in for almost 10 months.

Once the passive ICD completion model correlates to the actual PLT-log performance, standard procedure is to simulate how the well would have performed if the well was open hole (OH). The passive ICD static simulation is then juxtaposed against the OH simulation to compare oil flux per compartment (Figure 10a) and pressure along the well bore (Figure 10b).

This should be considered as an optimistic evaluation, because the OH would most likely not have been able to perform as predicted in the passive ICD static reservoir model. Specifically, the OH well would have higher skins in the toe due to non-uniform unloading; however, for comparative analysis, the skins in the two simulation scenarios are treated as identical and zero in both cases.

The modeling results show that the pressure across the ICD completion is about 80 psi, which is a substantial pressure loss in the system. The reason for having such a high additional pressure would be to eliminate any un-
foreseen events caused by fracture systems which could cone gas and cause excessive gas production. Figures 11a and 11b show the results of the open hole and ICD static reservoir simulations, evaluating the potential GOR decrease with the ICD completion if gas breaks through in the last compartment in the toe.

Figure 11 - Oil rate and GOR as a function of gas saturation:
- a) OH completion, Oil rate (Black lines) and GOR (Dashed Black line).
- b) ICD completion (Blue line) and GOR (Dashed Blue line).

As the gas saturation increases from 0 to 40% the GOR in the OH completion increases from the initial 1000 SCF/STB to 40,000 SCF/STB, while the ICD well is predicted to maintain a GOR of only about 4200 SCF/STB. These remarkable results have however not yet been verified in true field trial wells.

Lessons Learned and Future Completion Designs

Matching the PLT-log to a static reservoir simulation for the sandstone well, then removing the ICD completion and replacing it with a conventional screen completion, the model shows the theoretical performance of the well without ICD. When the rate is increased to 15,000 STB/D for a standard screen completion, the well suffers from extreme heel-toe effect with the toe only contributing 1/4th that of the heel (Figure 12a). Increasing the rate from 10,300 to 15,000 STB/D for the ICD completion shows better balancing of the inflow including higher contribution from the toe (Figure 12b). Clearly, the sweep efficiency of the ICD completion is improved over the conventional screen completion, deferring gas or water breakthrough and draining the reservoir layers in a more balanced way.

Taking the next step by looking at new options to utilize the advantages of the ICD completion, the wells can easily be extended without compromising the balancing effect, thus expanding the drainage area resulting in an increase of well reserves (Figure 13a represents 2700ft and 10,300 STB/D and Figure 13b represents 3300 ft and 12,000 STB/D). The well PI for the 3300ft well is increased from about 1300 to 1360 STB/D/psi. As a result, fewer numbers of wells are needed to drain the reservoir volumes; however, it is recommended to perform dynamic reservoir simulation evaluations to establish a drainage strategy for the entire reservoir with the longer ICD wells.

For carbonate wells with very low PI, the potential for enhancing the well life by using ICD completions is best illustrated by simulating water breakthrough in fractures for two cases with different packer density. In this case, the sensitivity of synthetic low permeability and the impact of upscaling the magnitude of this log (Figure 14) have been performed to study the difference in the static reservoir modeling results. Additionally, this well has a
large pressure differential along the wellbore of about 300 psi, being high at heel and lower at toe. This gradient is caused by pressure support from water injectors and low connectivity between the reservoir layers.

The ICD completion simulations are performed with two sets of different nozzle sizes in Figure 15 and 16 respectively. The “ICD” simulations have the same nozzle size along the entire wellbore and the “ICD variable” simulations have different sizes to balance the inflow according to the large pressure differential in the reservoir. The average pressure drop across the nozzle-based ICD units is initially only half of the previous carbonate well (about 40 psi in these cases), which should be sufficient for the ICD completion to achieve the upside potential for maintaining oil production at low water cut. It should however be noted that this pressure drop is designed specifically for this well to achieve good well performance, and should not be considered as a standard ICD unit pressure for low permeability reservoirs as a generality.

Simulation sensitivities are run for different packer spacing, based on both synthetic permeability logs (Figure 15a), and an average permeability (Figure 15b). In the first set of sensitivities, packer spacing is located every 120 ft (every 3rd joint).

![Figure 15 - Static modeling of perm variations with packers (Black lines) for every 3rd joint; OH (Blue lines), ICD (Pink lines) and ICD variable (Orange lines): a) Oil flux for Synthetic Perm log and b) Oil flux for Average Perm 120ft.](image)

Figure 16a and 16b are sensitivities for packer spacing every 480 ft (every 12th joint = four compartments). The impact on the simulations is noticeable when simulating is based on the upscaled permeability along the wellbore instead of using the log data. Figure 16a (Orange line), clearly shows that the ICD solution with four compartments is not able to capture high inflow from the high permeability layers towards the toe, which is much better captured with a packer on every third joint (Figure 15a, Orange line).

![Figure 16 - Static modeling of perm variations with packers (Black lines) for every 12th joint; OH (Blue lines), ICD (Pink lines) and ICD variable (Orange lines); a) Oil flux for Synthetic Perm log and b) Oil flux for Average Perm 120ft.](image)

Table 2 shows the results after simulating water breakthrough in 3 fractures in the heel. It is how much the ICD effectively decreases the water cut when water breaks through. If the well has “ICD variable” (designed accordingly to pressure differentials) and packers every third joint the water cut is estimated to be about 7% compared to an OH completion, which may be suffering from water cut of about 53%.

<table>
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<th>Completion Type</th>
<th>Oil rate</th>
<th>Gas rate</th>
<th>Water rate</th>
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<th>WKUT</th>
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<td>Packer per 12 joint</td>
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<td>1.206</td>
<td>250/4</td>
<td>256</td>
<td>7.2</td>
<td>260.1</td>
</tr>
<tr>
<td>Packer per 12 joint</td>
<td>320/2</td>
<td>1.206</td>
<td>250/4</td>
<td>256</td>
<td>7.2</td>
<td>260.1</td>
</tr>
<tr>
<td>OH, Synthetic Perm log</td>
<td>310/8</td>
<td>1.206</td>
<td>100/6</td>
<td>256</td>
<td>22.42</td>
<td>260.1</td>
</tr>
<tr>
<td>OH, Average Perm log</td>
<td>310/8</td>
<td>1.206</td>
<td>100/6</td>
<td>256</td>
<td>22.42</td>
<td>260.1</td>
</tr>
</tbody>
</table>

Table 2 - Comparison of OH completion and ICD completions with different packer density.

This is substantial water cut decrease, which could remarkably extend the well life. The ICD solution with 4 compartments showed the water cut of 22%. With respect to evaluating the number of packers to deploy, there is a cut-off limit as to how much water cut decrease will economically justify the increased quantity of packers. To accurately assess the economics, dynamic model is required, however, inferentially even the simplest dynamic studies would likely indicate that the additional expenditure is justifiable.

Recommendations for future design workflow:

1) To propose the best ICD completion design for future wells, the field or the development area should be evaluated as a whole.
2) The final ICD design of the completion should be performed based on LWD data and pressure gradients along wellbores. This means that drilling measurements are important to refine the ICD completion design.

3) If the well has severe pressure differentials, then firm operation guidelines for production rates should be established in order to avoid crossflow.

Conclusions
1) All completion and production objectives are met with the nozzle-based ICD completions.

2) Sandstone reservoir PLT evaluation: The well had initial indications of formation damage due to higher skin at the toe. After cleanup at higher rates, the ICD completion has increased the contribution for those zones by 2/3rd. Consequently better sweep efficiency is expected.

3) Carbonate reservoir PLT evaluation: There are no indications of formation damage in this well, because the well PI of about 500 STB/D/psi is as predicted for a perfect horizontal well PI.

4) For correlation purposes, perform PLT-logging at high rate first and low rate afterwards to ensure that well cleanup does not alter the rate-based inflow profiles while collecting data.

5) Conclusively the nozzle-based ICD completion have several advantages:
   a. The ICD unit is integrated with a screen, designed to exclude abrasive particles above 45 µm, securing a long lifetime without plugging and erosion risk of the nozzles and the ICD unit.
   b. The ICD unit is equipped with at least 2 or more nozzles, so at least one nozzle will be exposed to inflow of fluid, making the system reliable even if the well has been left with solids-laden fluids down hole for a longer period before the well is put on production.

6) Recommendations for future completion design options:
   a. Explore options of drilling and completing longer horizontal wells.
   b. Use annular packers more extensively in order to decrease gas or water rates when breaking through.

Recommendations for future completion design options:
a. Explore options of drilling and completing longer horizontal wells.

   b. Use annular packers more extensively in order to decrease gas or water rates when breaking through.

Nomenclature

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>inflow area nozzles [sq. ft or m^2]</td>
</tr>
<tr>
<td>Bo</td>
<td>oil volume factor [RB/STB or ft^3/Sm^3]</td>
</tr>
<tr>
<td>h</td>
<td>reservoir height, ft [m]</td>
</tr>
<tr>
<td>ICD</td>
<td>inflow control device</td>
</tr>
<tr>
<td>J</td>
<td>productivity index (PI), STB/D/psi [Sm^3/d/psi]</td>
</tr>
<tr>
<td>k_h</td>
<td>horizontal permeability, D [m^2]</td>
</tr>
<tr>
<td>k_v</td>
<td>vertical permeability, D [m^2]</td>
</tr>
<tr>
<td>L_w</td>
<td>well length, ft [m]</td>
</tr>
<tr>
<td>LWD</td>
<td>logging while drilling</td>
</tr>
<tr>
<td>ΔP_f</td>
<td>pressure drop from reservoir pressure to Pwf</td>
</tr>
<tr>
<td>ΔP_wf</td>
<td>total pressure drop from reservoir pressure to</td>
</tr>
<tr>
<td>ΔP_ICD</td>
<td>Pwf for an ICD completion, psi [bar]</td>
</tr>
<tr>
<td>ΔP_fi</td>
<td>pressure drop from formation into Annulus, psi</td>
</tr>
<tr>
<td>ΔP_N</td>
<td>pressure from the annulus to the tubing</td>
</tr>
<tr>
<td>r_e</td>
<td>external boundary radius and wellbore radius, ft [m]</td>
</tr>
<tr>
<td>ρ</td>
<td>density, lb/ft^3 [kg/m^3]</td>
</tr>
<tr>
<td>μ</td>
<td>viscosity, cP [Pa*sec]</td>
</tr>
</tbody>
</table>

References
1. SPE 85332 New-Technology Application to Extend the Life of Horizontal Wells by Creating Uniform-Flow-Profiles: Production Completion System: Case Study.
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Petrochemicals

Comperj will increase Brazil’s capacity for refining heavy oil, reduce imports of naphtha and petrochemical products and produce second-generation products for both the internal and external markets.

Rio de Janeiro’s Petrochemical Complex (Comperj) will be the largest industrial undertaking ever in the history of Petrobras and Brazil, and indeed the world, in terms of total investments in the order of US$ 8.5 billion. Due to come onstream in 2012 and become fully operational by 2013, Comperj will mark Petrobras’ return to the petrochemical sector in grand style. After almost two decades of reduced participation in first-generation industries, in line with decisions of former governments seeking to boost the private sector, the Company intends to increase Brazil’s heavy oil refining capacity through Comperj. As a result, this will reduce import requirements of by-products such as naphtha and petrochemical products. It will also produce second-generation products for the internal and external markets and revolutionize the socioeconomic profile of the complex’s entire sphere of influence. This will enable Brazil to achieve savings of over two billion dollars in foreign exchange and 200 million dollars per year in taxes.

Roberto Costa, Petrobras’ Director of Supply, explains, “It must be borne in mind that petrochemical plants rely on raw materials such as petrochemical naphtha, of which there is a worldwide shortage. Brazil is no exception in that it has insufficient quantities of the product with the paraffin content required for these plants. Furthermore, natural gas production has yet to reach levels to meet the demands of thermoelectric plants, industries in general, vehicles, private home and businesses. For the above reasons, the use of heavy oil in such plants by Comperj will represent a major advantage, as it will make it possible to process this oil – of which there are abundant supplies in Brazil – to generate propylene and ethylene directly. The latter are the raw materials that are converted into petrochemical products, which will then be transformed into consumer goods by industries drawn to the region surrounding the Itaboraí-based plant in the state of Rio de Janeiro. It will give added value to Brazilian heavy oil produced in the Campos Basin, which, if exported, would be sold at lower prices abroad than in Brazil, as it is the lighter oils that fetch higher prices on the international market. In addition to this, it will reduce Brazilian import requirements of naphtha, used in the petrochemical complexes of Capuava, Camaçari and Copesul, for example”.

Comperj is the upshot of a joint operation involving Petrobras, Grupo Ultra, BNDES and possibly some other minority shareholders, that will have processing capacity for 150,000 bpd of Brazilian heavy oil. It will bring together various operational stages in a single industrial complex. The initial phase is the First-Generation Refining Unit, or Basic Petrochemical Unit, for the production of basic petrochemical products including ethylene, propylene, benzene and paraxylene. Then there is a series of second-generation units that will transform the basic products into petrochemical products such as styrene, ethylene glycol, polyethylene, polypropylene and PTA, destined for the internal market (70%) and the external market (30%). There will also be a Utilities Plant, responsible for the supply of water, vapor and electrical energy throughout the complex. Lastly, there are the
third-generation or transformation industries drawn to the complex that will set up business in the surrounding area, in order to transform petrochemical products into consumer items, such as cups, plastic bags and components for automobile assembly plants and household electrical goods industries.

Social and environmental responsibility will be implicit commitments in the complex. “From the social standpoint, we will have a minimum impact on the surrounding area and be in a position to guarantee the necessary infrastructure. This is thanks to trade agreements signed with the United Nations Organization, the Federation of Industries of the State of Rio de Janeiro, the Getulio Vargas Foundation, institutions such as the National Industrial Apprenticeship Service and the National Commercial Apprenticeship Service, as well as universities and 11 city halls. Comperj will generate over 200,000 direct and indirect jobs with a knock-on income effect during the construction works, as well as over 50,000 jobs after the complex comes on stream. For this reason, we will train the labor force of the region and the neighboring municipalities to work on construction of the complex and on its maintenance. Working in partnership with city halls, we will create integration centers in all of the municipalities around the complex and train 30,000 professionals in 78 types of free courses. Of these courses, 78% will involve basic instruction, 21% technical level training and 1% university level qualification. The coordination of all training will be in São Gonçalo”, states Paulo Roberto Costa.

In the environmental sphere, there are plans to construct a green belt around the complex and also to plant waterside
woodland vegetation on the riverbanks. The neighboring population will be our partner in these undertakings. “We have already signed an agreement with Embrapa – Brazil’s Agriculture and Livestock Research Company – to oversee the green belt, the maintenance of which will be performed by laborers from the surrounding area, thereby generating even more jobs”, reveals Paulo Roberto Costa. The project coordinated by Comperj itself will also be eco-efficient. It will ensure the reutilization of treated water from the sewage treatment stations and also from the filter cleansing units of the Guandu System, to be used in refining processes, as well as in technological solutions that will reduce water consumption and effluent generation in the complex.

Now that Comperj’s conceptual project has been approved, project detailing is underway, the environmental licenses are expected to be released later this year and assuming that everything goes according to plan, thoughts are already turning towards expansion of the complex after five years of operation. “The location of Comperj was chosen after painstaking study, as it is close to the ports of Itaguaí and Rio de Janeiro and the waterway terminals of our Petrobras Transportes subsidiary in Angra dos Reis, Ilha d’Água and Ilha Redonda. There is also access by highways and railroads and it possesses synergies with our Reduc refinery, the Cenpes R&D unit and the Rio Polímeros petrochemical plant. In addition to this, it is next to an area of 20 million m$^2$ that belongs to Petrobras and can ensure the expansion of the complex,” explains Petrobras’ Director of Supply.

Whatever the case, the fact is that in 2013 the state of Rio de Janeiro – in which the municipality of Itaboraí is situated and Comperj is to be established – and indeed Brazil as a whole will never be quite the same again thanks to this undertaking. It will generate jobs, wealth and opportunities the likes of which have never been seen before that will have a powerful impact on the country’s economy and will leverage its development. Petrobras will have fulfilled its goal of making Brazil grow while also growing in tandem, with social and environmental responsibility as a central concern.
**Comperj Production**

<table>
<thead>
<tr>
<th>Basic petrochemical or first-generation products</th>
<th>Quantity (tons/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethylene</td>
<td>1,300,000</td>
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<tr>
<td>Propylene</td>
<td>880,000</td>
</tr>
<tr>
<td>Benzene</td>
<td>608,000</td>
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<tr>
<td>Paraxylene</td>
<td>700,000</td>
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<table>
<thead>
<tr>
<th>Second-generation products</th>
<th>Quantity (tons/year)</th>
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</thead>
<tbody>
<tr>
<td>Polyethylenes</td>
<td>800,000</td>
</tr>
<tr>
<td>Ethylene Glycol</td>
<td>600,000</td>
</tr>
<tr>
<td>Polypropylene</td>
<td>850,000</td>
</tr>
<tr>
<td>Styrene</td>
<td>500,000</td>
</tr>
</tbody>
</table>

Petrochemical FCC is considered just as important to the Supply area of Petrobras as the records in deepwater exploration and production are to the Exploration and Production area.

**Petrochemical FCC:**

**Comperj’s Technological Leap Forward**

Incorporating state-of-the-art concepts, Comperj will include a pioneering technological process that will represent a major technological leap forward. It is Petrochemical FCC, an evolution of the fluid catalytic cracking process developed and patented by Petrobras’ research and development center - Cenpes.

The new process, which will use fractions of raw Marlim heavy crude from the Campos Basin as its basic ingredient, will render feasible and maximize the direct production of propylene, ethylene and aromatic oils that are basic petrochemical raw materials. Therefore, unlike a conventional refinery, it will not maximize the production of gasoline, diesel and LPG and the priority will not be to produce petrochemical naphtha. There is a scarcity of the latter in national heavy crude oils, which only after being processed leads to petrochemical products.

This new development means that Petrobras will no longer need to export 150,000 barrels per day of heavy oil, which would fetch less on the international market, in order to put it to more lucrative use. Petrochemical FCC has already been field-tested at Cenpes and in the Technological Park of Petrobras’ Schist Industrialization Unit (SIX), where the Company has an FCC prototype-unit.

Petrochemical FCC is considered just as important to the Supply area of Petrobras as the records in deepwater exploration and production are to the Exploration and Production area.
The Oil Curtain - An excerpt from the Hydrocarbon Highway

The Oil Curtain neatly symbolizes resource sovereignty and separates the Hydrocarbon ‘haves’ from the ‘have-nots’. It has led to the major part of proved global oil reserves being booked by National or State Oil Companies*. To illustrate the change of ownership, in 1971 NOCs held 30% of total reserves while IOCs held 70%. Today NOC have increased their share to 93% while IOCs hold 7%¹ - what caused such a dramatic reversal in fortune?

By Wajid Rasheed

Since the early 1900s the importance of oil in financial, political and strategic matters has been bubbling up to the surface. Eventually, this led to a pressing need for producing states to control Oil. Mexico was first to ‘shut’ the Oil curtain by nationalizing its oil assets and forming the wholly state owned Pemex (Petróleos Mexicanos) in 1938². By 1960 resource sovereignty had fully matured into a global force and the Central Bank of Oil³ - OPEC (Organization of Petroleum Exporting Countries) was created.

OPEC’s central message was clear; oil was too important to leave in the hands of foreigners⁴. It would seek to regulate ‘oil-rents’ and end arbitrary payments from foreign oil companies. OPEC’s thinking was shaped threefold. Firstly, deals favored foreign oil companies and foreign governments, not producing states. Foreign oil companies also controlled an outward flow of profits which were often the greater part of producing countries’ GDP. Generally, beneficiaries were foreign governments either directly through shareholder dividends or indirectly through taxes. Secondly, foreigners took vital political decisions affecting the sovereignty of producing countries. Oil production, foreign exchange earnings through oil sales, and ultimately, national debt were unilaterally dictated by foreign oil companies. Lastly, the military and naval campaigns of the Second World War combined with the utility of oil in general transportation left no doubt that oil was a primary strategic asset.

Producing countries were united; the old deals had to be undone. New deals would treat territorial owners of resources and the international oil companies as equals.

Modern National oil policy has come full circle (see Figure 1). It has evolved from seeking equal treatment to maximising royalties to stipulating local content to full

Figure 1 - Oil and Gas Nationalization has come full circle from seeking higher royalties to partial privatization.

Part Privatization – Gas sectors

Stipulating local content

Open Market privatized

Initial low royalties

Certain Foreign Operators

Higher royalties with finds

Nationalization “The oil is ours”

Local capabilities

Local content stipulations
re-nationalization and now to partial privatization for
Gas developments.

**New Seven Sisters**

Nowadays, OPEC decisions get as much ink as those of major central banks. Yet beyond the paparazzi flashes and news-wire headlines, how important will OPEC and NOCs be for future oil supply? Realistically, the production of OPEC and certain NOCs will be vital for several generations to come. To understand that reality, simply look at (see Figure 2) the top ten reserve holders worldwide: Saudi Arabia, Iran, Iraq, Kuwait, UAE, Venezuela, Russia, Libya, Kazakhstan and Nigeria. Seven of these countries - the first six and Libya - are all OPEC members.

To see how important these new Seven Sisters are to future oil supplies, consider the reserves to production column (Figure 2) to see how many of today's top ten global reserve holders are likely to be producers in the EIA Energy Reference Case year of 2030.

At that time, I will be 60 years old and probably writing about the world's next 25 years of oil production. But more to the point of today's top ten reserve holders Russia would have dropped off the list while the new seven sisters and OPEC would still be producing away. Are you wondering where are the other current major producers? Canada has 22.9 years, the US has 11.7 years and Mexico has 9.6 years of oil reserves left at current production rates. Upshot: OPEC and the new Seven Sisters will grow both home and abroad. NOCs may not become global household brands but they have set the trend that restricts IOC access to oil, and lately, the dividing line between the two is not so clear.

**Fuzzy Logic**

The fuzziness between private and state oil companies stems from the NOCs that have 'gone global'. On the one hand for certain companies the logic and returns of going global are compelling; add new production and export 'home-grown' technology. Yet, on the other hand there is the risk of sudden nationalization. Once wellheads, fields, pipelines and refineries are built, they cannot be dismantled and sent back 'home'. In the event of political change or a major dispute the Oil company's bargaining power is effectively reduced. Any share it may have of production can only be sold off to the state concerned – which becomes a question of expedient valuations rather than ownership.
Corporate Social Responsibility

CSR has grown to encompass the building of local capacity that may export technology and know-how, the saving and investment of oil profits into non-oil related industries but essentially it means enfranchising locals in most aspects of the oil company’s business either locally owned or managed.

The politics of revenue distribution can be a potential minefield for Oil companies. They must satisfy the powers that be – state governments—and reconcile the valid needs of local groups whether these are communities that have right-of-way over pipelines or those that live the state that produces oil or gas. If there are competing ethnic groups or a self-perpetuating elite with poverty stricken masses then the oil company is sitting on a time-bomb. Paradoxically, it is the case sometimes that even if Oil companies keep locals happy and build local industries, the government may still nationalize.

What actually constitutes a National or State Oil Company? It is worth focusing here to see what distinguishes the NOC from the IOC. Is it 100% state ownership? Or just a state majority? What if the company floats on the world’s stock markets and has private shareholders yet retains a State majority? Yes to all.

The distinction depends on whoever holds 51% or more of voting shares and controls overall decision making power. If the majority shareholder is a Government or State, the company must answer to them, therefore such a company is defined a National Oil Company. The opposite applies also. If the company’s 51% voting majority is privately held or listed it would be defined as an International Oil Company.

Shareholder distinctions shed light on the responsibilities of each company too. NOCs have a strong responsibility to steward oil wealth to meet the needs of a given nation and its population in a sustainable way. IOCs focus primarily on maximizing returns, social responsibility is important also but not to the same degree as NOCs. Most people in the industry accept that profits must be balanced with social responsibility. Private shareholders generally accept this too. Corporate Social Responsibility (CSR) programs within IOCs are abundant and this type of social spending doesn’t raise investors’ eyebrows as long as returns are healthy. Part-privatized NOCs fall into this category also. Just how much social responsibility is deemed healthy depends on the shareholders. (See boxes above)

Setting Ethical Standards

Why do oil companies set ethical standards? Mainly due to past problems with ‘corruption’ and the lack of transparency which had savaged the reputations of IOCs. They learnt that they were being targeted by savvy lobbyists and environmental activists which could negatively impact their image and share price globally. This coupled with anti-corporate demonstrations even led some IOCs to publish sensitive figures regarding tax payments abroad made to foreign Governments in regard to operating agreements. Further, some Oil companies aligned themselves to protecting human rights by joining the UN World Compact. Legislation such as Sarbanes Oxley in the USA, with its emphasis on due diligence has tightened up and defined the limits of ethical behaviour for companies acting abroad, and this influence has permeated the industry as a whole which generally has high levels of corporate governance.

We speak your language

Notable NOCs such as Petrobras and CNPC operate well beyond their home territories. Both companies not only retain majority government stakes but also raise capital using a canny combination of state finance and international financial markets to develop domestic and foreign reserves. But where they really excel is by competing internationally for capital and upstream acreage and applying their unique technologies and know-how.

Accessing reserves or holding on to them is the producer’s top challenge. Consumption is a given. Subsequently, finance, human resources, and technology can be acquired.

NOCs go global

Naturally then it is a ‘no-brainer’ for NOCs with global ambitions to compete for foreign reserves and production. Entering this competition makes sense for those NOCs such as Petrobras or CNPC that have limited reserves or high production costs at ‘home’ or where they can export ‘home-grown’ technologies abroad. It does not make sense for the new Seven Sisters who have abundant domestic reserves at relatively low production cost. In the latter it makes more sense to stay ‘home’ and develop national reserves. But where do the IOCs fit into all of this?
In the corporate cost-cutting that ensued, locations and operations were rationalized. Many IOC’s consolidated their international operations in Houston. RD, technology activities and technical disciplines were seen as unnecessary fixed costs that could be more profitably outsourced.

**Original Seven Sisters**

A decade ago the price of a barrel of oil languished at US $10. This triggered ‘mergeritis’ and reformed the original Seven Sisters - a term coined by the Italian oil tycoon Enrico Mattei. The original Seven were Exxon (Esso), Shell, BP, Gulf, Texaco, Mobil, Socal (Chevron) - plus an eighth, the Compagnie Francaise Des Pétroles (CFP-Total). During the 1990s the new ‘Prize’ for these companies was finding synergies and economies of scale. Management consultants were set the task of merging these great disparate entities and analysts evaluated the mergers in terms of restructuring and costs.

In the corporate cost-cutting that ensued, locations and operations were rationalized. Many IOC’s consolidated their international operations in Houston. RD, technology activities and technical disciplines were seen as unnecessary fixed costs that could be more profitably outsourced. At that time, only a handful of voices questioned rationalization; it made sense financially and operationally. Ironically, this would strengthen the Oil Curtain and return to haunt IOC’s.

**Outsourcing Technology**

As operators and well profiles became leaner, service companies grew. They were required to contribute more value than ever before; to reduce well cost and optimize performance. IOC’s contracted out technical niches such as Directional Drilling or Reservoir Modelling as well as entire technical disciplines such as drilling or reservoir management. With the advent of outsourcing ‘in-house’ services became the ‘in-thing’. Simultaneously, service companies commercialized projects that IOC’s cast off.

As the industry consolidated, Houston emerged as its capital city and its downtown skyline became synonymous with the global oil business. Today Houston represents the oil consumption capital of the world. The oil production capital lies elsewhere. Characterized by a modest skyline and towering reserves, Dhahran takes that title. Moscow becomes the natural gas production capital and Doha that of LNG. Almaty, Baku, Bushehr, Lagos, Macae, Maracaibo are other emerging oil cities as the industry realigns. The combination of oil technology as a commodity, ascendant oil prices and the realignment of cities has strengthened the Oil Curtain. Ironically as oil production technology becomes freely available on the market so access to oil reserves becomes more restricted.

**Metamorphosis of IOC**

In the old days, IOC’s conferred access and monetized oil reserves. IOC’s alone had the technology, capital and know-how to tap the wealth of an unknown hidden natural resource. Naturally, they bargained hard and got the lion’s share. Those ‘old ways’ show that oil reserve holders used to recognize IOC’s as equals, perhaps, even as holding the upper hand as the IOC’s was required for revenues to be realized’.

Even before the Oil Curtain, some IOC’s noted that the pool of accessible oil reserves would one day shrink. Progressive IOC’s repositioned themselves for the future; some seeing ‘beyond petroleum’ others shut out by the ‘Oil Curtain’. However, this does not imply the fall of IOC’s. Some are perfectly adapted to evolve and there is still a healthy global EP environment for them to adapt to.
The drawback is that this environment of extreme EP has high replacement costs as margins are squeezed by technical challenges (See Figure 3). Extreme EP opportunities exist in ultra-deepwaters, Arctic, Unconventionals and in a dazzling array of Gas-related technologies. These include LNG (Liquefied Natural Gas) which mobilizes and commercializes stranded reserves as well as ‘Bio-Gas’ which is renewable through biologically produced methane. And in Compressed Natural Gas (CNG), Liquefied Petroleum Gas (LPG) that provide fuel for the transport and power-generation sectors. Capping it all, Gas to Liquids GTL offers high quality gasoline fuel. Of the original seven sisters most have already adapted to Extreme EP environment. Going further BP has distinguished itself in LNG and Solar power, and Shell in GTL and Hydrogen.

Undoubtedly IOCs face increasingly challenging operations – extreme EP. Additionally there are a wide-ranging set of challenges such as decommissioning, booking new reserves in a narrowing opportunity base, a lack of EP technology as a differentiator and environmental lobbyists. But perhaps, most of all, nationalization and resource sovereignty, has made business more difficult.

Despite this IOCs retain refineries, retailing networks, brands, and direct access to international consumers. Certain IOCs for example BP and Shell have continued to be early adopters of new technology. That is praiseworthy because by supporting innovative new ideas and signposting applications, these IOCs have significantly contributed to many EP innovations ie rotary steerables and expandables across the industry. Those IOCs took risks to prove tools down-hole and the benefits have been reaped by all types of oil company.

References
Credit should go to BP for compiling the Statistical Review of Energy. Regarding country and global data the issue is that ultimately, all collating organizations must rely on country export/reserves data and to an extent each others data. The statistics therefore incorporate OPEC / OGJ / Non OPEC data and so on. The approach has been to check regional or local data sources but to use the

Figure 3 - Costs for Oil Companies

Note: Net included are finding or development costs or production taxes/sharing agreement quotas. According to the 2008 US EIA DOE information on crude production, averaged over 2004, 2005 and 2006, finding costs ranged from about $5.26/barrel in the Middle East1 to $63.71/barrel for U.S. offshore.
Saudi Aramco

Considered by many to be the world’s largest oil company and the world’s largest NOC, Saudi Aramco controls 1/4 of all world hydrocarbon reserves and plays a vital role in fuelling Saudi Arabia’s socio-economic growth. In this context, Saudi Aramco routinely evaluates its development decisions on a combination of corporate and national contributions. For example, a petrochemical project with a Japanese Chemical company contributes at both these levels by seeking to transform the Rabigh Refinery in Saudi Arabia into an integrated refining and petrochemical complex. The evaluation showed that although Rabigh would be profitable, it was not the most profitable investment opportunity that Saudi Aramco was considering. However, what Rabigh provided was “the most combined value to the company and the nation”. The national component means that Saudi Arabian society will benefit from the foreign investment, the new jobs created and additional revenues. The corporate component means that Saudi Aramco will extend its petroleum value chain, upgrade oil processing and making its portfolio more profitable.

In the area of key performance indicators Saudi Aramco’s approach is to use IOC yardsticks in order to be best-in-class in areas such as finding and lifting costs, corporate governance and financial discipline.

PdVsa - Venezuela

For Venezuela’s Pdvsa sustainability is stated as being central to its existence. Its definition of sustainability considers oil and gas resources from both a production and consumption perspective. PdVsa’s stated policy is to regulate production of oil and gas so that EP is optimized while certain blocks are conserved for the benefit of future generations of both consumers and producers. Its central belief is that because Oil is a finite natural resource, producing countries must exercise the sovereign right to regulate production levels so that benefits accrue to current and future generations of indigenous people. PdVsa also sees its role as educational and to show consumers that oil is not a commodity that operates according to free market rules. Pdvsa recognizes that stability should exist in the market but this can only occur if there is political, economic and particularly social stability. It also asks consumers to consider whether they are consuming energy in an efficient way. For Pdvsa sustainability must include policies of integration that allow poorer countries to have access to oil and gas. This has been the reasoning behind the Petrocaribe initiative by which Venezuela supplies 200,000 bopd to more than 20 of the smallest countries of Latin America and the Caribbean under special financing. For Pdvsa “unrestricted access to (the) energy is not the same thing as sustainable access”. The company views the current model as consumers demanding unrestricted access to natural resources but not allowing resource holders to improve the socio-economic standing of their people. According to the company this model is characterized by infrastructure bottlenecks resulting from decades of under-investment caused mainly when IOCs held unrestricted access to reserves. Pdvsa’s view is that sustainability of access must mean that poor countries should be able to access sustainable energy sources.

BP SR 2008 as a reference point - see pages 6 and 8 for Global Proved Reserves and Production respectively.


2. The seeds of Nationalization had been sown by Mexico in 1934 when it led a hostile takeover of the shareholdings of foreign oil companies operating in Mexico creating Pemex in 1938 - the first ‘Nationalized Oil Company’. It can be said that BP or Anglo Persian was the first National Oil Company but this was taken over by the British government from British shareholders rather than foreign ownership. Mexico was followed by Venezuela and Iran who nationalized their hydrocarbons.

3. OPEC Bulletin 2007-8 Undoubtedly, production is one end of a transaction; refineries and consumers are needed too.


5. Undoubtedly, every move made by OPEC is watched by the major newswires who have assigned some of their brightest minds to cover the decisions that usually come out from the Austrian capital. The wires cover these
Petrobras

‘The oil is ours’ reads a sign as you leave Rio de Janeiro on the road to the oilfield city of Macae. That sign is not a historic throwback or juvenile street graffiti, but a modern official billboard paid for by the Brazilian Government. Its nationalistic message is that oil, and oil wealth, are too important to be left to foreigners and external market forces. The tightrope that Petrobras must walk is balancing the interests of two very different kinds of shareholders. The Brazilian government still owns a majority 51% of ordinary shares while the remainder is held privately. This kind of balancing is ultimately made easier because from both a medium and long term perspective, Petrobras is in an enviable position. It has helped the country reach self-sufficiency and added reserves, while growing its operations in the international arena, especially the US.

- Reserves (SEC criterion): 11.7 billion barrels of oil and gas equivalent (boe)
- Productive Wells: 14,194
- Production Platforms: 109 (77 fixed; 32 floating)
- Daily Production: 1,918 barrels per day (bpd) of oil and LPG
- 382,000 barrels of oil equivalent of natural gas per day

China National Petroleum Corporation (CNPC)

CNPC, China’s flagship oil company plays an important role in China’s oil and gas production and supply. Its oil and gas production account respectively for 57.7% and 78.3% of China’s total output. CNPC is also a global player with EP projects in Azerbaijan, Canada, Indonesia, Myanmar, Oman, Peru, Sudan, Thailand, Turkmenistan, and Venezuela.

CNPC has bet heavily on R&D to increase EP production and reduce risk in complex basins. It has developed solutions to improve recovery factor as well as reduce development costs. It has a strong sense of innovation and has technologies in reservoir characterization, as well as polymer and chemical-flooding. Other technologies include high-definition seismic, under-balanced drilling, ultra-deep well drilling rigs and X80 high-tensile steel pipes. According to the company, by the end of 2007, CNPC had acquired 7,010 patents out of its 9,693 patent applications.

It holds proved reserves of 3.7 billion barrels of oil equivalent.
- Oil production: 2.75 million barrels of crude oil/day
- Gas production: 5.6 billion cubic feet/day
- Oil reserves: 3.06 billion metric tons
- Gas reserves: 2,320.1 billion cubic meters

events pursuing the heads of delegation and hanging on any word or gesture in the same way celebrities are pursued by paparazzi.

6. The “New Seven Sisters” - 11th March 2007, the Financial Times redefined the “New Seven Sisters”: as the most influential and mainly state-owned national oil and gas companies from outside the OECD. They were: Saudi Aramco (Saudi Arabia), JSC Gazprom (Russia), CNPC (China), NIOC (Iran), PDVSA (Venezuela), Petrobras (Brazil) and Petronas (Malaysia). In terms of Oil reserves the major reserve holders are more influential than Gazprom, CNPC, Petrobras and Petronas who are influential in their own rights ie Gas, Technology and Internationalization respectively. A variant exercise would be to use market capitalization for top ten NYSE listed Oil companies, where organizations such as Petrobras and CNPC appear.


9. Rasheed, Wajid; Brazil Oil and Gas 2006 Issue 4 – Black Blessing.


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Preference is given to articles that are Oil Company co-authored, peer reviewed or those based on Academic research.

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### Bonus Circulation

- **MEOS**
  - March, 15-18, 2009
  - Kingdom of Bahrain

- **IADC/SPE**
  - March, 17-19, 2009
  - Amsterdam, The Netherlands

- **OTC**
  - May, 4-7, 2009
  - Houston, Texas

- **SPE/LACPEC**
  - May, 31 - 3 June, 2009
  - Cartagena, Colombia

- **SPE EUROPEC/EAGE**
  - June, 8-11, 2009
  - Amsterdam, The Netherlands

- **Brazil Offshore**
  - June, 16-19, 2009
  - Macae, RJ, Brazil

- **Offshore Europe Oil & Gas Conference & Exhibition**
  - Sept, 8-11, 2009
  - Aberdeen, UK

- **Rio Pipeline**
  - Sept, 22-24, 2009
  - Rio de Janeiro, Brazil

- **ATCE - SPE Annual Technical Conference and Exhibition**
  - Oct, 4-7, 2009
  - New Orleans, Louisiana, USA

### Special Publications

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