Why integration, along with technology and partnership, is emerging as a business imperative on oil and gas projects
INTRODUCTION

SEEING THE BIGGER PICTURE

Today’s global energy system is hugely complex and fast changing. It comprises numerous energy sources, technologies, stakeholders and end-users, with huge regional variations and complex webs of interdependency.

Take, for instance, the boom in unconventional gas in the USA. Its effects have reached far beyond the shores of North America because it has freed supplies of liquefied natural gas for use in other parts of the world. Now, we are seeing operators in the USA taking advantage of low-cost natural gas to generate the hydrogen that they require to upgrade heavy oils, including tight oil.

Meanwhile, other regions are also keen to exploit their own indigenous resources in the most cost-effective and environmentally responsible way. Technology is often key. In China, for instance, coal gasification technology offers a compelling route to producing syngas for conversion to chemical products.

Feeds, however, are not getting any easier to process. The Middle Eastern gas fields that have highly complex gas compositions are a case in point; these cannot be readily monetised owing to the presence of impurities such as carbon dioxide (CO₂), hydrogen sulphide (H₂S), mercaptans (RSH) and mercury. And the gas processing plants designed to remove these contaminants are subject to increasingly stringent emission limits. Nevertheless, there are examples of organisations that have found ways to meet their environmental mandate, such as Petroleum Development Oman (PDO) at Yibal Khuff.

The challenges facing refiners are not dissimilar. To be competitive, many are processing discounted crudes, which typically have a high sulphur content. During the refining process, this is converted to H₂S and sulphur dioxide (SO₂) but special precautions must be taken to limit the atmospheric release of these gases.

Several countries, most notably China, India and Russia, are embarking on programmes for cleaner transportation fuels. As Europe, the USA and Japan have already been down that path, their experience should be exploited. So, expect to see hydroprocessing unit revamps along with new hydrotreater and hydrocracker installations, combined with solvent deasphalting units or cokers.

Times have been tough for refiners, but there are numerous success stories involving companies that continued to invest in upgrading their assets through the economic downturn, and who are now reaping the rewards.

There has been a lot of interest lately in building highly efficient, mega-scale refineries that use the latest technology and have a large conversion capacity. But we would always advise caution to an executive considering such a development, as this is rarely the optimum solution. Refiners can often achieve better payback with less risk by improving or upgrading their existing assets. There are usually many low-hanging fruit they can recover.

Shell is perhaps the only technology licensor that has technology and expertise in the three main hydrocarbon-based energy sources: crude oil, gas and coal. This can be useful when, for instance, governments are exploring their energy diversification options or when investor projects involve multiple feeds. For example, a project to develop a gas processing plant could benefit from an integrated plan to handle the associated condensate. Seeing the bigger picture can help to make sense of the highly complex global energy system in which we all operate.

Kelvin Halliwell
Global General Manager for Gas Processing and Gasification, Shell Global Solutions International BV

Süleyman Özmen
Vice President, Refining and Chemical Licensing, Shell Global Solutions International BV
A report by the management consultancy AT Kearney has warned that one in three refineries in North America and Western Europe will need to reconsider their operating models in order to remain competitive. And with refiners in other regions facing their own array of challenges, the report cautions that, in this shifting landscape, refining excellence is a prerequisite. In this article, we look at two possible scenarios for meeting these challenges.
As they strive to remain competitive against the new breed of world-scale, highly efficient refineries under construction in Asia and the Middle East, many refiners are looking for ways to process discounted crudes and provide higher-value products. Meanwhile, air quality standards and product specifications continue to tighten around the globe, which makes it increasingly difficult for refiners to meet their environmental mandate and secure their licence to operate.

Clearly, many technological solutions could help them to meet these objectives, but enormous value is at stake when trying to identify the most appropriate solution for a specific situation.

To demonstrate this, we have devised two fictional scenarios called “flexibility/upgrading constrained” and “capacity/quality constrained” (see below). Although both refineries are fictional, they are representative of many facilities operating today.

<table>
<thead>
<tr>
<th>SCENARIO</th>
<th>A: FLEXIBILITY/UPGRADING CONSTRAINED</th>
<th>B: CAPACITY/QUALITY CONSTRAINED</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scale</td>
<td>World scale (30 Mt/y)</td>
<td>Medium scale (20 Mt/y)</td>
</tr>
<tr>
<td>Complexity (NCI)</td>
<td>7</td>
<td>14</td>
</tr>
<tr>
<td>Market situation</td>
<td>Weak state regulation of fuel quality and standards</td>
<td>Increasing state regulation of fuel quality and standards</td>
</tr>
<tr>
<td>Feed flexibility</td>
<td>Refinery scheme enables processing of only light to medium crude oils</td>
<td>Refinery scheme enables processing of even the most difficult crude oils</td>
</tr>
<tr>
<td>Operational flexibility</td>
<td>Limited conversion capacity with little or no flexibility to adapt to seasonal product demand shifts</td>
<td>Ability to swing between the gasoline mode and the distillate mode</td>
</tr>
<tr>
<td>Primary conversion</td>
<td>FCC</td>
<td>Delayed coking, hydrocracking</td>
</tr>
<tr>
<td>Secondary processes</td>
<td>Alkylation, hydrotreating</td>
<td>FCC, alkylation, reforming, coking</td>
</tr>
<tr>
<td>Product slate</td>
<td>Gasoline, diesel and fuel oil</td>
<td>High percentage of diesel, jet and gasoline, along with fuel-grade petroleum coke</td>
</tr>
<tr>
<td>High-value product yield (%)</td>
<td>75</td>
<td>87</td>
</tr>
<tr>
<td>Business objectives</td>
<td>Increase upgrading capability</td>
<td>Comply with increasingly stringent emissions standards and meet tighter product quality specifications</td>
</tr>
</tbody>
</table>

“AS THEY STRIVE TO REMAIN COMPETITIVE AGAINST THE NEW BREED OF WORLD-SCALE, HIGHLY EFFICIENT REFINERIES UNDER CONSTRUCTION IN ASIA AND THE MIDDLE EAST, MANY REFINERS ARE LOOKING FOR WAYS TO PROCESS DISCOUNTED CRUDES AND PROVIDE HIGHER VALUE PRODUCTS.”
In the capacity/quality-constrained scenario, a highly complex, medium-scale refinery is contending with increasingly stringent environmental regulations. With both a hydrocracker and a fluidised catalytic cracking (FCC) unit in the line-up, it benefits from highly flexible assets that enable it to process difficult feeds and to adapt its product slate in response to market demand. Its current principal business objectives are to comply with new, stringent emissions standards that are on the horizon and also to meet tighter product quality specifications.

The other scenario, flexibility/upgrading constrained, features a larger facility but, because it has less-demanding product specifications and air quality standards to meet, its Nelson Complexity Index (NCI) is lower. It also has less feed flexibility; it can upgrade only light or medium crude oils. With only an FCC unit as the main conversion vehicle, it has limited conversion capacity and its current principal business objective is to increase its upgrading capability.

**SCENARIO A: FLEXIBILITY/UPGRADING CONSTRAINED**

This refiner has expressed a desire to increase its upgrading capacity. However, before identifying capital projects that will help to achieve such goals, Shell Global Solutions always recommends that refiners should first focus on maximising the value of their existing assets, as proposed in the Shell Global Solutions Multiplatform Pentagon Model. Maintenance and reliability studies, energy management projects and hydrocarbon management reviews, which do not require capital expenditure, are likely to come into play here. These are short-term initiatives, and can help to fund the medium-term capital projects that follow.

How do you select which longer-term projects to embark on? An experienced strategic licensor might be drawn to one indicator of a lack of value: the level of refinery bottoms (which in this case is 100% – 75% = 25%). With some very brief, indicative calculations we can calculate how much value the refiner is failing to capture by not converting the bottom of the barrel to high-value products.

We will assume a figure of $30/bbl for the light–heavy differential, a term that describes the difference in margin between high-value (light) products such as gasoline and diesel, and low-value (heavy) products such as fuel oil and bitumen. Of course, this uplift potential varies on a daily basis, but $30/bbl is a reasonable ballpark figure to use.

Next, if we assume that 1 t of crude oil = 7.3 bbl (with a specific gravity of 33 API) then the refinery’s capacity, 30 Mt/y, can be also expressed as 219 MMbbl/y.

This means that the plant currently generates 164.25 MMbbl/y of high-value products and 54.75 MMbbl/y of low-value products. Running the calculations with those capacities and prices, reveals that every percentage point by which the refinery can reduce its bottoms (and, therefore, increase its yield of high-value products) could add up to $65.7 million to its bottom line (although, of course, the refinery’s energy costs would also increase in line with the increase in upgrading).

To capture at least some of this value, the flexibility/upgrading-constrained refinery may investigate reducing its bottoms (vacuum gas oil and short residue). Options to consider may include:

- thermal cracking, visbreaking or delayed coking;
- solvent deasphalting;
- hydrocracking; and
- gasification.

Determining the most appropriate technology option requires a much closer look at the refinery’s economics, local regulatory environment and market trends. For instance, owing to the oil–gas price disconnect that has emerged in recent years, liquid residue gasification is, generally speaking, uncompetitive at the moment in some regions, especially Europe and the USA, although it remains attractive in others.

All of these technology options should be rigorously tested against several different economic, regulatory and market outcomes. This can be key to avoiding regret solutions and is an area in which experience is key. This is the objective of the Shell Global Solutions value creation architecture (VCA), see box page 6.

**SCENARIO B: CAPACITY/QUALITY CONSTRAINED**

Although the fictional refineries shown in scenarios A and B have very different circumstances and the eventual solutions are also likely to be very different, the process that they both work through should be broadly similar. So, as in scenario A, this refiner would be advised to start by ensuring that it is maximising the value of its current assets.

This may involve ensuring operational reliability, pushing capacity and optimising the crude slate so that it can achieve the highest product values from the lowest feedstock prices.
Like the previous scenario, there is a wide range of longer-term options that could help the capacity/quality-constrained refinery to achieve its business objectives of complying with increasingly stringent emissions standards and meeting tighter product quality specifications.

For instance, the options to be investigated could include:

- optimising the integration between the hydrocracker and FCC unit, including feedstock distribution between the two units and hydrocracking conversion;
- revamping the hydrocracker to increase conversion and, therefore, produce less FCC feed and more middle distillates;
- refilling the hydrocracker with next-generation catalysts and installing state-of-the-art reactor internals;
- installing a new hydroprocessing unit to help comply with tighter product specifications;
- upgrading low-value streams such as light cycle oil or thermally cracked gas oil from fuel oil into diesel; and
- upgrading naphtha from gasoline into chemicals (aromatics or propylene).

The VCA provides the platform for Shell Global Solutions’ diagnostic and collaborative way of working. It comprises the following elements:

- **External pressures**: What does the competitive landscape look like?
- **Owner’s objectives**: What is the organisation striving to achieve?
- **Licensors’ perspective**: A strategic licensor with operational experience can bring expertise and perspectives that help to create a deep level of understanding of an owner’s business challenges.
- **Owner’s perspective**: The value of the expertise and experience that exist within a customer’s organisation should never be underestimated. Nobody understands their business or their processes better than they do.

- **Value creation**: What projects will help the owner to achieve its objectives? Typically, there are many. Improvements are possible right across the value chain, from crude evaluation and procurement through operations and processing to investment planning. Experience can help to identify the widest possible technical solution set.
- **Optionality**: There are usually many ways to deliver a solution. For instance, if the objective is to enhance the yield of high-value products, the refiner should evaluate the benefits of a unit revamp, the possibility of upgrading existing hardware and the feasibility of building a new unit.
- **Sustainability**: This area of the VCA is designed to help prevent regret decisions. It considers whether the decisions taken reflect the current market situation, the refiner’s longer-term objectives and the potential future market conditions.
- **Execution**: It is imperative that the plant starts up on time and on budget, and works in concert with all the existing pieces of hardware and the interfaces that make the current refinery work so well.
- **Co-created solution**: Customers benefit from the VCA because it brings together distinct viewpoints that help to provide a fundamentally better understanding of their problem or situation. It also ensures that the widest possible technical solution set is evaluated so that truly effective, no-regret solutions can be devised.
When installing new hydroprocessing units to comply with tighter product specifications, the treating systems, utility systems and logistics infrastructure can often be a key constraint. It is likely that the refinery will have to handle \( \text{H}_2\text{S} \) and ammonia, which will require additional capacity in the sulphur recovery unit (SRU) (Claus/SCOT™), sour water strippers and wastewater treatment plants. The refinery’s import/export facilities and tank allocation scheme may also need to be adapted.

As with scenario A, all of the options above must be screened against potential future economic, regulatory and market outcomes in order to ensure that the most robust project is selected. Again, this is the objective of the Shell Global Solutions VCA. In recent years, Shell Global Solutions has been involved in projects that exploit many of these options and that have delivered strong results.

**VALUE CREATION ARCHITECTURE (VCA)**

In this article, we have presented two simplistic, but typical, refinery scenarios. In both, there are numerous potential solutions to the same problem.

At Shell Global Solutions, we believe that the precursor to added value is the ability to tailor the solution to the particular nuances of the problem. Every organisation’s marketplace and asset portfolio are unique; what is an appropriate solution for one refiner may be sub-optimal for another.

This is the basis of the Shell Global Solutions VCA (see left): a methodology that guides our approach to technical collaboration and helps to merge the owner’s highly valuable site-specific knowledge and marketplace perspectives with our global operational and technical expertise. The articles on the following pages demonstrate how we have applied this methodology in practice.

**Süleyman Özmen**
Vice President, Refining and Chemical Licensing, Shell Global Solutions International BV

CANSOLV is a Cansolv Technologies Inc. trademark.
SCOT is a Shell trademark.

**COMMON SOLUTIONS**

**Revamp or grassroots unit?** Estimates suggest that new capacity is about 25% less expensive to install through a revamp than with a grassroots unit. Moreover, the gestation period for a revamp is far less than the three to four years it takes to deliver a major project.

**Looking to increase diesel yield?** Refilling a hydrocracker with next-generation catalysts can often be a compelling solution. A new hydrocracking catalyst, Advanced Trilobe Xtreme, from Criterion Catalysts & Technologies can increase diesel yield by up to 1.5%. So, a 50,000-bbl/d hydrocracker could produce as much as an extra 750 bbl/d simply by adopting one of these catalysts, which are trilobal rather than cylindrical.

**Striving for ultra-high levels of sulphur recovery?** When sulphur recovery levels of up to 99.99% are required, the CANSOLV™ tail-gas treating plus (TGT+) system can be an attractive solution. It offers a simplified process line-up (compared with conventional line-ups used to treat complex gases) with centralised treating of all sulphur-containing process off-gases.

"**WE BELIEVE THAT THE PRECURSOR TO ADDED VALUE IS THE ABILITY TO TAILOR THE SOLUTION TO THE PARTICULAR NUANCES OF THE PROBLEM.**"
CO-CREATE. INTEGRATE. INNOVATE

EXPLOITING REFINERY AND PETROCHEMICAL INTEGRATION

How joined-up thinking is capturing synergies between refineries and chemical plants

Amid the growing number of mega-scale refineries under construction, especially in the Middle East and China, there is a noticeable trend for many to be built next to and closely linked with a petrochemicals facility. And this trend is not restricted to grassroots facilities; numerous existing refineries are finding ways to enhance the level of integration that they have with a petrochemical neighbour.

Süleyman Özmen, Vice President, Refining and Chemical Licensing, Shell Global Solutions International BV, explains the premise. “There are often optimisation opportunities across the refinery–petrochemicals interface. Some refineries are sending hydrocracker residue to the steam cracker to make ethylene, for example, thereby enhancing the economics at both sites. Some refiners are also tuning their fluidised catalytic cracking units to maximise propylene for polypropylene production.”

Shell’s approach is to run the entire hydrocarbon chain, from the refinery through to the chemical crackers and derivative plants, as a single, optimised operation. This can help to maximise the value to the overall enterprise, rather than just to an individual unit.

Aslam Moola, New Business Development Manager, Shell Chemicals, says that most of the integration value comes from directing hydrocarbons to the highest-value application, irrespective of traditional refining–chemical boundaries. “Secondary or by-product streams from refining units may have their highest value as feedstock for chemical units,” he says. “Likewise, by-products from chemical units may be most cost-effective as refinery feeds or fuel blending components.”

Shell has had great success in capturing these synergies at several sites worldwide. These include Norco in the USA, and Pernis and Moerdijk in the Netherlands. Perhaps the highest profile example, however, is the Shell Eastern Petrochemicals Complex investment project in Singapore, which created a world-scale, fully integrated refinery and petrochemicals hub from new and existing assets.

This project involved the installation of an ethylene cracker, a butadiene unit and a monoethylene glycol plant on Jurong Island, a major petrochemical zone, and their full integration with Shell’s Pulau Bukom refinery. The refinery was upgraded so it produces a variety of feedstocks for the cracker ranging from liquefied petroleum gas to heavy liquid hydrocarbons such as hydrowax, thereby enabling Shell to change feedstocks on the basis of market economics. It also provides greater security of supply for customers.

Although this project unlocked synergies in terms of feedstocks, operations and logistics, some analysts view refinery–petrochemical integration less favourably because of the volatility of petrochemical prices. However, Bakhit Al Rashidi, Deputy Managing Director, Planning and Local Marketing, Kuwait National Petroleum Company, recently described it as not an option but a necessity. “Cyclic trends in refining margins and a thin band of margin operation for overall profitability make integration essential to even out the margin vagaries,” he says. “All new refinery projects essentially incorporate integration with petrochemicals because much greater savings in investment and operating costs will result.”
STRAIGHT TALK
ON REFINERY–PETROCHEMICAL INTEGRATION

When the hydrocracker at Shell’s Pernis refinery was approaching the end of its cycle, the unit’s technologists evaluated installing a new cracking catalyst that promised greater yields of high-value middle distillates such as ultra-low-sulphur diesel (ULSD) and kerosene. However, any such change could have had adverse effects on Shell’s nearby Moerdijk petrochemicals facility, which takes hydrowax (unconverted oil) as a steam cracker feedstock (Figure 1).

If the new catalyst caused the hydrogen content of the hydrowax to decrease then the steam cracker’s ethylene yield or the furnace’s run length would have been severely curtailed, and so the technologists were keen to ensure that their new catalyst system could maintain the hydrowax quality as well as improving the middle distillate yield.

Although taking such an integrated approach added substantial complexity to the catalyst selection process, post-project calculations show that it has enhanced the combined economics of Pernis and Moerdijk by some $5 million a year. In this interview, three of the unit’s technologists discuss the steps they took to ensure that the new catalyst system had a positive effect at both sites.

DISCUSSION PARTICIPANTS

JEROEN GROENHAGEN, Senior Technologist, Shell Pernis, was responsible for the catalyst selection study, and loading and starting up the hydrocracker after the new catalyst package’s installation.

BASTIAAN VAN HASSELT, Hydroprocessing Team Leader, Shell Pernis, has 15 years’ experience in hydrocracking and played a key role in the project.

JELLE SIETSmA, Hydrocracking Technologist, Shell Pernis, was involved in loading, starting up and monitoring the hydrocracker after the new catalyst package’s installation.

Figure 1: High-level block scheme showing the integration between the hydrocracker and the steam cracker.
Q: How did you evaluate the impact of the new catalyst?

Groenhagen: We performed a catalyst selection study. However, such studies usually only consider improving the kerosene and gas oil outputs, the level of conversion and the cycle length. Here, we had another level of complexity because we also had to consider the integration aspect: the quality of the hydrowax was an important parameter.

Van Hasselt: We could have simply tuned the catalyst package to improve middle distillate yield, which is the goal for most refiners, but we needed to consider the bigger picture. The hydrogen content of the hydrowax was particularly important because it determines the ethylene and pitch yields, and the furnace run length. If our new catalyst were to alter the hydrowax’s hydrogen content, this might adversely affect Moerdijk’s economics, so we had to find a balance.

Q: What catalyst have you installed in the unit?

Sietsma: The unit has a completely new cracking catalyst from Criterion Catalyst & Technologies called Z-FX10, which uses a special zeolite technology designed to increase middle distillate yield, product quality and catalyst stability.

Van Hasselt: In the pretreatment section, where we remove the impurities that could poison the sensitive cracking catalyst, we have a carefully designed combination of demetallisation, hydrodenitrogenation and hydrodesulphurisation catalysts. Criterion tuned the pretreatment section to ensure that we achieve the right cycle length and quality.

Q: As this was the catalyst’s first commercial application, what steps did you take to verify how it would perform in your unit and with your specific feed?

Groenhagen: We ran a full pilot-plant testing programme at the Shell Technology Centre in Amsterdam, the Netherlands, to compare the novel cracking catalyst with the existing catalyst. This was important because it gave us confidence that the catalyst package would deliver what it was designed to.

It also verified the quality of hydrowax that we would be sending to Moerdijk. This was vital because the lower the hydrogen content in the hydrowax, the more easily the furnaces in the steam cracker coke up.

Even the slightest deterioration in hydrowax quality can have a huge impact on ethylene yield, furnace run length and coke make, so we really needed to understand that parameter’s behaviour over the run length of the catalyst and what it would mean in margin or dollar terms.

Q: How has the catalyst been performing?

Sietsma: When we first started up, the catalyst was slightly more selective towards middle distillates than anticipated. Criterion helped us to fine-tune the process conditions and, within a short time, the unit was meeting the performance guarantees.
Van Hasselt: We are now nine months into the cycle, and so far it has performed very well. The catalyst has been delivering on-specification products, increased middle distillate yield, and there have been no surprises.

Q: How valuable has the project been for both plants?
Sietsma: At Pernis, we have been able to maximise our middle distillate yield: we now make more kerosene and diesel than before, and less naphtha, while operating at a similar conversion severity.

There are clear advantages for Moerdijk too. Because we were able to optimise the hydrowax quality for their specific processes, they have been able to enhance the ethylene and pitch yields, and maximise the furnace run length.

By balancing the objectives of both units, we have enhanced Shell’s overall margin, we call this enterprise economics, by some $5 million per year.

Q: Because there is a clear trend across the industry towards refinery–petrochemical integration, other plants may find themselves in a similar situation to you. What advice would you offer to them?
Groenhagen: Align the economics that you use: that is really important. Normally, when we do catalyst selections, we only look at the refinery impact and that is relatively straightforward, especially because we have our own economic models to use. However, if the refinery site model is not connected to the petrochemicals site model, you have to be extremely careful.

Sietsma: If there is anything unusual about your application, whether it is an unusual feed or a novel catalyst, for example, you might want to consider pilot plant tests as part of your management of change process. These can give substantial insights into how the catalyst package will perform in the commercial facility and minimise the risk of surprises when you start up.

Van Hasselt: Engage all of your stakeholders and do it as early as possible. This was key to the success of our project. Because we brought all parties in at the right time, they have been extremely co-operative and the project has delivered enormous value for the two sites.
Refineries worldwide may increasingly face mandates to recover at least 99.98% of the sulphur present in their feedstocks and to limit SO₂ emissions to less than 100 ppm. The challenge facing Venezuela’s national oil company, Petróleos de Venezuela SA (PDVSA), is perhaps more difficult than most because the country’s crude oils are especially heavy and sour. Nevertheless, on completion of an important expansion project, its El Palito refinery expects to be able to meet these stringent regulatory requirements. Moreover, PDVSA’s journey may offer valuable insights for other refiners.

PDVSA’s expansion of the El Palito refinery in Carabobo is part of the organisation’s drive to strengthen its asset base so that it remains highly relevant to today’s global oil markets. The objectives of the project, which is now at the detailed engineering phase, are to double the refinery’s capacity, enable processing of the abundant heavy crude oil produced from the Orinoco Belt of the country and increase the production of cleaner fuels.

PDVSA has received funding for the project on the condition that it achieves the World Bank limits of 99.98% sulphur removal and 150 mg/Nm³ (approximately 100 ppm) atmospheric release of SO₂. These requirements are substantially more challenging than those specified by many local regulators; for example, the United States Environmental Protection Agency limit for SO₂ content is typically 250 ppm.

Shell Global Solutions worked with PDVSA to design a refining configuration that would help the refiner to meet its objectives. To enable the production of diesel and gasoline meeting stringent sulphur targets, the team opted to add two new hydrotreaters. However, state-of-the-art sulphur-removal technologies will also be necessary.

The hydrotreating units are designed to remove impurities such as sulphur and nitrogen from two distinct fractions: the heavy oil and diesel streams. The resultant H₂S will be sent to the SRU, where it is partly burned to form SO₂ and water. The SO₂ reacts with more H₂S to form sulphur and more water. Two distinct streams emerge from the SRU: sulphur, which is cooled to a liquid, and gases, which are sent for further catalytic conversion.

The liquid sulphur recovered from sour crudes contains dissolved H₂S, which could be problematic if it were to leave the liquid sulphur and accumulate. There would be the
possibility of explosion or of the gas reaching a lethal (>10-ppm) concentration. Consequently, the H₂S in the sulphur has to be reduced to a lower level, and this is envisaged to be supported by using Shell Global Solutions’ degassing technology.

In many facilities, the H₂S that the degassing units recover is disposed of in an incinerator. However, the lower limits that apply to the PDVSA projects mean that this option is unavailable. Shell Global Solutions’ solution involves degassing the sulphur and returning the H₂S to the front of the SRU for a second cycle.

Limiting the atmospheric release of SO₂ to below 100 ppm was especially challenging because a conventional Shell Claus off-gas treating (SCOT) unit would typically be unable to meet this specification, so Shell has devised a solution that features Low-Sulphur SCOT (LS SCOT) technology as part of the sulphur recovery complex. This is Shell’s most advanced sulphur-removal technology and will help PDVSA to meet the tight World Bank limits.

The complex at the refinery will consist of an integrated SRU, a tail-gas unit, a sulphur degasser, an acid gas removal unit (AGRU) and a water-stripping unit.

PDVSA has commissioned a similar project at its Centro de Refinación de Paraguán refinery complex, which is an amalgamation of the Amuay, Bajo Grande and Cardón refineries. With a refining capacity of 940 MMbbl/d, PDVSA claims that this is the largest refining centre in the world: it accounts for more than 70% of the Venezuela’s refining capacity.

Again, Shell is licensing hydrotreaters and sulphur-removal technologies to help the complex to process more Venezuelan crudes and comply with tight World Bank limits. Shell is currently working on the basic design package for this project.

The projects at El Palito and Centro de Refinación de Paraguán have been vital in helping PDVSA to meet its business objectives and demonstrate that it is possible for refiners to achieve extremely high levels of sulphur recovery and very low levels of SO₂ emissions.

Pankaj Desai
Licensing Sales Manager, Americas, Shell Global Solutions (US) Inc.

THE HYDROTREATING UNITS ARE DESIGNED TO REMOVE IMPURITIES SUCH AS SULPHUR AND NITROGEN FROM TWO DISTINCT FRACTIONS: THE HEAVY OIL AND DIESEL STREAMS.

---

**SCENARIO**

<table>
<thead>
<tr>
<th>Refinery</th>
<th>El Palito</th>
</tr>
</thead>
<tbody>
<tr>
<td>Owner</td>
<td>Petróleos de Venezuela SA</td>
</tr>
<tr>
<td>Location</td>
<td>Carabobo, Venezuela</td>
</tr>
<tr>
<td>Refining capacity</td>
<td>140 MMbbl/d rising to 280,000 MMbbl/d on project completion</td>
</tr>
</tbody>
</table>

**Objectives**

- Increase capacity
- Achieve 99.5% sulphur recovery efficiency
- Comply with 100-ppm SO₂ emission limits
- Process difficult crudes
- Produce cleaner, high-value fuels

**Solution type**

New units

**Conversion facilities to be installed**

Hydrotreating units

**Sulphur recovery facilities to be installed**

SRU, tail-gas unit, sulphur degasser, acid gas removal unit and water-stripping units

**Post-project feed**

Heavy and extra-heavy crudes from the Orinoco Belt

**Post-project product slate**

Euro V diesel and low-sulphur gasoline
The environment is a key issue on the agenda of governments around the world – and refiners are right on the front line. They have a major role to play, not only in delivering the cleaner fuels that society is calling for but also in curbing plant emissions.

Despite having a strong track record of applying innovative solutions to meet environmental legislation, a South-East Asian refinery faced a particularly severe challenge in 2006. The regulator that sets the environmental emissions limits for the country’s industrial facilities had indicated that the refinery’s emission limits were going to be acutely curtailed. The regulator had been reducing SO₂ emissions limits by 15% every three years, but now it was warning of a step change. It was going to adopt the World Bank guidelines of 500 mg/Nm³ for fuel burning equipment and 150 mg/Nm³ for SRUs. As the SO₂ emissions from the SRUs were, at the time, substantially higher at about 30,000 mg/Nm³, this would require a change in operating philosophy.

The refinery was already operating close to its current limits, so much so that it had to process more expensive, low-sulphur crude to avoid exceeding its limit.

The challenge was exacerbated because the refinery had plans to install a new hydodesulphurisation unit to produce ULSD, as even better sulphur recovery capabilities would be required.

Moreover, sulphur was not the only challenge. Although the plant’s carbon monoxide (CO) emission limit was unlikely to change, the plant had difficulty meeting its existing CO emissions limit because of the gas treating configuration at that time. Any solution would have to factor this in as well.

The refinery’s response was to commission a sulphur master plan study. This involved site technologists, and gas processing specialists and process engineers from Shell Global Solutions. Working closely as an integrated on-site team, they conducted brainstorming sessions and technology selection studies before delivering detailed proposals for how the refinery could reduce its sulphur emissions. The team also spearheaded the implementation of these proposals, including the installation of new units.

Divergent thinking was a recurring theme of these early phases. The team invested a lot of effort in challenging all aspects of the site’s situation and exploring technology options. There are usually multiple solutions to a problem and the team was keen to identify all the paths that were available to them to ensure that they would ultimately select the solution most appropriate for their specific situation.

The refinery’s original gas processing configuration featured an amine treating system using diisopropanolamine as the...
solvent for removing H₂S from the various refinery units. The removed acid gas, along with sour water-stripper off-gas, which also contains significant quantities of H₂S and ammonia, went to five SRUs that converted the H₂S to liquid sulphur. The tail gas from the SRUs passed to a common third-stage Claus unit and a third-party tail-gas-treating unit for enhanced sulphur recovery. The remaining H₂S was incinerated in catalytic incinerators and the tail gas produced was sent to the stacks. A sulphur pelletiser unit solidifies the liquid sulphur from the SRUs. The solid sulphur was collected in a storage pit and periodically removed and loaded on barges for transport to customers.

The team calculated that the 500 mg/Nm³ and 150 mg/Nm³ limits of SO₂ translated to sulphur recovery efficiencies of 99.90 and 99.98% respectively. The existing tail-gas-treating unit could only take the refinery to about 99.3% sulphur recovery; to go beyond this would require a different tail-gas-treating technology.

The team considered numerous tail-gas-treating processes, including the standard Shell Claus off-gas treating (SCOT) process, which uses catalytic conversion and amine absorption processes to remove sulphur compounds from Claus tail gas; the LS SCOT process, in which a low concentration of an inexpensive additive is added to the amine to improve solvent regeneration and achieve very low sulphur emissions (as low as 10-ppmv H₂S or 50-ppmv total sulphur); and the Super SCOT process, which uses an additional regeneration stage and can meet SCOT off-gas specifications of as low as 30-ppmv H₂S.

The team also evaluated non-Shell technologies, but determined that the conventional SCOT process offered the most compelling solution for tail-gas treating. This was more appropriate because it offered the capability to reduce both SO₂ and CO emissions from the SRUs. In addition, the reduction in SO₂ emissions from the SRUs created short-term margin benefits. SCOT is a proven technology that is capable of meeting SO₂ point source emission limits and hence is a no-regret investment for future compliance. Availability levels of greater than 98% can be achieved.

Crucially, the team was also able to meet the CO emissions regulation by making small modifications to the catalyst, the operating temperature and the reactor design typically used in a standard SCOT design.

In addition, to provide the extra sulphur recovery capacity that would be necessary when the new hydrodesulphurisation unit came on-stream, an additional SRU had to be installed.
The SCOT unit and the additional SRU have delivered value in several ways. First, and perhaps most importantly, they have improved the refinery’s environmental performance and secured its licence to operate. Second, there have been margin benefits through the refinery’s ability to process higher-sulphur, less-expensive crude and its ability to maximise its yield of ULSD without exceeding its sulphur emissions. Third, operating costs have also fallen because of the enhanced reliability of the new gas processing plant.

The SCOT unit and the new SRU have been performing well since they were commissioned in mid-2012 and early 2013 respectively. All performance guarantees have been met.

The success of the project is due, in large part, to the refinery taking early, positive action when faced with the prospect of having to substantially cut both sulphur and CO emissions. This meant that it was able to take a reasoned, phased approach, which helped to manage the capital expenditure requirements. It also meant that the team could evaluate the widest possible technical solution set, something that can be key to avoiding regret investments.

The refiner’s willingness to bring in external expertise was also a significant factor. The refinery technologists played a vital role, as they brought knowledge of the refinery’s specific processes, drivers and constraints to complement the global operating experience of Shell Global Solutions. Its staff, for instance, were able to relay their experiences of what has worked well at other similar projects around the world and to show them reference sites to demonstrate similar technology schemes in operation.

This customer’s drivers are not uncommon – other refiners are likely to face similar challenges in the next few years as regulators worldwide tighten their emissions controls. Many will have to adapt to World Bank standards, which prescribe that refineries should emit no more than 150 mg/Nm³ SO₂, and restrictions on CO emissions are also imminent, but this particular case demonstrates that technology solutions exist to meet them.

Sathish Balasubramanian
Senior Engineer, Shell India Markets Pvt. Ltd
HOW PDO WILL MEET ITS ENVIRONMENTAL MANDATE AT YIBAL KHUFF

PDO is developing new, highly sour gas reservoirs in Oman. The Yibal Khuff integrated development is a brownfield project involving stacked sour gas and oil reservoirs lying below producing sweet reservoirs.

The gas produced will contain about 3% \( \text{H}_2\text{S} \), about 5% \( \text{CO}_2 \) and contaminants including RSH, carbonyl sulphide (COS) and nitrogen, and must be processed to meet an export gas total sulphur specification of <5 ppmv.

The sulphur recovery efficiency (the proportion of sulphur that is recovered from the feed gas) requirement of 99.9% is in line with the regulations in most countries. However, the \( \text{SO}_2 \) emission requirement of 35 mg/Nm\(^3\) is much lower than the World Bank guidelines for SRUs, which stipulate less than 150 mg/Nm\(^3\). The combination of these two regulatory requirements made the design of the gas treatment and sulphur recovery facilities extremely challenging. It was clear that best-in-class solutions would be necessary for the project to comply with the Omani standards. Cost would also be an issue, as achieving an ultra-high sulphur recovery efficiency typically sees costs increase dramatically.

A ROBUST INTEGRATED SOLUTION

The project is using an integrated gas processing approach based on Shell Global Solutions’ portfolio of gas processing and sulphur recovery technologies. Seven process units have been interlinked to develop a robust solution.

As shown in Figure 2, the gas treating line-up has several process blocks:
- an AGRU for deep removal of \( \text{H}_2\text{S}, \text{CO}_2 \), RSH and COS;
- molecular sieves to dry the treated gas and remove traces of RSH;
- an aqueous methyl diethanolamine (MDEA) process to enrich the acid gas to improve the operating conditions of the SRU;
- an SRU for converting sulphur components to elemental sulphur;
- a sulphur degasser to reduce the \( \text{H}_2\text{S} \) level to <10 ppmv; and
- a CANSOLV unit to quench the flue gas from the incinerator and remove \( \text{SO}_2 \) and sulphur trioxide (\( \text{SO}_3 \)) to meet the flue gas specification from the stack (\( \text{SO}_2 \) <35 mg/Nm\(^3\)).
The AGRU removes most of the H₂S, CO₂, RSH, COS and other sulphur species from the sour gas that is routed to it using Sulfinol™-X technology. This is an enhanced treating solvent containing MDEA, sulfolane and a secondary amine (piperazine), which acts as an accelerator for CO₂ and COS removal. In addition to improved sulphur species removal, Sulfinol-X offers considerably less solvent degradation and residue build-up compared with other Sulfinol processes, and can help to reduce the energy consumption of the process compared with other amine solvents.

A molecular sieve unit downstream of the AGRU dehydrates the treated gas, which also contains small amounts of RSH, COS and H₂S. The molecular sieve unit has three large vessels containing a regenerative zeolite molecular sieve and an alumina adsorbent (beds) in parallel. At any time, two of the parallel beds are in adsorption mode, while the other bed is in regeneration mode. Downstream of the adsorbers, the treated, dry natural gas flows to a hydrocarbon dew-pointing unit, which is outside the scope of the licensed package, before being compressed for export to sales.

The remaining acid gas stream from the AGRU is routed to the acid gas enrichment unit (AGEU), which enriches the acid gas to the SRU to enable stable operation of the SRU. Aqueous MDEA is contacted countercurrently with the feed to selectively remove H₂S over CO₂ from the feed gas to the AGEU, thereby producing an H₂S-rich acid gas stream. The treated gas from the AGEU contains low concentrations of acid components, including RSH, which are then routed to the incinerator unit.

The enriched acid gas from the AGEU is fed to two 65% SRUs, which are a two-stage modified Claus design. The aim of the SRUs is to:

- convert sulphur-containing components into liquid elemental sulphur at a temperature of 150°C so that it is suitable for degassing; and
- convert hydrocarbons in the feed to CO₂ and water.

These aims have to be met with minimum pressure drop through the unit to maintain a sufficiently low back pressure at the incinerator. This is necessary to enable other process gas to freely flow from the downstream CANSOLV regenerator overhead to the incinerator.

The SRU removes approximately 95% of the sulphur in the feed gas as elemental sulphur. The sulphur product is brought to a specification of <10 ppm H₂S in the sulphur degassing unit: a common above-ground degassing vessel for both SRUs. The degasser has stripping air and sweep air supplied by dedicated air blowers. The liquid elemental sulphur from the degasser vessel is then pumped to the sulphur storage tank.
The residual sulphur compounds not recovered in the SRU are incinerated to convert them to $SO_2$. This occurs in a thermal incinerator operating at a sufficiently high temperature to ensure the destruction of the remaining aromatic hydrocarbon compounds, ethylbenzene and xylene, and to completely oxidise the CO to $CO_2$. Destruction of the aromatic compounds governs the operating temperature of the incinerator.

The following streams are routed to the incinerator:
- tail gas from the SRUs;
- flash gas from the AGRU;
- treated gas from the AGEU, which contains most of the $CO_2$ and aromatic hydrocarbons; and
- vent gas from the liquid sulphur degasser.

To meet the sulphur recovery efficiency and $SO_2$ emission regulations, the CANSOLV $SO_2$ scrubbing process treats the tail gas from the incinerator. Before entering the CANSOLV unit, the incinerator tail gas must be scrubbed to remove dust and reduce $SO_2$ and sulphuric acid mist to a tolerable level. This pre-scrubbing prevents excessive degradation of the absorbent used in the CANSOLV $SO_2$ scrubbing system and serves to cool the flue gas to an acceptable temperature for the absorption process.

The CANSOLV unit is a four-stage scrubber system comprising:
- a hot gas jet scrubber quench;
- a sub-cooling packed tower;
- a particulate separator (venturi); and
- a high-pressure system to enhance acid mist removal.

The conditioned tail gas leaves the pre-scrubber system at a maximum temperature of 37°C and containing low levels of contaminants, as per the requirements of the downstream CANSOLV process.

The gas exiting the pre-scrubbing system is discharged from the droplet separator and ducted to the bottom of the CANSOLV $SO_2$ scrubbing system absorber. This has two distinct sections: a lower section for $SO_2$ absorption and an upper section for caustic polishing.

The process line-up of the CANSOLV unit is similar to any conventional regenerable amine unit. The key difference is that the CANSOLV unit has an online absorbent (ion exchange) purification unit to treat a slipstream of the amine solvent. The ion exchange technology removes non-regenerable heat stable salts from the solvent. The unit is sized to operate for eight cycles a day under normal operating conditions.

**SETTING NEW STANDARDS**

By working with Shell Global Solutions and taking an integrated approach to the design of the sulphur recovery process line-up, PDO has managed the interfaces between the different units and optimised the configuration to enhance energy efficiency and thereby deliver maximum value. The design that the two organisations have developed through close technical collaboration is set to achieve ultra-high sulphur recovery levels and adhere to some of the most stringent emissions standards that the industry has seen. PDO is pushing technological boundaries and, as a result, can set new standards.

**Rajiv Srinivasan**
Senior Process Engineer, Petroleum Development Oman

Sulfinol is a Shell trademark.

<table>
<thead>
<tr>
<th>SCENARIO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project</td>
</tr>
<tr>
<td>Owner</td>
</tr>
<tr>
<td>Location</td>
</tr>
</tbody>
</table>
| Objectives | Process highly sour gas  
|          | Achieve an sulphur recovery efficiency of 99.9%  
|          | Comply with an $SO_2$ emission specification of <35 mg/Nm³ |
| Solution type | Brownfield project |
| Gas processing and sulphur recovery facilities to be installed | AGRU with Shell Sulfinol-X solvent, an AGEU, CANSOLV technology and a Shell sulphur degassing unit |
| Feed | Sour gas containing 3% $H_2S$, 5% $CO_2$, RSH, COS and nitrogen |
| Product slate | Export gas with <5-ppmv sulphur |
CONVERSATIONS
FROM THE CUTTING EDGE OF TECHNOLOGY

Advanced technologies and game-changing innovations are vital for the energy industry, and behind every technological solution you are likely to find creative, passionate people. In this article, we profile three Shell experts whose fresh thinking has either helped to push the limits of what a technology can achieve or helped customers to apply technology to enhance their business’s performance.

**GURMINDER SINGH**
Downstream Licensing Sales Manager Asia Pacific, Shell Global Solutions (Malaysia) Sdn Bhd

Although he now supports refiners as they strive to respond to hydroprocessing challenges, Gurminder Singh has also sat on the other side of the refiner–supplier relationship. He has held senior posts in operating plants and as a process designer in engineering, procurement and construction companies serving the refining industry, and this gives him a special perspective when it comes to working with customers: he has walked in their shoes.

**Q: Which of your projects has given you the most professional satisfaction?**
I have been involved in numerous revamps, but a recent project with Hyundai Oilbank Co. Ltd was especially interesting. They were keen to build a base oils manufacturing plant at Daesan, South Korea, because demand for Group II products is robust in the region. At the same time, they asked us to explore whether they could use hydrocracker bottoms as the feed for this new plant. Such a project could have a strong impact on a refinery’s economics, as this stream of unconverted oil has limited value otherwise. There are a handful of plants that use hydrocracker bottoms in this way. However, there are challenges to resolve and every situation is unique.

When licensing the technology for the 650,000 t/y base oil plant, we felt that it was vital for us to take a closer look and check on how this would integrate with the existing refinery. We found that, to get the right amount of feed at the right quality, we would have to revamp the hydrocracker. Moreover, to get the desired feed heaviness, we also needed to revamp the unit upstream of the hydrocracker, the vacuum distillation unit. It was important to see the whole integrated picture.

When the plant comes on stream in 2014, Hyundai will become a key player in the lucrative Asian lubricant base oils market.

**Q: What advice would you give to other refiners that are striving to remain competitive?**
Sweat your assets. That is always the first thing; make sure that you are exploiting the maximum returns from your existing asset base. Small, inexpensive changes such as catalyst drop-in solutions and/or the addition of new reactor internals in hydproprocessing units can be an extremely cost-effective way to improve unit economics or to adapt to changing product specifications.

To make more money or margin, some companies will think about going big. Before they begin to install new process units or build a new facility, I always recommend that refiners should talk to licensors, catalyst companies and contractors, and that they should involve them at the scouting or front-end engineering phase when they are taking their first steps to shape the project. A project has to be tuned to a refinery’s specific circumstances, but experience of other, similar projects can help to ensure consideration of a wide range of technical options.

**Q: What is the outlook for refiners?**
The refining industry has a long-term future because there will be demand for its products for many years to come. Nevertheless, it is likely to remain a hugely competitive arena and those with highly flexible assets are likely to enjoy greater margins.

This is where technology can help. The configuration of the units, the type of catalysts and the type of reactor internals all determine how effectively a hydproprocessing plant can help a business to fulfil its objectives. However, the good news for refiners is that there is a huge amount of innovation and research and development going on in these areas, as technology licensors and catalyst companies strive to help them to meet their challenges.
Q: How has Shell gasification technology developed over the years?

The Shell coal gasification process is highly regarded in the industry; it is very efficient, safe and reliable. Nevertheless, we are always trying to improve it. However, because the level of investment required for Shell’s coal gasification units has been a barrier for some projects, we mandated a special research group to explore simplifying the technology.

The key is that we have devised a different way to cool the hot syngas. In the traditional Shell syngas cooler design, the hot gas passes along steel tubes containing water and releases its heat to the water. As the gas cools, steam forms inside the tubes. However, the hardware that is required is a complicated beast – in effect, it is an almost 100-m-long cooler.

In the new design, which uses novel bottom water-quench technology, the hot gas passes directly into a water bath. Instead of raising steam separately using expensive equipment, the steam is now generated by mixing the hot syngas with water. The devil is in the detail, though. Ensuring that the very hot syngas is cooled in this way is something of an art form.

Nevertheless, the capital cost of a plant based on this concept can be up to 35% less than one based on standard technology. As a result, we have had a lot of interest from chemical companies keen to explore whether the hybrid gasifier, as we call it, would be a good fit for them.

Q: Has the hybrid gasifier been applied?

Actually, a demonstration plant is now gearing up for operations. It has been a long story of novelty creation and development, but we are now extremely close to starting up and producing syngas from this new type of gasifier.

It is very exciting. We will be firing up the burners soon! When that happens, it will switch from being experimental technology that exists only in the minds, models and drawings of the technologists who created it, to being real, proven technology.

Q: Do you expect the hybrid gasifier to replace the standard technology?

Well, the conventional process still has a big role to play. But now we have two different processes that we can use to gasify coal, each with its own merits. Although the standard one has a higher capital cost, its capacity and efficiency are also higher, and so we expect that to be the preferred option for large projects or for power generation.

However, when low capital cost is more important than efficiency, the hybrid gasifier will play a key role. In fact, one of the most promising applications is chemicals production in China. Gasification is helping to unlock abundant coal reserves as a feedstock for the chemicals value chain. So, companies are looking at it with a view to generating syngas that will feed, for instance, a process that produces olefins or synthetic natural gas (pipeline quality gas).
**Q: What prompted you to suggest that Shell should consider buying Cansolv?**

There were several reasons. First, the oil and gas reserves that the industry is exploiting are increasingly high in sulphur and, as we know, SO₂ emission regulations are tightening around the world. This is an increasingly difficult issue for Shell and Shell Global Solutions’ customers, but Shell Cansolv’s SO₂ scrubbing technology can help facilities to achieve compliance. So, it was a great opportunity to bolster our portfolio of gas processing technologies. Shell Cansolv’s technology is the industry’s leading regenerable SO₂ scrubbing process: 15 units are in operation and more are in development.

Second, we identified that the CO₂ technology might be able to contribute to future CCS projects. The CO₂ and SO₂ technologies are very similar – both are regenerable amine processes – but, unlike the SO₂ technology, the CO₂ technology was unproven. Since then, the technology has advanced. Two projects that will deploy CANSOLV CO₂ technology are under construction, and a third is at the design stage.

**Q: What differentiates the technology from alternative solutions?**

One of the key aspects is that it is regenerable. There are several types of non-regenerable SO₂ scrubbers, but these generate aqueous and solid waste streams that usually need to be disposed of to landfill or wastewater treating systems. In contrast, the CANSOLV SO₂ scrubbing system uses a proprietary amine technology and reduces effluents to a minimum. Moreover, SO₂ emission levels of as low as 20 ppm are achievable.

So, you can see that it is an extremely innovative and effective solution. The developers, John Sarlis and Leo Hakka who were two of the Cansolv founders, have done a remarkable job. Since the acquisition, we have combined our efforts to take the SO₂ scrubbing and CO₂ capture technologies to the next level. For instance, together, we have been addressing scale-up issues and we are currently developing a next generation of solvent that is designed to minimise the impact of the capture process on the power plant’s energy efficiency.

**Q: Where is the technology being deployed?**

Well, Shell Cansolv’s reference list is growing rapidly around the world and in different applications, including up- and downstream oil and gas, and coal- and gas-fired power stations.

Perhaps one of the most exciting potential applications is the Peterhead CCS project. Together with the power firm SSE, Shell is looking to develop the world’s first full-scale CCS project at a gas-fired power plant. The project would capture 10 Mt of CO₂ over 10 years from SSE’s Peterhead gas-fired power station in Aberdeenshire, UK, and store it permanently in a depleted reservoir more than 2 km under the floor of the North Sea so that it no longer contributes to climate change.

What would make this such a significant development is that it reduces the CO₂ emissions by 90% from what is already the cleanest burning fossil fuel, natural gas. This means that such electricity generated from natural gas would be defined by the UK as clean energy.

---

**FRANK GEUZEBROEK**

General Manager, Gas Separation Research and Development, Shell Global Solutions International B.V.

Back in 2004 when working as a Shell research and development technologist, Frank Geuzebroek was introduced to Cansolv Technologies Inc. and immediately became excited about the potential of its SO₂ scrubbing and CO₂ capture technologies. After investigating further, he recommended Shell to install the technology at its facilities and to evaluate the potential strategic value of bringing the technology in-house. Following further analysis by the Shell leadership and interaction with Cansolv, Shell acquired the company in 2008. Today, Shell Cansolv’s technology is a key enabler behind important commercial-scale carbon capture and storage (CCS) projects that are in development.
Q: What is the most significant innovation in catalysis that you have seen during your career?

It would probably be the research that culminated in CENTINEL. If you look at a plot of catalyst performance improvements through the years (Figure 3), you see that from 1980 to about 1998 the improvements were very gradual. There were improvements but they tended to be incremental improvements of existing catalysts and technology. But that changed in 1998.

This is because we figured out a way to improve the intrinsic activity of the active sites on a catalyst. This was a hugely significant advance, and we capitalised on that innovation by enhancing the alumina supports and using promoters and additives to unlock additional improvements. The result was CENTINEL, which served as the workhorse of the initial ULSD wave in Europe. Moreover, this provided the platform for our next generation of catalyst technology, CENTERA.

As the graph shows, the activity improvements that we have achieved over the past 10 years are almost three times greater than over the previous 20.

Q: How has the catalyst development process changed over the years?

It is a lot faster! About six years ago, we invested heavily in high-throughput experimentation equipment and this has really accelerated the discovery and development process.

For example, one new piece of high-throughput equipment that we use for primary screening can test many catalysts in a short time. Those that do not show promise are eliminated straight away and the rest progress to the secondary screening phase. The traditional approach is to test one catalyst at a time, but the high-throughput apparatus features 16 miniature reactors, each of which can test a catalyst using real feedstocks and provide representative results.

The great thing about being able to test a large number of catalysts is that you can evaluate a wide variety of approaches in a short period. In the past, because you had a limited number of reactors, you had to rely on scientific intuition and select the catalysts that you thought had the best chance of achieving your objectives. But high-throughput equipment enables us to get really creative and to look at a lot of things.

Q: Given all these advances, should we expect the magnitude of those performance improvements to begin to tail off?

That is a very good question. I have been working in catalyst development since 1985 and it does surprise me that these improvements have not somehow plateaued. The issues facing refiners, especially changing feedstock slates and product specifications, are increasingly challenging.

Nevertheless, through the persistence and creativity of our scientists in technology centres around the world we are still finding ways to improve these catalysts. High-throughput experimentation, improved understanding of catalysis and customer focus will enable us to continue developing new, fit-for-purpose catalysts very quickly. There is still much more to explore.

Figure 3: History of Criterion’s increases in hydrotreating catalyst activity.
Disclaimer

This document contains forward-looking statements concerning the financial condition, results of operations and businesses of Royal Dutch Shell plc. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements.

Forward-looking statements are statements of future expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements.

Forward-looking statements include, among other things, statements concerning the potential exposure of Royal Dutch Shell to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as “anticipate”, “believe”, “could”, “estimate”, “expect”, “intend”, “may”, “plan”, “objectives”, “outlook”, “probably”, “project”, “will”, “seek”, “target”, “risks”, “goals”, “should” and similar terms and phrases.

There are a number of factors that could affect the future operations of Royal Dutch Shell plc and could cause those results to differ materially from those expressed in the forward-looking statements included in this announcement, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for the Shell Group’s products; (c) currency fluctuations; (d) drilling and production results; (e) reserve estimates; (f) loss of market and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including potential litigation and regulatory effects arising from recategorisation of reserves; (k) economic and financial market conditions in various countries and regions; (l) political risks, project delay or advancement, approvals and cost estimates; and (m) changes in trading conditions.

All statements regarding Hyundai, Kuwait National Petroleum Company, PDO and PDVSA and their products and services are based solely on information provided by Hyundai, Kuwait National Petroleum Company, PDO and PDVSA and have not been independently verified by Shell Global Solutions.

Copyright © 2013 Shell Global Solutions International BV. All rights reserved. No part of this publication may be reproduced or transmitted in any form or by any means, electronic or mechanical including by photocopy, recording or information storage and retrieval system, without permission in writing from Shell Global Solutions International BV.