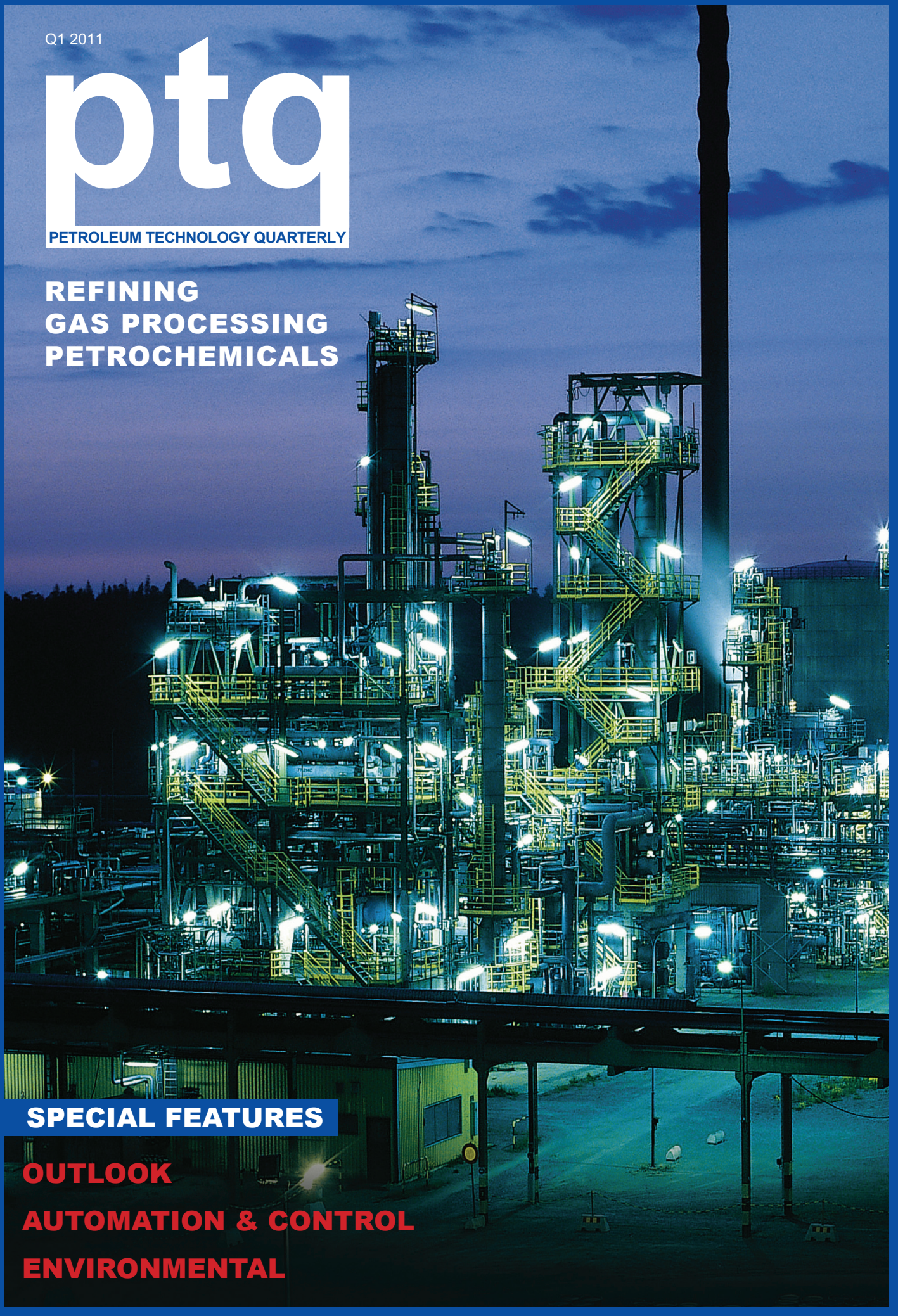
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Nynäshamn refinery, Sweden, recently inaugurated a new hydrogen plant. *Photo: Nynas AB*

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PETROLEUM TECHNOLOGY QUARTERLY

Vol 16 No 1
Q1 (Jan, Feb, Mar) 2011

Editor
Chris Cunningham
editor@petroleumtechnology.com

Production Editor
Rachel Zamorski
production@petroleumtechnology.com

Graphics Editors
Rob Fris
Mohammed Samiuddin
graphics@petroleumtechnology.com

Editorial
tel +44 844 5888 773
fax +44 844 5888 667

Advertising Sales Manager
Paul Mason
sales@petroleumtechnology.com

Advertising Sales
Bob Aldridge
sales@petroleumtechnology.com

Advertising Sales Office
tel +44 844 5888 771
fax +44 844 5888 662

Publisher
Nic Allen
publisher@petroleumtechnology.com

Circulation
Jacki Watts
circulation@petroleumtechnology.com

Crambeth Allen Publishing Ltd
Hopesay, Craven Arms SY7 8HD, UK
tel +44 844 5888 776
fax +44 844 5888 667

ISSN 1362-363X

Petroleum Technology Quarterly (USPS 0014-781) is published quarterly plus annual Catalysis edition by Crambeth Allen Publishing Ltd and is distributed in the USA by SPP, 75 Aberdeen Rd, Emigsville, PA 17318. Periodicals postage paid at Emigsville PA. Postmaster: send address changes to Petroleum Technology Quarterly c/o PO Box 437, Emigsville, PA 17318-0437
Back numbers available from the Publisher at $25 per copy inc postage.

ABC



Peak oil? What peak oil?

It is that forward-looking time of year. At *PTQ*, we like to think that our Q1 edition's Outlook section is a key contributor to strategic thinking in the coming months. We are delighted, as ever, that leading executives from the world of refining and refining technology have taken the time to share their insights, in this issue, into the many challenges facing the industry in the year ahead and beyond.

Talking of "beyond", the leading energy agencies have been sharing their long-range views of the world's energy supply. As usual, the International Energy Agency's own *World Energy Outlook* gives pause for deep thought. The good news from the IEA is that we can all stop worrying about when peak oil will arrive. The world apparently passed that point about four years ago. Or, to look at things another way, there will never be a peak. According to the IEA's calculations to 2035, global demand for conventional supplies of crude oil reached a plateau and will stay there, more or less, for the next 25 years.

Total demand will rise by around 12%, according to the IEA, the rising portion of the crude made up by LNG and "unconventional" sources of oil, including biofuels. The portion of the supply graph worth special attention is the flat-lining trend for conventional petroleum. The official estimate sees the portion of undiscovered or undeveloped fields contributing to the complete picture of petroleum supply increasing from zero now (obviously) to three-quarters of the total over the coming quarter century.

What does this mean? Well, taking the crude view, petroleum refining capacity hardly needs to increase over the period under review. At the same time, supplies of heavy, sulphurous raw material, currently an increasingly important feature of raw material supply, will become the dominant feature of the refining industry. If pressure to develop deep refining techniques, emissions control technology and increasingly advanced catalysis feels high at the moment, it appears as little compared with the challenges to come.

In the shorter term, the US is the only developed nation projected to show any significant growth in oil consumption in 2011, demand rising by about 200 000 b/d to 19.26 million b/d, according to the Energy Information Administration in its own end-of-year report.

Like the IEA, the US government agency forecasts world growth in oil demand in 2011 as virtually zero. The EIA says that it expects world oil consumption to rise 1.43 million b/d in 2011, down 10 000 b/d from the 1.44 million b/d increase it had projected earlier.

World oil demand is expected to reach 87.78 million b/d in 2011, compared with 86.35 million b/d in 2010, the EIA says. Global oil use in 2011 will continue to be driven by developing areas such as China, the Middle East and Brazil. On the supply side, non-OPEC crude oil is projected to grow by more than 1 million b/d to an average of 51.5 million b/d, the largest yearly increase since 2002. The increase is the result of higher output from the US, Brazil, China and Russia.

Non-OPEC supply in 2011 is expected to fall by 280 000 b/d, only the third time in the last 15 years that non-OPEC output has declined year-on-year. Gradual tightening in global oil markets continues to support world oil prices, according to the EIA.

CHRIS CUNNINGHAM

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What are the important trends affecting the downstream processing industry this year? Executives and experts forecast challenges and prospects that could affect profitability

Rajeev Gautam
President & CEO
UOP LLC, A Honeywell Company



Our industry is poised to enter a new phase of growth and technology evolution, but there continue to be problems we must solve. The shift in product demand, tighter fuel specification regulations, the need to maximise the products we get from a barrel of oil and the emergence of new alternative feedstocks will present challenges to refiners around the globe and ultimately drive new solutions.

We are experiencing a shift in the mix of fuels consumed. The demand from emerging regions such as India, China and the Middle East, along with ethanol substitution for gasoline and enhancements in engine technology, are driving higher demand for diesel relative to gasoline. For our industry, this results in increased emphasis on hydrocracking technology and catalysts. For UOP specifically, it means continued enhancement to our Unicracking process technology and new catalyst solutions that will maximise distillate yields.

Many refiners will look to shift fuels production from gasoline to diesel or remain flexible to shift between the two as needed. The economic solutions to address these requirements are often not straightforward, but continued advancements in both process and catalyst technology will allow refiners to respond intelligently to changes in the market while maximising profitability.

This shift to diesel also drives an emphasis on bottom-of-the-barrel processing. Technology advances and improved configurations for heavy oil processing will drive higher distillate yields and give refiners a significant advantage when competing in a global market.

The tightening of fuel quality regulations around the world, including reductions in benzene, olefins and aromatics in gasoline and the global movement towards ultra-low sulphur fuels, will continue to be a driver for our industry. The recent implementation of MARPOL regulations has led to the creation of emissions control areas restricting SO_x emissions in the North and Baltic Seas, with future implementation in North America occurring over the next few years. Refiners will need to convert high-sulphur bunker fuel to fuels that comply with these emissions control area requirements.

Additionally, the continued increase in global petrochemical demand, particularly in regions such as China and India, is driving rapid expansion in this sector. This demand also has refiners looking for new ways to improve the value of their existing product slate with petrochemicals production. The latest FCC technology enhancements can achieve more than 20 wt% propylene yield, but new ways to upgrade other FCC products to higher value petrochemical products can bring more profitability.

Of course, there continues to be a great deal of interest and many global drivers for renewable fuels. Technology improvements in the last several years and advancements in feedstock availability and processing are bringing efficient, cost-effective drop-in biofuels closer to commercial reality. We have successfully demonstrated technologies that maximise existing infrastructure, meet fuel specifications and address concerns around growing greenhouse gas emissions. These fuels have an enormous potential to contribute to our fuel supply.

There is a great deal of change happening in the refining industry today. The real key for all players will be to maximise the yield of valuable finished products from every single barrel of oil processed. This will include new processing solutions and optimisation projects that deliver strong returns.

Umberto della Sala
CEO, President and Chief Operating Officer
Foster Wheeler



We are certainly seeing increased activity in all of the hydrocarbon-related business sectors in which Foster Wheeler's Global Engineering and Construction Group operates: onshore and offshore upstream oil and gas, midstream/LNG, refining and chemicals. The global economy continues to recover, broadly in line with expectations. Product demand is also recovering, and is helping

to bolster client confidence in progressing their investment plans.

Certainly, we have a good prospects pipeline, although it is true that clients are in some cases taking longer to reach final investment decision or are releasing projects in phases. We have a number of projects that are going through the final investment decision-making process and for which we believe we are well positioned. And we are seeing new opportunities continuing to emerge, particularly in Asia, the Middle East and South America.

Looking forward into 2011, we see three key themes. First, client confidence in pursuing upstream oil exploration and development opportunities has returned. The offshore and onshore upstream sector remains a strategically important market for us and one in which we are further developing our skills and service portfolio. The award of the pre-FEED and FEED for the Cardon IV Perla Field Development, an offshore development by ENI and Repsol in the Gulf of Venezuela late in 2010, is a good example of our success in leveraging the offshore skills and expertise we have brought on board through acquisition.

Second, we are seeing increased emphasis on local service delivery. This has always been important to us and is becoming an even stronger area of focus for us and for our clients. We have made further strides forward this year, for example in Saudi Arabia, by developing our own resources and by building relationships with local or regional contractors to enable us to deliver the Foster Wheeler product locally and competitively to our clients, in line with local content requirements and our clients' preferences.

The third theme relates to the size and complexity of projects. Large projects are getting even larger and more complex; for example, the planned Saudi Aramco/Dow petrochemicals complex in Saudi Arabia, the scope and scale of some of the planned investments in Iraq, and the planned investments in both upstream and downstream in Brazil. Size and complexity play to our strength.

As we have said before, competition remains strong everywhere. We are focusing on those opportunities where we believe we have differentiators, such as our technologies, our know-how, our client relationships, our global presence and our ability to work with clients from the very earliest phases of projects to help them shape their investment, and our proven track record of safely delivering technically complex and very large projects.

Based on our discussions with our clients regarding their investment plans, and the underlying supply and demand fundamentals, the outlook for the industries we serve is improving.

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George Bright
Chief Executive
KBC Advanced Technologies



With global refining capacity far in excess of current demand and still more capacity under construction, a key question for the downstream energy industry in the next several years is: how will global markets find balance between this surplus refining capacity and post-recession demand recovery?

The dichotomy between regions is quite striking: lower demand, ageing assets and declining operating rates in Europe, North America and Japan vs GDP growth and increased demand in China, the Middle East and Latin America. With explicit national energy security and job creation objectives, growth markets are adding refining capacity despite an existing global glut. Like the collisional boundaries of two tectonic plates, the geographic shift in the supply-demand curve will have volatile consequences. KBC has just released its first *Global Energy Perspectives*, discussing our views on the global refining sector over the next several years, and the factors influencing returns on energy investment and economics.

While there are numerous factors determining the overall global balance, there are three trends we have identified that are particularly noteworthy:

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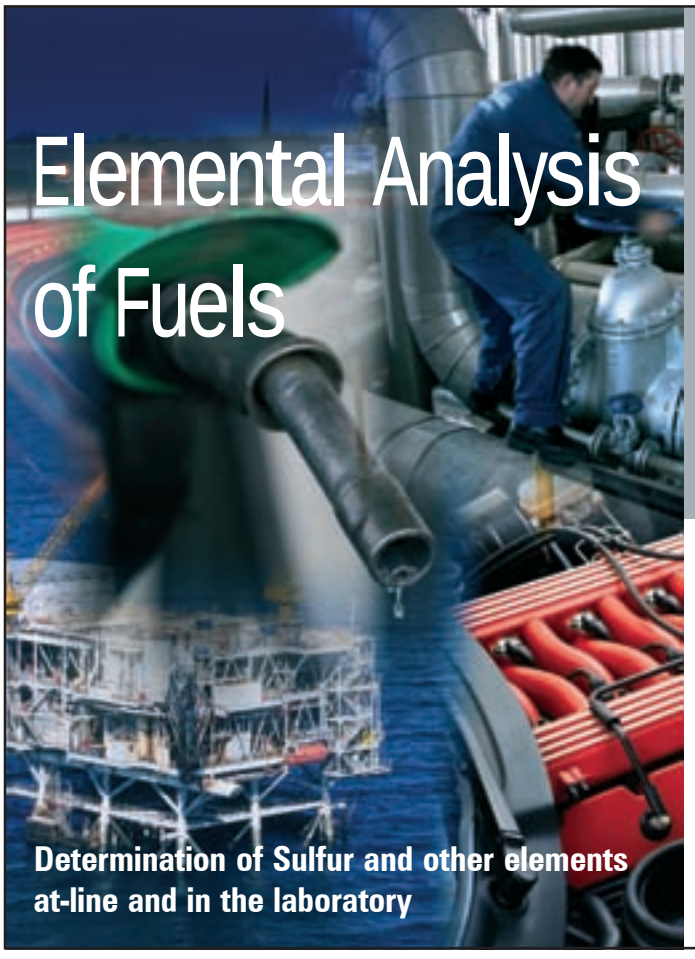
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- Traditional rules of free market economics do not completely apply in the energy sector, yet they are not completely ignored either. Despite overcapacity, certain large-scale projects will likely progress. It is no longer solely about economic returns; decisions have also been made based on local job creation and "corporate social responsibility". Only certain national oil companies and a very few, select independent oil companies can bear the financial burden of such projects alone, irrespective of economic returns. Third-party financing, however, does follow free market economics and to an extent certain projects progress, others may be delayed or cancelled until rates of return are adequate to justify their investment
- Capacity in mature markets is clearly at risk of closure or idling. Traditionally, the view has been that the bulk of this closure would occur in the Americas. However, while no geography is immune, KBC's alternate view of the market as three vertical segments (vs the traditional Pacific-Atlantic Basin view) illustrates key issues that would suggest European capacity is at the greatest risk. The announced closure of two French refineries in recent months is an example of this
- Much focus has been placed on India and China. It is true that refined product demand in these geographies will drive overall growth for the next 20 years. However, less often discussed are the global impacts that Brazil, the Middle East and Russia will also have on world markets. With the completion of planned projects in Brazil and the Middle East, both regions will become product powerhouses that can create significant shifts in the traditional industry dynamics. Furthermore, depending on future strategic actions, Russia has the potential to significantly influence both the European and Asian refining markets.

Bharat Srinivasan
Co-Managing Director
Chevron Lummus Global



For refining and the technology providers that support refining, the outlook for 2011 appears hazy with a chance of clearing. After the 2008+ downturn, 2010 did show some signs of life which varied regionally and within regions, locally. The Europe/Middle East region demonstrates this. Russia and other Eastern European countries continued with projects that had been sanctioned prior to the downturn but at a measured pace, as companies struggled with costs and ownership issues.



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Thus, projects that Chevron Lummus Global (CLG) had designed in Russia at multiple locations went into detailed design and construction, but with changes and some delays. The Kirishi plant that had been designed over a decade ago is gradually approaching mechanical completion. Meanwhile, several new plants designed by CLG in the same region are advancing at varied pace. For example, the new hydrocracking complex in Croatia at INA's Rijeka refinery went into commissioning mode and a similar complex at NIS Pancevo in Serbia moved into EPC.

Heading towards southern Europe, some projects contemplated by ENI in Italy were deferred, while others were commissioned successfully. Similarly, the Samir hydrocracker plant in Morocco was commissioned. GALP in Portugal continued the construction of its hydrocracker in Sines for a start-up in 2011. The Saudi projects progressed, with the Saudi Aramco-Total Jubail venture and its huge hydroprocessing complex on schedule, and the Yanbu project suffering a schedule setback when Conoco-Phillips pulled out, only to have Saudi Aramco decide to proceed on its own.

In contrast, the fate of the New Refinery Project (NRP) and Clean Fuels Projects (CFP) in Kuwait remain unclear. The Asia-Pacific region does show more vitality, but some of the same trends can be seen. Korean companies actually cancelled or deferred projects, although Hyundai advanced its RDS/RFCC project towards mechanical completion in 2010 and GS-Caltex plans to commission its HOU-3 project by the end of 2010. Both the RDS plant at Hyundai and the LC-Fining unit at GSC are CLG licensed. Japan's government is attempting to impose upgrading/distillation ratio controls and some capacity rationalisation will be the result.

China started out 2010 full of promise for more than a dozen projects, yet, through the year, the projects remain but their execution has been delayed. In some cases, Chinese companies are in joint ventures with upstream suppliers (eg, PDVSA or Rosneft) and getting agreements on configurations, product objectives and crude slates has been difficult. In other cases, there have been issues with environmental clearances and competing projects, but generally the major state-owned companies — PetroChina, Sinopec, CNOOC and Sinochem — appear to have slowed down their project execution schedules, although none of the projects has been cancelled. In the meantime, private companies seem to be filling some of the void. Fuel demand continues to grow at an impressive rate and, while supply at the moment appears to balance, over the next five years the projects will need to be executed to maintain this balance, which seems to be China's intent.

India appears for the time being to be in an overall product surplus mode and, with new plans by Reliance to expand its complex further, new projects over the next years may be limited to revamps and expansions in existing refineries. BORL (a joint venture between BPCL and Oman Oil Co) is commissioning its first refinery in the middle of the country at Bina this year to address local product shortfalls. The rest of Asia-Pacific has projects under evaluation phase. A major decision will be made next year on Vietnam's third refinery project (NSRP), a joint venture between PetroVietnam and Kuwaiti and Japanese partners.

The Americas continue the storyline. Some small refinery shutdowns have been announced as well as

For refining and the technology providers that support refining, the outlook for 2011 appears hazy with a chance of clearing

refineries for sale. PBF Energy is picking up assets from Valero at Delaware and Paulsboro. Slow signs of revival in the Tar Sands of Canada are evident as deferred projects such as North West Upgrading and Nexen/OptiCanada look set to restart. Although Shell Canada announced cancellation of its Upgrader-2 project, it also opted to increase processing capacity gradually through a series of paced expansions at its existing facilities.

South of the US border, there is more action, as countries such as Bolivia, Costa Rica and Mexico

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revive plans to rectify their local product imbalances and product quality deficits, while Brazil's intention to refine its own growing crude production could lead to increased refining capacity.

Charles T Drevna
President
National Petrochemical & Refiners Association



President Barack Obama and congressional leaders in both parties agree that cap-and-trade schemes designed to reduce greenhouse gas emissions face too much opposition in Congress to become law in 2011 or 2012.

The cap-and-trade bill passed by the House of Representatives in 2009, and similar proposals that never even came to a vote in the Senate, would have been both economically prohibitive and highly ineffective in reducing global carbon dioxide and other greenhouse gas emissions.

Reducing greenhouse gas emissions in the US or any other developed nation will accomplish nothing if the emissions are just moved to developing countries in Asia and elsewhere, where they do not have strict emission controls. This is exactly what is happening as a result of the cap-and-trade restrictions being imposed in some developed nations.

As a result, the International Energy Agency says that more than 80% of the expected worldwide increase in greenhouse gas emissions between 2005 and 2050 will come from developing countries. These are primarily China, India and nations in Southeast Asia.

The only thing a US cap-and-trade plan would have created if it had become law would have been a complex and confusing trading system similar to a giant casino. Speculators would have wagered huge sums of money on the ups and downs of a new carbon market, benefitting no-one except those who made the right bets.

Where does America — and the world — go from here? Can the divide between environmentalists who rail against any energy source-emitting carbon and the petroleum refining and petrochemical industries ever be bridged? If we focus more on ideas and less on ideology, we can make important progress.

Nations around the globe can best deal with climate change and build a successful energy future by relying on three things that turned the US and most other industrialised nations into the productive, prosperous and advanced countries they are today: science, technology and the free market system.

The same creativity, inventiveness and entrepreneurial spirit that drove Alexander Graham Bell, Thomas Edison, Henry Ford and, more recently, Bill Gates and the pioneers of the internet to transform our world should be unleashed again to solve energy challenges that some consider insurmountable.

Instead of focusing on picking winners and losers, governments should encourage "all of the above" solutions to the climate and energy challenges the world faces, utilising technology and a broad range of energy choices.

The world's energy and climate future should be built on a strong foundation of incentivising innovation and excellence. If nations around the world do this — focusing on creating a new prosperity with the creative power of our minds — there is no limit to what we can accomplish.

Suleyman Ozmen
Vice President, Refining and Chemical Licensing
Shell Global Solutions



Refiners globally will continue to face numerous challenges in the coming year, and principal among them is "the sulphur paradox" or the increasing need to manage sulphur to help increase margins, while simultaneously meeting legislative requirements. As the global population rises, we can expect limits on sulphur in retail and transportation fuels to become more stringent as the demand for these resources increases.

At a time when the economy is lagging and many refiners are short of cash, the need to meet or exceed changing product specifications will be an undoubted concern for refinery managers. For example, the economy in Russia remains extremely tight and, despite financial constraints, refiners must be in a position to meet the Euro III transportation fuel regulations beginning in January 2011 and prepared for Euro V by 2015. Also, while local product specifications need to be taken into account, export markets can bring different demands. With the Middle East now providing significant product to Europe, refiners must comply with 10 wppm sulphur product specifications even when it is not required for their own domestic market. In developing markets, tighter specifications for motor gasoline (mogas) or gas oil will also be imposed increasingly.

To confound the issue, with insufficient "easy" oil and gas to meet demand on a global scale, refineries will have to process heavier, sourer crudes. As such, during the next five years and beyond, refiners must look forward to find more viable solutions. Sour crudes have a greater sulphur content that after conversion comes out as more hydrogen sulphide (H_2S) and sulphur oxide (SO_2). Additionally, nitrogen oxide (NO_x) and carbon dioxide (CO_2) are emitted during the refining processes. One solution to this challenge can be found in the advanced hydroprocessing technologies that process heavier,

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more sour crudes into high-value transportation fuels. Additionally, depending on country emissions requirements, minimum amounts of SO_x and NO_x may be released via the stack. These hydroprocessing technologies can be combined with gas treating/absorption solutions to help cap these emissions.

In response to the sulphur management issues that are arising within the industry, Shell Global Solutions, Criterion Catalysts & Technologies and other alliances introduced The Sulphur Technology Platform, a comprehensive, customisable and integrated sulphur solution to meet emissions and product requirements and facilitate the processing of heavier, more sour crudes. This sulphur technology platform uses deep flash technology that cuts deeper into the bottom of the barrel, resulting in higher vacuum distillate yields compared to conventional vacuum units. These integrated solutions also include effective revamps, such as hydrocracking units converted to process resid feedstocks, optimised hydroprocessing of gasoline, kerosene and diesel components to low-sulphur products and gas treating technologies to remove refinery emissions.

Ultimately, innovative process and catalyst technology solutions are required for processing heavier, more sour crudes while meeting emission and clean transportation fuels specifications, specifically in relation to sulphur (although benefits in relation to other emissions are often achieved at the same time). The key is managing sulphur levels by employing hydroprocessing, conversion and sulphur recovery technologies. By using integrated technology solutions to optimise sulphur management strategies, we can face today's refining challenges head on.

Eric Benazzi
Marketing Director
Axens



The European refining industry is coping with declining domestic demand for fuels, while the imbalance between product supply and market demand persists. This especially applies with regard to a deficit in diesel supply and an excess in gasoline production. The European gasoline surplus in 2009 exceeded 0.75 Mbdoe (million barrels per day of oil equivalent), while the diesel deficit reached about 0.5 Mbdoe.

The US market presents a recurring gasoline deficit of about 0.7 Mbdoe and, since 2008, the refining industry has been exporting diesel.

What are the main causes of such a situation?

Although there is no fundamental shortfall between the structure of US production compared with the local demand structure when expressed as percentages, the

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main problem currently stems from insufficient gasoline throughput compared to US demand. As a result, the US is importing gasoline.

In Europe, meanwhile, the imbalance is structural. European refineries do not produce enough diesel but they do produce too much gasoline. As a result, Europe is importing diesel and exporting gasoline to the US. How will the situation evolve?

Our studies take into account product demand forecasts, including the potential impact of changes in the balance of on-road fuel demand. It is also necessary to study the effects of incorporation of biofuels and the reduction in refining capacity that will occur in the coming years.

Axens' 2020 Reference Scenario makes certain assumptions about the incorporation of biofuels and reduction in refining capacity. Our assumption is that regulatory levels of biofuels will be reached later than the expected schedule. By 2020, we estimate that biofuels content will reach 8% (energy basis) in Europe, well below the regulatory level of 10%, and for the US our assumption is 9.5% instead of 10.7% corresponding to the 30 billion gallons of renewable fuels by 2020 according to the RFS2 rule.

In addition, our Reference Scenario incorporates refining capacity reduction both in Europe and in the US.

The US demand forecast is based on passenger car sales of mainly gasoline models, with the implementation of new programmes aimed at reducing fuel consumption.

For Europe, our forecast is based on the following passenger car sales breakdown in 2020: diesel cars at 54%, gasoline cars at 36% and hybrid-gasoline cars at 10%. In such a scenario, on-road diesel demand will represent just above 70% of on-road fuels consumed in the EU in 2020. Our analysis shows that even a drastic change in new passenger car sales trends will not rebalance the on-road-fuel demand before 2020, mainly because about 55% of the on-road diesel demand in the EU is for commercial vehicles (freight and light trucks plus buses).

As a result, the European gasoline surplus will be inflated by the incorporation of ethanol in the gasoline pool and a declining demand. Strong cuts in refining capacity will not be able to suppress the gasoline surplus; meanwhile, they will deteriorate the diesel balance.

Technology and catalysts will play a major role on both sides of the Atlantic in adapting refinery production to market demand

The US market presents a better fit between supply and demand, in which a gasoline deficit will be mechanically flattened by falling demand and further incorporation of ethanol.

At Axens, we are convinced that technology and catalysts will play a major role on both sides of the Atlantic in adapting refinery production to market demand.



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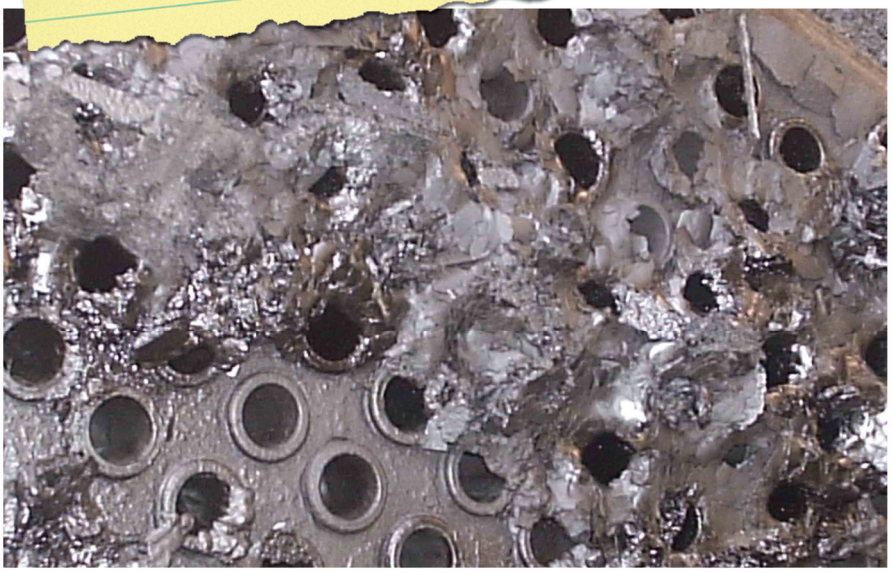
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Process Notes



This exchanger has seen better slates.

Nasty Stuff

Heavy crudes are here to stay. As longs as oil prices remain high, Canadian, Venezuelan, Deep Water Gulf of Mexico, Mexican and other low API gravity crude oils will play an ever more important role in supplying world refineries. And prices promise to remain high because gainsayers notwithstanding, Hubbert was right.

A big question is how to handle best these nasty crudes? Do you revamp existing units or invest in new capacity? With refineries now running flat out, the balance might seem to favor grass roots expansion, but given the substantial cost multiplier over revamps, this could be questioned.

Whichever the case, however, an inescapable fact is that the process design of the project will prove crucial. Between the charge pump and the desalter and the units' distillation columns there are many places where miscalculations in the process design could wreck the entire project.

Can you really be sure of attaining desired crude rates? Desalting viscous crude is extremely difficult. Minimizing coking or asphaltene precipitation in the heaters demands extreme care. Can you reasonably expect high diesel and HVGO recoveries, acceptable levels of nickel, vanadium, and microcarbon residue (MCR)? Refiners who cut deep should not be surprised when the HVGO product MCR is over 2 wt% and the vanadium content is in excess of 10 ppmw. Any one of such difficulties can result in lower revenue, unstable operation or even an inoperable unit. It is critical to understand that the inherent properties of these low API gravity crudes dictate that exact process design is of paramount importance.

The point of this litany of possible problems is to remind you not to skimp in the early phases of engineering. From the start of the LP work through the completion of front-end process engineering, actual product yield and product qualities depend on the process design.

The message is clear. Nasty crudes will continue to make up an increasing proportion of refineries' crude slates. But time is precious. The sooner we face this fact, unwelcome as it may be, the more expeditiously we can adapt.



For a more in depth review, ask for Technical Papers 173, 185 and 197.

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Functional safety management

Jeff Beijk, Functional Safety Expert, Yokogawa Europe
jeff.beijk@nl.yokogawa.com

The IEC 61508 and IEC 61511 international safety standards define the requirements for guaranteeing the safety integrity of equipment used to safeguard potentially hazardous processes in the process industry. These standards, however, are not restricted to the equipment itself, but cover the complete safety life cycle for the design, realisation, operation and maintenance of the safety systems. This implies developing the concept for risk reduction measures from the initiation up to and including the decommissioning or disposal of the process equipment.

Functional safety management (FSM) is a method — as well as an aid — for going through all the phases of the safety life cycle (see Figure 1) in the way defined by the two standards. The standards require those involved in activities during the safety lifecycle to have an FSM system in place and to use it.

In order to obtain a better understanding of what FSM means, it is first important to understand the term safety integrity. The definition of safety integrity in the IEC 61508 standard reads: "The probability of a safety-related system satisfactorily performing the required safety functions under all the stated conditions within a stated period of time." Safety integrity covers both hardware safety integrity, which is the result of the random failures in the hardware used and hence cannot be avoided once the design is fixed, and systematic safety integrity, which is the result of work methods and other procedures.

Hardware safety integrity

Hardware safety integrity has to do with random hardware failures within safeguarding equipment. Depending on the required risk reduction for a potential hazardous process, the equipment needs to achieve a certain Safety Integrity Level (SIL) as defined in the IEC standards.

The Safety Integrity Level — a standard reference item in process safety management — varies from SIL1 to SIL4, with a higher number implying that there are greater risks in the loop. They are described in the IEC safety standards, and can be interpreted as follows:

- SIL0 (risk lower than SIL1) implies tolerable risk and no safety measures are required
- For SIL1 to SIL4, the need for appropriate countermeasures increases with the level, and thus a different

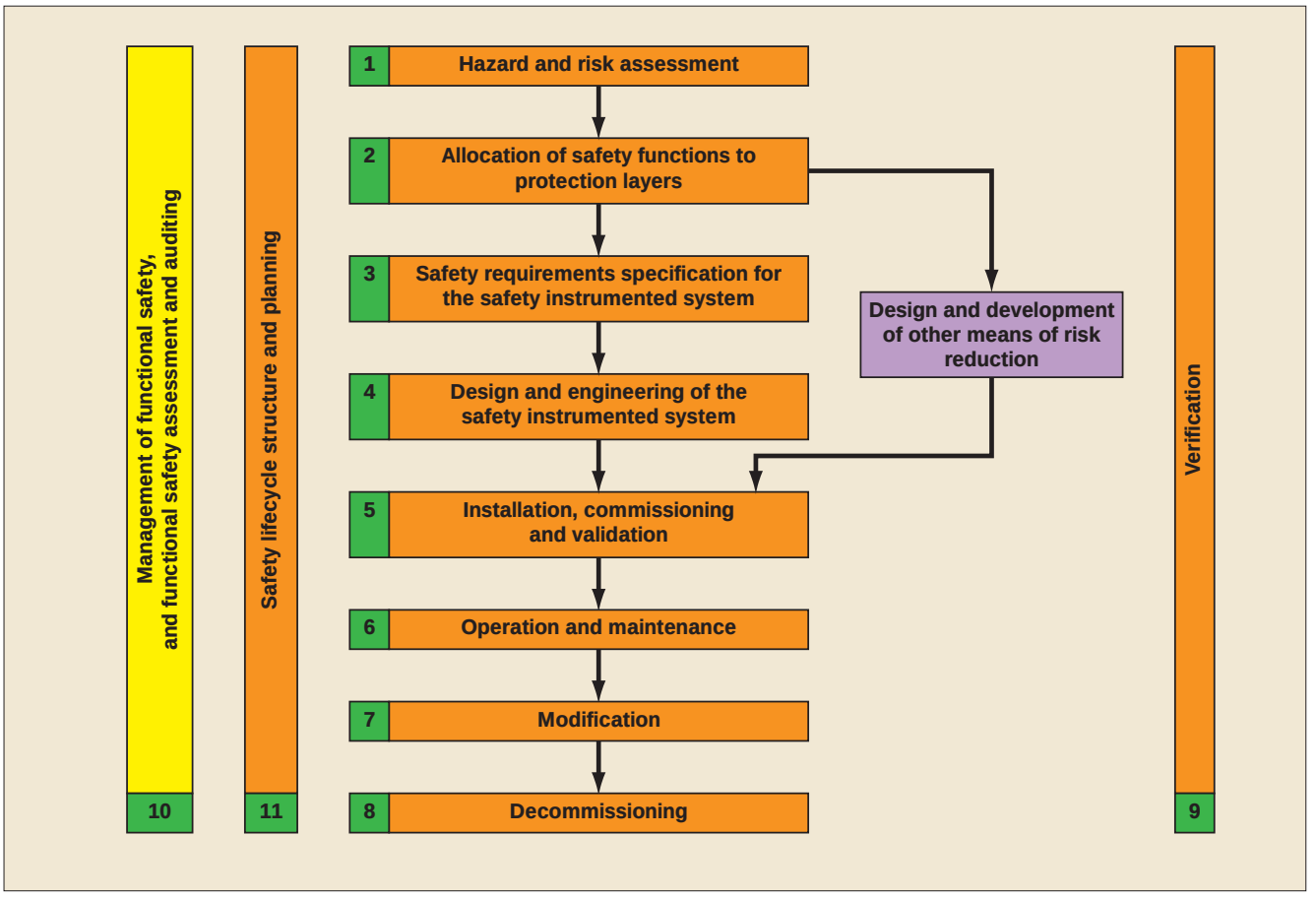


Figure 1 The safety life cycle

Average probability of failure on demand and risk reduction factor

Safety integrity level	Average probability of failure, on demand PFD_{AVG}	Risk reduction factor, $1 / PFD_{AVG}$
4	10^{-5} to $<10^{-4}$	>10 000
3	10^{-4} to $<10^{-3}$	>1 000 to ≤10 000
2	10^{-3} to $<10^{-2}$	>100 to ≤1000
1	10^{-2} to $<10^{-1}$	>10 to ≤100
0	No safety requirements	

Source: IEC 61508-1, Table 2

Table 1

Hardware safety integrity: architectural constraints on type A safety-related subsystems

Safe failure fraction	Hardware fault tolerance		
	0	1	2
<60%	SIL1	SIL2	SIL3
60–<90%	SIL2	SIL3	SIL4
90–<99%	SIL3	SIL4	SIL4
>99%	SIL3	SIL4	SIL4

Table 2

Hardware safety integrity: architectural constraints on type B safety-related subsystems

Safe failure fraction	Hardware fault tolerance		
	0	1	2
<60%	Not allowed	SIL1	SIL2
60-<90%	SIL1	SIL2	SIL3
90-<99%	SIL2	SIL3	SIL4
>99%	SIL3	SIL4	SIL4

Table 3

Minimum hardware fault tolerance of PE logic solvers

SIL	Minimum hardware fault tolerance		
	SFF <60%	SFF 60-90%	SFF >90%
1	1	0	0
2	2	1	0
3	3	2	1
4	Special requirements apply - See IEC 61508		

Table 4

Minimum hardware fault tolerance of sensors and final elements and non-PE logic solvers

SIL	Minimum hardware fault tolerance
1	0
2	1
3	2
4	Special requirements apply - See IEC 61508

Table 5

degree of risk reduction is required for each level: for SIL1 the risk reduction must be at least a factor of 10; for SIL2 at least a factor of 100; for SIL3 at least a factor of 1000; and finally for SIL4 risk reduction must be at least a factor of 10 000.

This interpretation is not sufficient to explain what the SIL in the IEC standards exactly defines quantitatively. It is still important to understand what the SIL means in terms of the safety loop and the selection of appropriate sensors, logic solvers and final elements to meet the classified safety level, and thereby to realise a safety system that complies with the targeted SIL.

Today, industrial sensors are available that provide highly capable self-diagnostic functions as a standard feature, and many of them are certified for use in Safety Instrumented Functions (SIF), many times for use in SIFs up to SIL2 when used as single instruments and up to SIL3 in redundant use. Similarly, today's safety systems include logic solvers certified for use in SIFs classified as SIL3 or SIL4.

Together, the two IEC standards require that the achieved SIL of a complete safety instrumented function be proven. There are two aspects involved in demonstrating that the required SIL will be achieved:

- The safety architectures of sensors, logic solvers and final elements (see Tables 2–5) have to comply with the relevant tables for fault tolerance: IEC 61508-2
- The achieved compound PFD_{AVG} (probability of a failure on demand averaged over the lifetime of the safety instrumented system) of all hardware elements that are part of the safety instrumented function has to be calculated and has to comply with the required SIL. The risk reduction of the SIF now computes as the inverse of the $PFDA_{VG}$; for example, when PFD_{AVG} = 0.01, risk reduction = 100 (see Table 1).

Architectural constraints have to do with the fault tolerance of devices: depending on the complexity of devices and on their so-called safe failure fraction (see Table 2), end users (and successively engineering contractors) have to apply single, dual redundant or even multiple redundant systems. It is also a system integrator's responsibility to check whether the safety requirements comply with these regulations, not only at acceptance of a project but also during early involvement in front-end engineering design (FEED) studies and in bid phases.

Vendors of safety-related elements have to provide relevant failure data for their products to make it possible for system integrators and/or end users to determine the safety architecture and to calculate the PFD_{AVG}.

Systematic safety integrity

The fewer the number of systematic failures, the higher the systematic safety integrity of safety-related devices and systems. In general, systematic failures occur as a result of work methods — for example, if designs are not well checked, if (sub) systems and application programs are not well tested, or if document control is a mess. In other words, aspects such as hardware and

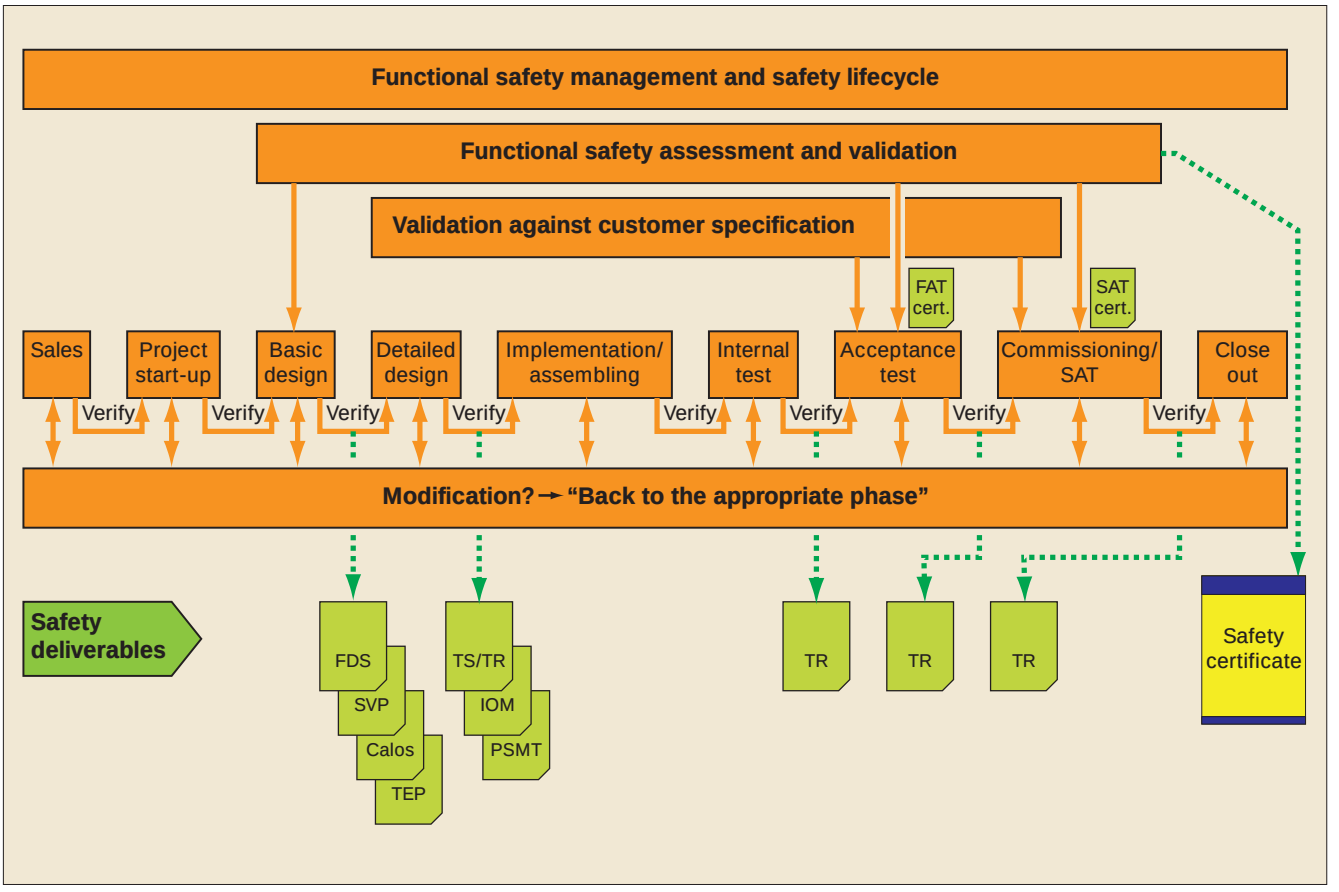


Figure 2 Yokogawa's implementation of functional safety management

software design, application engineering and programming, verification and validation, testing and configuration management all have to be carried out in a structured manner and well documented in such a way that there is an auditable trail.

To guarantee this structured way of working, the IEC standards require users to have a functional safety management system in place and to apply it. Adequate procedures, templates and tools need to be in place — and to be used — to ensure the integrity of project execution. All staff involved in the realisation of safety-related systems have to be safety competent. As part of (all) safety-related projects, a safety validation exercise has to be carried out — either by an independent functional safety expert within the company or by a third-party expert.

The route to FSM

To summarise, management of functional safety means that:

- Functional safety-related procedures, work instructions, tools and templates need to be in place and, even more importantly, it can be shown that they are all used during project execution
- Project engineers are employed who are fully trained (and retrained) in safety and thus totally understand the basic requirements of safety as well as those of safety systems
- It is not only the engineers and maintenance staff who need to be trained, but also the project managers and line managers in aspects of engineering, designing, assembling, testing, commissioning and maintaining of safety systems. Moreover, these staff must know and understand the safety regulations
- The execution of functional safety assessment and validation must take place on every safety project and must be carried out by functional safety experts who operate independently from the project execution team
- Periodic functional safety audits must be executed — again by independent functional safety experts
- All these activities have to be well documented to provide an auditable trail.

These principles are summarised in Figure 2.

It is not just suppliers and system integrators of safety instrumented systems who have to comply with the requirements of the safety standards for functional safety management. All those parties who are involved in one or more phases of the safety life cycle have to have a FSM system in place if they aim to comply with the standards.

To assist users in implementing this approach, safety consultancy services based on the expertise of companies such as Yokogawa are now being offered to external parties, including end users and engineering contractors. In addition to providing support to users setting up an FSM system, these services cover more phases of the safety life cycle, including advice on the preparation of hazard and risk assessments, safety requirements specifications, safety site validation, and the operation and maintenance of safety applications.

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Clean diesel project

A process review, including the improvement of atmospheric and vacuum distillation columns, for the reformulation of the diesel pool

LUIGI VALAGUSSA
Koch-Glitsch Italia

The reformulation of diesel oil fuel was introduced by the European Union in 2009. The aim of the Fuel Directive is to reduce pollution from vehicle emissions. One feature of this directive, discussed in this article, is the specification that the maximum distillation final point of the diesel oil is set at 360°C for 95% of distilled volume measured according to the ASTM D86 analysis (D86T95). Additionally, the Fuel Directive requires a reduction of sulphur content to a maximum 10 ppm. Both the specifications affect refinery operations. More specifically, catalytic processes such as hydrocracking (HDC) and hydrotreating (HDT) are used to improve the diesel yield and to limit the sulphur content respectively. A more extensive analysis, which looks at the atmospheric distillation unit (CDU) and vacuum distillation unit (VDU), may improve total diesel production and minimise the impact on existing units of the refinery. This analysis has the benefit of lower capital cost for the project; furthermore, the improvements can no longer be postponed in view of the market regulation of diesel oil.

Study approach

The scope of this work was to analyse and compare different ways to achieve the required diesel distillation end point from the CDU / VDU as specified by the shorter diesel oil cut (D86T95=360°C), while minimising the impact on the HDC and HDT downstream units and optimising the total diesel production yield.

A refinery requested a licensor to conduct a feasibility study and to draw up a cost estimate for the revamp of the refinery's HDT unit to achieve the specified clean diesel oil requirements.

No consideration was given and no modification was proposed to produce in-specification, straight-run diesel from the existing CDU. Therefore, the design basis for the HDT revamp was a diesel stream with D86T95=360°C at the HDT battery limit. The HDT does not significantly change the diesel distillation endpoint. The HDT feasibility study investigated whether this diesel stream property can be achieved by mixing the present straight-run diesel from the CDU with an additional light stream to reach the maximum distillation point. The evaluation showed that if a D86T95=325°C blending stream is mixed with the present straight-run diesel stream at D86T95=382°C, the

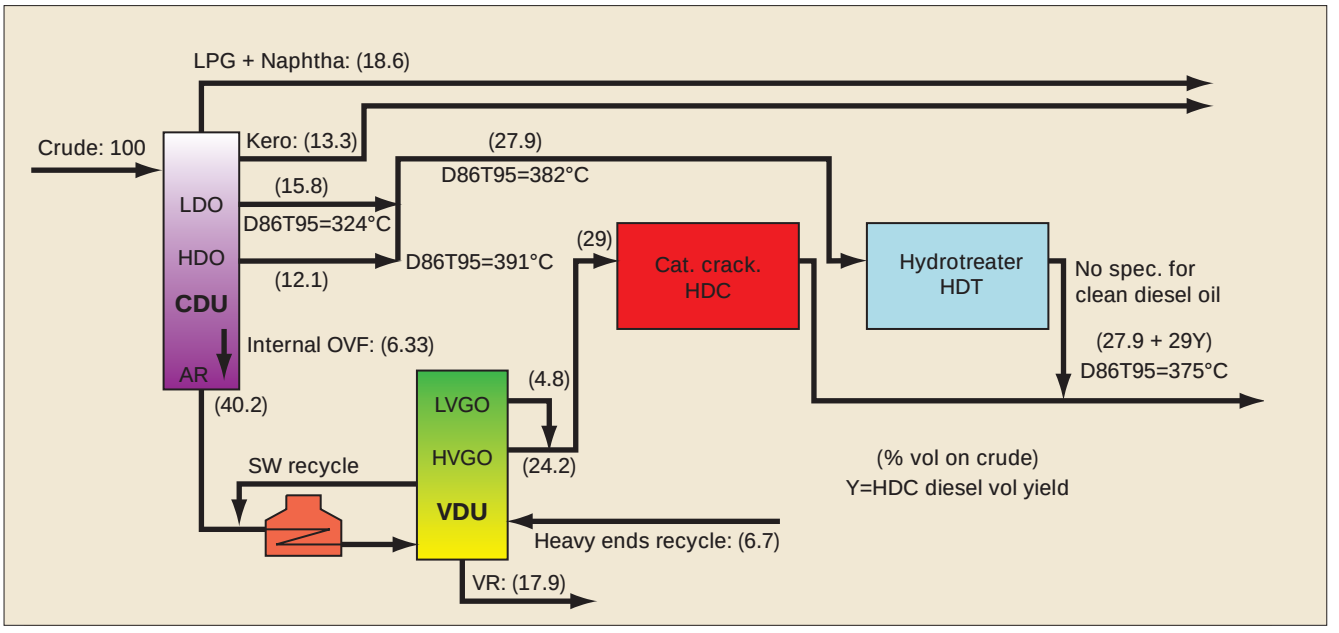


Figure 1 Present scheme

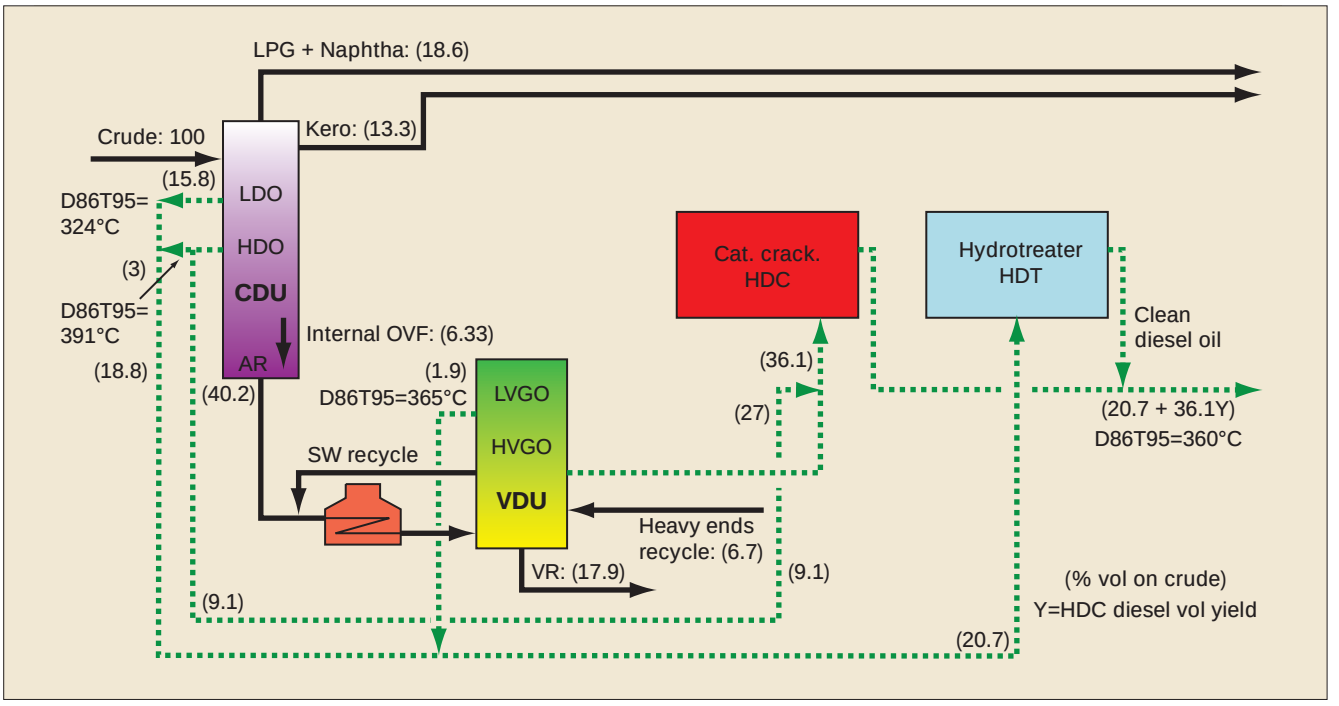


Figure 2 HDO splitting and vacuum revamp

light blending should be about 1.7 times (by volume) the total atmospheric diesel produced. This solution does not look very attractive because it requires an increase in treatment capacity, which can affect the revamp of the existing HDT unit substantially and the size of a new unit as well. It also omits any consideration of the availability of a light blending stream and the total cost.

Two main points to consider from this example are:

- The clean diesel project must take the overall refinery process scheme and production capacity into account
- Alternatives are available to improve clean diesel production and to limit the impact on the new/existing equipment and facilities.

Present scheme

The main features of the existing refinery (see Figure 1) are listed below. The refinery is presently producing non-clean diesel oil:

- The crude oil-handling capacity is 125 000 b/d. To increase the handling capacity, the atmospheric column was revamped some years ago by Koch-Glitsch with Superfrac trays and Flexipac HC structured packing; it thus contains the most advanced column internals technology
- Light diesel oil (LDO) and heavy diesel oil (HDO) are produced in the atmospheric column. These streams are mixed together and fed to the HDT unit. The analysis of this straight-run diesel oil is D86T95=382°C, and this does not change significantly after HDT treatment. The present HDT unit is not able to reduce the sulphur content to the required level for clean diesel oil
- The atmospheric residue (AR) is fed to the vacuum column, which is equipped with three beds of grid packing (old style). One bed at the top of the column for top pumparound service produces a light vacuum gas oil (LVGO), a second bed at the middle of the column for mid pumparound service produces a heavy vacuum gas oil (HVGO), and a third bed at the bottom of the column is a wash bed. The two gas oils are mixed together and fed to the HDC unit
- The diesel stream from the HDC unit is mixed with the HDT straight-run diesel and a final diesel stream with D86T95=375°C (value from refinery), which is above the distillation endpoint requirement for clean diesel oil, is produced.

The refinery has to consider two main modifications in order to comply with the clean diesel specification: first, the revamp of the HDT unit (to reduce sulphur content), which will be approached and solved by a catalyst licensor; and, second, the distillation point specification of the diesel stream.

Alternative scheme to produce clean diesel oil

The first step was to evaluate whether the CDU and VDU columns can reach the target through enhanced performance. It is clear from Figure 1 that the deep cut of HDO greatly affects the diesel quality. In addition, no sensible benefit is achieved by modifying the internals of the existing atmospheric column to produce in-specification, straight-run diesel oil and by minimising the loss of HDO yield. The main reasons are:

- There is a low margin for improving the HDO final distillation points because the present column internals are already designed according to the most advanced and efficient technology
- Any attempt to maximise the straight-run diesel oil, including different splitting of LDO/HDO, affects existing equipment and operations (for instance, pumparound and heat recovery). The total diesel oil yield must be reduced and the heavy ends that are not recoverable into the HDO stream must be left in the atmospheric

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residue fed to the vacuum column. An increase in atmospheric residue could affect the existing vacuum heater performance, which is already limiting the present operations.

On the other hand, a total revamp of the vacuum column internals (from the old grid packing to new structured packing beds) can produce the LVGO stream in specification for clean diesel oil and therefore be suitable for blending with the atmospheric straight-run diesel oil. This avoids additional processing of this stream through HDC. The vacuum column revamp calls for four new structured packing beds, instead of the three existing beds, with the additional bed located below the top pumparound bed for fractionation service. This is necessary to produce the in-specification LVGO product.

Currently, this arrangement is one of our recommended options, because there is extensive experience that it provides a stream suitable for a diesel oil pool without further processing. In our study, we determined that the recoverable LVGO with the revamped vacuum column is about 2 vol% on a crude feed basis.

On the basis of the above considerations, an alternative scheme, the HDO splitting and vacuum revamp scheme (HDO splitting scheme), to produce clean diesel oil without reducing the HDO yield, can be utilised (see Figure 2):

- The HDO from the atmospheric column is split into a stream that can be mixed with the LDO stream and then with the LVGO stream produced by the vacuum column in a ratio suitable to obtain D86T95=360°C in the resulting stream (LDO + HDO partially + LVGO). This stream can be sent to HDT for the final treatment
- As discussed already, the vacuum column is revamped from the existing three beds to four beds. The produced LVGO is suitable for the diesel oil pool, and the HVGO is sent to the HDC together with the excess HDO stream. Even if the vacuum column revamp reduces the total vacuum gas oil (VGO) to HDC, the total feed to HDC must account for the extra feed coming from the HDO stream not conveyed to HDT.

Comparing the HDO splitting scheme to the present scheme, it can be seen that the total feed to HDT decreases from 27.9 vol% based on crude to 20.7 vol%; however, the HDC feed increases from 29 vol% based on crude to 36.1 vol%, resulting in a capacity increase of 24.5% for HDC. The increased HDC capacity requires a deeper investigation into the suitability of running the existing unit under the new conditions, and the expected conclusion is that the HDC unit itself has to be revamped. Additionally, we have to note that diesel production from HDC depends on the conversion yield, and this may result in a decrease in overall diesel production.

New scheme for maximising clean diesel oil

The main feature of the new scheme proposal involves the atmospheric over-flash (OVF). As Figure 3 shows, this stream is drawn off from the atmospheric column, bypasses the vacuum heater and is fed to the VDU above the wash section. In this case, the vacuum column is also revamped with four beds.

The benefit of the new scheme can be quantified by comparing the values reported in Figure 1 (present scheme), Figure 2 (HDO splitting and vacuum revamp scheme) and Figure 3 (new scheme). The benefits are:

- The new scheme gives better overall clean diesel oil recovery compared to the HDO splitting solution

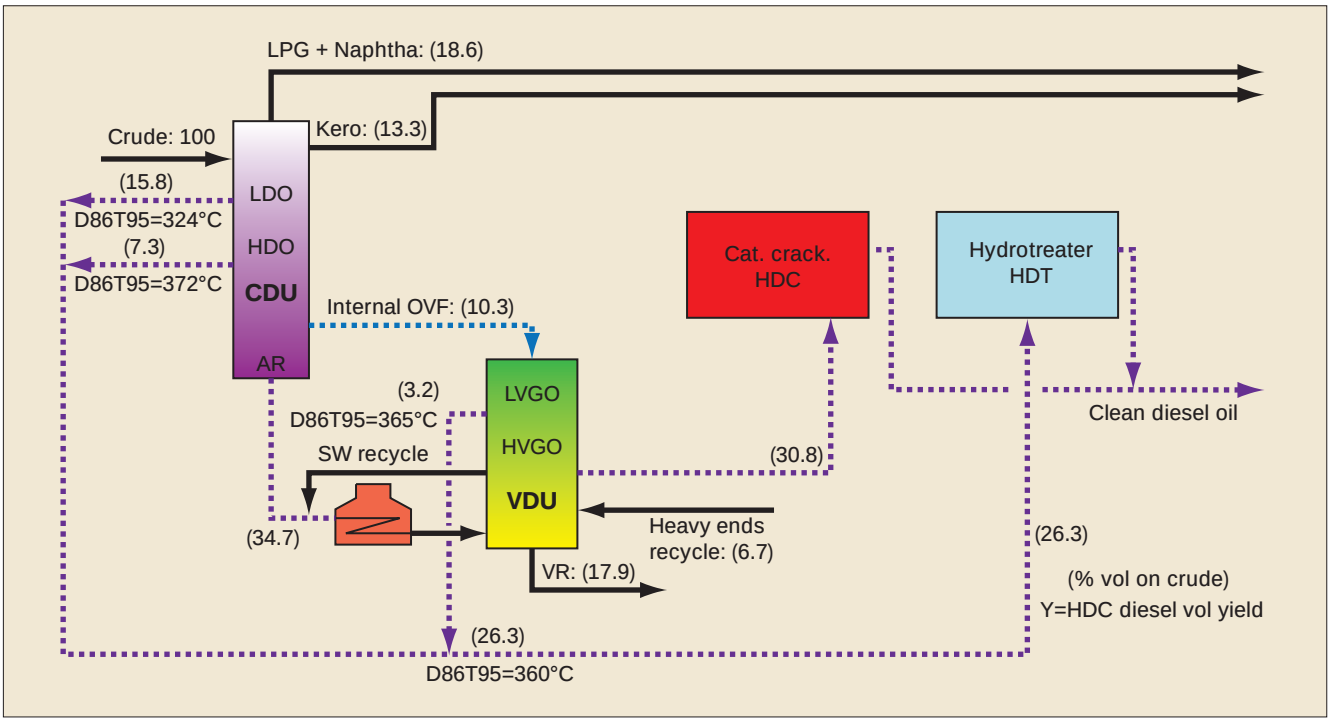


Figure 3 New scheme

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- In the new scheme, the feed to HDC decreases by approximately 14.7% compared to the HDO splitting scheme and therefore the required treatment capacity of HDC results in an approximate increase of only 6.2% in comparison to the present arrangement. We can expect no, or only minor, modifications to the existing HDC unit
- In the new scheme, the feed to HDT increases approximately 27% compared to the HDO splitting scheme; however, it is less than the present capacity and it is actually about 5.7% less than the capacity of the present scheme. The existing HDT could need some modifications due to the ultra-low sulphur level required by the clean fuel regulation. On the contrary, the decreased feed rate can provide additional benefit by allowing improved performances with the same arrangement or with minor modifications compared with the HDO splitting scheme
- The new scheme saves on vacuum heater duty demand, which generally is a bottleneck in revamping projects.

The new scheme is unusual in existing plants where the atmospheric over-flash is typically combined with the atmospheric residue. Recent atmospheric column revamps have mostly been carried out to increase not only capacity but also the distillates yield (including diesel oil yields), therefore reducing gas oil losses in the atmospheric residue. This approach was acceptable because a longer diesel oil cut was allowed, enabling the atmospheric residue to dry up. Practically all of the straight-run diesel product was recovered in the atmospheric column, and the vacuum column was arranged to produce a long gas oil cut from the mixing of LVGO and HVGO (see Figure 1) containing heavy ends to be converted into lighter products in HDC.

The new scheme (see Figure 3) shows how a review of conditions in the CDU and VDU allows for major benefits with minor impact.

CDU operations

In Figure 3, it can be seen that the HDO yield from the CDU has been reduced to produce a HDO stream that can be mixed with LDO (same yield as the present scheme and the HDO splitting scheme) and with LVGO from the VDU to produce a straight-run, in-specification diesel oil (D86T95=360°C) that is fed to HDT. This stream results in 26.3 vol% based on crude, which is lower than the not-in-specification present feed, but definitely higher than the feed computed for the HDO splitting scheme. The crude heater duty is the same for all the schemes and, because of the reduced yield of HDO in the new scheme, the extra distillate is recovered in the over-flash stream, which increases to 10.3 vol% based on crude, compared with 6.33 vol% in the earlier schemes. Different rates for the over-flash stream or splitting thereof (partially drawn off and partially conveyed into atmospheric residue) can be investigated more deeply according to needs and constraints, while taking the recoverable yield of HDO and the impact on crude and vacuum heater duties into account.

In the new scheme, we used all of the crude heater duty available from the present scheme. Since the over-flash stream is totally conveyed to the vacuum column rather than being sent to atmospheric residue as in the other schemes, the resulting atmospheric residue product decreases to 34.7 vol% based on crude, compared with 40.2 vol% in the earlier schemes. In this specific case, a few mechanical modifications to the existing unit are needed to be able to apply the new processing scheme:

- A new draw-off nozzle is installed in the atmospheric column vessel for over-flash service
- A new circuit complete with pumps, piping, control and instrumentation is installed to feed the over-flash product to the vacuum column.

VDU operations

The existing vacuum column is still arranged with an old-style design consisting of three beds with low-efficiency grid packing. We propose a total revamp of the column internals, providing four beds equipped with new structured packing from Koch-Glitsch.

The additional bed is located between the HVGO and LVGO pumparound beds, providing a fractionation section for the LVGO product. In this way, the LVGO product, drawn off below the LVGO pumparound bed, is made available in specification for mixing with the atmospheric diesel oil and avoiding further processing in HDC, as in the present scheme. The arrangement shown is not necessarily required to realise the clean diesel project, but it has been applied in many projects (practically since the introduction of structured packing in the market) to improve the performance of vacuum columns worldwide with significant results. It is clear that the clean diesel regulation pushes heavily towards any investment that can improve the recovery of diesel oil while limiting the penalty of paying for the production of the required shorter cut.

Figure 3 shows that the recovery of in-specification LVGO is 3.2 vol% based on crude, compared with 1.9 vol% according to the HDO splitting scheme. Furthermore, the recovery of HVGO (with a slightly higher endpoint compared with the previous cases) is 30.8 vol% based on crude, compared with 24.2 vol% according to the present scheme and 27 vol% according to the HDO splitting scheme.

The new scheme (with the atmospheric over-flash fed to the vacuum column) enables better recovery of in-specification LVGO and also increases the HVGO yield, resulting in a maximisation of the total distillates yield (LVGO + HVGO) compared with the other schemes. In conclusion, this looks to be the most efficient way to improve gas oil recovery.

In the reported comparisons, the slop wax (SW) recycle to the vacuum heater, the external feed (heavy ends recycle) and the yield of vacuum residue (VR) product have been set at the same values for all of the schemes.

Since the over-flash is drawn off totally from the atmospheric

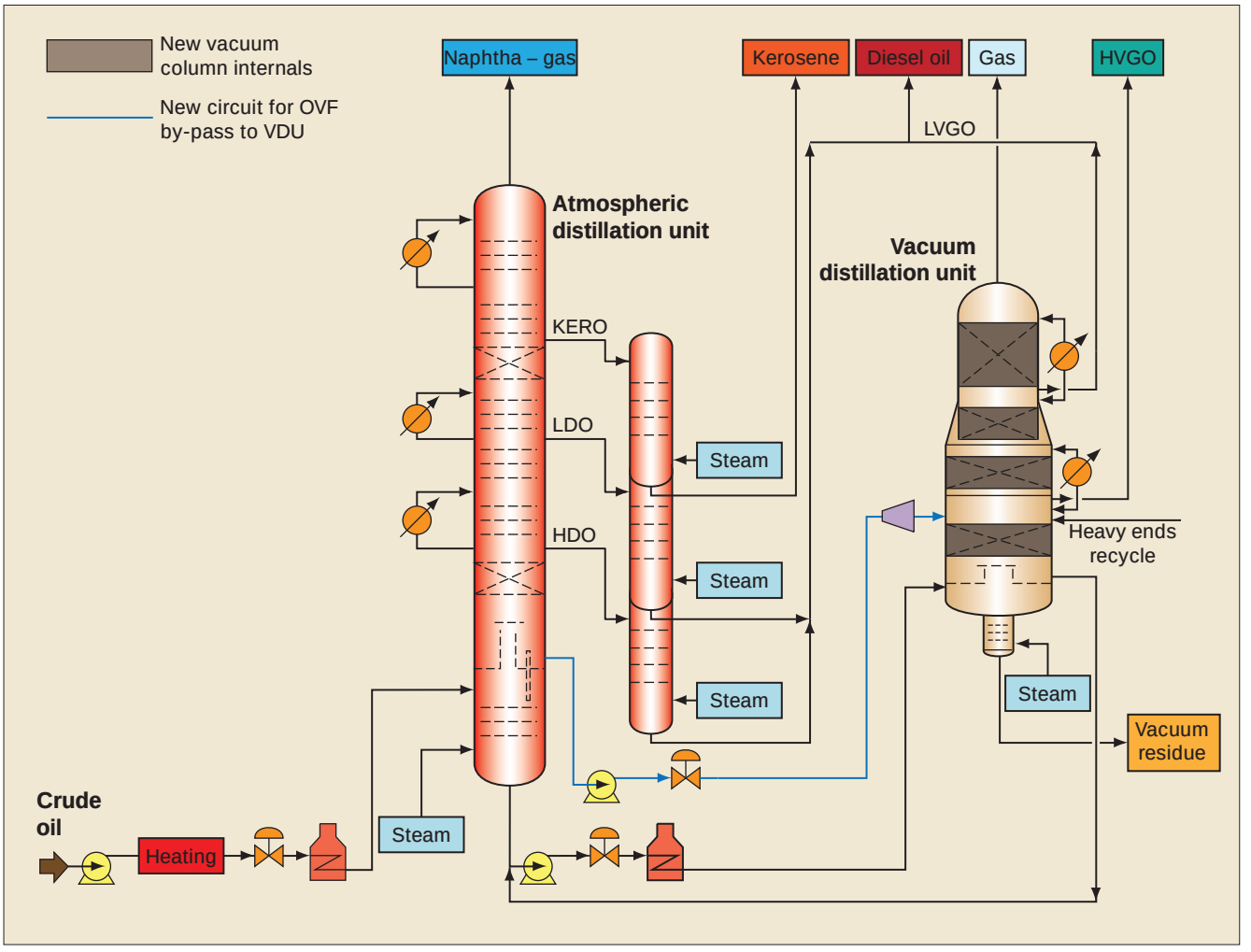


Figure 4 New process flow diagram

column, rather than being conveyed into the atmospheric residue according to the new scheme, the atmospheric residue feed decreases to 34.7 vol% based on crude, compared with 40.2 vol% for the other schemes; as a result, the vacuum heater will be affected.

For the same vacuum residue, the vapourisation rate to the furnace according to the new scheme is thus less than that required for the other schemes, both as quantity of vapour flow and as percentage of total feed to the heater. As a result, the heater duty demand in the new scheme is 12.7 MMKcal/h with a vapourisation of 22 wt% of total feed, compared with 14.8 MMKcal/h and a vapourisation of 24.8 wt% in the other schemes. These figures are very attractive when evaluating the performance of an existing furnace at the new conditions, even with the increased temperature at the heater outlet. In fact, this temperature increases in the new scheme by approximately 6°C compared with the previous schemes because a heavier cut of atmospheric residue is fed to the heater. This point should be evaluated more deeply during the engineering phase, as well as the fact that the lower vapour rate will cause a reduction in the pressure drop along the transfer line, which results in a lower heater outlet temperature.

Some final consideration must be given to the conditions and location of the over-flash stream entering the vacuum column. In the new scheme, the atmospheric over-flash is fed above the wash bed of the vacuum column at the draw-off conditions from the atmospheric column. This means that this stream is fed at about 363°C, a very high temperature, into a column under vacuum. This will cause high flashing rates at the inlet of the vacuum column or, more specifically, downstream of the valve controlling the over-flash flow rate. This condition requires a relatively large nozzle. In the case of a revamp, the necessary room has to be evaluated carefully to provide sufficient room for the nozzle, the disengagement space above the wash bed and a feed inlet device.

Cooling of the over-flash stream, before feeding it to the wash section of the vacuum column, reduces the flashing rate but increases the heater duty demand. In this case, a critical piece of equipment, such as the vacuum heater, can cause a bottleneck because of the increase in the vapourisation rate and the heater outlet temperature.

An alternative was evaluated; namely, cooling down the over-flash stream to the temperature of the bottom pumparound (150°C) and moving the feed location to above the bottom pumparound bed. The results are in line with the new scheme in terms of recovery, product characteristics and heater duty, but the bottom pumparound

Total clean diesel production summary

Case		vol% on crude (% difference vs present) Present scheme	HDO splitting scheme	New scheme
LDO to HDT (hydrotreating)		15.80	15.80	15.80
HDO to HDT		12.10	3.00	7.30
LVGO to HDT		0.00	1.90	3.20
Total to HDT		27.90	20.70	26.30
LVGO to HDC (hydrocracking)		4.80	0.00	0.00
HVGO to HDC		24.20	27.00	30.80
HDO to HDC		0.00	9.10	0.00
Total to HDC		29.00	36.10	30.80
Total diesel D86 95%v, °C		375	360	360
HDC diesel conversion yield %v	30	36.60	31.53 (-5.07)	35.54 (-1.06)
	50	42.40	38.75 (-3.65)	41.70 (-0.70)
	70	48.20	45.97 (-2.23)	47.86 (-0.34)
	90	54.00	53.19 (-0.81)	54.02 (0.00)

Table 1

duty decreases substantially (approximately half that of the new scheme). However, flashing of the over-flash stream is practically nil, and this solves the space problems described earlier.

On the other side, feeding the over-flash between the bottom pumparound bed and the LVGO fractionation bed increases the risk of contamination with unwanted material that can be entrained into the distillates products. The risk is higher than in the case where the over-flash is fed above the wash bed. This matter should be evaluated in more detail, while taking the quality and characteristics of the over-flash stream into account.

The simplified process flow diagram shown in Figure 4 indicates the new over-flash circuit and the new beds of the vacuum column.

Summary and conclusion

The diesel oil pool is now subject to more stringent specifications according to the EU's Fuel Directive for the utilisation of clean diesel oil. The reformulation of the diesel oil pool can be achieved by a review of operations and improvement of the performances of the atmospheric and vacuum distillation columns.

A new processing scheme, applied to an existing refinery, has been presented and the attainable benefits have been discussed. These benefits include increased overall clean diesel recovery with minor impact on the existing downstream HDC and HDT units. The new scheme is compared with the present scheme (reproducing the actual operations/ arrangement) and with the HDO splitting scheme. The new scheme, representing an alternative for clean diesel production based on a traditional route, is shown and discussed.

A new process route where the atmospheric over-flash is fed to the vacuum column bypassing the vacuum heater has been suggested. With this scheme, the recovery of gas oil in the vacuum column can be enhanced, partially as in-specification LVGO for the diesel pool (3.2 vol% based on crude) and partially as HVGO feedstock to HDC, resulting in an increase in total gas oil recovery (LVGO + HVGO) of about 17 vol% in comparison to the present operations. Under the stated conditions, the vacuum heater duty demand decreases by approximately 14% in comparison to the present operations. This adds a solid benefit because the vacuum heater, a critical item, is often a bottleneck in revamp projects. The vacuum column internals play an especially important role in improving products separation and gas oil recovery. Two main modifications to the vacuum column are proposed: first, the installation of the latest generation of structured packing; and second, the introduction of a new LVGO fractionation bed below the top pumparound (not shown in the present arrangement). These modifications will improve the product quality and yields as described.

The diesel oil pool is now subject to more stringent specifications according to the EU's Fuel Directive

Important issues to resolve while developing a revamp project according to the new scheme are the increased temperature at the vacuum heater outlet and the feed location of the atmospheric over-flash stream to the vacuum column. In the reported new scheme, the over-flash has been fed hot above the wash section, but an alternative with a cold feed above the bottom pumparound bed could be considered.

In Table 1, the production rates referred to are reported in terms of vol% based on crude feed. Total diesel production depends on the conversion yield of the HDC unit; therefore, we reported several cases at various values of conversion yield. The new scheme, in comparison with the alternative HDO splitting scheme, enables better splitting of the treatment capacity between HDT and HDC, which is closer to the existing capacities. Total clean diesel production is better in the new scheme, in comparison with the HDO splitting scheme, for all the assumed conversion yields in HDC. We conclude that the new scheme can achieve the recovery of clean diesel while minimising the penalty in clean diesel production, which is an expected result of the stricter specification for market diesel oil.

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Luigi Valagussa is Refining Process Manager with Koch-Glitsch in Italy. He has more than 30 years' experience in oil refining and process design, and graduated in chemical engineering from Politecnico of Milan, Italy.
Email: luigi.valagussa@kochglitsch.com



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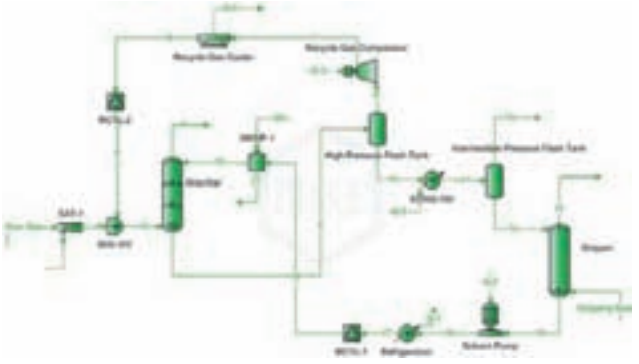
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Comparing Physical Solvents for Acid Gas Removal

Physical solvents such as DEPG, NMP, Methanol, and Propylene Carbonate are often used to treat sour gas. These physical solvents differ from chemical solvents such as ethanolamines and hot potassium carbonate in a number of ways. The regeneration of chemical solvents is achieved by the application of heat whereas physical solvents can often be stripped of impurities by simply reducing the pressure. Physical solvents tend to be favored over chemical solvents when the concentration of acid gases or other impurities is very high and the operating pressure is high. Unlike chemical solvents, physical solvents are non-corrosive, requiring only carbon steel construction. A physical solvent's capacity for absorbing acid gases increases significantly as the temperature decreases, resulting in reduced circulation rate and associated operating costs.

Typical Physical Solvent Process



DEPG (Dimethyl Ether of Polyethylene Glycol)

DEPG is a mixture of dimethyl ethers of polyethylene glycol. Solvents containing DEPG are marketed by several companies including Coastal Chemical Company (as Coastal AGR®), Dow (Selexol™), and UOP (Selexol). DEPG can be used for selective H_2S removal and can be configured to yield both a rich H_2S feed to the Claus unit as well as bulk CO_2 removal. DEPG is suitable for operation at temperatures up to 347°F (175°C). The minimum operating temperature is usually 0°F (-18°C).

MeOH (Methanol)

The most common Methanol processes for acid gas removal are the Rectisol process (by Lurgi AG) and Ifpexol® process (by Prosernat). The main application for the Rectisol process is purification of synthesis gases derived from the gasification of heavy oil and coal rather than natural gas treating applications. The two-stage Ifpexol process can be used for natural gas applications. Methanol has a relatively high vapor pressure at normal process conditions, so deep refrigeration or special recovery methods are required to prevent high solvent losses. The process usually operates between -40°F and -80°F (-40°C and -62°C).

NMP (N-Methyl-2-Pyrrolidone)

The Purisol Process uses NMP® and is marketed by Lurgi AG. The flow schemes used for this solvent are similar to those for DEPG. The process can be operated either at ambient temperature or with refrigeration down to about 5°F (-15°C). The Purisol process is particularly well suited to the purification of high-pressure, high CO_2 synthesis gas for gas turbine integrated gasification combined cycle (IGCC) systems because of the high selectivity for H_2S.

PC (Propylene Carbonate)

The Fluor Solvent process uses JEFFSOL® PC and is by Fluor Daniel, Inc. The light hydrocarbons in natural gas and hydrogen in synthesis gas are less soluble in PC than in the other solvents. PC cannot be used for selective H_2S treating because it is unstable at the high temperature required to completely strip H_2S from the rich solvent. The FLUOR Solvent process is generally limited to treating feed gases containing less than 20 ppmv; however, improved stripping with medium pressure flash gas in a vacuum stripper allows treatment to 4 ppmv for gases containing up to 200 ppmv H_2S. The operating temperature for PC is limited to a minimum of 0°F (-18°C) and a maximum of 149°F (65°C).

Gas Solubilities in Physical Solvents

All of these physical solvents are more selective for acid gas than for the main constituent of the gas. Relative solubilities of some selected gases in solvents relative to carbon dioxide are presented in the following table.

The solubility of hydrocarbons in physical solvents increases with the molecular weight of the hydrocarbon. Since heavy hydrocarbons tend to accumulate in the solvent, physical solvent processes are generally not economical for the treatment of hydrocarbon streams that contain a substantial amount of pentane-plus unless a stripping column with a reboiler is used.

Gas Component	DEPG at 25°C	PC at 25°C	NMP at 25°C	MeOH at -25°C
H_2	0.013	0.0078	0.0064	0.0054
Methane	0.066	0.038	0.072	0.051
Ethane	0.42	0.17	0.38	0.42
CO_2	1.0	1.0	1.0	1.0
Propane	1.01	0.51	1.07	2.35
n-Butane	2.37	1.75	3.48	-
COS	2.30	1.88	2.72	3.92
H_2S	8.82	3.29	10.2	7.06
n-Hexane	11.0	13.5	42.7	-
Methyl Mercaptan	22.4	27.2	34.0	-

Choosing the Best Alternative

A detailed analysis must be performed to determine the most economical choice of solvent based on the product requirements. Feed gas composition, minor components present, and limitations of the individual physical solvent processes are all important factors in the selection process. Engineers can easily investigate the available alternatives using a verified process simulator such as ProMax® which has been verified with plant operating data.

For additional information about this topic, view the technical article "A Comparison of Physical Solvents for Acid Gas Removal" at http://www.bre.com/tabid/147/Default.aspx. For more information about ProMax, contact Bryan Research & Engineering or visit www.bre.com.

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Simulation model increases visbreaker conversion

Introduction of advanced analytical monitoring, chemical treatment and process optimisation has raised the profitability of a visbreaker unit

ERNESTO AGORRETA, CARLOS ANGULO and ALEIXANDRE SORIANO *Repsol Tarragona*
CRISTINA FONT and MARCO RESPINI *Baker Hughes*

In today's refining climate, the economics of a visbreaking unit are mainly related to the conversion levels achieved. Conversion is limited by the impact of cracking reactions on the progressive destabilisation of the asphaltenes present in the unit feed. This destabilisation causes fouling phenomena, due to precipitation of the asphaltenes and conversion of some of the asphaltenes to generate coke particles at cracking temperatures above 400°C (752°F), and these phenomena limit unit run lengths. On the other hand, destabilised asphaltenes can easily aggregate over time and, since produced visbreaker resid is often a base stock for the production of heavy fuel oils, this can lead to problems with hot filtration test (HFT) results.

Visbreaker severity is monitored to maximise conversion, taking into account excessive coke generation and the tendency of asphaltenes to precipitate, either inside process equipment or as sediments in the heavy fuel oil produced. As fouling increases exponentially at higher conversions, process control becomes more and more important to prevent drastic negative outcomes.

Severity is a function of operating temperatures and velocity steam. This article presents a case of optimisation of these two variables at the Repsol Tarragona visbreaker, resulting in major improvements to visbreaker conversion.

Repsol Tarragona

The Repsol Tarragona refinery is a state-of-the-art 200 000 b/d refinery that has broad experience processing opportunity crudes and feeding different residues to the visbreaker unit. The first step of this project was the implementation of Baker Hughes' advanced analytical VisTec technologies for the rapid and reliable assessment of visbreaker tar (vistar) and heavy fuel oil stability, and to evaluate fouling tendencies in the unit. This step enabled the refinery to run the unit close to its operating limits and maximise conversion, while rapidly adapting process conditions to changes in processed feed quality or flow rate.

A second step for increasing unit profitability was based on a new development using a proprietary simulation model of flow regimes and liquid-phase velocities across the visbreaker heater coils as a function of flow rates, operating temperatures and velocity steam.

The results of the model were validated in the unit by Repsol process and operation engineers with Baker Hughes service engineers and its technical service group. Operational changes were implemented based on the results from the simulation work, while the impact on fouling and sediments formation, which could potentially affect produced fuel oil quality, was continuously monitored. At the same time, furnace skin temperature trends were continuously tracked and normalised to achieve targeted unit run length.

The implementation of all the steps described in this article resulted in further valuable increases in conversion without negative effects on unit run length and fuel oil specifications.

Visbreaker monitoring

The main purpose of a visbreaker unit is to reduce feed viscosity up to the vistar stability limit, as well as to achieve high distillate yields; in other words, to achieve maximum conversion value, which, in turn, has a strong dependence on feed quality.

Increasing conversion means operating the unit at higher severities, either by increasing the heater outlet temperature or by decreasing the velocity steam and thus increasing residence time. Thermal cracking results in a decrease in the asphaltene fraction's solubility and dispersibility. When extreme cracking occurs, asphaltene molecules can no longer stay in a dispersed phase and start to aggregate as a separate phase.

Aggregation of asphaltenes at thermal cracking temperatures above 400°C (752°F) leads to cross-linking and dehydration, and yields coke particles with a radius of typically 1–5 microns. Aggregation of asphaltenes at lower temperatures results in fouling of heat exchangers and columns downstream of the process furnace. High generation of coke particles causes rapid heater coking and shortens unit run length.

In addition, aggregated asphaltenes tend to precipitate with time, leading to sediment problems. The heavy fuel oil fails the HFT when vistar is blended with cutter stocks. Both heater coking and vistar stability limit maximum conversion. Therefore, severity must be optimised regularly to achieve the best compromise between maximum conversion and acceptable unit run length.

The tendency for asphaltenes to aggregate is measured as stability reserve, or simply stability; the higher the stability, the lower the tendency to produce fouling problems and/or development of sediments. Stability is normally defined as the maximum amount of aliphatic solvent (usually heptane or hexadecane) that can be added per gram of resid/vistar or heavy fuel oil before asphaltene precipitation occurs. The higher this ratio, the higher the stability reserve.

Controlling visbreaking severity to maintain visbreaker tar stability minimises serious fouling problems and the formation of sediments. Whenever severity is pushed excessively and vistar stability drops below the minimum control limit, fouling and sediments tend to increase exponentially compared to the increase in conversion. Even when using antifoulants and/or asphaltene stabilisers, the extent of fouling and asphaltene precipitation to produce heavy fuel sediments tends to be so extensive that it is difficult to control.

Visbreaker severity is usually controlled in refineries with p-value and HFT sediments tests. Both techniques are not fully reliable and accurate. Details of the VisTec methods and improvements over traditional techniques are given in reference 1.

Visbreaker fouling control

Optimal results in visbreaker fouling control are achieved using VisTec additives. These additives produce increased visbreaker feed stability, thus allowing the unit to be operated at increased severity. Additives also help control fouling phenomena within critical locations of the process (charge/resid preheat exchangers and column) and improve the stability of heavy fuel oil made from vistar. Visbreakers have achieved optimal performance when using a combination of additives and monitoring. The VisTec additives enable the unit to reach higher severities and thus higher conversions, while monitoring helps to determine and control the unit limits. If the limits are exceeded, fouling rates can be very high at typical additive injection rates. In such cases, higher injection rates may be required. Given the sensitivity of the fouling rate to severity, constant monitoring is essential. The VisTec chemical treatment programme is based on the following control mechanisms:

- Preventing asphaltene aggregation
- Reducing foulant deposition rate
- Reducing asphaltene destabilisation
- Reducing coke particle size
- Suppressing coke formation by reducing the catalytic effects of tube metal surfaces.

Use of different product combinations, dosing rates and injection locations are customised, depending on each unit's problems and targets. At Repsol Tarragona, four of these five mechanisms were identified as significant contributors to problems. A VisTec additive treatment programme was designed to address those four primary mechanisms to control fouling and coking.

Optimal visbreaker operating limits

In the first phase of the programme's implementation at Repsol Tarragona, limits for vistar stability and coke generation control parameters were optimised. These parameters are monitored on a daily basis using the VisTec Stability Index (VSI) and VisTec Coking Index (VCI) respectively.[1]

These measurements are essential for the control of fouling, the control of sediment generation and setting of the proper unit severity. Operating the unit outside the appropriate limits results in either too conservative a unit severity and subsequent lost conversion or, conversely, severe fouling and HFT sediments issues.

In the early implementation stage of the programme, general and conservative limits are applied. Then, optimisation work is undertaken to reach more specific limits for the particular unit. Optimal limits were obtained by comparison with the desired unit run length and with sediment specifications. This optimisation involves key parameters for controlling changes in operations and management of the unit, such as the change in the velocity steam levels.

Simulation of coil flow regime

Most visbreakers inject steam or boiler feed water in the heater passes, which helps increase turbulence and improves heat transfer from the coil surface to the cracking residuum. As a result, with constant feed quality and heater outlet temperature, the heat flux provided is constant. Increasing turbulence and overall heat transfer by steam injection enables the unit to operate with lower skin temperatures. In addition, increasing turbulence decreases coke formation and has a positive effect on increases in skin temperature during the run.

However, velocity steam reduces the residence time, hence cracking and conversion are reduced. This decrease must be compensated for with higher cracking temperatures, which may easily lead to an exponential increase in coking reaction rates. When it is used excessively, the positive effects of steam are then completely offset.

Another aspect to be considered is the flow regime in the cracking section of the coils. Two different phases are present: vapourised light products generated by cracking reactions and liquid resid. Steam increases the velocity of both phases, until gas slip occurs. In this phenomenon, the vapour-phase velocity increase is higher than that of the liquid phase.

Since the liquid-phase velocity controls coking phenomena, optimal velocity steam rates can be defined as those where a marked increase in vapour-phase velocity has only a minor effect on the liquid-phase velocity. At high gas velocities, after gas slip has occurred, the gas phase tends to segregate from the bulk liquid, and in the extreme case, annular-type flow patterns occur. In this regime, gas flows at high speed in the centre of the coil, while liquid segregates and circulates over the coil walls, thus tending to overheat. In this situation, any further increase in steam rates has an effect only on gas-phase velocity. Experience in visbreaker operations

has shown that this kind of flow regime causes an increase in coking phenomena, thus accelerating increases in tube skin temperature. Figure 1 shows these different flow regimes schematically.[2]

The optimal steam injection rate is a function of several parameters, including feedstock quality, coil size and geometry (vertical vs horizontal tube arrangement), operating conditions and feed flow rate. A wide range of operating guidelines is used by refiners with steam ratios varying from 0.1–1 wt%, based on the feed flow rate.

Since this is an important aspect for maximising conversion while effectively controlling coke deposition on the coil surface, Baker Hughes developed a proprietary simulation method that predicts flow regime and velocities in the visbreaker coils. This method is based on commercially available simulation packages and correlations. Since various thermodynamic models and flow regime correlations are available, the Baker Petrolite modelling procedure has been refined over time using field data. The output of the simulation is a determination of optimal flow regimes and liquid-phase velocities, which result in a decreased generation of coke particles and heater fouling at a given conversion level for a constant processed feed quality and flow rate. These data are available for field monitoring activities on visbreakers and serve as a basis for optimising operating procedures. This method has been applied to several visbreakers in Europe and Asia, resulting in improved best practices for velocity steam management.

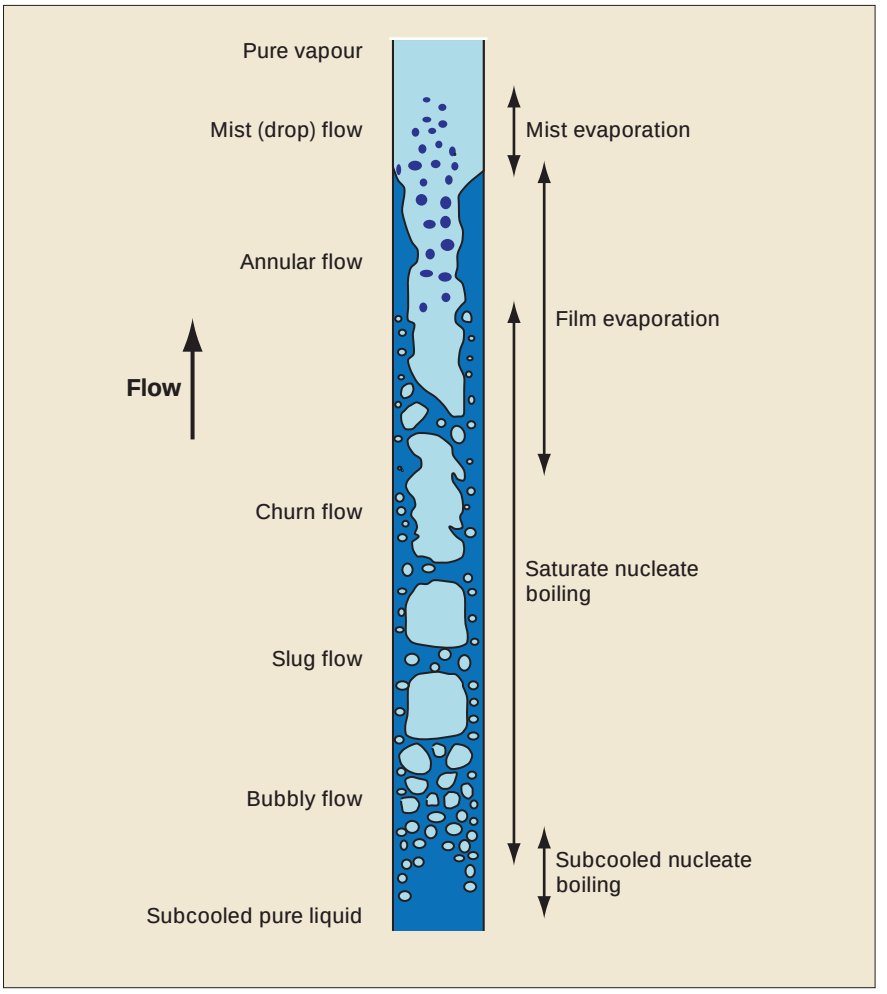


Figure 1 Different flow regimes

Flow regime and velocities at 90 t/h (198 416 lb/h)

Steam, wt%	Velocity, mt/sec, out	Reynolds no •10^5	Flow regime in	Flow regime out	Velocity liquid phase, mt/sec
0.00	0.95	1.10	Single phase	Single phase	0.95
0.10	0.95	1.15	Single phase	Single phase	0.95
0.20	1.13	1.27	Single phase	Single phase	0.96
0.22	1.14	1.27	Bubble	Intermittent	0.97
0.23	1.14	1.28	Intermittent	Intermittent	0.97
0.30	1.20	1.31	Annular	Annular	1.00
0.50	1.28	1.64	Annular	Annular	1.33
1.00	1.99	2.48	Annular	Annular	2.06

Table 1

The optimal steam levels have often been found to be lower than expected. In some visbreakers, steam injection can even be completely cut at maximum unit capacity. Baker Hughes discussed these experiences with Repsol refinery operations and technology engineers, and the velocity steam injection rates for Tarragona were found to be quite high compared to other visbreakers. In the past, asphaltenic feeds had produced severe problems due to high coking rates. As a result, steam injection rates were pushed up on a regular basis. In addition, analysis of the Repsol unit identified an unusual phenomenon: a rapid increase in skin temperatures in one particular location at a relatively cold portion of the radiant section.

While several parameters can affect tube skin temperatures, including the distribution of heat or flame patterns in the radiant section that can create higher temperatures on coil skin locally, the simulation revealed that at this location an annular-type flow regime was likely to develop above moderate steam levels of 0.20–0.30 wt%, and this flow regime would contribute to faster heater coking. This determination is interesting, as it demonstrates how poor flow regimes can be developed even at moderate steam injection rates in the case of vertical furnace tubes.

Calculations at 90 t/h (198 416 lb/h) flow rate show the different transitions in this tube, with the

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development of annular flow regimes (see Table 1).

Most of the modelling effort was directed to the hottest part of the radiant section. This is the most critical part of the furnace in terms of unit run length because it is where the rates of skin temperature increase are highest. Calculations were performed at different flow rates and temperatures. Table 2 shows the example output at 120 t/h (264 554 lb/h) and 450°C (842°F) heater outlet temperatures.

The ideal flow regime was identified as a zone between bubble type and annular/slug flow. Optimal steam injection ratios at 120 t/h (264 554 lb/h) are then in the range between 0.10 wt% and 0.25–0.30 wt%. Under these conditions, flow regime and liquid-phase velocities were in the ideal range.

Graphs have been created for different simulations. Figure 2 shows simulation results for liquid-phase velocity at 450°C (842°F) heater outlet temperature as a function of flow rate and steam injection ratios.

From this graph, optimal levels of steam as a function of unit feed rate can be determined. The simulation has been extended to other operating heater outlet temperatures.

The simulation results revealed the relationship between flow regime and liquid-phase velocity at decreasing steam ratios. Based on these results, a test run was programmed at the Repsol Tarragona refinery. The effect of process changes on the fouling tendency of the visbreaker heater and main fractionator column, as well as existing or potential sediments in the produced heavy fuel oil (fluxed vistar), was monitored using VisTec analytical techniques.

Test run for velocity and heater outlet temperatures optimal range

Based on the simulation results, a detailed programme for the test run was designed by the refinery's process and operations engineers, with programmed step-down of velocity steam at a constant flow rate and resid feed quality. Repsol's technical staff, in co-operation with Baker Hughes, provided support for definition of the targets and for its achievement within a test run of the Tarragona visbreaker. The temperature was changed during the test run according to the programme. VisTec monitoring techniques were used to measure the fouling and stability limits of the vistar and fluxed vistar (heavy fuel oil) and coke particle concentrations.

In the first phase, the heater outlet temperature was set close to the normal limit of VSI stability to 442°C (828°F), starting from a lower than usual operating heater outlet temperature of 440°C (824°F), while the VCI was being controlled in the normal range, below a control limit of 350 000. Steam was set at normal adopted levels, about 0.85 wt%. Then, keeping a constant temperature of 442°C (828°F), an initial decrease of velocity steam was

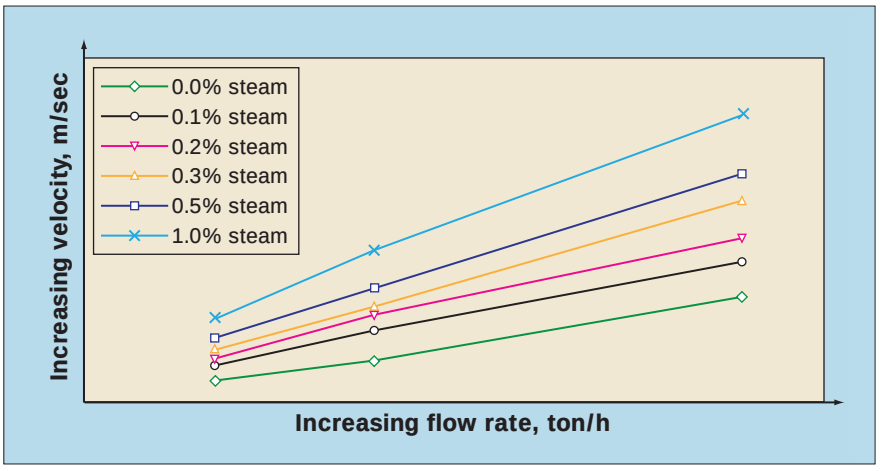


Figure 2 Simulation results of liquid-phase velocities at critical radiant sections

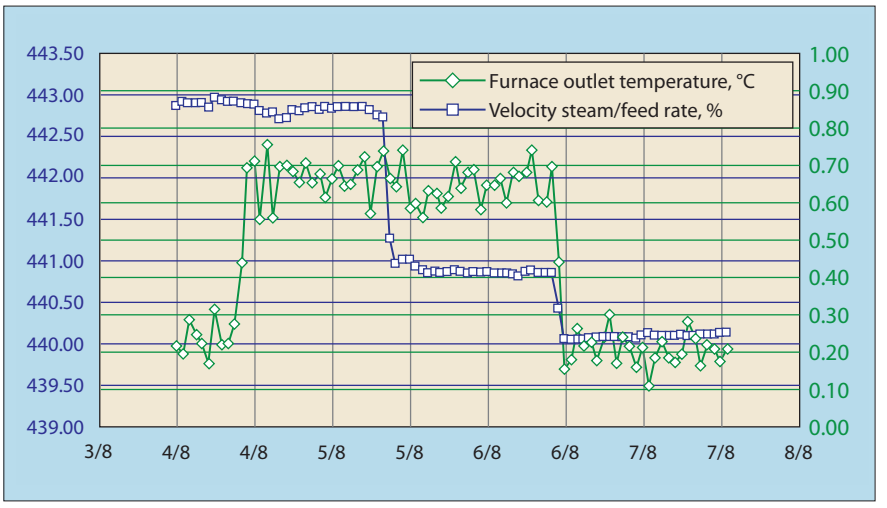


Figure 3 Test run: steps in steam percentage and heater outlet temperatures

Hottest tube in radiant section: simulation results

Steam, wt%	Velocity mixed phase, mt/sec, tube outlet	Reynolds no •10^5	Flow regime tube inlet	Flow regime tube outlet	Velocity liquid phase, mt/sec
0.00	1.89	5.68	Bubble	Bubble	1.72
0.10	2.37	6.87	Intermittent	Intermittent	2.23
0.20	2.78	7.83	Intermittent	Intermittent	2.50
0.30	3.15	8.68	Intermittent	Intermittent	2.67
0.50	3.84	1.02	Annular	Annular	2.97
1.00	5.38	1.50	Annular	Annular	3.66
1.25	6.10	1.64	Annular	Annular	3.80

Table 2

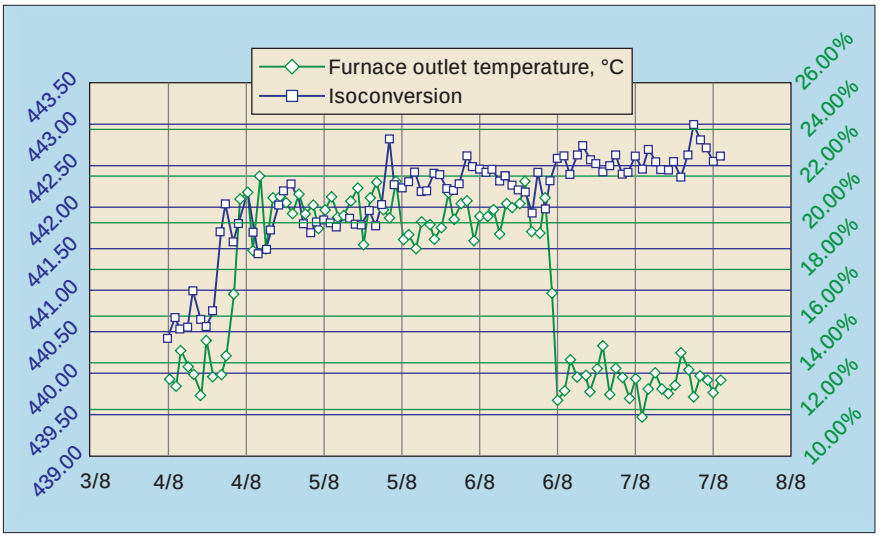


Figure 4 Isoconversion and heater outlet temperature during test run

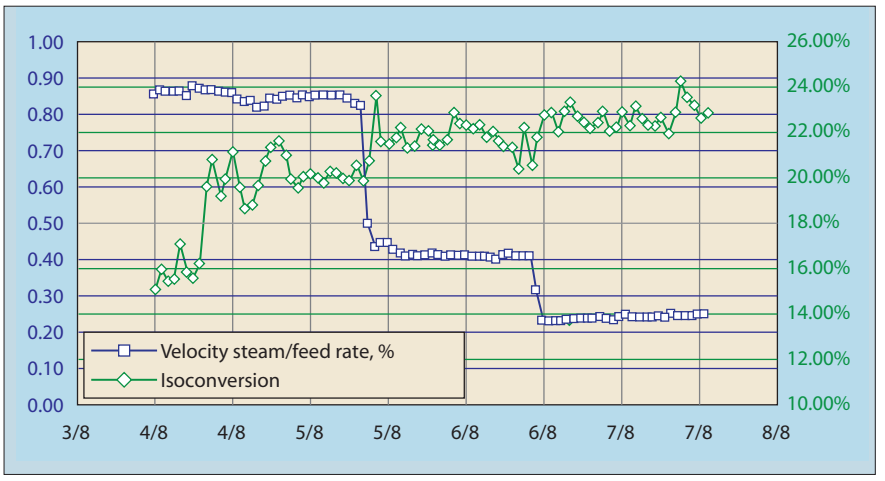


Figure 5 Isoconversion and velocity steam percentage during test run

performed, setting it down to 0.40 wt%. Finally, the temperature was set back to the value used before the start of the test, 440°C (824°F), while steam was cut to 0.25 wt%. Changes in steam percentage and heater outlet temperatures are shown in Figure 3.

A marked decrease in steam resulted in a higher residence time with a very positive effect on conversion. The conversion of resid feed to distillates is reported as isoconversion, as is typically used by the refinery to monitor the visbreaking unit's performance, instead of raw conversion. Isoconversion takes into account the amount of distillates within the produced vistar, whose distillation would yield a resid with the same viscosity as the visbreaker feed, and represents the real conversion achieved in the process. Isoconversion is shown in Figures 4 and 5 as a function of changes in temperatures and steam ratios.

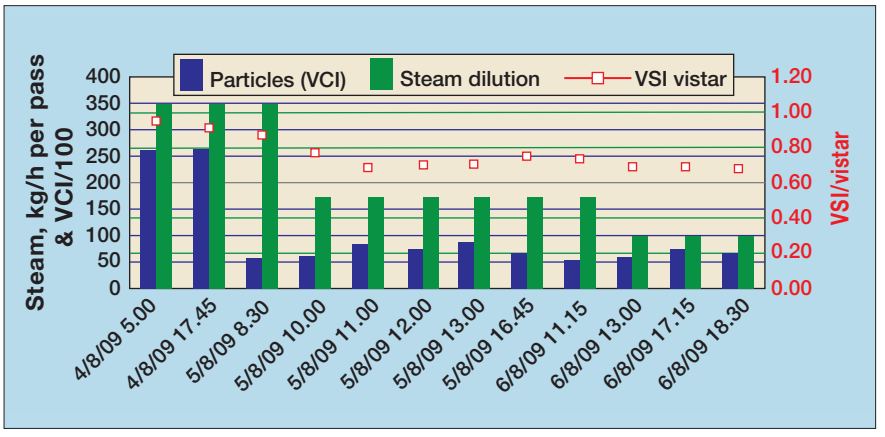


Figure 6 Velocity steam reduction vs VSI and VCI

The reduction in the steam-to-feed ratio clearly has a positive impact on severity. The decrease in steam ratio from 0.85–0.25 wt% at 440°C (824°F) heater outlet temperature resulted in a very marked increase in isoconversion, from 20% to about 22%. Even when the temperature was decreased to 440°C (824°F), the corresponding cut from 0.40–0.25 wt% of steam resulted in a further increase of 1% in isoconversion. These data clearly show how steam rate optimisation can be an effective way to increase conversion without raising heater outlet temperatures.

Figure 6 shows the effect of velocity steam reduction on vistar stability (VSI) and also on the coke particles (VCI). Vistar stability decreased from a VSI average of 0.85–0.70 when steam was reduced from 0.85–0.40 wt%, while further reduction from 0.40–0.25 wt% showed no further impact on VSI. With a VSI control value of 0.60, vistar stability was well above the limit. Optimised flow regime and optimal liquid-phase velocities achieved at reduced steam resulted in decreased generation of coke particles.

The generation of coke particles decreased from VCI values of 250 000 to less than 100 000. Both VSI and VCI at final conditions indicated room for further increase.

Following the steam reduction (for the same furnace outlet temperature), the increase in the highest skin temperatures was relatively small (2–3ºC [3.6–5.4ºF], see Figure 7).

The decrease in steam from 0.85–0.40 wt% resulted in a skin temperature increase of about 3°C (5.4ºF), while at a constant 440°C (824°F) heater outlet temperature the final test period at 0.25 wt% produced an increase of about 2°C (3.6ºF) in skin temperature compared to the start-up condition,

at 0.85 wt% steam. Based on these results, new guidelines were adopted and steam injection was kept at lower rates, with continuous optimisation, after the test run.

Table 3 shows a comparison of average values for two similar crude blends, within a period of two weeks before the test and two weeks after the test. The positive effect of reducing steam can be seen, as well as an increase in conversion and a decrease in coke particles generated.

Increase in conversion after the test run

As a result of the simulation and test run, new guidelines for optimal steam injection were adopted and continuously optimised by the refinery's personnel using VisTec monitoring information and correlations of process data, engineering know-how and fouling rate data.

A decrease in steam resulted in an increase in conversion, in the same run, from an average of 20.0% to 22.1% after optimisation. The following run, after optimisation of steam injection, yielded an average isoconversion of 22.7%. This was obtained without affecting heavy fuel oil sediments or unit run length. Trends in skin temperature increase were comparable.

Conclusions

This article illustrates how optimising velocity steam can result in a remarkable increase in conversion without negative impacts on unit run length. It also demonstrates how specific analytical information, stability and particles generation, provided by the Baker Petrolite VisTec programme, was used by Repsol's process and operation engineers to identify and apply best practices specific to their visbreaker unit while critically controlling fouling rates.

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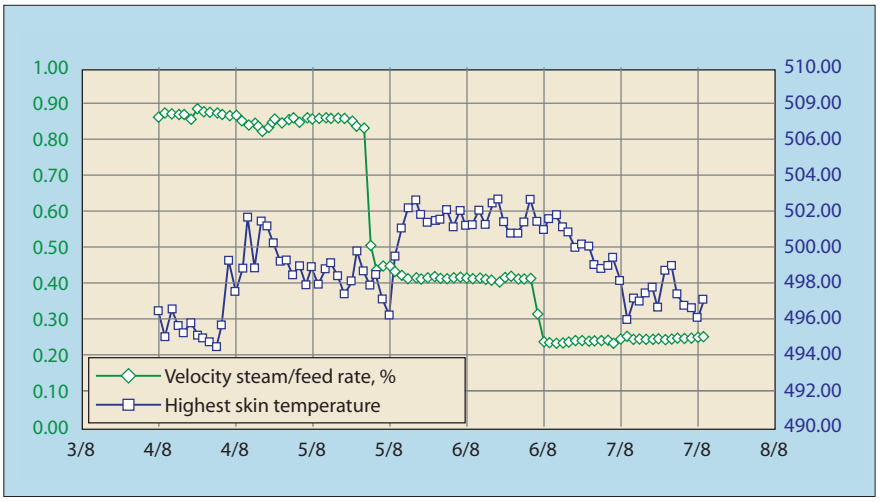


Figure 7 Variation of critical skin temperature as a function of steam changes

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Ernesto Agorreta is a Distillation Plant Manager at Repsol Tarragona refinery. He has 20 years' experience in process troubleshooting and refinery plant operations supervision, including crude and vacuum distillation, visbreaking, HDS, and hydrocracking units, and holds a bachelor's degree in chemistry and a master's in chemical engineering from the University of Zaragoza, Spain.
Email: eagorretaf@repsol.com

Carlos Angulo is a Process Engineer at Repsol Tarragona refinery, Spain. He has nine years' experience in monitoring, troubleshooting, simulation and revamping projects in refining processes, including crude and vacuum distillation, visbreaking and hydrocracking, and has a degree in chemical engineering from the University of Tarragona, Spain.
Email: cangulon@repsol.com

Aleixandre Soriano is a Process Engineer at Repsol Tarragona refinery. He has five years' experience in monitoring, troubleshooting and simulation in refining processes, including crude and vacuum distillation, visbreaking and isomerization units. He holds a degree in chemical engineering from the Polytechnic University of Valencia, Spain.
Email: asorianod@repsol.com

Cristina Font is the Baker Hughes Account Manager at Repsol Tarragona refinery. She has seven years' refining experience in crude, vacuum distillation, visbreaking and olefins plant, and holds a degree in chemistry and biochemistry from the Universitat Rovira I Virgili, Tarragona, Spain, and a MS degree in Health, Safety and Environment.
Email: cristina.font@bakerhughes.com

Marco Respini is a Technology Development Specialist in the Baker Petrolite Industrial Technology Group of Baker Hughes in Europe, specialising in refinery process fouling control. He has 12 years' experience in asph altene-related problems in refining, and holds a degree in industrial chemistry from Milan University, Italy. He is a registered professional chemist in Italy and an inventor of two US patents.
Email: marco.respini@bakerhughes.com

Average values for similar crude blends, before and after steam optimisation

	Before steam optimisation	After steam optimisation
Feed rate, t/h (lb/h)	175 (385 808)	176 (388 013)
Heater outlet temperature, °C (°F)	441(826)	438 (820)
Highest TSK, °C (°F)	498 (928)	502 (936)
Raw conversion, wt%	10.84	12.61
Isoconversion, wt%	16.71	22.32
Velocity steam ratio, wt%	0.80	0.24
Vistar VSI	0.77	0.58
Vistar BPI	6620	16 472
Vistar VCI	263 814	211 930
Crude blend, vol%	68% Basrah 15% Sirtica 8% Maya 9% Others	58% Basrah 9% Sirtica 3% Maya 15% Azeri 15% Others

Table 3

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Drivers for zero discharge in refineries

Wastewater treatment utilising zero-discharge techniques has reduced the impact of effluent discharges

GARY HOWARD
Foster Wheeler

Recent years have seen an increasing focus on the environmental impacts of refineries and petrochemical plants, not only on reducing concentrations of contaminants in effluent discharges but also on overall pollution load and discharge volumes. Increasing demands on water consumption around the globe mean that existing facilities need to reduce water use. New facilities have to be designed to minimise water use and some to even achieve zero effluent discharge. This article looks at common drivers for reduced water usage. It reviews the technologies that are typically used and key challenges that have to be addressed if this strategy is to be successful. It will also look at two recent examples of how designs utilising zero discharge techniques have minimised the impact of effluent discharges.

Drivers

Refineries and petrochemical facilities use a considerable amount of water. Table 1 shows some typical values for a refinery and an ethylene cracker.

Typical plant water usage

Whole life costs are currently favouring evaporative cooling over seawater usage, increasing the typical demand of potable water. However, recovering water for reuse is an expensive undertaking, and this is driving the increased adoption of a range of site-specific water-recovery techniques.

The petrochemical industry is only one of many users competing for the existing water supplies.

Typical plant water usage

Type of plant	Utility water usage (m^3)/tonne product
Refinery:	
Seawater cooling	1
Evaporative cooling	2.5
Ethylene plant:	
Seawater cooling	3.5
Evaporative cooling	25
With water recovery	16

Table 1

Many industrial developments have to rely on water supplies from remote locations, or desalination of seawater, to provide reliable supplies. The increasing level of investment required to maintain reliable supplies is promoting a serious review of water usage in an attempt to reduce the relative cost of recovery.

At the same time as water scarcity increases, best practice with regards to environmental discharges is becoming more onerous. In some instances, political rather than sound environmental science can result in consents that are difficult to achieve with conventional treatment systems. Table 2 is a summary of various discharge consent criteria and the typical capability of a basic wastewater treatment process using a conventional activated sludge plant without tertiary treatments.

Consents and limits

It is important to understand the implication of the compliance level required. A maximum allowable concentration (MAC) needs to be met at all times. A 95 percentile basis allows one failure in every 20 samples. Often a 95 percentile basis will also have an upper tier requirement that is a MAC. In rough terms, the MAC equates to about four times the average, while a 95 percentile is about double the average. In Table 2, this means that the IFC and Saudi standards can be reasonably met by a conventional plant, while the Russian standards would need significant tertiary treatment or even zero discharge.

Uses of recovered water

Across an industrial site there are many operations and processes that require water. Good waste minimisation techniques look at elimination

Consents and limits

Parameter	International Finance Corporation (IFC)	Russian	Saudi	Typical plant
Compliance	95%ile	MAC	30-day average	Average
pH	6-9	7-8	6-9	6-9
BOD	30	6	25	10
COD	150	35	150	60
SS	30	10	15 (MAC)	15
Total N	40	20	5 (TKN)	20
Total P	2	0.2	1	1

Table 2

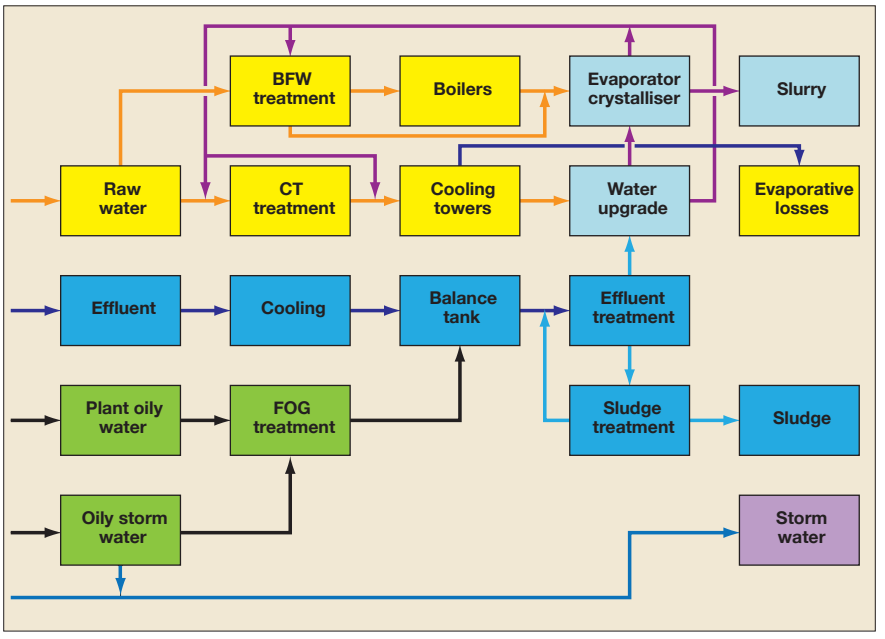


Figure 1 Typical zero-discharge scheme

or direct reuse of water as the first step. An example of direct reuse in a refinery is the now common use of stripped sour water in the desalters. Once the water has undergone conventional treatment, it can be used in washing down dirty areas and for dust suppression in partially paved sites. Use for irrigation is possible if the sodium absorption ratio is low enough, although chloride is also an issue for some plants. If the total dissolved solids (TDS) level is low enough, use as cooling water feed is another option. Typically, these low-grade uses are insufficient to use up all of the wastewater produced on site and further treatment is then required. Once at a higher purity, use in the demineralisation system and unlimited use in cooling towers is common. One novel use that is being applied in Australia is irrigation of salt-resistant Eucalyptus. This salt-controlling plant uses brackish water and directs the salt to below the root system.

Technologies used

The processes used in water recovery up to a full zero-discharge plant are now established processes. A typical plant scheme is shown in Figure 1. This shows a typical industrial plant with pretreatment to protect a conventional effluent treatment plant. Water recovery is usually employed after the majority of the contaminants have been removed. A water upgrade step is used, which recovers high-quality water that is then reused in the cooling towers or to feed into the boiler system. The remaining fluid is reduced to slurry suitable for landfilling after further, more intense water recovery.

When recovery to high-grade water is required, the conventional

A well-designed zero-discharge plant requires the wastewater treatment and recovery plants to have high reliability

treatment scheme is often enhanced to remove more contaminants. The processes that might be considered are:

- Nutrient removal (eg, AO process)
- Tertiary treatment (eg, DAF, sand filtration)
- MBR (membrane bioreactor)
- MBBR (moving bed bireactor)
- PACT (powdered activated carbon treatment).

Following secondary treatment, the TDS need to be removed and this is usually achieved by either reverse osmosis (RO) or multiple effect distillation (MED). This step results in a concentrate that can be further concentrated by solar evaporation in arid climates, or by using evaporator/crystalliser systems. Both of these processes produce a slurry or solid that should be suitable for controlled landfill.

Challenges

The challenges with a zero or partial-zero-discharge system are essentially operational issues.

The contaminated streams will become more concentrated as good-quality water is recovered. If we take a typical industrial effluent with a refractory chemical oxygen demand (COD) of around 50 mg/l, this is concentrated to an average 250 mg/l in a RO system recovering 80% of the feed. At this concentration, the effluent is no longer compliant with any of the discharge standards shown in Table 2. This means the concentrated reject stream needs further treatment.

A well-designed zero-discharge plant requires the wastewater treatment and recovery plants to have high reliability. In addition, a realistic approach needs to be taken to managing out of specification events and agreeing with the regulators on how to deal with these infrequent events. This might require large buffering storage ponds around the site or an agreement for temporary discharge during such events.

The quality issues require a careful assessment of the detailed chemistry and recycle loops. The primary concern is always that the water that is recovered is now being used in the process, and the plant process engineers need to decide what is the worst quality water they can receive, rather than the best. Things like trace elements, particularly soluble ones, become more important, and often new analysis is required for existing systems. For instance, most operators know what they can expect from a well-operating activated sludge (AS) plant in terms of COD, but what is a typical silt density

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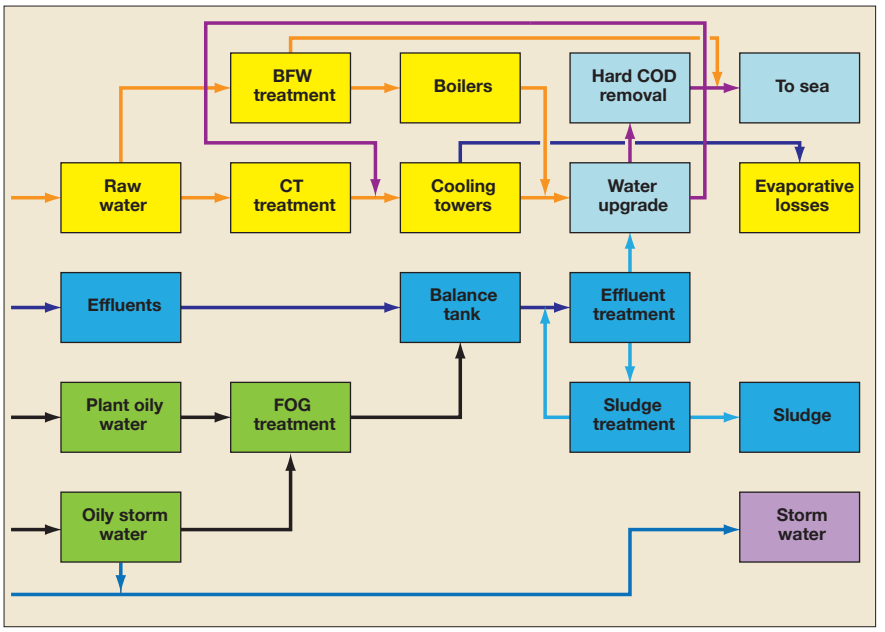


Figure 2 Refinery: Asia

index (SDI) for the same system? SDI is a typical constraint in the design and reliability of RO plants. The issue of buffering capacity has been discussed already, but if the effluent or intermediates are off-specification they need to be reprocessed and the quality of this effluent also needs to be treated, albeit at a slow or even trickle rate.

The disposal of sludge becomes increasingly problematic when undertaking zero discharge, as more contaminants end up in the sludge and will be at higher concentrations. It is critical in considering a zero discharge system that reliable disposal of the salt-rich slurry from the crystallisers is secured.

The final challenge is how to produce a realistic map or mass balance of the water system. Any calculation or software needs to have the ability to map multiple components individually. In addition to typical wastewater system design concerns (COD, suspended solids, and so on), the salts and TDS need careful tracking. With a conventional wastewater mass balance, the flow and pollution load can be calculated from knowledge of the contaminants and how the various processes deal with each component.

The real trick to accurate mapping for water recovery against demand is the ability to feed back flow and then recalculate the load and resulting flow to the recovery system. From extensive work with effluent systems, the ability to add a new component to any mapping is also necessary. A typical example of such problems is a licensor identifying a heavy metal in the final months of a front-end engineering design (FEED). This needs to be mapped to ensure that the sludge disposal routes are not compromised. In working with partial and full zero discharge systems, Foster Wheeler has developed a spreadsheet-based program called WM-SET (water management — system evaluation tool), which enables design engineers to provide realistic mapping.

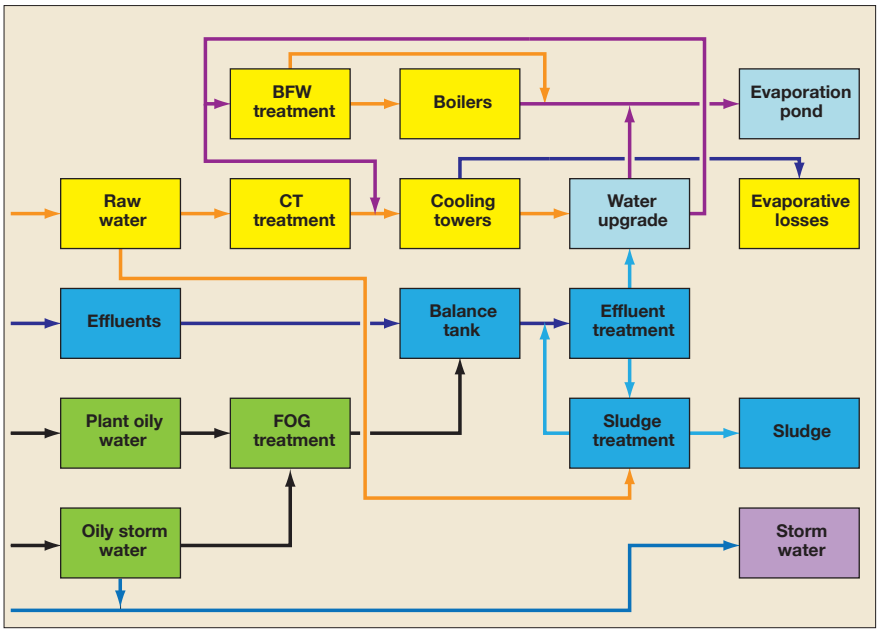


Figure 3 Petrochemical plant: Asia

Examples

Not all facilities are going to require a full zero-discharge system. The drivers, demands and constraints for water recovery are very site-specific. The following two examples of recent projects show that zero-discharge system methodology is now being applied at the design stage and then constructed for the installed plant.

Refinery: Asia

At the FEED stage of a new green field refinery in Asia, it was realised that some water recovery would be required. Figure 2 is a block flow diagram of the final system adopted at the engineering, procurement and construction (EPC) stage.

With this plant, the conventional AS treatment plant is expected to meet IFC and local standards. During development of the refinery, it doubled in size, but the regulator imposed the volumetric consent for the original smaller refinery. This meant that water recovery was needed to reliably reduce the normal total combined flow from the plant to less than the volumetric consent. By using RO (for water recovery), the resulting COD of the reject stream is above the IFC and local standards. In this instance, the EPC contractor elected to remove

the hard COD down to the required standard by using PAC, settling the carbon-rich solids in a clarifier and returning it to the AS plant. This will in turn increase the removal of COD in the AS plant.

Petrochemical plant: Asia

A company based in a remote, gas-rich area was developing a polyethylene facility. The remote location and water scarcity indicated that water recovery would be essential. Figure 3 is a block diagram of the selected process.

In this country, the discharge standards are extremely tight. The location has environmental extremes with bitter winters and scorching summers. The typical approach driven by the local regulator was to treat the effluent to IFC standards and then place it in an evaporation pond for final disposal. The resulting ponds are large, as evaporation mostly occurs in the six-month warm season.

The remote location and arid site conditions required water supply via a long pipeline. For this site, a study was undertaken looking at the costs of no recovery, partial recovery and zero discharge. The preferred option on a net present value (NPV) basis was to recover the wastewater with RO and use it in the cooling towers. This resulted in an 80% reduction in the required size of evaporation ponds, which meant overall that the cost of buying and operating the RO plant was less than for building large evaporation ponds. The option of a zero-discharge system was more expensive in NPV terms. This means that for this site, evaporator crystallisers cost more to build and operate than the evaporation ponds.

Conclusions

There are some projects where zero discharge is the preferred option. In an increasing number of projects, there is a driver for some water recovery. Is zero discharge a good environmental solution? The extra energy expended in effectively distilling effluent to recover water increases the carbon footprint of the manufacturing process and increases the cost of the final product. A higher production cost may drive companies to consider the countries into which new investment is best targeted. If the driver is due to the regulator attempting to reduce the environmental impact, is the increase in energy usage worth the reduction in effluent entering the aqueous phase? In future, it is anticipated, a pragmatic regulator will review the whole lifecycle impact of zero-discharge schemes.

This article is based on a presentation at the Green Refining & Petrochemicals Forum, London, October 2010 (org. Europe Petroleum Consultants).

Gary Howard is a Principal Process Engineer with Foster Wheeler, Reading, UK. He is a registered European Engineer, Chartered Chemical Engineer, Fellow of the Institution of Chemical Engineers and a Chartered Water & Environmental Manager, with over 20 years' experience in environmental, water and wastewater engineering, and holds a BSc (Eng) degree in biochemical engineering from University College London.



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Petrochemical and refinery processes rely on efficient heat transfer to maximise efficiencies and ensure safe operations. While most plant operators manage a utilities system sufficient to supply a small city, many are not aware of proven rental strategies to better manage risks, limit losses and seize unexpected market opportunities.

In particular, ambient air temperature and humidity rise significantly during the peak summer months, relative to winter conditions, which adversely affect major heat exchange equipment throughout the plant. Often quite significant deterioration in performance forces plant operators to make some unpleasant choices, chief among which is a reduction in unit throughput. Owing to the integrated nature of major refinery and petrochemical processes, such problems at any unit usually force both upstream and downstream units to also cut production.

Market demands often peak during the summer. For example, gasoline sales are highest when ambient conditions force production bottlenecks throughout the refinery. These scarcities drive refining margins up significantly, thereby creating huge economic incentives to restore unit capacities. The magnitude of monthly economic losses caused by production cutback can easily equate to millions of dollars.

Temporary seasonal strategies

This article examines seasonal cooling problems and issues that commonly occur every year, and how owners have justified acquiring engineered solutions to solve emergencies and production shortfalls in such instances. Additionally, the benefits of employing rented equipment, best practices and results that have been achieved are presented in several examples.

The chief merit of the rental model for solving seasonal cooling problems is that solutions can be deployed at short notice, often within a month or less. The main requirements are:

- Engineering services to develop all feasible alternatives and the benefit-to-cost ratio in each case
- Ready availability of process equipment that has been fabricated and maintained in a manner fully consistent with industry best practices
- Transportation and field assembly, with full cognisance of applicable safety and environmental standards
- Full documentation of process and equipment design details; emergency, startup and shutdown procedures; operator training materials; and all pertinent details to help ensure conformance with management of change and process safety review criteria.

Monthly economic losses caused by production cutback can easily equate to millions of dollars

In the past, many operators have not expected that seasonal or temporary projects relying on rental equipment could successfully meet such requirements. This is simply because most players in the equipment rental industry either have not emphasised such aspects or face difficulties in adhering to stringent industry requirements, thereby precluding their participation in the development of systematic, sound solutions.

It is useful to think of temporary solutions for problems in three categories:

- **Emergencies** These are situations where the failure of crucial equipment must be rectified immediately. Replacement by a suitable equivalent is the best alternative in such cases
- **Planned outages** Here, major parts of a unit (or the entire process unit) are scheduled to be taken out of service for routine maintenance. The degree of the challenge faced is directly related to the impact such outages have on the rest of the facility. One solution can be to cool and divert the unit feed to temporary storage while the unit is out of service, thus allowing upstream units to stay online. Otherwise, it is imperative to take all possible measures to minimise the duration of the outage by expediting unit depressuring, cooldown, degassing and comfort cooling to enable expeditious repairs
- **Process enhancements** Often, unit performance (capacity or quality) degrades seasonally during summertime, when ambient air and cooling water temperatures are at their peak. Systematic elimination of the resultant cooling bottlenecks can help restore unit performance to levels seen only during the winter months.

To better understand the importance and impact of these operational issues, one must first understand the larger economic and regulatory factors driving these operational issues.

Challenges addressed by rental strategies

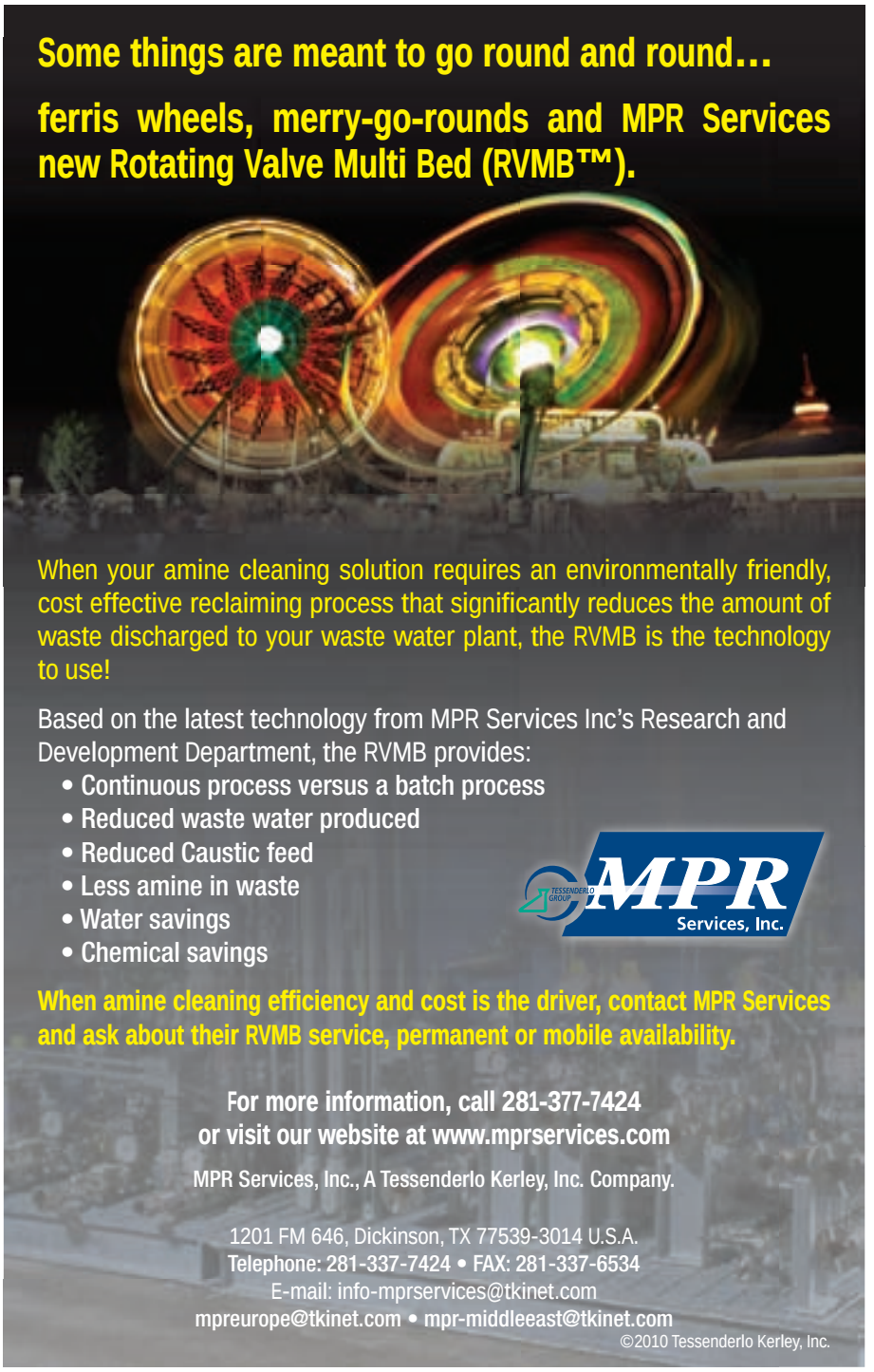
In spite of an ageing infrastructure, the petrochemical and refining industries must meet increased consumer demand, adhere to stringent regulatory oversight, respond quickly to volatile market conditions, and operate within strict safety and environmental limits. They must meet all of these expectations under the watchful eye of citizens in their communities who, while they have easy access to news and information, often lack the technical knowledge to understand the issues and implications of many of the decisions plant managers must make.

To meet increased demand for commodities, and to maximise profitability, mature plants and refineries must work at capacity round the clock, seven days a week. This requires limiting downtime and mitigating outages within safety and environmental constraints. While many of the corrective actions needed in these ageing facilities are temporary, others require longer-term, and sometimes permanent, changes. Rental strategies, often viewed as temporary-only, are being designed by engineering teams and deployed routinely for a few months each year, for many years.

In a commodity-driven business, the ability to respond quickly to market fluctuations often means the difference between profit and loss. Prices fluctuate during peak usage periods, weather events, extreme seasonal climate changes, variances in regional demands and unexpected economic downturns. Operators must have an arsenal of just-in-time tools to adjust the plant's operation — all within accessible maintenance budgets.

Refineries and plants located in regions susceptible to events such as hurricanes, tornadoes and earthquakes may also need to combat emergency situations. Tools often deployed in such situations include generators, compressors, air dryers and dehumidifiers.

Regulatory changes and current environmental standards also require plants and refineries to be more efficient, which is often challenging to an industry operating with decades-old equipment. It is also worth noting that the design basis for many of these older plants was set at considerably lower plant capacities than might currently be in effect. The systematic push to debottleneck existing plants, to take advantage of all available capacity, has resulted in significantly increased loads on plant utility systems, especially for cooling water. Often, owing to their complexity, the utility systems in place cannot easily be debottlenecked. The excess utility loads result in permanent increases in available cooling water temperatures, so that equipment performance, especially in the



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summer, becomes sub-par when compared to the original design basis.

Other significant changes arise from the systematic tightening of regulatory standards and product quality specifications across the entire spectrum of the process industries. These changes require installation of additional equipment or processes and further increase the strain on plant utility systems, often with highly undesirable consequences.

Flaring, for example, is a visible operation that has garnered much attention of late and increasingly is becoming the focus of stricter regulatory limits. The need to reduce flaring to decrease emissions is paramount. Lack of adequate cooling in critical process equipment is the most common contributor to this problem. Operators are forced to allow operating pressures to rise, sometimes to levels uncomfortably close to vessel relief valve settings.

In amine treating (tail gas) units, H_2S emissions to fuel gas can become excessive as a result of a high-circulating lean amine temperature. A rental strategy utilising in-process cooling can diminish these emissions dramatically. For example, strategic deployment of heat exchangers for in-process cooling has proven to be hugely successful when high ambient temperatures and humidities force cooling water temperatures to be significantly above design specifications. Installing heat exchangers and cooling towers, or refrigerated mechanical chillers, provides temporary yet critically needed relief. Cooling the process to reduce H_2S emissions is often far more effective than increasing the circulation rate in an attempt to limit violations and avoid air quality compliance issues.

While equipment replacement in an emergency may take only a few days to rectify, more lead time is required to design and commission equipment for applications such as reactor cooling, vessel drying, dehumidification and catalyst regeneration. Longer-term projects — such as increasing product rundown rates, improving aromatics recovery and achieving lower temperatures in distillation column overheads — increase the complexity level. Even then, acting on a window of opportunity often generates attractive paybacks (benefit-to-cost ratios ranging from 3:1 up to 30:1). This approach helps manage risk, minimises loss of production and restores revenue in a matter of days or weeks.

Additionally, seasonal rental solutions are useful to test and prove the viability of more capital-intensive, permanent solutions. They enable operators to test the viability of permanent solutions in the field, and to verify equipment capacities and configurations before making a business case for capital budget allocations.

Seasonal strategies require process knowledge and expertise

Deploying rental solutions to address seasonal operating challenges requires deep knowledge in process technology, equipment design and operation, and project management. Operators require industry partners who understand the processing complexities, the ramifications of any changes and the cost-benefit analysis required for ensuring success.

Best operating practices require operators to minimise the risk of an unplanned shutdown with regular maintenance. Therefore, those providing equipment and services should be obligated to observe these high standards. Equipment provided even for short-term or seasonal projects in no way diminishes the provider's responsibility to ensure full conformance with safety regulations. Additionally, it is essential that suppliers evaluate the impact of their equipment or solutions on the client's facilities. Such analyses are non-trivial and require up-to-date software and expert process design and engineering skills.

Emergency restoration puts plant back on track

Despite ever more stringent safety and environmental limits, operators are achieving increased capacity and performance for new, modified or reconstructed facilities without increasing the risk of failure. They also respond to disasters, such as in the example of a US Gulf Coast chemical plant.

Some years ago, a catastrophic hurricane that hit the Gulf of Mexico coast destroyed the main cooling tower at an ethylene plant, resulting in a 100% loss of production. Rebuilding the cooling tower would require several months. The situation required a two-fold resolution: resume operations as quickly as possible and restore production for the duration of the rebuild. Time was of the essence, and Aggreko provided a temporary solution within 10 days.

Restoring full production meant providing 300 000 litres per minute of cooling water, requiring 27 000 tons of cooling capacity. Over two dozen cooling towers with 10 cells each were deployed. Aggreko's process engineers also scrutinised the water chemistry to determine the proper blowdown rate. Additional considerations included setup space and pumping requirements.

Project success was assured by a combination of ready equipment availability, engineering design capability, and project planning and execution. The plant achieved 100% operating capacity in the 10-day period. The rental approach significantly limited downtime and enabled reconstruction of the permanent cooling tower on a normal schedule.

Cooling in the summer is generally a systematic problem that is compounded by the fact that production demand is also at its peak. For this ethylene plant, which produces 1361 t/d of ethylene, the ability to resume production quickly was crucial to retaining its market position and profitability.

Turnaround planning

A delayed coker unit at a US refinery was scheduled for a major six-week turnaround. The refinery converts more than 300 000 b/d of crude oil into motor gasoline, jet fuel and diesel fuel, among other products. The refinery approached Aggreko to explore ways to keep

the crude and vacuum units running despite the shutdown of the coker, which takes vacuum tower bottoms (VTB) as its primary feedstock. This was a valuable proposition, as major sections of the refinery would remain operational.

The solution entailed cooling the 600°F (315°C) VTB stream to a safe temperature for storage in tanks. As the tanks were filled, they could be unloaded to ships for export, ensuring that adequate tankage was always available.

The VTB was very viscous at storage temperature. Aggreko provided several refinery-grade shell and tube heat exchangers, cooling towers and cooling water pumps to cool the VTB to 150°F (65°C). Diesel was used as a cutter stock to reduce the VTB's viscosity and ensure good heat transfer and pumping capability. The cooled VTB product was immediately shipped for export via barges, and the refinery had enough tankage to maintain upstream unit production.

After the turnaround, during startup of the coker, the same exchangers were again deployed to preheat coker feed from storage, this time using condensing steam, to ensure coker feed rates were maximised. The temporary equipment was decommissioned once the coker was back online. The value realised with rental equipment has prompted the refinery to use this service rather than capital investment for future coker outages.

Seasonal strategies minimise losses

Regardless of the locale, process plant operating efficiency and throughput are markedly affected by ambient temperatures and humidity during the summer months. In the following examples, operators overcame throughput limitations by deploying rental engineered solutions.

Maximising oxygen supply to the catalyst cracker regenerator

During the height of the summer, a US refinery wished to create winter-like conditions to help restore air density and thus maximise oxygen supply to the catalytic cracker regenerator, where coke is burned in a fluidised bed to regenerate catalyst for recycling to the main reactor. A seasonal solution was optimal, since the oxygen deficit occurs during the summer months only.

The operator set a regenerator air supply target of 50°F (10°C). Aggreko's cooling system design considered ambient temperature, humidity and the required air rate. Cooling humid air at 90°F down to 50°F increased the mass flow rate of oxygen by 6–8%, which translated into an equal percentage increase in carbon burn-off and thus in unit throughput (see Figure 1). This strategy is repeated every year and represents a valuable contribution to refinery profit at a time when gasoline demand is at its peak.

The equipment configuration consisted of mechanical chillers, refrigerated coils and coolant circulating pumps. The solution was designed to minimise entrainment of moisture into the air supplied to the regenerator.

After the summer, the equipment was decommissioned. Since this temporary solution is reapplied annually when conditions dictate, it is unnecessary to incur capital expenditures for equipment that might sit idle for six months each year.

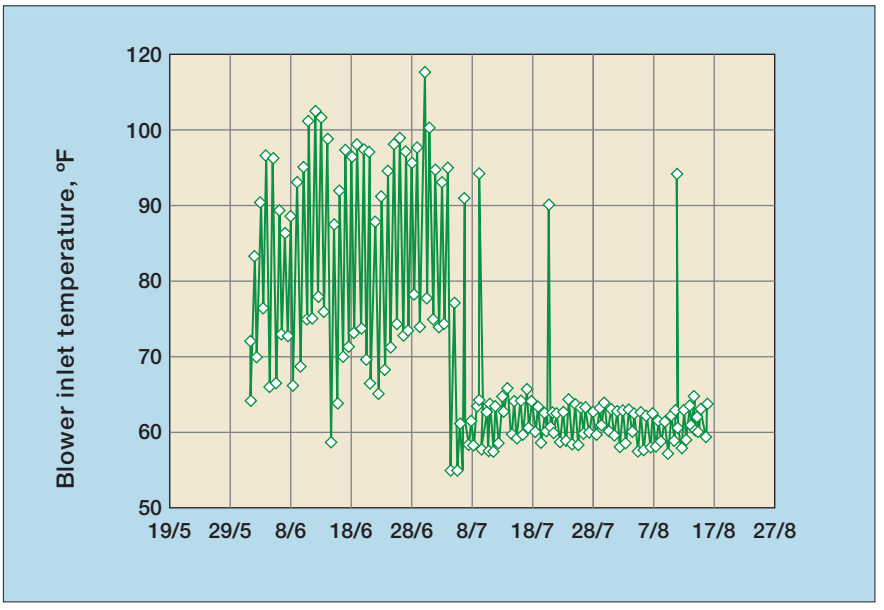


Figure 1 Operators maximise summertime FCCU profits with temporary chillers to increase regenerator air supply 6–8%

Rental strategies seize market opportunities

Seasonal strategies enable petrochemical operators to capitalise on market opportunities. With a commodities market in constant flux, what may be profitable today could be a money-losing venture next year. Small changes in price can create significant short-term opportunities, as the following examples show.

Maximising LPG recovery in refinery gas plants

In the summer, as refinery cooling water temperature rises by 20°F (11°C) or more, absorber lean oil temperatures rise markedly, often by more than 20°F when compared to winter conditions. This results in a considerable increase in the loss of propane to fuel gas, sometimes to a point where the refinery becomes long on fuel gas and must even contemplate flaring excess fuel gas. A Gulf Coast refinery wanted to recover as much of the propane as possible, for sale as LPG product, by minimising losses to fuel gas.

Aggreko designed a cooling solution for the absorber column using auxiliary mechanical chillers and heat exchangers. The project enabled the plant to restore summertime propane recovery to winter levels, delivering a production increase of several hundred barrels per day of propane. This

translated into an economic benefit of over $25 000 per day.

Very low temperature cooling of a petrochemical plant

A Gulf Coast chemical plant making polyurethane precursors requires a circulating coolant kerosine stream at -20°F (-29°C) using two large refrigeration machines. When one of these machines failed, the operator estimated that the outage would last three months for repairs. A 50% loss of capacity was unacceptable, especially since the market was in a sold-out condition. The operator needed urgently to resume production at full capacity to meet demand, and also to build up inventory to meet customer demand during a forthcoming scheduled maintenance shutdown.

Supplying enough refrigeration tonnage for such low-temperature applications required several large process chillers and condenser water circulating pumps, powered by temporary generators. The plant was able to achieve full production within a matter of three weeks from project initiation. Moreover, production was restored fully and inventory build-up was achieved as planned.

Conclusions

The examples described demonstrate that field-proven, engineered solutions are available for reversing the adverse effects of summertime heat and humidity, and other common issues, in a systematic and reliable way. Taking advantage of these capabilities using rental solutions creates economic benefits in the short term. Such projects are implemented without incurring capital expenditures and the often lengthy delays encountered if more permanent solutions were to be considered.

Attempting to justify a permanent solution for solving seasonal operating problems often runs into the issue of economic risk assessment. In the face of volatile feed, utility and product prices, and considering that the equipment would lie idle during the winter months, it becomes hard to make projections with much certainty. Also, the project execution cycle for longer-term, capital-intensive projects is of the order of 18 months to three years. Selecting several vendors and factoring in the risk of cost escalations in hardware can result in additional delays. Even the internal project justification and review cycle can sometimes thwart achieving temporary market-driven opportunities.

Temporary seasonal solutions, on the other hand, eliminate most, if not all, such traditional roadblocks because of the speed with which they can be implemented. Since no capital expenditures are required, project approval can be accomplished far more quickly, especially considering the favourable benefit-to-cost ratios for such projects.

Umesh Mathur is a Principal Process Engineer with Aggreko. He holds a BTech degree in chemical engineering from the Indian Institute of Technology, Delhi, a post-graduate diploma in petroleum refining and petrochemicals from the Indian Institute of Petroleum, Dehradun, an MS in chemical engineering from the University of Tulsa, Oklahoma, USA, and is a licensed professional engineer in Oklahoma.

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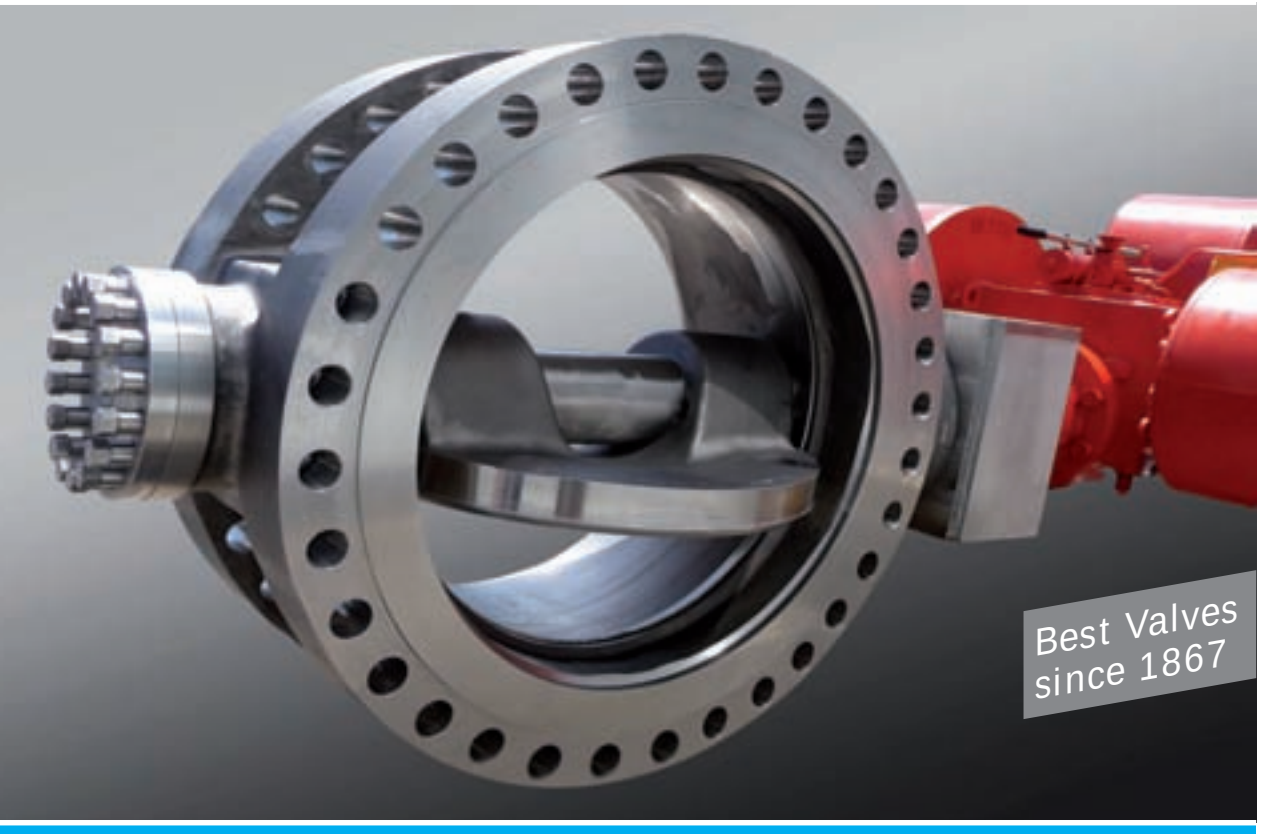
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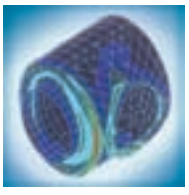


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Independent verification of refineries

Independent verification should focus on areas of greatest risk and so contribute to risk reduction measures

DONALD PAYNE
DNV Vietnam

We live in a world where risk is a bad word. We are living in probably the safest time in human existence and are probably the most risk-averse generation there has ever been. We are under more scrutiny from stakeholders than ever before: from governments, lenders, NGOs, press and the general population. This scrutiny is not going to decrease, so we must be prepared to manage the risks associated with our activities.

Risk, in the hydrocarbon processing business, takes many forms (see Figure 1). Some risks are obvious and are the ones we think of most often, such as fatality or injury and asset damage.

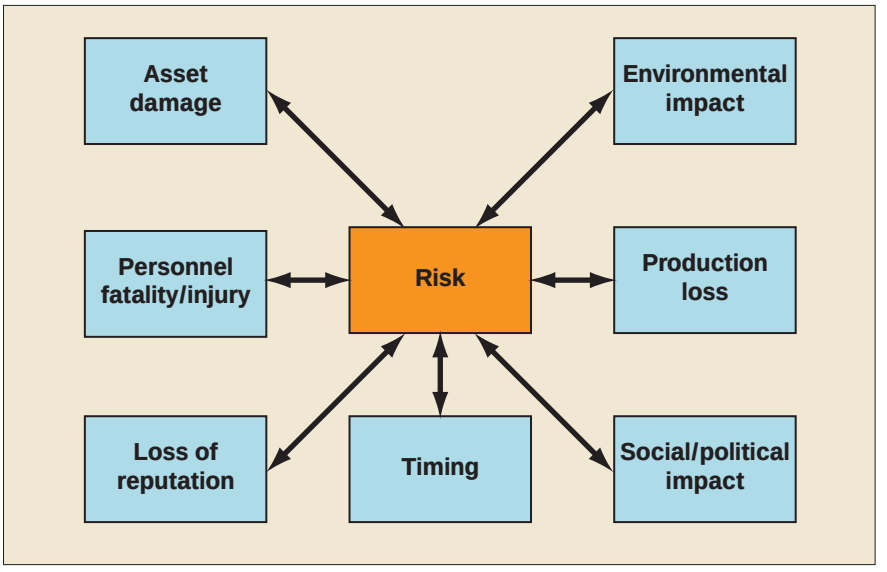


Figure 1 Types of risk

Often, we do not pay as much attention to production losses, but these can be considerable and many times the cost of asset damage. DNV is aware of one offshore installation, producing 50 000 b/d of condensate that was shut down for 14 months due to a pipeline failure. At $70/bbl, production losses were approximately $1.5 billion and, with a rate of return on revenue of 10%, lost profits amounted to $150 million.

Other losses are even less at the forefront of our minds; for instance, production delays that may affect our ability to start paying back loans. Recent events in the Gulf of Mexico have illustrated further risks in relation to environmental impact, loss of reputation and political impact, with their consequential financial liabilities.

A further politically related risk affects governments and national oil companies that commission the building of a refinery from one of the international turnkey contractors, but have insufficient experience themselves and are not well qualified to query cost and schedule estimates.

Independent verification

Refinery and petrochemical projects are complex, with many interactions between the various units and project phases. Decisions taken in one phase may have adverse implications for another phase. It can be difficult in a project, when involved in day-to-day work, to identify all of these interactions.

In addition, we develop projects today in a truly global market, with many of the components, systems and design processes developed in locations remote from the facility.

A particular challenge are fast-track projects that often start many phases in parallel with a preceding one, without all aspects being fully developed, and with overlapping decision gates.

Therefore, in managing these challenges, the use of an independent party with wide experience is beneficial, and independent verification will lead to a reduction in design, supply, construction and commissioning errors.

Independent verification is a valuable tool for the refinery or petrochemical facility owner to obtain assurance of the contractors' work or to show partners, financiers, insurers and the public that the refinery or petrochemical facility has sufficient integrity to fulfil its specified purpose, and that the risks to personnel associated with the facility are reduced as much as is reasonably practicable.

Additionally, it is good business practice to subject critical work to an independent check; this minimises the possibility of errors remaining undetected.

Independent verification will ensure that the verifier has an unbiased view and perspective when performing this activity. Furthermore, it will avoid the situation where errors could be overlooked by engineers because of their closeness to work within the facility.

Verification can also be used as a part of the project risk management process. The failure of any part of the facility may expose the owner to:

- Safety risks
- Environmental risks
- Economic risks
- Political risks.

Since verification increases confidence levels that the refinery or petrochemical facility complies with the requirements placed on it by national authorities, the owner or the lenders, it follows that the risk of failure of the facility decreases as a result of independent verification. Thus, independent verification contributes to project risk management and reduction.

Verification and risk

Risk is the likelihood of an accident or unplanned event occurring, considered in conjunction with the potential consequences of such a failure. In quantitative terms, risk is proportional to the probability of failure multiplied by the consequence of such failure.

Measures usually taken to reduce the risks to the operation of the refinery and process facility, and to protect the health and safety of personnel associated with it or in its vicinity, are through reduction in the probability of failure, and/or mitigation of the consequences of failure.

Independent verification of refineries and petrochemical facilities has a key part to play in both aspects of risk reduction. Once the risks to the facility have been identified, as well as the measures to be taken to reduce these risks, verification work can be focused on these critical areas.

The benefits of this risk-based approach are:

- Improved safety and financial performance by optimisation
- Cost savings with the main focus on critical areas
- Management of supply chain risks
- A transparent, traceable and well-documented verification system.

As verification work is focused on the identified critical areas rather than on a scatter-gun approach, it can result in the apparent, but beneficial, anomaly of spending less money for improved safety.

Traditional verification activities, for a variety of industrial facilities, as practised all over the world for many years, include:

- Design review
- Inspection during equipment procurement
- Inspection during construction and installation of equipment

Since verification increases confidence levels..., it follows that the risk of failure of the facility decreases as a result of independent verification

- Witnessing of hydrotests and commissioning activities
- Review of documentation
- Issue of certificate of compliance.

We should challenge this tradition, as it is unclear how effective the approach is in reducing the risks to the refinery or petrochemical facility. To illustrate this point:

- **Level of involvement of the third party** The level of involvement of the third party is not defined and it cannot be deduced from the certificate. This involvement could be very detailed, including a comprehensive review of the design and construction, independent analysis and audits or surveillance on site. Conversely, it could be much less comprehensive, with only a brief review of documents and no site attendance.
- **Link between design, construction and commissioning** The link between design, construction and commissioning frequently is not fully understood. Activities in each phase often are carried out in isolation, with no link between phases. For example, critical design issues are almost never given additional focus during construction. Often this is the case because the construction personnel do not know that these issues exist.

Verification: cost or benefit?

The use of independent verification frequently is seen by projects simply as a cost that has to be borne. Therefore, the argument is often made that verification must be as cheap as possible. Frequently, the verification contract is with the contractor, not the owner, and therefore the successful verification body has tendered the lowest price by proposing the minimum verification scope.

Verification rarely is seen as a benefit, because often there is no evidence that it is. However, it must be said that this situation is more to do with the inability of third parties to demonstrate the benefits of their involvement than in the inability of owners and contractors to understand those benefits. As a result, the knowledge of the third party is not used actively in the project, as it is an expense only.

Frequently, the verification body is often involved late in the project when there is limited opportunity to use its expertise. The use of the third party's expertise is more effective the earlier it is involved in the project, when changes to the design concept can be made at minimal expense. Such early-phase involvement should include verification of the feasibility and conceptual studies, with early identification of critical aspects. This approach would focus on the risks to the facility, with comprehensive involvement during all critical phases with independent risk assessment and validation.

Such early and comprehensive involvement could be termed active verification, where the third party has active participation in the

design and construction processes rather than passive verification, where the third party merely reacts to what has already been decided.

Certificates and other statements from the third party are often valuable for finance and insurance. However, these documents would be more valuable if the level of independent involvement was clearly defined and understood for all phases of the project and stated clearly in documents.

This should minimise a source of conflict in some projects where the service the owner or contractor thought they were purchasing was not the service the third party thought they were contracted to provide.

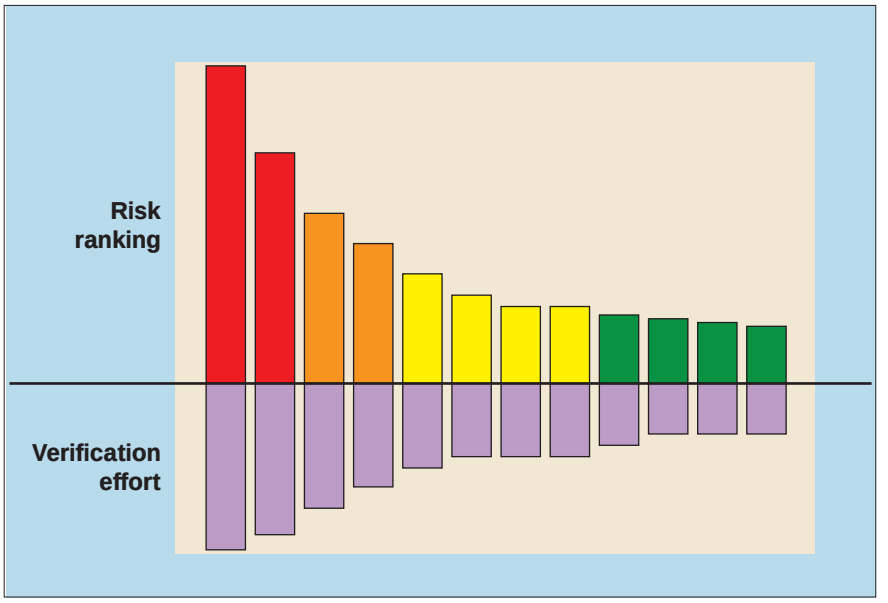


Figure 2 Risk-based verification

Risk-differentiated verification

The concept behind this approach to the verification of refineries and petrochemical plants is that the level of verification involvement can be differentiated according to the risks to the facility. Figure 2 illustrates this concept and shows that:

- The lower the risk, the less involvement
- The higher the risk, the more involvement.

It is true to say that with a lower level of involvement there is a greater possibility of failing to discover things that are not correct. On the other hand, with a lower level of risk, the consequences of this failure are lower.

Selection of verification level

The selection of the level of verification depends on the criticality of each of the elements that have an

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impact on the management of risks to a hydrocarbon facility.

Verification directs the greatest effort at those elements of the plant where the risk is highest and whose failure, or reduced performance, will have the most significant impact on the safety and integrity of the facility. Other risks, such as environmental and economic risks, may be considered if this is required by the owner.

Due to the diversity of various refining and petrochemical facilities, their contents, their degree of innovation, geographic location and so on, it is not possible to give precise guidelines on how to decide what level of verification is appropriate for each particular facility.

In view of the complexity of most hydrocarbon facilities, we recommend strongly that the verification level be derived from the results of a quantitative risk assessment of the facility.

The outcome of a quantitative risk analysis (QRA) should be a ranking of the risks associated with particular parts of, or equipment in, the hydrocarbon facility. This ranking is used to set the verification level for parts of the facility as well as for the facility as a whole (see Figure 2).

The scope of QRA should include tasks typically required to assess risks from hazards to human life, equipment and the environment. It includes:

- Hazard identification
- Frequency estimation
- Consequence criteria
- Consequence analysis
- Domino effect analysis
- Risk summation and evaluation
- Sensitivity analysis
- Assessment of inherent safety, detection, prevention, control, mitigation and emergency response measures.

Only in the simplest of hydrocarbon facilities, with consequently lower levels of risk, would we consider that simplified qualitative verification planning without using a QRA is justifiable.

Factors to be taken into account in this simplified method for identifying the risks and selecting the level of verification involvement are:

- The overall safety objectives of the facility
- An assessment of the risks associated with the facility and the measures taken to reduce these risks
- The degree of technical innovation in the facility
- The experience of the contractors in carrying out similar work
- The quality management systems of the owner and the contractors involved.

The first three of these factors are straightforward, but the last two require some amplification.

Contractors may be widely experienced, but not in a particular material or installation method. The refinery business is characterised by examples of well-known and well-respected design or construction contractors who have run into difficulties when trying something new.

It is worth emphasising that risks during one phase may be different to those in another phase. For example, an experienced design contractor and an inexperienced construction contractor may be involved, or vice versa. Therefore, because the risk varies from one project phase to another, it is important to vary the verification level in a similar manner.

Virtually all contractors have quality systems certified as complying with ISO 9001. But, if contractors take on many new staff, usually on short-term contract, at the start of a project, these new staff may not be completely familiar with the contractor's quality system and errors may occur.

Similar difficulties have been encountered in trying to amalgamate two or more quality management systems in a joint venture.

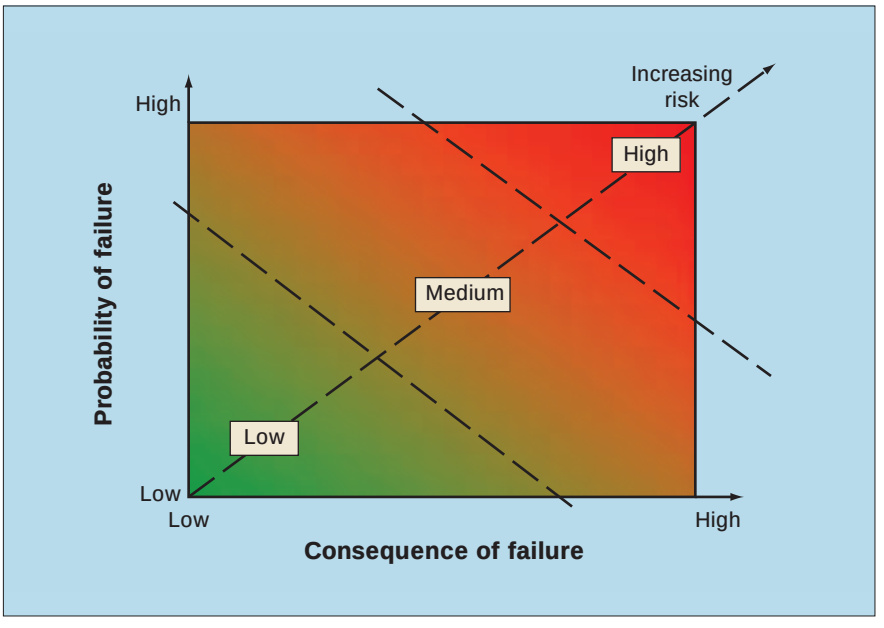


Figure 3 Verification and risk – the levelled approach

Risk-differentiated verification in practice

Risk-differentiated verification may be carried out at three levels of increasing complexity, known, for simplicity, as low, medium and high (see Figure 3).

Low-level verification includes activities such as:

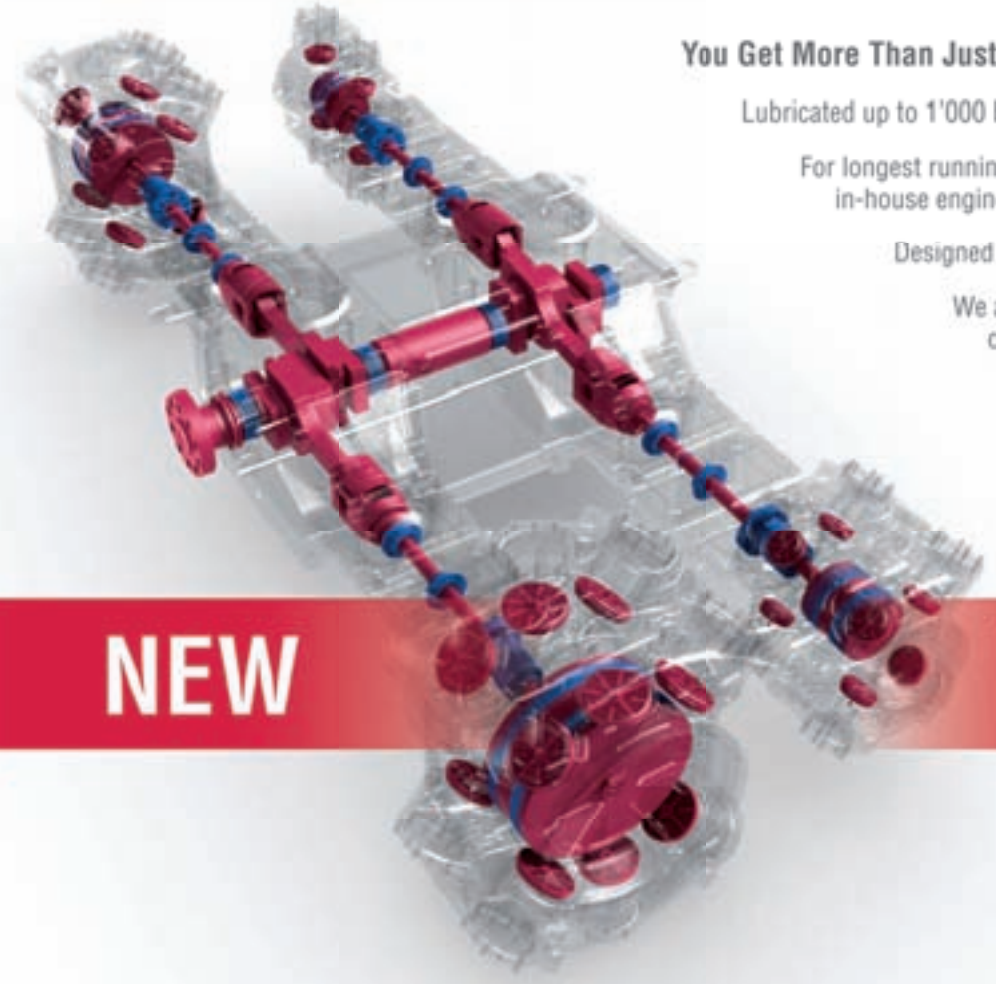
- Review of general principles and production systems during design and construction
- Review of principal design documents, construction procedures and qualification reports
- Visit-based attendance during system testing and startup activities.

Medium-level verification includes activities such as:

- Review of general principles and production systems during design and construction
- Detailed review of principal and other selected design documents with support of simplified independent analyses
- Full-time attendance during

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qualification and review of the resulting reports
- Visit-based or intermittent presence on site.

High-level verification includes activities such as:
- Review of general principles and production systems during design and construction
- Detailed review of most design documents with support of simplified and advanced independent analyses
- Full-time attendance during qualification and review of the resulting reports
- Full-time presence on site for most activities.

Risk-differentiated verification in the supply chain

The risks associated with supply chain management can be reduced by a combination of the quantitative and qualitative methods of selecting the verification level.

As was previously discussed, the outcome of a quantitative risk analysis should be a ranking of the risks associated with particular parts or equipment of the hydrocarbon facility. This ranking should be used to set the initial verification level for verification of the supply chain.

This initial verification level may be modified as a result of the answers to the trigger questions in the qualitative method, especially those relating to contractors' experience and effectiveness of their quality management system.

Verification activity, therefore, is concentrated on those items in the supply chain that contribute most to the overall risk to the facility and its successful completion.

DNV OSS-314

Based on its experience in refineries throughout the world, DNV recently published its *Service Specification OSS-314: Verification of Hydrocarbon Refineries and Petrochemical Facilities*. The objectives of this document are threefold, to:
- Ensure that the market knows what the company is offering
- Ensure commonality of service among the company's various offices in this field

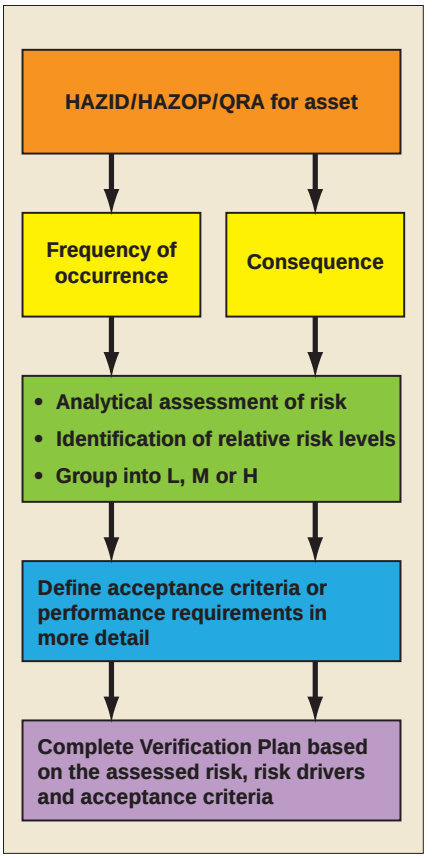


Figure 4 Detailed verification planning, based on analytical risk assessment

- Establish a baseline for refinery and petrochemical facility verification services throughout the world, irrespective of service provider.

Service specification OSS-314:
- Describes DNV's verification services for refineries and petrochemical facilities
- Introduces and describes the levelled approach to verification
- Guides the selection of level of involvement by introducing risk-differentiated verification
- Results in a predictable and uniform verification service.

The document is divided into three sections and five appendices.

Section 1: Introduction to risk-based verification

This section describes verification services for refineries and petrochemical facilities and provides guidance for owners and other parties for the selection of the level of involvement of those carrying out verification activities. In addition, it provides a common communication platform for describing the extent of verification activities.

Section 2: Principles of risk-based verification

This provides an introduction to the principles of verification of refineries and petrochemical facilities, an introduction to the principles of risk-differentiated levels of verification activity, and gives guidance on the selection of levels of certification and verification.

Section 3: Service overview

This section is an overview of certification and verification activities relating to facility systems, and gives details of certification and verification services in this area.

Appendix A: Selection of verification level

This gives guidance on the selection of verification level quantitatively by means of a QRA (the preferred method; see Figure 4) and, alternatively, qualitatively by means of a series of trigger questions.

Appendix B: Verification documents

Gives example of documents produced during various verification and certification activities.

Appendix C: Generic detailed scopes of work tables

Provides detailed scopes of work tables for activities during the independent verification of refineries and petrochemical facilities The titles of these tables are shown below.

Appendix D: Major accident hazards vs safety-critical elements

This appendix shows typical refinery hazards and the interface with safety-critical elements and risk mitigation measures.

Appendix E: Guidance on the development of verification plans

Provides guidance on the development of verification plans tailored to a specific hydrocarbon facility and its specific risks.

Detailed scopes of work tables

DNV OSS-314 contains generic detailed scopes of work descriptions for the verification of refineries and petrochemical facilities for the three levels of verification: low,

medium and high. A specific scope of work description, based on the generic ones in DNV OSS-314, should be made for each particular project.

Generic scopes of work tables given for project and operational phases include:

- Design
- Construction (procurement)
- Commissioning
- Operations
- Upgrades.

These scopes of work tables are divided mainly into systems, such as:

General

- Overall project management
- General design matters
- Safety, environmental or other functional requirements.

Inherent safety measures

- Layout
- Hydrocarbon inventory and leak source minimisation.

Hazard prevention measures

- Pressure vessels
- Offloading and loading facilities
- Jetties
- Loading and unloading arms
- Process system
- Relief valves and relief system
- Structural integrity
- Above-ground storage tanks
- Control systems
- Control of ignition
- Dropped object and impact protection
- Hazard detection and control measures.

Fire and gas detection

- Emergency shutdown system
- Blowdown header and flare system
- Control room
- Active fire-fighting systems
- Passive fire protection
- Bunding and drainage.

Hazard mitigation measures

- Emergency power and uninterruptible power supply
- Communications and alarms
- HVAC.

Emergency response measures

- Egress and evacuation system.

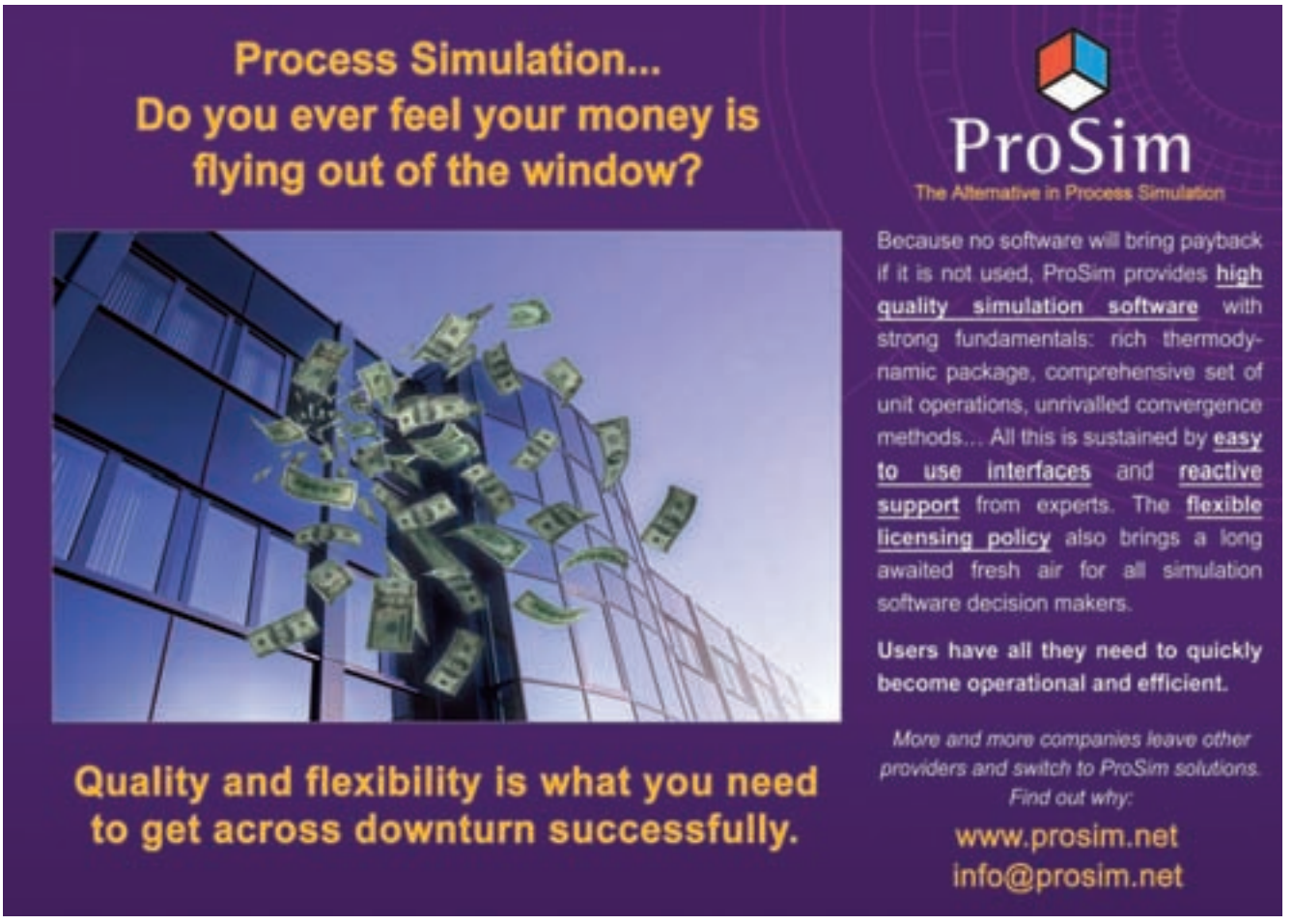
Conclusions

Independent verification is needed as part of a refinery's or petrochemical facility's risk management process. The extent of independent verification should be linked to the risks to the facility so that verification efforts may be focused on those areas of greatest risk and so contribute to risk-reduction measures.

Thus, the extent of verification can be linked to the risks to the facility, and the activities for each of the project phases can be increased or decreased, depending on the risks.

DNV has developed its *Service Specification OSS-314 Verification: of Hydrocarbon Refineries and Petrochemical Facilities* that describes the company's risk-based verification services.

Donald Payne is a Principal Engineer and a Director of DNV Vietnam. He has experience in verification and consultancy during the design, installation, commissioning and operation of offshore and onshore oil and gas installations, pipelines and refineries.



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Bottom of the barrel upgrading

The predicted and demonstrated role of additives in raising bottoms product yields and properties from the FCC unit

ALAN KRAMER
Albemarle

One thing is certain in the ever-evolving world of refining: refiners need to capitalise upon opportunities that allow them to profitably crack increasingly difficult feedstocks in the fluid catalytic cracking (FCC) unit. This is apparent in the sheer quantity of new technologies appearing in the industry within the past few years. Two decades ago, Albemarle pioneered the technology platform from which the original Bottoms Cracking Additives (BCA) were developed. Subsequent improvement of these first BCAs, with enhanced zeolites and metals trapping components, has resulted in today's BCMT series of additives.

Although market demands vary globally, refinery economics always present a considerable driving force towards reducing bottoms. Traditionally in the European marketplace, distillate yield is optimised on the FCC unit. The demand for diesel fuels has been driven by aggressive automobile efficiency regulations and policies favouring diesel-powered vehicles. Conversely, North American refiners have typically operated the FCC unit to generate the optimal amount of gasoline barrels. Recent regulations within the US, such as the Renewable Fuels Standard, have upset the traditional paradigm. Now, North American refiners are finding themselves in long positions in both gasoline and octane. This has resulted in the oversupply of high-octane gasoline and depressed gasoline margins. Coupled with increased global demand for diesel, many refiners have shifted focus away from optimising the gasoline yield towards increasing diesel production instead.

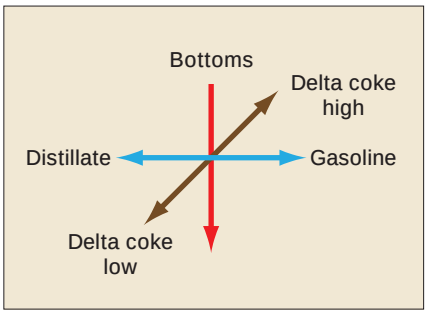


Figure 1 The yield space of a FCC unit

Figure 1 shows the concept of the yield space of the FCC unit. The yield space defines, in a three-dimensional co-ordinate system, the primary factors to be considered when optimising the FCC unit profitability. Economics always drive bottoms minimisation (vertical axis), market factors determine the predominant yield (horizontal axis) and heat balance considerations determine the optimal delta coke target (orthogonal axis).

When utilising a BCMT additive, choice depends not only on the primary product slate, but also on the configuration of the refinery

When utilising a BCMT additive, additive choice depends not only on the primary product slate, but also on the configuration of the refinery, especially the existence of a feed hydrotreater. Refiners charging resid to the FCC unit without the capability of feed hydrotreating may face a delta coke limitation. This limitation often manifests itself as a metallurgical limit within the FCC unit regenerator or associated downstream piping and hardware; or as a reduction in the catalyst-to-oil ratio, resulting in unacceptable yields from the FCC unit. Resid processors also suffer from increased metals contamination on the equilibrated catalyst, leading to wet gas compressor constraints resulting from increased hydrogen and light gas production.

At the other end of the feed spectrum, some refiners choose to severely hydrotreat the feed sent to the FCC unit. This improves conversion and provides the opportunity for the FCC unit to generate products with specific properties, such as 10 ppm ultra-low sulphur gasoline. Refiners processing deeply hydrotreated feeds can find themselves in the situation where the regenerator temperature is too cool to maintain stable operation, but the wet gas compressor is operating at its design limit. In this situation, a coke-selective increase in delta coke is required, but this change must occur in a manner by which the gas volume is not increased.

Regardless of whether or not a feed hydrotreater is present in a refinery, the minimum bottoms yield will ultimately be defined by the concentration of non-crackable, multi-ringed aromatic cores present in the FCC unit feed that boil above 340°C. Besides feed, there are two

other main variables strongly influencing bottoms cracking.

Accessibility, defined as the ability of the large feed molecule to diffuse into the catalyst particle (without forming coke along the way) and subsequently crack upon the appropriate active site, is absolutely critical for profitable bottoms cracking. Just as critical is metals tolerance. Nickel, vanadium and iron increase coke, hydrogen and dry gas yields. When not properly passivated, these metals can lead to reductions in the catalyst-to-oil ratio and increased bottoms yield. Vanadium and sodium both destroy the zeolite crystal and neutralise acid sites, reducing conversion. Iron is known to glaze the outer surface of catalyst particles lacking sufficient metals tolerance, significantly reducing accessibility. The presence of calcium, vanadium and sodium further exacerbates accessibility loss.

Returning to the concept of the yield space (see Figure 1), refiners agree that minimising bottoms (moving downward in the yield space) is a fundamental driver behind profitable FCC unit optimisation. However, feed, accessibility and contaminant metals commonly prevent them from moving towards greater profitability in their yield space.

Solving the bottoms cracking problem

While improved profitability is found by moving downwards in the yield space, maximised profitability is realised by simultaneously moving in the other two yield space dimensions as well. The primary product yield (the horizontal axis in the yield space) is defined by the local or regional product market. Delta coke considerations (the orthogonal axis in the yield space) will vary from refiner to refiner, depending on hardware and unit constraints. Given the myriad of possibilities present in these two dimensions of the yield space, it is illogical for one single additive solution to meet every refiner's needs. Simply stated, the same additive cannot be expected to provide maximum gasoline barrels and a cooler regenerator temperature in one FCC unit, and increase LCO yield and delta coke in another unit.

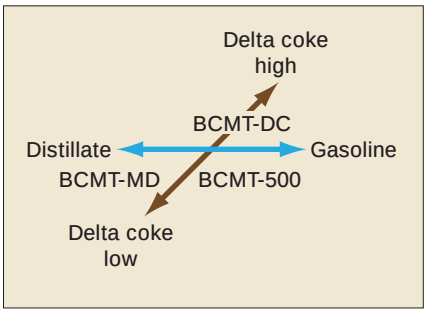


Figure 2 Within the FCC yield space, three formulations of BCMT additives are required to meet the needs of refiners for improved bottoms cracking

Necessity therefore dictates three distinct solutions for refiners employing BCMT additives to maximise profitability within their yield space. Figure 2 overlays the names of these different additives, each of which is especially formulated to target specific regions of the yield space. Selection of the correct formulation depends on each refiner's requirements for primary product yield and heat balance.

BCMT additives aim to improve catalyst accessibility by enhancing the diffusional architecture of the catalyst system

The BCMT solutions available to refiners are as follows:

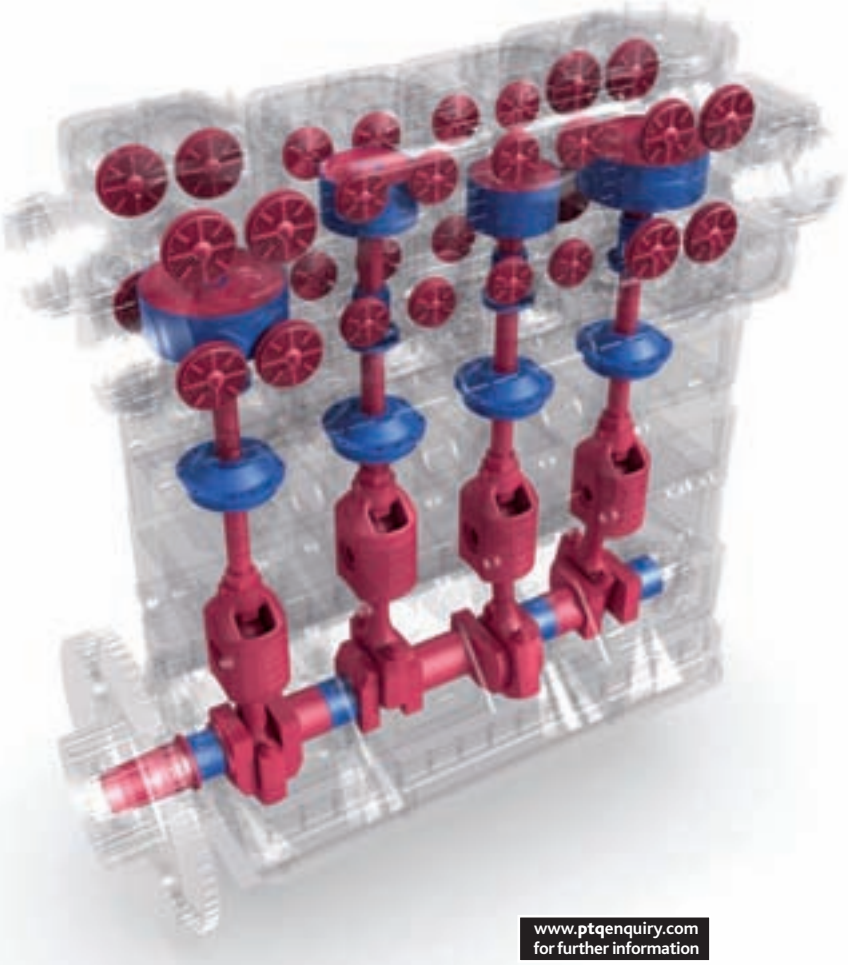
- BCMT-500 minimises bottoms yields through a combination of Albemarle Developed Matrices (ADM), specifically ADM-20 and ADM-60, which in combination provide a robust bottoms cracking matrix with tailored mesoporosity and acid site distribution. The ADM-60 alumina also provides metals trapping capabilities, allowing the additive to increase the metals tolerance of the unit inventory.[1] A rare earth stabilised zeolite is also incorporated into BCMT-500, bestowing excellent hydrothermal stability, increased gasoline yield and lower gas make
- BCMT-MD utilises the raw bottoms cracking strength of ADM-20 matrix, the metals trapping of ADM-60 and a combination of speciality zeolites designed to minimise the overcracking of light cycle oils into gasoline, while at the same time ensuring a sufficient wet gas yield to maintain volume expansion. Together, the combination of ADM-20 and the speciality zeolites result in a low delta coke and gas make, which can be leveraged to increase the catalyst-to-oil ratio or increase the fraction of resid charged to the FCC unit
- BCMT-DC solves the problem faced by many refiners running severely hydrotreated feeds; that is, how to increase the regenerator temperature (delta coke) and improve the operational stability of the FCC unit without increasing the dry gas yield. Since metals trapping is usually not a primary concern for heavily hydrotreated FCC units, BCMT-DC combines different ADMs, rare earths and zeolites focused solely on maximising bottoms cracking activity at a higher delta coke. It is important to stress that the higher delta coke with BCMT-DC is not achieved by poorer coke selectivity; rather, the higher delta coke is achieved by increasing the overall activity while maintaining coke selectivity. Due to the inherent difficulty of squeezing additional bottoms cracking activity out of hydrotreated feedstocks, BCMT-DC is bound by a proprietary binding system, allowing a large quantity of catalytically active components to be assembled into the catalyst particle while maintaining attrition resistance equal to typical base cracking catalyst formulations.

Regardless of the additive employed by the refiner, BCMT additives aim to improve catalyst accessibility by enhancing the diffusional architecture of the catalyst system. This allows the feed molecule to pre-crack prior to entering the zeolite, whereupon it cracks further into valuable products. All three of the BCMT additives deliver

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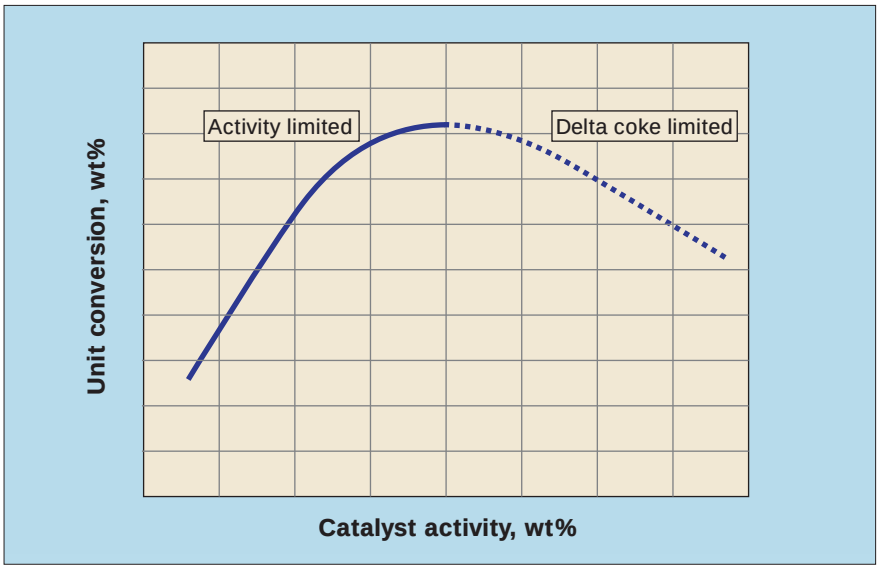


Figure 3 Simply increasing the catalyst activity will not improve bottoms cracking. For delta coke-limited units, increasing activity can result in lower conversion due to a reduced catalyst-to-oil ratio

large quantities of pre-cracking sites while only making up a small fraction of the circulating inventory. Since these materials are designed as additives to the base catalyst, they can be added to the inventory to enable an improvement in the profitability of the FCC unit by:

- Decreasing the bottoms yield and increasing bottoms density
- Increasing the liquid product yield (LCO, gasoline, LPG)
- Increasing the processing of opportunity crude
- Increasing the amount of resid feedstock.

On occasion, refiners may think that they can lower the bottoms yield by selecting a lower delta coke catalyst, increasing the catalyst-to-oil ratio and subsequently increasing bottoms conversion. While this non-selective approach may reduce the bottoms yield slightly if no circulation constraint is encountered first, it comes at the cost of increased coke production.

Other times, refiners may think they can increase the bottoms cracking activity of their FCC unit by simply increasing the catalyst activity. Increasing the catalyst activity can be accomplished by reformulating the base catalyst or by adding more catalyst per barrel of feed processed. However, experience has shown that simply increasing catalyst activity by these methods usually does not result in improved bottoms cracking. When a FCC unit is constrained by a regenerator temperature or air blower limit, increasing the catalyst activity in a non-coke selective manner may not increase the conversion on the FCC unit — the conversion could potentially drop. This is because the increased activity will cause the regenerator temperature to rise, forcing the refiner to lower the riser temperature in response. The catalyst-to-oil ratio is subsequently lower, resulting in fewer catalyst sites present for the feed to crack upon, lower conversion and an undesired increase in bottoms.[2] This concept is illustrated in Figure 3.

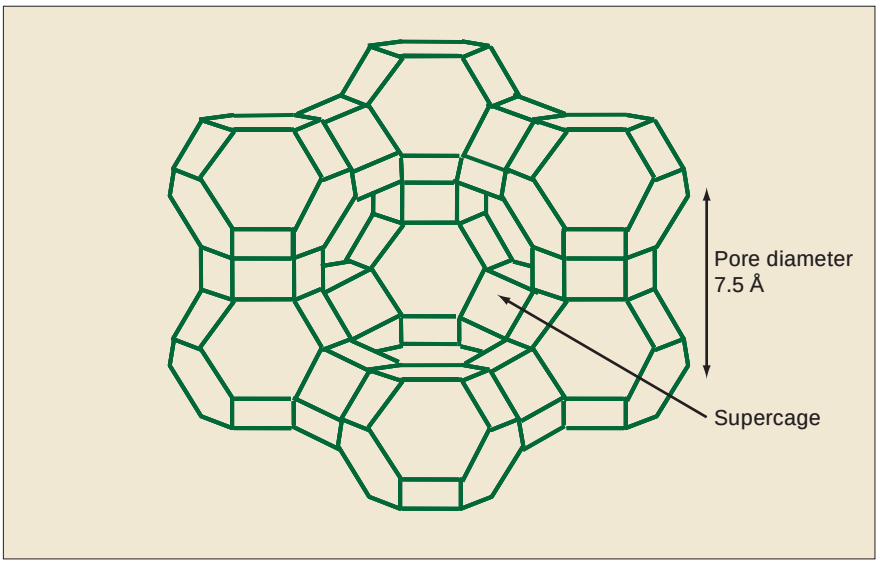


Figure 4 Graphical representation of the Faujasite (Y-zeolite) supercage

How BCMT additives work

The introduction of Y zeolite in catalysts was the major breakthrough in FCC in the latter half of the twentieth century.[3] This technology enabled catalyst activity to increase tremendously, paving the way for the change from dense bed to riser cracking. Subsequently, contact time between oil and the catalyst in the FCC unit decreased.[4] The decrease in contact time has caused many units to be ultimately limited by the ability of the matrix of the FCC catalyst to convert the large feed molecules in a much shorter time, especially as increasing quantities of residual feedstocks are routed to the FCC unit.

The supercage in Y zeolite, where most of the primary cracking reactions take place, is shown in Figure 4. The diameter of the supercage is 14 Å. However the entrance diameter is only 7.5 Å. Molecules with boiling points of 480°C or higher typically are too large to enter the zeolite supercage, since these molecules have kinetic diameters ranging from 10 Å to as large as 100 Å.

The diffusional character of the catalyst determines whether or not molecules with kinetic diameters greater than 7.5 Å are accessible to the active sites that pre-crack these large molecules into intermediate products, thus allowing them to enter the zeolite supercage and continue cracking into the desired final products. Feed molecules that

cannot be admitted into the supercage are restricted to cracking only on the outer shell and surface of the zeolite,[5] which ultimately limits the conversion of the feed to product.

Previously published work showing the relative cracking activity of branched naphthenic compounds over matrix and Y-zeolite[6] is shown in Figure 5. This further illustrates the need for a highly active, accessible matrix component to pre-crack large molecules so that they can be admitted into the zeolite.

The accessibility of a catalyst can be quantified by measuring the dynamic diffusion of high molecular weight molecules into the FCC unit catalyst particle. This number is commonly known as the AAI, or Albemarle Accessibility Index.[7] The AAI reflects the capability of the catalyst to facilitate high molecular weight, sterically hindered molecules to diffuse into a catalyst particle, bind with active sites, crack into product molecules, and then diffuse back out of the catalyst particle to be recovered as product.[8,9]

In all FCC units, especially those that are processing a high fraction of residual feedstock, there exists a critical AAI level, below which catalyst performance (and unit yields) fall drastically.[10] With the proper catalyst technology, it can be easy to maintain the AAI above the critical level. Small improvements in accessibility, when leveraged across the entire unit inventory, can return significant improvements in yield.

However, because of seasonal demand, supply chain logistics and FCC unit circulating inventory sizes, it can be difficult for refiners to improve the catalyst AAI in a timely enough fashion to meet product demands. In these situations, an accessible FCC additive can be employed to boost the AAI above the critical level. This provides the necessary pre-cracking of the feed components so that the available zeolite can be more fully utilised.

Contaminant metals that are typically found in high concentrations in resid feeds can quickly damage overall unit performance. Metals

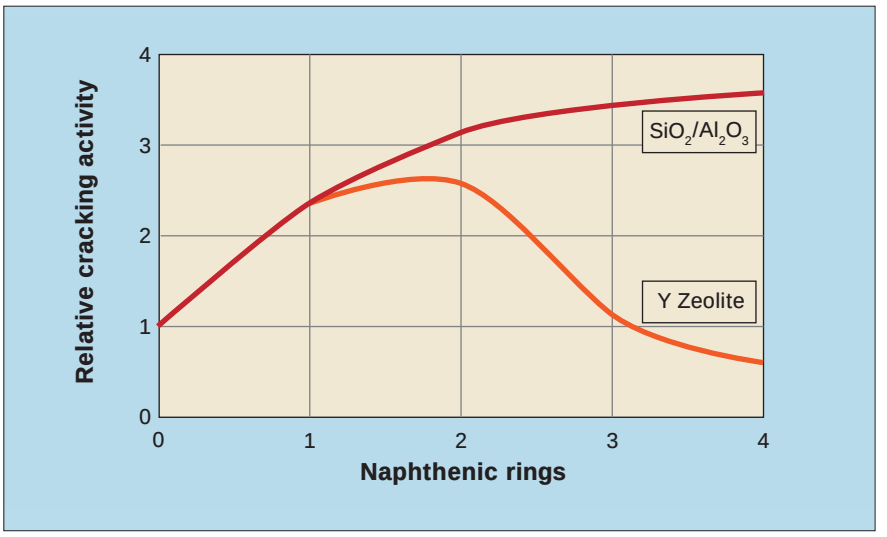


Figure 5 Relative cracking activities of model compounds over zeolite and matrix catalyst components

such as nickel will be deposited on the surface of the catalyst, forming *in situ* dehydrogenation catalysts. These can be quite catalytically active, removing what little precious hydrogen may be available from large, hydrogen-deficient molecules. These dehydrogenated molecules form a covering of coke on the surface of the catalyst particle, blocking other oil molecules from the active sites. In addition, this coke must be combusted in the regenerator, which results in a higher regenerator temperature and lower catalyst-to-oil ratio. The covering of active sites and the reduction of the catalyst-to-oil ratio both lower unit conversion.

The additive approach to improving accessibility must push past the bounds of existing catalyst technologies

To combat the deleterious effects of contaminant metals in delta coke-limited units, both BCMT-500 and BCMT-MD are formulated with ADM-60 alumina. ADM-60 alumina binds with nickel to form nickel aluminate, $NiAl_2O_4$. Nickel aluminate has been found in laboratory testing to be both stable and significantly less reactive than nickel oxide for generating hydrogen. More importantly, catalysts that have the ability to passivate nickel into nickel aluminate exhibit superior metals tolerance in the FCC unit.[11]

In order to be successful, the additive approach to improving accessibility must push past the bounds of existing catalyst technologies, because with additives the improvements in accessibility and metals tolerance can stem only from a small fraction of the circulating inventory rather than the entire catalyst load. BCMT additives, therefore, are uniquely designed to meet the challenge of quickly increasing catalyst accessibility, since they are specially formulated to provide extreme accessibility in a highly concentrated additive form. BCMT additives utilise advanced manufacturing technologies that greatly increase molecular diffusion and maximise AAI,[12] while delivering the proper balance of pre-cracking matrix, selective zeolite sites and metals tolerance. BCMT-500 and BCMT-MD provide all of these benefits without increasing or adversely affecting the delta coke make on the FCC unit. BCMT-DC provides additional delta coke for FCC units with hydrotreated feedstocks, but does so without the dry gas penalties typically associated with increased delta coke.

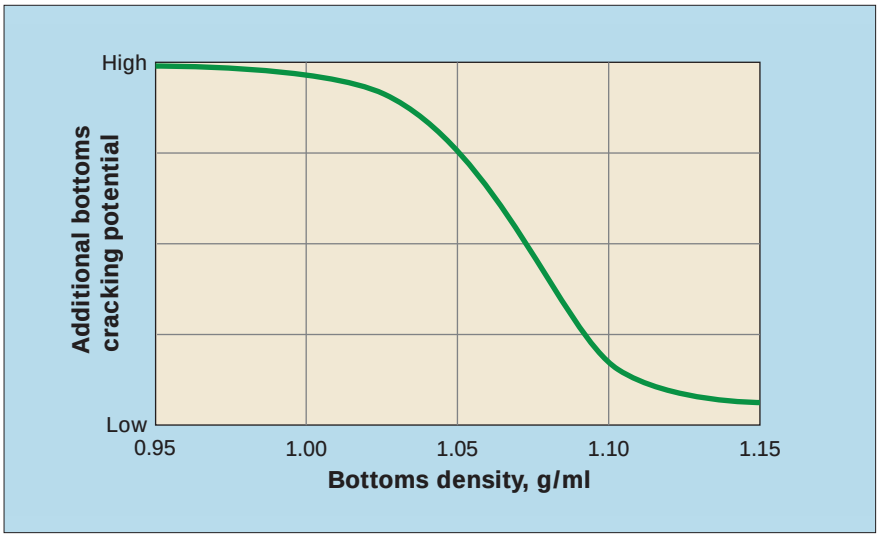


Figure 6 Estimating the bottoms cracking potential based on the bottoms gravity

Identifying the potential

The key question that must be answered prior to using any BCMT additive is how much of the bottoms is truly crackable? Some of the more common methods of determining how to answer this question are:

- Estimation based on the commercial bottoms gravity
- Laboratory analysis of the commercial bottoms fraction
- Ecat benchmarking
- Lab-scale testing.

Estimation based on bottoms gravity

The simplest method, and perhaps also the least accurate of the options described here for determining whether or not additional bottoms cracking potential exists, is a qualitative estimate based on the density of the bottoms (see Figure 6).

Generally speaking, the lighter the bottoms density, the higher the propensity that crackable material remains unconverted in the bottoms fraction. Densities less than 1.07 g/ml usually indicate a good chance that BCMT additives will return a measurably positive, and often lucrative, benefit to the refiner. Between 1.07 and 1.11 g/ml, the probability of major success is usually less certain. Some refiners employing BCMT additives have seen significant bottoms reductions past 1.11 g/ml, whereas in other cases the incremental performance benefits have waned by this bottoms point. Densities greater than 1.12 g/ml generally indicate the base catalyst is sufficiently cracking bottoms, and it is unlikely that the addition of BCMT will improve the bottoms cracking situation by a significant margin.

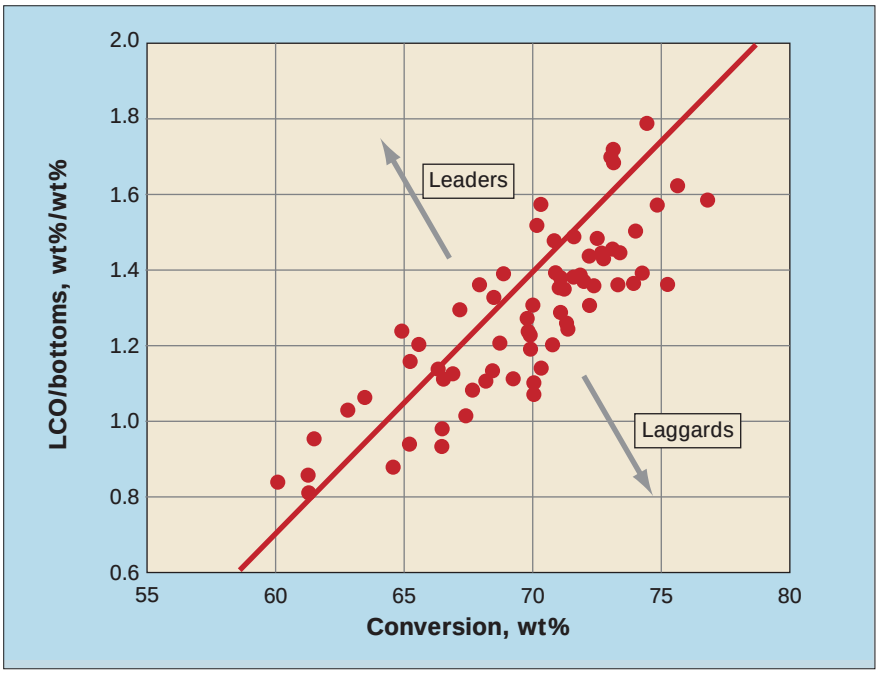


Figure 7 Comparison of the FST results for many refiners' Ecat samples averaged over a monthly time period indicates which refiners successfully beat their peers at maximising LCO at constant conversion

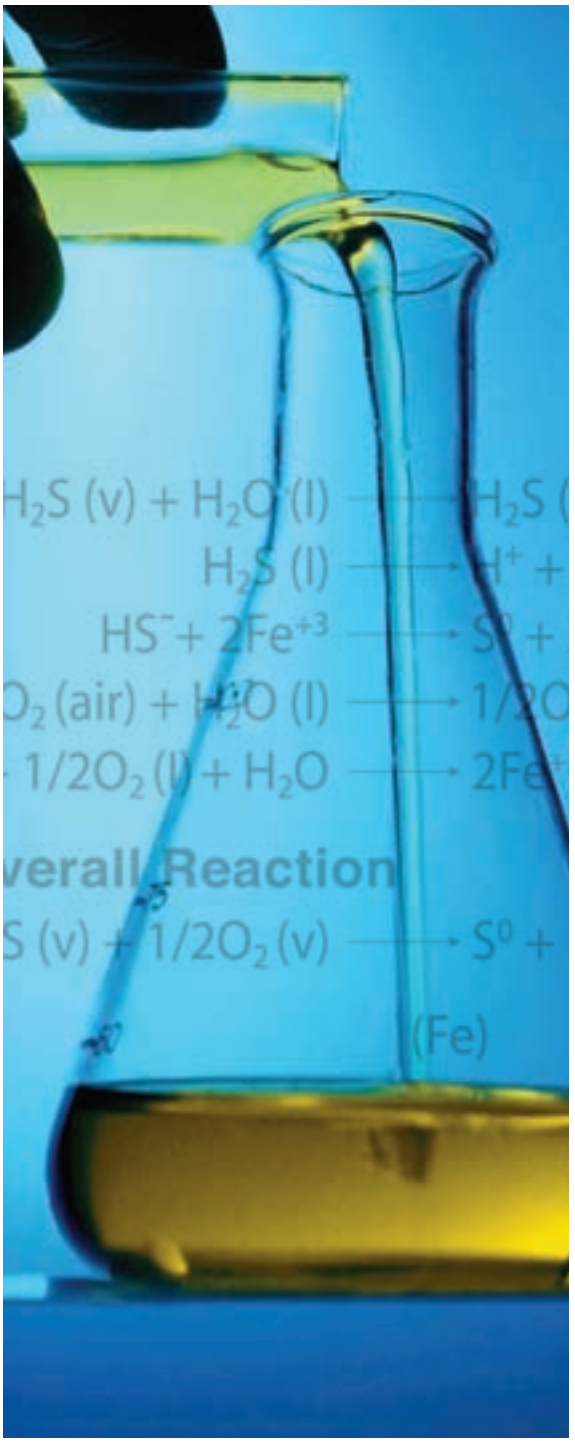
Laboratory analysis of the bottoms

High boiling-range feed molecules typically found in the bottoms fraction of the FCC yield slate are usually too large to enter a Y-zeolite supercage. Previously published work indicates that large amounts of zeolite will be effective in removing alkyl side chains from aromatic cores (dealkylation).[13] While this reaction certainly occurs, the bulk of mass in the bottoms yield is not located in the side chains attached to aromatic or polynuclear-aromatic cores, but is rather in the cores themselves. This is because the alkyl side chains attached to the polynuclear-aromatic cores are usually quite short in length. Dealkylation generally results in an increased LPG yield instead of increased transportation fuels, which are typically desired from the FCC unit. Therefore, quantifying the degree of potential core destruction is paramount when gauging the bottoms crackability.

Ecat benchmarking

Most major FCC catalyst suppliers provide some degree of fluidised bed lab-scale testing of Ecat samples on a routine basis. This testing is often performed on a fluidised simulation test (FST) unit or an advanced cracking evaluation (ACE) unit. While the testing equipment and conditions may vary from supplier to supplier, the inherent value to this type of testing is that within each supplier's labs, all of the equilibrium catalyst testing is performed over the same feed at constant lab conditions. Therefore, given adequate laboratory controls, the only variable that changes over time is the equilibrium catalyst itself.

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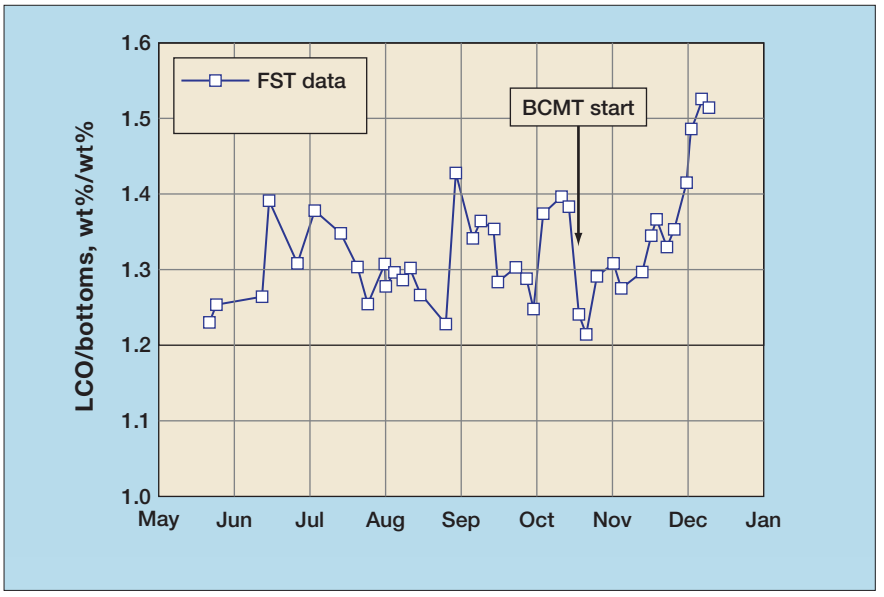


Figure 8 The trend of the FST results of one refiner's Ecat indicates a dramatic (positive) change in the bottoms cracking ability of the catalyst. In this case, the change is due to BCMT usage

Benchmarking data is valuable to the refiner in two ways. Since the feed and laboratory testing conditions are constant for all samples tested, accurate comparisons can be made across different FCC units. One way to compare bottoms cracking prowess across different FCC units can be to analyse the LCO-to-bottoms ratio (see Figure 7).

In Figure 7, those units which, for a given conversion level, are towards the upper-left side of the plot should be considered leaders relative to their peer group for maximising LCO at the expense of bottoms. Units desirous of converting bottoms into LCO that are closer to the bottom-right side of the plot should consider using BCMT-MD to improve their LCO-to-bottoms ratio. If a unit were focused on maximising gasoline or total transportation fuel yield, gasoline/bottoms or (gasoline + LCO)/bottoms could be plotted in a similar manner and provide equally useful information.

It is very important that the operational parameters of the lab-scale unit match as closely as possible the commercial conditions at the refinery

Second, Ecat benchmarking can show trends over time of the bottoms cracking ability of the base catalyst at constant feed and conditions. Ecat FST data from a single refiner are shown in Figure 8. The data points represented by squares quantify the bottoms cracking ability of the equilibrium catalyst in the same manner shown in Figure 7 — through the LCO-to-bottoms ratio. The upswing in the LCO-to-bottoms ratio towards the right side of the plot is due to an Albemarle BCMT additive being introduced to the unit.

Comparison of commercial yields to yields measured by routine Ecat FST testing and laboratory deactivated catalyst and additive on a constant conversion basis with 10% BCMT-500

	Commercial	Ecat FST	Lab deactivated
Coke	No change	+20%*	+250%*
Catalyst-to-oil	Slight increase	–	-0.7
Delta coke	-0.03	–	–
Bottoms	-1.3	-0.6	-0.9

* indicates relative change vs BCMT-free base case

Table 1

Lab-scale testing

For BCMT additives to provide a meaningful shift in the bottoms cracking and metals tolerance capability of the entire FCC unit inventory, their technology and performance must be rather extreme when compared to normal cracking catalysts. This can often pose a challenge when it comes to scaling up lab-scale testing results to the commercial unit.

Some refiners, especially those with in-house testing capabilities, choose to rely on the outcome of lab-scale testing to gauge the performance potential of catalyst changes and some additive trials. Just as no two FCC units are identical, testing equipment can vary considerably between laboratories. Many employ small-scale reactors such as ACE units, short contact time — resid tests (SCT-RT) or microactivity tests (MAT). Some larger oil companies and third-party testing labs have circulating pilot riser capabilities in addition to the smaller-scale test units listed above. Regardless of the equipment employed, it is of utmost importance that the operational parameters of the lab-scale unit match as closely as possible the commercial conditions present at the refinery. This includes, but is not limited to:

- Temperatures
- Oil/catalyst contact time
- Feed composition and quality
- Catalyst properties.

It is always recommended to perform lab-scale testing with the actual feed from the FCC unit. It goes without saying that if a feed is not representative of the actual commercial feed, one can drastically misestimate the performance of a BCMT additive. Even if the

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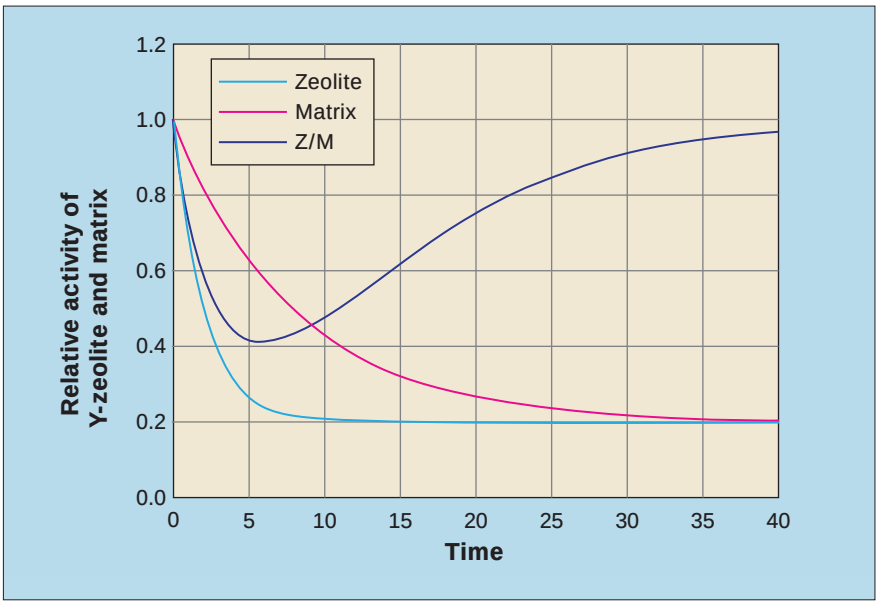


Figure 9 Long and mild deactivation conditions are necessary to balance the relative activity of the zeolite and matrix components of BCMT additives

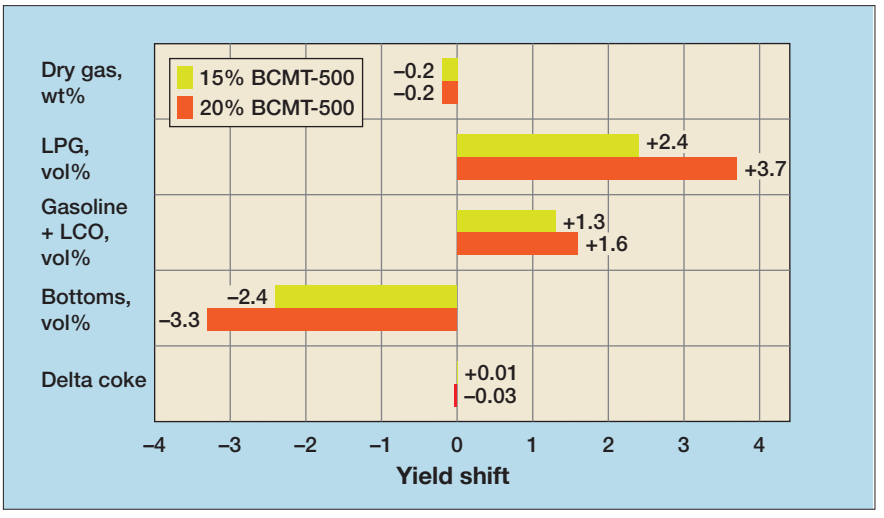


Figure 10 Yield shifts observed at a North American refinery utilising BCMT-500. CatOp modelling was used to normalise the data to a consistent basis

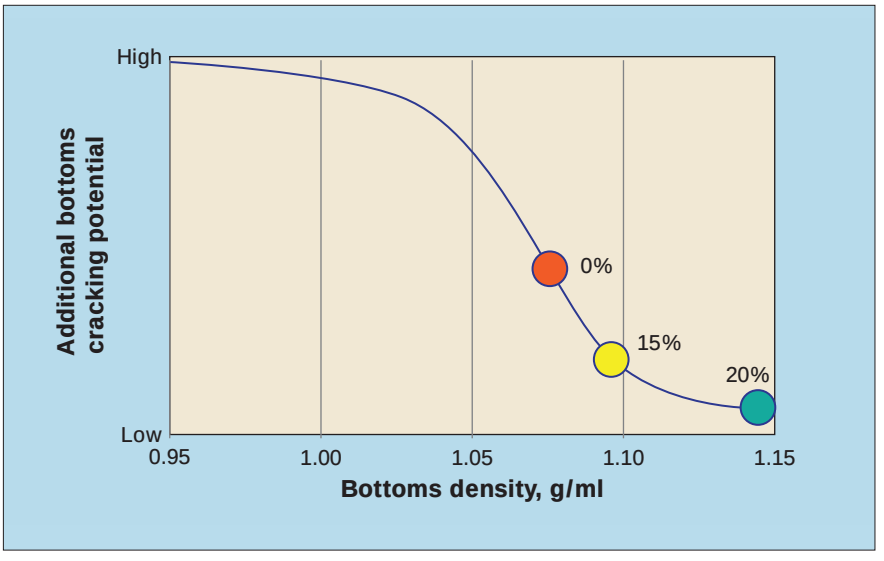


Figure 11 Bottoms density measurements indicate little crackable material was left in the bottoms with 20% BCMT-500 use

bulk properties of two feeds may be similar, a difference in the degree of saturation of three-ringed polynuclear core compounds in the feed can lead to a mis-estimation of the ability of BCMT's ability to decrease the bottoms yield. One should not rely such differences presenting themselves in the boiling point distribution, density or other bulk feed properties. Crackable naphthenic and naphtheno-aromatic rings will break easily in the presence of BCMT, whereas a feed containing a high concentration of polynuclear-aromatic cores, which are not crackable by any catalyst or additives, will exhibit poor bottoms cracking potential.

Many different methods exist for attempting to deactivate fresh catalyst to match the properties of an equilibrated catalyst. Whenever possible, it is recommended that actual equilibrium catalyst be used as the base case for testing BCMT additives. Simply, this eliminates any discrepancies that deactivation method may create in the lab-scale yields. These discrepancies are often due to the fact that the base catalyst technology differs, in some cases greatly, from the additive. If insufficient time or conditions are present to deactivate the highly accessible matrix components of the host catalyst or BCMT additive, the balance between catalyst and additive activities and selectivities will not be accurate (see Figure 9).

Short and severe deactivations are excellent for reducing zeolite activity in a cracking catalyst, but the matrix components in the BCMT additive may not be sufficiently deactivated by such methods. We have found that long, mild (lower temperatures, lower steam partial pressures) deactivation conditions have proven effective in deactivating both the matrix and zeolitic components of catalysts and BCMT additives.

An additional challenge that must be rectified when utilising lab-deactivated catalysts in testing rather than equilibrium catalysts is that many of the current laboratory deactivation methods result in considerably higher accessibilities

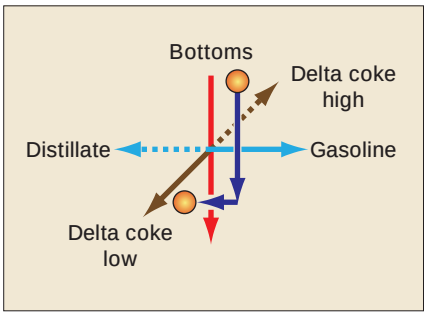


Figure 12 BCMT-500 moved this refiner to a significantly more profitable position within their yield space

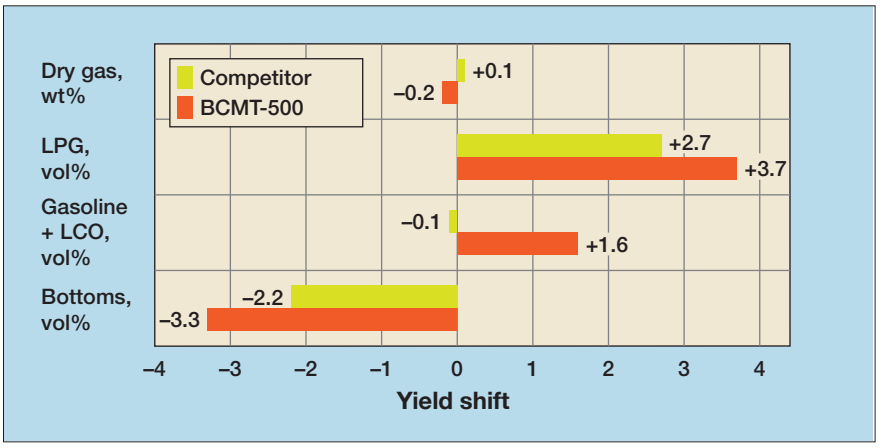


Figure 13 Not all bottoms-cracking solutions provide the desired result, as is shown here. The use of a competitive catalyst enhanced dealkylation reactions, but did nothing to crack naphtheno-aromatic cores remaining in the bottoms fraction

than would exist in the analogous equilibrium catalyst. Some protocols, including the Mitchell method followed by cyclic propylene steaming (CPS), as well as several other cyclic deactivation (CD) methods, result in higher accessibilities after deactivation than the original fresh, non-deactivated catalyst. The accessibility of deactivated catalysts must be quantified both before and after deactivation to ensure that the deactivation method has the desired effect on accessibility. Otherwise, the base catalyst can exhibit an unrealistic level of bottoms cracking activity in lab-scale testing, resulting in an incorrect predictor of BCMT performance.

Furthermore, it is important to decide whether or not the coke effects measured in lab-scale testing are truly reflective of commercial operations. In the case of the second commercial example presented later in this article, commercial performance at 10% BCMT-500 in inventory was compared to FST test results from an equilibrium catalyst sample taken at the same time, and the base fresh catalyst blended with 10% BCMT-500 and deactivated in the laboratory. The results are summarised in Table 1.

These data show that laboratory deactivated catalyst blended with 10% BCMT-500 resulted in an exaggerated coke (and hence delta coke) yield; however, no such delta coke penalty was seen commercially — illustrating the point that testing with laboratory-deactivated catalysts may lead to erroneous conclusions.

Commercial examples

Regardless of the conclusions drawn from bottoms analyses, benchmarking, and lab testing, commercial performance is the ultimate proof of BCMT additives.

North American refinery

A nominal 200 000 bpd refinery in the US recently utilised BCMT-500. This refinery processed many opportunity crudes and needed BCMT-500 to improve the stability and bottoms cracking activity of the base aluminasol catalyst employed. The FCC unit is a UOP high-efficiency design with a 360-tonne inventory and maximum capacity of approximately 100 000 b/d. Typical fresh catalyst addition rates were in the range 9–11 t/d. The feed was partially hydrotreated, but prevailing economics have increasingly favoured the introduction of non-hydrotreated, high metals feedstocks.

BCMT-500's benefits yield significant profitability improvements

	20% BCMT-500	
	Yield shift	Product value shift, $/bbl
Dry gas, wt%	-0.2	-0.02
LPG, vol%	+3.7	+1.66
Gasoline + LCO, vol%	+1.6	+1.18
Bottoms, vol%	-3.3	-1.51
Coke, wt%	+0.1	+0.02
Incremental profit, $/bbl	_	+1.33
Annualised benefit, $/yr	_	34 000 000

Table 2

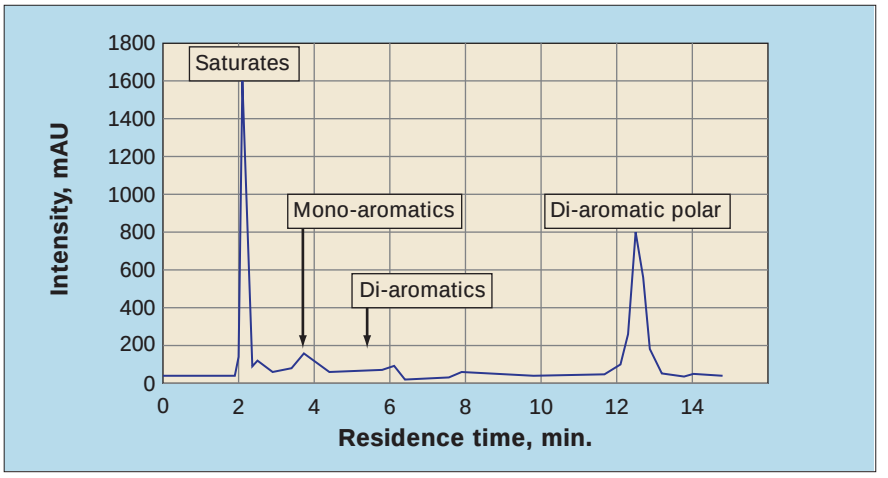


Figure 14 HPLC results show saturates and mono-aromatic compounds exist at significant enough levels in the bottoms fraction to suggest improvement with BCMT-500


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Strong diesel margins provided the economic incentive for this refiner to maximise transportation fuel yield and quality. The potential for BCMT to improve bottoms cracking was suggested by the bottoms density, which indicated that moderate opportunity existed for improvement.

This unit added 20% of BCMT-500 to the inventory and maintained steady addition rates at or slightly above that level for approximately one month. After this, the refinery chose to allow the BCMT-500 concentration to decay to 15% in inventory, with continued additions at the 15% level for a brief period until the on-site additive supply was exhausted.

In this case, FCC unit operating conditions were significantly different between the base and trial period. To correct the data to a consistent reference base, Albemarle's CatOp FCC unit model was employed, enabling the effects of the BCMT-500 additive to be readily apparent and not complicated by simultaneous operational changes. Figure 10 shows the yield shifts realised with the use of 20% and 15% BCMT-500.

Of greatest impact is the reduction in bottoms volume and gravity. Figure 11 shows that with 20% BCMT-500 in inventory, the 3.3 vol% reduction in bottoms resulted in little crackable material left in the bottoms fraction. The increase in the LPG yield indicates that BCMT-500 was able significantly to enhance dealkylation reactions targeting the bottoms fraction. As a result, the olefinicity of the LPG increased by 1%. BCMT also cracked naphtheno-aromatic cores that were left in the bottoms by the base cracking catalyst. The cracking of these cores resulted in increased LCO and gasoline yields of 1.6 vol%. This improvement was seen without any delta coke penalty.

The ability of BCMT-500 to upgrade the bottoms fraction is apparent from the large decrease in bottoms yield and density. Simply increasing the unit activity by adding more of the base fresh catalyst rarely decreases the bottoms yield by any appreciable extent for two reasons: first, the activity delivered by the base catalyst is not solely designed to target bottoms; and second, adding more of a non-Albemarle base catalyst has a small, if any, effect on the accessibility of the catalyst inventory. To truly destroy the bottoms, as in this example, a bottoms cracking additive with the proper active ingredients and high accessibility is required.

To quantify the increase in accessibility, equilibrium catalyst samples were taken from the unit during the trial at the 15% level in inventory and after the unit had returned to base conditions. The application of 15% BCMT-500 increased the overall accessibility of the catalyst in the inventory by 50% over the base case. This demonstrates the additive's ability to deliver concentrated accessibility into the unit by boosting the accessibility above the critical level necessary to maintain satisfactory bottoms conversion.

Figure 12 shows the change

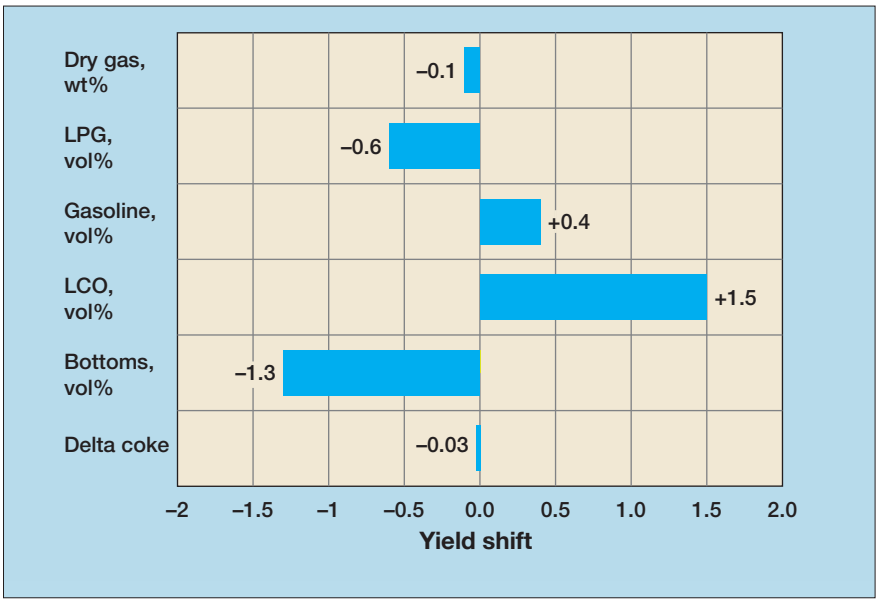


Figure 15 Yield shifts observed at a European refinery utilising BCMT-500

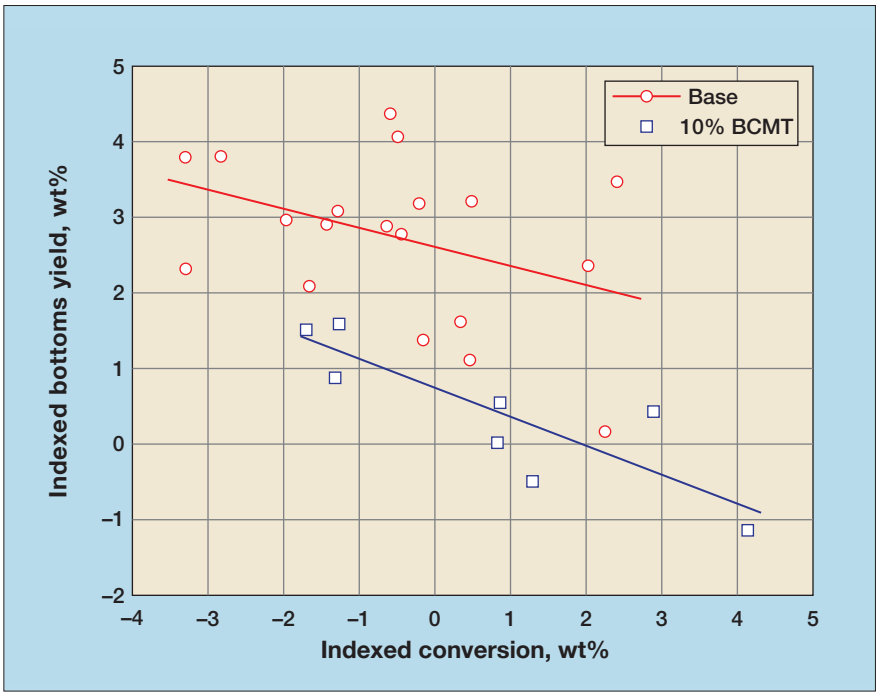


Figure 16 Commercial observations show that BCMT-500 cracks bottoms at constant conversion

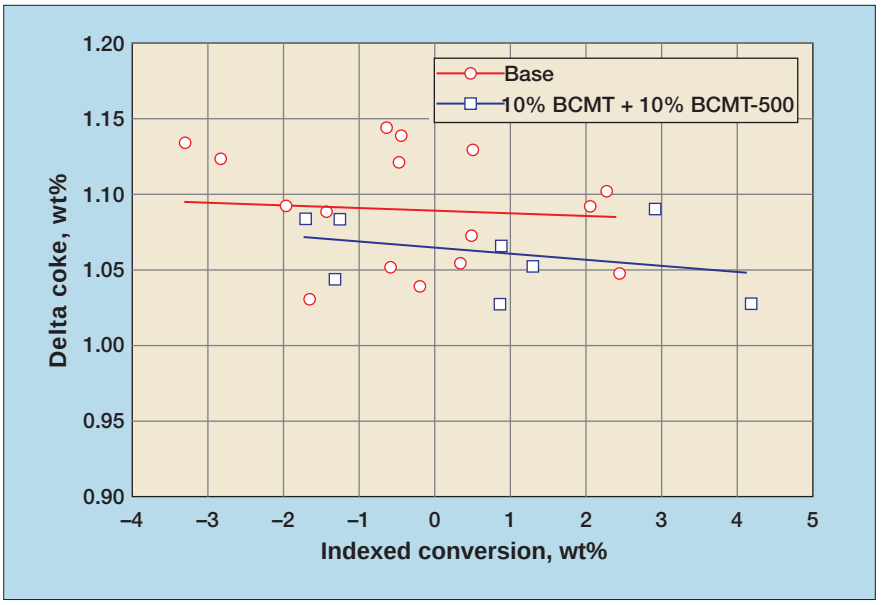


Figure 17 BCMT-500 offered this refiner slightly lower delta coke with increased bottoms cracking

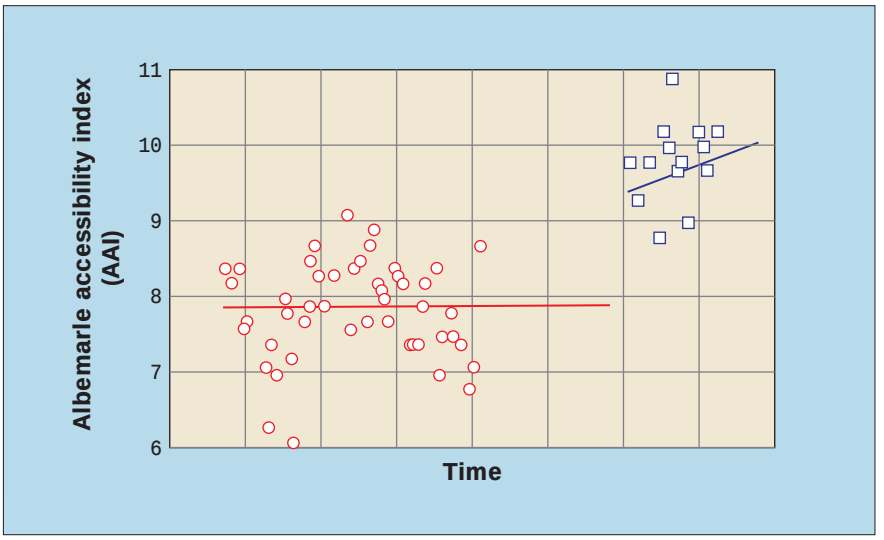


Figure 18 Replacing 10% of the already highly accessible Coral base catalyst with BCMT still increased overall inventory accessibility by 25%

BCMT-500 made in this refiner's yield space: significantly reduced bottoms yield, increased distillate in the product slate and no change in delta coke.

Applying published US Gulf Coast economics[14] to the yield shifts realised with BCMT-500 during the time period of the trial, Table 2 shows how 20% BCMT-500 in inventory was able to deliver $1.33 additional profit per barrel through the FCC unit. On an annualised basis, these yield improvements net an additional $34 million to the refinery.

This refinery later attempted to use a competitive catalyst as a bottoms cracking additive without success (see Figure 13). While some bottoms reduction did occur at the target concentration in inventory, it was limited solely to dealkylation reactions, since gas yields increased significantly but overall transportation fuel precursors declined by 0.1%. This is in contrast to BCMT-500 performance, where yields increased by 1.6 vol% due to higher accessibility and the ability to crack naphthenoaromatic cores. Comparing the economics of these two additives, BCMT-500 delivered almost nine times more dollars per barrel — $1.33 vs only 15 cents or, on an annual basis, over $30 million more in profit.

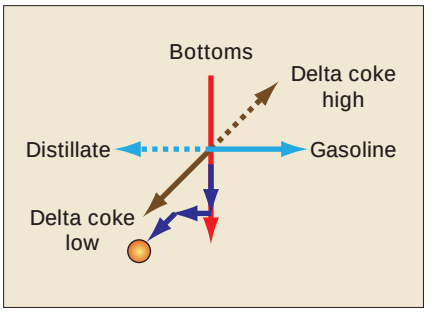


Figure 19 Yield space diagram for a European refiner. BCMT-500 decreased bottoms yield, allowing higher distillate make in return. A slight increase in catalyst-to-oil ratio is reflected in lower delta coke

European refinery

A European refinery structurally replaced 10% of its daily catalyst additions with BCMT-500 additive. This refinery operates a nominal 80 000 b/d UOP SBS FCC unit in partial burn. Feed consisted of resid and mild hydrocracker bottoms. Contaminant metals on equilibrium catalyst were 3300 ppm nickel, 800 ppm vanadium and 3100 ppm iron. The refiner's objectives were to maximise LCO and gasoline while minimising bottoms yield. The unit is constrained by the combined gasoline and LPG rundown capacity, air blower capacity and regenerator temperature. The refinery used Albemarle's Coral resid catalyst.

A sample of this refiner's bottoms fraction was obtained and a high-pressure liquid chromatography (HPLC) analysis was performed. The results of this analysis are shown in Figure 14. A significant amount of saturates and mono-aromatic compounds were found in the bottoms. These molecular types are crackable with the use of BCMT-500.[15]

The shifts in commercial yields attributable to BCMT-500 are detailed in Figure 15, and clearly show a substantial decrease in bottoms yield and subsequent increase in LCO and gasoline yield.

Further insight into improved bottoms cracking is gained by plotting the bottoms yield vs conversion. Figure 16 shows a lower bottoms yield relative to the base, and that the performance benefit of BCMT-500 is achieved

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across a wide range of conversion. The 1.3 wt% reduction in bottoms volume corresponds with an impressive 4 number API decrease.

Figure 17 further demonstrates that the increased bottom conversion is achieved with no increase in delta coke, highlighting the cracking chemistry occurring with BCMT-500. The traditional paradigm that incremental bottoms cracking comes at the expense of a hotter regenerator (increased delta coke) and additional dry gas make is not true with BCMT-500.

LPG olefinicity is of interest to refiners operating alkylation units or those with a petrochemical operation. BCMT-500 increased C_3 olefinicity by 2.7% and C_4 olefinicity by almost 1%. The increased LPG olefinicity is also a direct effect of the increased Ecat AAI and has been observed in many commercial applications.[16,17]

Figure 18 shows the AAI increase apparent after adding 10% BCMT-500 to the inventory. While in this case the base catalyst's accessibility was high, BCMT-500 still added 25% of additional accessibility with only 10% in inventory.

Returning once again to the concept of the yield space, this refiner started with a fairly efficient and accessible bottoms cracking catalyst, as shown by the low starting point on the bottoms axis in Figure 19.

Table 3 shows the application of regional product values from the time period of the trial applied to the refinery yields. Ten per cent BCMT-500 provided this refiner with an additional €25 000 per day additional profit from the FCC unit. This translates to an additional €9 300 000 in product value annually.

Due to the high intrinsic activity of BCMT-500, this refiner was able to replace 10% of the fresh catalyst with BCMT-500. Bottoms decreased by 1.3 wt%, LCO yield increased by 1.5 wt%, C_3 olefinicity increased by 2.7% — all with no negative impact on delta coke. On a tonne of feed basis, these yield improvements netted an additional product value of just over €2 per barrel, or €9.3 million on an annualised basis.

BCMT-500's benefits yield significant profitability improvements for this European refiner

	210% BCMT-500	
	Yield shift	Product value shift, €/MT
Dry gas, wt%	- 0.1	-0.43
LPG, wt%	-0.6	-5.19
Gasoline, wt%	+0.4	+4.19
LCO, wt%	+1.5	+8.52
Bottoms, wt%	-1.3	-5.07
Coke, wt%	0.0	0.00
Incremental profit, €/MT feed	_	2.02
Annualised benefit, €/year	_	9 300 000

Table 3

Conclusions

These two examples demonstrate how refiners are able to leverage BCMT additives to lower bottoms, customise their liquid product yield selectivity and optimise their delta coke to maximise their profitability within the yield space.

Many different options exist for identifying the performance potential of BCMT additives. These range from quite basic, in the case of simply making an estimate based on the bottoms gravity, to more scientific molecular analysis of the bottoms composition by HPLC (or other similar means), as was done in the case of the second commercial example. Lab-scale testing can provide further insight into the performance potential of BCMT, either when results are compared vs a representative peer group in the case of equilibrium catalyst benchmarking, or when blended with the individual unit's equilibrium catalyst and tested at conditions similar to those in the commercial FCC unit.

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Alan Kramer is Global FCC Additives Specialist with Albemarle in Houston, Texas.
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Steps towards optimal refinery blending

A practitioner's guide to optimising refinery blending systems by choosing control options with the highest return on investment

DAVID SEIVER
Valero Energy Corporation

Refinery blending typically consists of gasoline and diesel product blending and can be considered the cash register of the refinery. It is the last chance to optimise composition and to get as close to product specification as possible without excessive giveaway. If there is specification giveaway at blending, it is truly lost revenue. At a typical refinery, optimised blending could represent more than 50% of the total advanced process control (APC) savings, and may exceed $20 million/year in bottom-line savings. Bear in mind that a small reduction in giveaway yields impressive results through scale-up.

Figure 1 shows five basic elements of refinery blending complexity that define a refinery's overall product blending strategy. In practice, there are several permutations that span the continuum from optimal to undesirable. A pragmatic starting point for optimisation of refinery blending would begin by locating a profile matching your refinery's operations in the table. Throughout this article, we will work from the optimal (green in Figure 1) starting profile, stepping backwards towards the least preferred profile, thereby illustrating some cost or benefit effects associated with each profile bifurcation. The intention is for blending and APC engineers to identify where they are in their current product blending strategy, and then determine the next logical step(s) to a more optimal blending strategy. The examples in this article should help when justifying a move in that direction. It is not necessary to implement all of the steps from the current to the optimum, but rather the step(s) most relevant to the local situation.

Cost of blend frequency

As a general rule, shorter-in-time (smaller-in-volume) blends generally allow for more commercial opportunities than longer blends. However, pragmatic limitations exist, such as minimum time to get the blend on-spec, equipment stabilised and spot samples taken and analysed. Less than eight hours is generally regarded as risky, considering the criteria mentioned earlier. However, this usually would facilitate blends as small as 20 000 bbl (at reduced rates of 2500 bbls/hr), which could lead to more niche or spot commercial sales opportunities than those refineries restricted to, say,

Control method	Certification method	Waiver methodology	Blend flexibility	Blend frequency	Benefit impact
On-line	On-line	In-line blending (direct to pipeline)	Many grades and/or recipe types	Short duration blends (small batches)	Optimal
				Long duration blends (large batches) only	Commercial "small sales" opportunities penalty
			Few grades and/or recipe types	Short duration blends	Same as above + limits markets/ customers one can sell product to
				Long duration blends only	
	Off-line	In-line blending	Many grades and/or recipe types	Short duration blends	Same as above + must account for primary method reproducibility => automatic giveaway
				Long duration blends only	
			Few grades and/or recipe types	Short duration blends	Throughput penalty associated with blend "fix-ups" & more on-site tankage
		Tank blending		Long duration blends only	
*Off-line	Off-line	In-line blending	Many grades and/or recipe types	Short duration blends	*Same as above + more spot samples needed meaning more lab analysis / personnel & limits minimum blend duration
				Long duration blends only	
		Tank blending	Few grades and/or recipe types	Short duration blends	
				Long duration blends only	Least desirable

Figure 1 Refinery blending complexity/optimisation matrix

100 000 bbl minimum blends. The main challenge to being able to make smaller blends is ensuring a quality system around the blending controls/systems that will enable you to minimise specification giveaway with these short-duration blends. A way to visualise the added benefit of making smaller product blends could be seen as follows:

> Smaller blends ⇒ More spot product sales ⇒ Higher blender utilisation ⇒ Higher refinery throughput ⇒ Higher profitability

This relationship is somewhat general and each refinery would have to determine its unique values to ascertain the economic feasibility of taking this next step forward in refinery blending optimisation.

Cost of blend flexibility

Some refineries are limited, or limit themselves, to very few products. This simplifies blending to keep the number of recipe types or grades low, at a high opportunity cost with regard to markets and/or customers. These days, a typical, complex refinery can easily produce 50% or more reformulated and/or oxygenated gasoline. Blend flexibility leads to many more recipe types; 50 unique recipe types might be common. This is advantageous commercially yet more challenging from a standpoint of blend execution, as reformulated and oxygenated blends are typically more challenging to produce than conventional gasolines.

Why might 50 unique recipe types be considered such a challenge? First of all, it is not hard to envision 50 recipes if you are making both regular and premium grades; producing conventional, sub-grade and reformulated or/and oxygenated gasolines; have customers with unique RVP-class specifications; sell VOC-limited blends; and have targeted near-infrared (NIR) or Raman calibration models for various blending seasons, including summer, early/late winter and the blend-down and blend-up intermediate seasons. The permutations of these different recipe types can easily reach 50 or more.

The blend certification method can be the most significant option for optimisation available to most refineries

If you utilise NIR or Raman technology to control the blenders online, typically 12–15 (or more) properties can be determined for each product, including, but not limited to, RON, MON, D86 properties (eight or so might be typical, including IPB, T10, T20, T50, T90, FBP, E200, E300), %benzene, %olefins, %aromatics and API and/or specific gravity. The challenge becomes clear when considering the modelling and organisational/co-ordination challenges associated with 50 possibly unique recipe types, each needing calibration models to characterise 12–15 properties. One could end up with several hundred models to create and maintain.

In order to keep the calibration models properly organised, a model catalogue should be considered to spell out specifically which targeted calibration models for each recipe type are currently in use, and any relevant modelling data such as biases, "goodness-of-fit" of each model, number of latent variables used (if partial least squares, or PLS, is used), number of spectra in the model and model range. It is also good practice to match up final blend recipe data associated with the NIR or Raman spectra and laboratory data. This is particularly useful for detecting outliers. Remember, targeted NIR or Raman calibration models minimise giveaway in various blending seasons; for instance, winter blending requires different blend components and mixes compared to summer blending. Therefore, the NIR or Raman models should be unique to capture these recipe-type specificities, without sacrificing the robustness of the models.

Another way to maximise blend flexibility would be to increase the number of blend components, in essence increasing the degrees of freedom the optimiser has at its disposal. If there is a way to segregate a mixed or multi-component stream further into different blend components, say with similar octane values but drastically different RVP values, this will be advantageous in

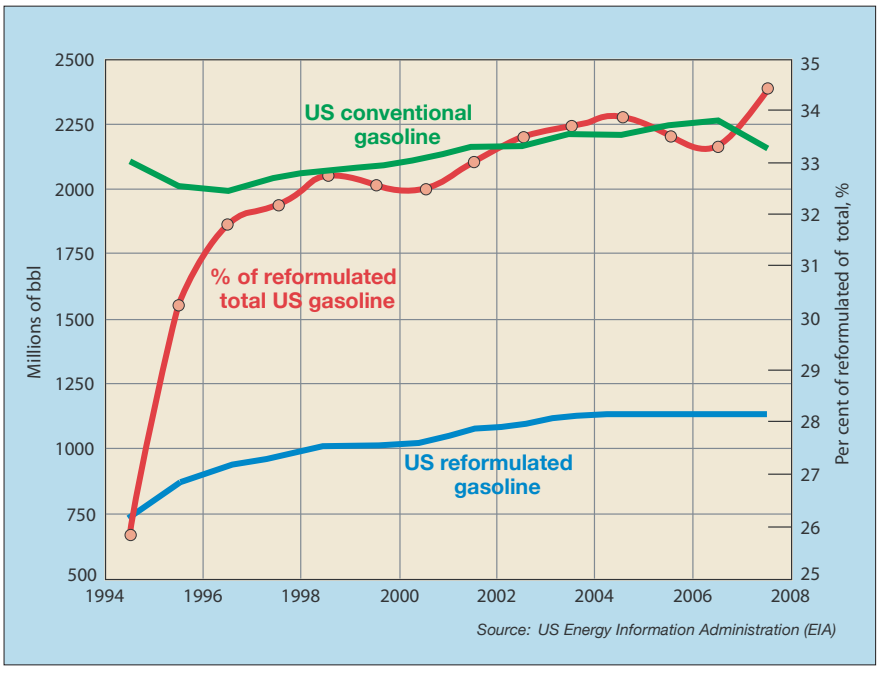


Figure 1 Reformulated gasoline supplied in the US

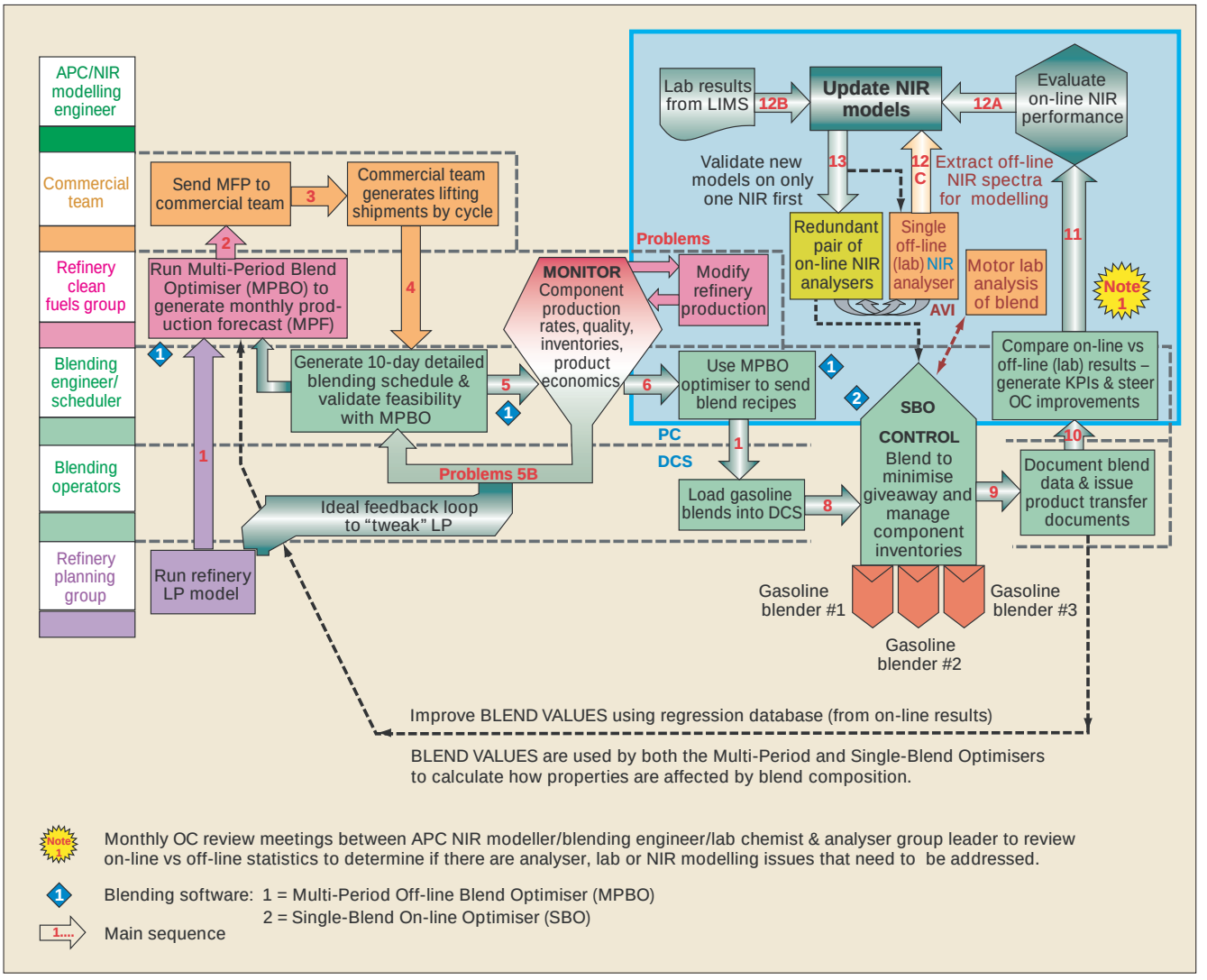


Figure 2 Refinery blending work process overview

optimising product blending. So, for example, if your refinery has some mixed or multi-component streams with low octane and high RVP, you might consider re-routing one of the streams that might be similarly low octane but low RVP as a separate component that could be utilised in summer reformulated blending, where the octane specification is often easier to achieve than the RVP value. This is a common optimisation strategy used with mixed FCC naphtha streams, where the heavy naphtha stream is segregated from the lighter stream(s).

Cost of waiver methodology

There are two general methodologies associated with where refiners blend their products: in-line or pipeline blending, and tank blending. Typically, in-line blending requires a regulatory blend waiver that specifies the refiner's systems to produce on-spec products directly into a pipeline. The obvious risk/reward proposition with in-line blending is the lack of "buffer to fix-up" blends that tank blending allows, with the obvious benefit of less tankage and higher refinery product throughput. The effect on throughput can be illustrated in the following example:

Basis: 100 000 bbl blends both cases; 5000 bbl/hr
product pumps both cases
Case 1: In-line blending
100 000 bbl pipeline blend @
5000 bbl/hr = 20 hours
Case 2: Tank blending
95 000 bbl initial tank blend @
5000 bbl/hr = 19 hours
Tank testing and analysis 2 hours
Creation of "fix-up" blend based on test results 1 hour
5000 bbl "fix-up" tank blend @
5000 bbl/hr = 1 hour
23 hours

The outcome with tank blending is 15% additional time to move the same barrels of product, or a reduction in throughput of 15%.

Cost of certification method

The blend certification method can be the most significant option for optimisation available to most refineries. The two blend certification methods are: traditional off-line certification, where ASTM (or other governing bodies') primary testing methods are applied to the blended products; and on-line certification — in the US, this normally would apply only to non-EPA regulated properties such as octane, which is a performance specification — where product properties are tested as the blend is being produced and these properties are certified against; that

is, no additional laboratory testing is required. Clearly, on-line certification has advantages in terms of product throughput by eliminating the need to wait for additional testing at end-of-blend, and in terms of laboratory personnel because fewer testers are generally needed. But, most important of all, it enables the control system to target more closely the actual product specifications without the need for an on-line target bias to ensure that the reproducibility of off-line results is still on-spec.

On-line certification requires a greater commitment to maintenance and quality control for on-line analysers and instrumentation. Some corporate cultures find the concept of on-line certification uncomfortable. In order to capture the benefits associated with not needing a bias between the on-line control system and the off-line testing results, consider choosing an on-line system proxy for the primary laboratory methods that has good reproducibility and repeatability. This is why most refiners choose NIR, Raman, or its variants over on-line knock engines and on-line distillers. Both NIR and Raman analysers have markedly better repeatability (basically very few if any moving parts) and, when properly calibrated, their reproducibility can be better than the primary methods for which they are a proxy. Mechanical methods such as knock engines have an inherent disadvantage in repeatability over spectrometers with no or few critical moving parts. As for reproducibility, NIR/Raman octane results are generally better than those from knock engines and are normally on a par with, or slightly better than, distillation (D86) analysers. In all cases, analysis with an NIR/Raman analyser is much faster and significantly less labour-intensive than with primary methods such as knock engines, D86 distillisers, gravitometers and gas chromatographs.

If NIR/Raman technology is chosen for an on-line certification method, it is important to understand that full redundancy is critical, since this analyser system will be replacing numerous analysers in the blending system. Care should be taken in the design of the on-line analysis system, including sample systems, so that there are no single points of failure that could jeopardise the availability of blending operations. Also, success using NIR/Raman analysers for on-line certification requires a commitment from the analyser maintenance group as well as the APC group that is often asked to perform calibration or modelling. A typical work process that could be used as a guideline is highlighted in blue in Figure 2.

On-line certification requires a more focused approach to analyser diagnostics. NIR and Raman analysers are equipped with powerful, and often ignored or under-utilised, on-line diagnostic capabilities that should be exploited to ensure a robust on-line certification system. On-line blending feedback based on the status of the NIR/Raman real-time diagnostics for each inferred property such as the residual ratio (RR) and/or the Mahalanobis distance (M-Dist) should be built into the blending control system and appropriate standard operating procedures (SOPs) developed so that blending operators know how to react (that is, take additional spot samples within the blend) when the on-line analysers are telling them that the confidence of the inferred property (for instance, high RR and/or M-Dist values) is questionable. The long-term historical trends of these valuable on-line diagnostic tools should be analysed in the routine quality control meetings that are part of a robust on-line certification system.

Analysis with an NIR/Raman analyser is much faster and significantly less labour-intensive than with primary methods such as knock engines

Cost of control method

In common with certification methodology, control methodology for refinery blending also falls into one of two general classifications: on-line or off-line. As on-line control is the *de facto* standard in refining, it is the methodology discussed here. The control method is the mechanism by which the tender is created. This mechanism includes the process control hardware and software, and the interface with the refinery planning cycle.

The control method has a choice of objectives. Most on-line single-blend optimisers (SBO) have several optimisation objective functions to choose from, including minimum cost, minimum giveaway, or minimum deviation from blend recipe. Minimum blend recipe deviation should ideally be a refinery's optimum strategy if multi-period recipe planning is very accurate and optimum over the entire multi-period plan. In practice, this is rarely, if ever, the case, or correct for a fleeting period of time and thus unrealisable, due to commercial and refinery dynamics. Therefore, generally the APC engineer is left to choose between the minimum cost and minimum giveaway objective functions.

However, deviation of the recipe from plan should be tracked and minimised where possible. Ideally, the multi-period planning software should download suitable minimum/maximum recipe percentages, which the single-blend optimiser should stay within, so as not to make the multi-period plan unfeasible.

While these two remaining strategies (minimum cost and minimum giveaway) appear very similar at first sight, there are many subtle differences in their operation and in the results they produce. Minimum cost tries to create an on-spec blend using the least costly combination of blend components

(or cheapest blend), which does not ensure minimum specification giveaway, whereas minimum giveaway tries to minimise specification giveaway without regard for utilising the least costly blend components (although most modern SBOs operating in corporate, multi-level optimisation can combine the benefits of both strategies to some extent). An important distinction between the two strategies is that minimum giveaway is based on real costs that are outside the refinery's economic envelope, whereas minimum cost is based on internal shadow pricing of components that are not always correlated with actual costs. Therefore, it is generally advisable to set the primary optimisation strategy to minimum giveaway, with a secondary optimisation strategy of minimum cost. Most contemporary single-blend optimisers can be set up this way.

Another important facet to optimal on-line blend control is the reliability of the blend recipe data, both initial recipe and blend values, which are obtained from the off-line blend recipe planning software, or multi-period blend optimiser (MPBO). Experience has shown that significant deviation from initial blend recipes often leads to sub-optimal final product blends (giveaway). This is especially true for blending systems that are designed to allow barrel splitting among product tenders (blend segment control is one common strategy), where poor-quality initial recipes will lead to large deviations in product specifications early in the blend, which can never be recovered.

Often, the off-line blend recipe generation tool determines the blend values (roughly, the steady-state gains used by the optimiser if non-linear blend equations are not used in the on-line optimiser) for each blend, and the accuracy of these blend values is critical for good blend control. This is fairly obvious from a multivariable control perspective, where APC engineers are familiar with optimiser cycling associated with incorrect steady-state gains.

RBOB recipe dependency of ethanol boost effect on octane

Recipe	Neat octane	Blended octane	EtOH octane boost
High toluene concentrate; low alkylate blend	91.6	93.2	1.6
Low toluene concentrate; high alkylate blend	91.6	94.9	3.3

Table 1

If your refinery makes oxygenated gasoline, both the off-line blend recipe generation tool and the online blend optimiser should take into account the non-linear blending effect that oxygenate induces in blend properties. Oxygenates such as ethanol (the most common in the US) are not allowed in product pipelines because of corrosion problems (ethanol is hydrophilic); they are typically added at product terminals. Therefore, refineries typically blend neat reformulated/oxygenated gasoline (RBOB), and conventional oxygenated gasoline (CBOB), without ethanol. It is also well known that the so-called ethanol boost effect on the final blended gasoline's properties is both recipe-dependent and non-linear. The ratio of olefins to aromatics used in the neat blendstock significantly determines the final blended octane of oxygenated gasolines. An example of this is shown in Table 1.

Experience has shown that significant deviation from initial blend recipes often leads to sub-optimal final product blends (giveaway)

This boost effect should be properly modelled to optimise RBOB/CBOB gasoline blends, and properly accounted for in both the off-line and on-line blending systems. Estimating the ethanol boost *a priori*, as opposed to directly measuring blended properties throughout the blend will ultimately lead to either excessive giveaway (you must target a worst-case, low boost effect, which will lead to giveaway if the olefins/aromatics ratio deviates substantially throughout the blend) or limited blend optimisation flexibility. (If you clamp down the olefins/aromatics ratio, you might risk giveaway or sub-optimal blends, which are more expensive blends.)

Conclusions

The five basic elements of refinery blending complexity have been described in sufficient detail to enable blending and APC engineers to plan the next step(s) towards optimal refinery blending at their location. Furthermore, specific examples of implementable measures, techniques and technologies have been described, with some economic considerations presented where applicable.

Not all refineries will be able to achieve the ideal refinery blending profile, but instead may only move incrementally towards that objective. It is the refinery's challenge to identify its unique place in the matrix of refinery blending complexity and to then produce a project plan to reach the next step(s) towards a more optimal state.

Special thanks to Atique Malik (atiquemalik@mac.com) for his help in putting this article together, and for his always valuable insight into optimisation strategies and philosophies.

David S Seiver is Manager of Blending APC Technology for the Valero Energy Corporation. With more than 20 years' experience in the petrochemical and industrial gas industries, he previously specialised in gasoline and diesel product single-blend optimisation for ConocoPhillips at the Wood River Refinery, as well as providing technical blending project assistance to other sites. He is a registered professional engineer in the State of Texas.
Email: david.seiver@valero.com



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Processing high TAN crude: part II

Huizhou, which is the first refinery for processing 100% high TAN crude, started up in 2009. This article describes the challenges of an opportunity crude operation

WU QING
CNOOC

High total acid number (TAN) crude has the following properties: high acid value, fewer light components, high density and viscosity, high gel asphalt content, and high salts and heavy metals content, which give rise to equipment corrosion and severe problems with product quality and environmental protection. The price of opportunity crude oil is about 80% of the price of conventional crude oil. The extra cost of processing high TAN crude is in the range $1.15–10.73/bbl, but the savings compared to conventional crude processing are $43.54–62.7/bbl. The cost of crude accounts for about 90–95% of the total running costs of refineries, so it is very attractive for refineries to process opportunity crude, especially high TAN crude.

With an annual capacity of 12 million tonnes (240 000 b/d), CNOOC's Huizhou refinery is the first large-scale refinery designed for the full conversion of high TAN crude. The refinery has done a tremendous amount of work to address the potential risks of refining opportunity crude oil and to achieve successful production start-up and smooth operation. The grassroots refinery started operations in April 2009 and currently all units are running smoothly, with excellent product quality achieved from a slate of around a dozen high-acid crude oils.

The first part of this article dealt with specific corrosion types and

Measures in response to high TAN crude oil characteristics

Features of high TAN crude oil	Implemented measures
Due to the oil's high density and viscosity, electric desalting emulsification will be more demanding, oil water separation will be more difficult, and the high content of asphalt and gel in high-acid crude oil will increase emulsification and result in low working efficiency of the electric desalting tank and the problem of oil entrainment in water	**Equipment:** electric desalting tanks are designed at three levels; level 1 is the high-velocity level, and levels 2 and 3 are low-velocity tanks specially designed with back flush facilities inside the electric desalting tube **Process:** carry out small- and media-scale tests, add dewatering and demulsifying agents, supplement reverse demulsifier on the basis of existing demulsifier **Environmental protection:** special treatment
High-density crude oil contains high levels of solid particles and suspended substances, which may result in accumulation of material at the bottom of the electric desalting tank, and fouling blocking in the heat exchanger	**Equipment:** supplemental installation of deoiler behind electric desalting tanks **Process:** add anti-sludging agents, dispersants or carry out washing, change operation mode **Environmental protection:** special treatment
Both high- and low-temperature corrosion are very heavy	**Equipment:** carry out corrosion mechanism analysis, to research corrosion of different materials in different types of acids contained in crude oils under corresponding process unit conditions; formulate equipment material selection guidance for high-acid crude oil equipment; select materials according to this guidance; install corrosion probes and coupons; measure thicknesses at specific points **Process:** add high-temperature anti-corrosion agent to system to monitor the effectiveness of anti-corrosion agent chemical test analysis
High-acid crude oil has a high content of salts and heavy metals, which may result in catalyst poisoning in secondary processing units, catalyst bed blocking, and fouling and coking in high-temperature heat exchangers	Enhance monitoring of secondary processing units Add chemical agents
High-acid crude oils are generally naphthenic- or middle-paraffin-based oils, with high nitrogen contents, which is a big challenge with regard to aviation kerosene smoke point, diesel cetane number and oil colour	Use correct hydrogenation and catalytic cracking technologies

Table 1

Solutions for electric desalting of high TAN crude oils

Problems	Solutions
High salt content in crude oil High density, viscosity	Three-level tank design Electric desalting tank design operating at 139°C
High acid value; oil entrainment in drainage water	Install deoiler behind electric desalting tank, together with specially designed back flush structure
Desalting efficiency lower	Increase reverse demulsifier, dispersant, crude oil dewatering demulsifier, desalter's process injection system, agile water injection, agent injection procedure

Table 2

environmental issues arising from high TAN crude processing. This second part deals with operational solutions to those issues.

Design and operation of crude distillation

We have co-operated with domestic and international research and design institutes, and have carried out crude oil assessments, demulsifier selection and electric desalting operation condition analysis, anti-corrosion mechanism and material selection, corrosion process analysis, detection and monitoring system analysis, and scientific assessment and risk identification for all potential problems relating to high acid crude oil processing. To guarantee safe, environmentally sound and extended operations, we have formulated a technical document that includes solutions to supplement the original designs.

Measures taken to deal with the characteristics of high TAN crude oil are listed in Table 1, while problems and solutions for processing high TAN crude oils in the electric desalting unit are listed in Table 2.

Equipment material selection (metallurgy)

The atmospheric and vacuum distillation unit of Huizhou refinery is designed for crude oil with an acid value of 3.57 mgKOH/g and a sulphur content of 0.28–0.3%. However, 14 different oils with acid numbers of 0.3–3.57 mgKOH/g from all over the world have been processed by the refinery. In order to supply qualified and approved materials to downstream units, and guarantee four years of operation, we have formulated a guide for high acid crude oil equipment material selection. When it comes to the selection of pipeline material, the following recommendations are made:

- For 220°C or lower, use carbon steel
- For 220–288°C, use 1Cr5Mo, 1Cr9Mo, 0Cr19Ni10Ti or 00Cr17Ni14Mo2 (SS316L material in this plant is required for higher molybdenum content)
- For media of 288°C and above, 00Cr17Ni14Mo2 austenitic stainless steel is recommended
- For temperatures of ≥220°C and a flow velocity of ≥30 m/s, 00Cr17Ni14Mo2 austenitic stainless steel is recommended
- For large-diameter pipelines, a composite of carbon steel and 00Cr17Ni14Mo2 stainless steel is recommended
- Where flow velocities are highest, large-radius elbows and slot-branching tee joints should be selected.

Monitoring methods should include both:

- Corrosion probe monitoring: there are 17 probes installed in different positions on the

Corrosion monitoring probes in the atmospheric and vacuum distillation unit

	Position	Type	Pipe diameter	Pipe material	Material flow t/h	Design temp, C
101-AE-01101	Before feed pressure control valve of flashing tower	Continuous high-temperature resistor with P5 coupon	600	304L	1428	224
101-AE-01201	Atmospheric overhead oil gas volatilisation line	Continuous low-temperature inductor with CS coupon	900	CS	65	118
101-AE-01401	After E-401 pipeline inlet valve	Continuous low-temperature inductor with CS coupon	450	CS	18	118
101-AE-01501	After A-101A inlet valve	Continuous low-temperature inductor with CS coupon	700	CS	18	93
101-AE-01502	After atmospheric overhead water cooler valve	Continuous low-temperature inductor with 09 coupon	500	CS	32	60
101-AE-01701	Before 3rd vacuum cut backflow control valve	Continuous high-temperature inductor with 316 coupon	250	316L	209	307
101-AE-01702	Before 4th vacuum cut output control valve	Continuous high-temperature inductor with 316 coupon	150	316L	54	361
101-AE-01703	After P-115A inlet valve	Continuous high-temperature inductor with 316 coupon	700	316L	489	369
101-AE-01801	Vacuum overhead level 1 vacuumising device water chiller inlet	Continuous low-temperature inductor with CS coupon	900	CS	4.2	180
101-AE-01802	Vacuum overhead level 1 vacuumising device water chiller inlet	Continuous low-temperature inductor with CS coupon	150	CS	4.2	37
101-AE-02101	After E-202 1st vacuum cut inlet valve	Continuous low-temperature inductor with CS coupon	250	CS	138	142
101-AE-02301	After E-205AB 2rd vacuum cut inlet valve	Continuous high-temperature inductor with 321 coupon	450	321	800	237
101-AE-02401	After E-206 3rd atmospheric cut inlet valve	Continuous high-temperature inductor with 316 coupon	200	316L	110	303
101-AE-02601	After E-306 atmospheric cut inlet valve	Continuous high-temperature inductor with 321 coupon	200	321	131	253
101-AE-03201	After E-501 1st atmospheric middle-cut inlet valve	Continuous high-temperature inductor with P5 coupon	300	Cr5Mo	223	263
101-AE-04001	Before atmospheric heater 1st feed line control valve	Continuous high-temperature inductor with 316 coupon	200	316L	175	311
101-AE-04301	Before vacuum heater 1st feed line control valve	Continuous high-temperature inductor with 316 coupon	200	316L	129	352

Table 3

Chemical agent injection				
Agent name	**Product features**	**Injection point**	**Injection amount**	**Injection method**
Crude oil tank dewatering and demulsifer EC2045A	• Can reduce crude oil desalting costs • Wide range of adaptability • Reduces oil entrainment in the desalting tank's salty water • Can effectively reduce solid impurities in downstream heat exchangers and other equipment, and reduces fouling on the interior walls of equipment • Increases desalting efficiency and reduces corrosion of unit overhead system. • Controls the solids content of the crude oil/emulsion interface in the desalting tank • Removes oil contained in inorganic substances in crude oil • Promotes fast demulsifying • Increases dewatering efficiency in the crude oil storage tank	Crude oil storage tank, header feedline	Keep the amount injected between 2–24 ppm, usually starting at 6 ppm. If the electric desalting tank can fix desalting and dewatering issues, there is no need to inject demulsifier	Basic solution injection
Electric desalting tank demulsifier EC2506A	• Reduces crude oil desalting costs • Wide-ranging adaptability • Reduces oil entrainment in the desalting tank's salty water • Can effectively reduce the solid impurities in downstream heat exchangers and other equipment, and reduces fouling on the interior walls of equipment • Increases desalting efficiency, reduces corrosion of unit overhead system • Controls the solids content of the crude oil/emulsion interface in the desalting tank • Removes oil contained in inorganic substances in crude oil • Promotes fast demulsifying	Crude oil pump inlet Level 1, 2 & 3 tank inlet	Keep the amount injected between 2–24 ppm, usually starting at 6 ppm	Basic solution injection

Table 4

atmospheric and vacuum distillation unit (see Table 3)

- Test analysis and monitoring: thickness measuring and coupons are fixed at specific points.

Chemical agents injection

An integrated, multiple-treatment system at Huizhou refinery applies the following chemical agents: crude oil dewatering demulsifier EC2045A, electric desalting demulsifier EC2506A, reverse demulsifier EC2345A, electric desalting tank demetalisation agent EC2047A, low-temperature corrosion inhibitor EC1021A, high-temperature inhibitor EC1023N and scale inhibitor EC3238A. Table 4 shows a sample of the design for the chemical agents injection system.

Environmental protection

Since its start-up, Huizhou refinery has kept wastewater from the plant treated to the approved level, including wastewater from electric desalting, which is drained into deep seawater via pipeline after approved treatment. Any oil-contaminated wastewater is recycled after approved treatment.

Periodic back flush water from the bottom of the electric desalting tank cannot be processed as is by the wastewater treatment system because of its high salts content. For this reason, during back flushing, this waste stream is first fed to a tank, where its concentration can be adjusted. The water is then blended to adjust its concentration and treated gradually. We are now trying to use a continuous, low-level flush to replace periodic (once-per-week) flushing. Other possible approaches to treating this highly polluted wastewater are under development, such as adding acidic organic substances extracted from naphtha.

In view of the process technology chosen for the subsequent level 2 and 3 processing units, all units are operating smoothly and all products meet the approved quality standards. However, because the atmospheric and vacuum distillation unit is designed for operation with Penglai 19-3 crude oil, with a light oil yield of only 4.8%, when this crude is blended with other crude oil types overhead load restriction on the atmospheric distillation tower is a concern. Of course, the sulphur content in blend crude oils especially for the refining blended crude oils and sulphur recycle capability are the main restrictions in the selection of crude oil type and amount for refining blending.

Another factor to be considered with respect to appropriate crude oil blending ratios and oil types is the change in the quality of waste water from atmospheric and vacuum distillation electric desalting after crude oil blending, and the acceptance level of the wastewater treatment plant.

Electric desalting following start-up

Month	Desalting pass rate, %			Prior-desalting salt content, mgNaCl/l			Post-desalting salt content, mgNaCl/l		
	Sample qty	Approved sample qty	Pass rate	Max	Min	Average	Max	Min	Average
5	18	2	11.11	120.5	12	38.77	9.4	2.64	4.93
6	22	21	95.45	33	4.95	17.66	3.4	1.65	2.77
7	21	20	95.24	135.3	9.07	33.12	4.46	2.18	2.95

Table 5

Effectiveness of crude demetalisation

Item	Fe	Pb	Al	Zn	Na	K	Ca	Mg	Total
June crude oil before demetalisation	5.86	0.01	3.37	0.48	6.63	1.04	35.52	15.22	_
July crude oil before demetalisation	9.6	0.09	9.49	0.59	11.3	2.25	17.05	15.9	_
Crude oil average before demetalisation	7.73	0.05	6.43	0.54	8.97	1.65	26.29	15.56	_
June crude oil after demetalisation	1.95	0	0.2	0.14	0.8	0.06	27.26	9.86	_
July crude oil after demetalisation	0.34	0	1.96	0.37	1.2	0.68	11.69	1.14	_
Crude oil average after demetalisation	1.145	0	1.08	0.255	1	0.37	19.48	5.5	_
Average demetalisation rate	0.8519	1	0.832	0.523	0.8885	0.7751	0.259	0.6465	0.7221

Table 6

Effectiveness of electric desalting

Despite frequent switching between different crude oils and the severe effects of low-quality crude oils, the electric desalting process has been effective and comparatively stable in operation. During the optimisation and adjustment of the refinery, desalting required a lower approval rate; nonetheless, most of the salt content results were in the range of 3.0–3.5 mgKOH/g after desalting. The pass level is 3.0 mgKOH/g and below.

Over the following two months, the electric desalting units operated well, with a desalting pass rate of more than 90%. During this time, more types of crude oil were blended for processing, which influenced performance (see Table 5).

Table 6 shows the results of crude demetalisation. They are generally good. Electric desalting of the drainage water reduced metal entrainment, which in turn could affect the wastewater treatment system, so the sewage water treatment plan needed to be adjusted and optimised accordingly.

Low-temperature corrosion resistance

In the overhead of the atmospheric and vacuum distillation unit, the Fe ion content was ≤1 mg/l, the probe corrosion rate was ≤0.2 mm/y and the pH value was within the range 5.5–7 (see Table 7), which means corrosion was under control according to domestic and international standards.

Corrosion tended to fluctuate during the early period of start-up. In particular, the pH value showed wide variation. However, after a series of optimisations and adjustments, both pH values and Fe ion concentrations were brought under reliable control with an approval rating of more than 90%.

By observing the probe trend, the higher corrosion rate before the charging of neutraliser and corrosion inhibitor becomes obvious. The corrosion rate decreased dramatically following the addition of these additives, indicating that the correct anti-corrosion measures had been implemented. The wastewater in the reflux accumulator of the atmospheric distillation tower overhead was clear and contained a lower level of iron.

The vacuum distillation tower overhead contained large amounts of low molecular weight organic acids. These enter the water tank after cooling in the level one condenser and result in an increase in the probe corrosion rate after E-510W. Optimisation of the charging

Improvement in overhead Fe ion concentration

Month	Tower overhead Fe ion pass rate, %			Atmospheric overhead Fe ion content, mg/l			Vacuum overhead Fe ion amount, mg/l		
	Total sample amount	Sample pass amount	Pass rate	Max	Min	Average	Max	Min	Average
5	36	29	80.56	1	0.15	0.44	4.2	0.3	1.12
6	43	39	90.70	1	0.05	0.56	1.8	0.5	0.87
7	46	44	95.65	1	0.1	0.59	1.4	0.7	0.89
8	42	42	100.00	1	0.1	0.45	10.4	0.68	
9	50	47	94.00	1	0.1	0.46	1.3	0.3	0.77
10	40	40	100.00	0.9	0.2	0.36	1	0.35	0.69
11	41	40	97.56	1	0.2	0.49	1.2	0.2	0.58
sum	298	281	94.30	1.00	0.05	0.48	4.20	0.20	0.80

Table 7

High-temperature corrosion control

Date	3/6/2009		22/6/2009		6/7/2009		20/7/2009	
	Fe, ppm	Ni, ppm	Fe, ppm	Ni, ppm	Fe, ppm	Ni, ppm	Fe, ppm	Ni, ppm
2rd atmospheric cuts	0.27	0.01	0.55	0	0.01	0.03	2	0.39
3rd atmospheric cuts	0.01	0.01	0.2	2	0.03	0.02	0.07	0.11
2rd vacuum cuts	0.01	0.01	0.77	0.01	0.15	0.05	0	0.02
3rd vacuum cuts	0.01	0.01	0.42	0.01	0.81	0.05	0	0.19
4th vacuum cuts	3.19	62.54	12.84	51.68	3.84	20.73	4.6	28.85
Vacuum residues	8.75	92.22	11.92	83.33	8.94	62.83	7.16	53.02
Crude oil	2.93	32.36	8.51	23.97	0.34	26.87	1.29	17.21

Note: Fe/Ni ion content analysis results conform to material balance; corrosion has been effectively controlled

Table 8

operation led to the corrosion rate decreasing from a high of 3 mm/y or more to less than 0.2 mm/y.

During start-up, analysis revealed a large amount of organic acid (about 1200–1800 ppm as acetic acid) in the overhead system, which was beyond expectation. Application of Nalco's adjustment and treatment plan quickly brought the resulting corrosion under control. The ferric ion concentration decreased from 100 ppm or more to 1 ppm.

High-temperature naphthenic acid corrosion

Taking into account that the acid value of crude oil and side streams is higher than 3 mgKOH/g, the Fe ion content of the side streams is <1.0 mg/l and the corrosion probe reading is less than 0.2 mm/y; hence, all parameters achieved the required control targets.

This demonstrates that upgraded material treated with an effective high-temperature corrosion inhibitor can control the high-temperature corrosion resulting from high acid crude oil refining (see Table 8).

Fouling control

During the early months following operational start-up, accurate assessment of plant fouling control was not available. The focus here is to install temperature sensors on the inlets and outlets of the main heat exchangers, transmit the temperature data to the distributed control system and calculate the efficiency of a single exchanger, or a series of heat exchangers, to judge the fouling trend and implement further measures accordingly.

Table 9 lists the existing problems and solutions in the crude distillation units.

Conclusion

Producing clean fuel or high-value petrochemical products from heavy, low-quality crude oils is a big challenge for oil refiners. Characteristics of high acid crude oil include a high acid value, fewer light components, high density and viscosity, a high gel and asphalt content, and a high salts and metals content, which may result in the serious corrosion of equipment and concerns with product quality, environmental protection and processibility.

CNOOC's Huizhou refinery is a full conversion site exclusively processing high acid heavy crude oil at an annual rate of 12 million tonnes. Just one year on from production start-up, the refinery achieved a high standard of performance in electric desalting, high- and low-temperature corrosion control, and the processing and treatment of kerosene and diesel, wax oil and residuum.

Wu Qing is the Chief Engineer of Huizhou refinery, Guangdong, China, part of the Refining and Marketing Group of China National Offshore Oil Corporation (CNOOC).
Email: wuqing@cnooc.com.cn

Problems and solutions in the crude distillation units

Problems	Cause	Improvement solutions
Occasional water content during electric desalting	Excessive pH value of feed water, and content of NH_4 and impurities exceeds limit High content of gel-asphalt and solid particles Excessive use of additives in crude oil upstream processing	Improve feed water quality Assess the mix ratio between crude oils Add asphalt dispersants
Overhead condensate water, ammonia and nitrogen content exceeds limit	Overhead system has a high content of organic acids: acetic acid content is very high and use of neutraliser exceeds the limit with respect to corrosion control	Reduce upstream acetic acid usage, reselect the neutraliser, consider adding alkali to crude oil
High content of solids, ammonia nitrogen, metal, oil, COD	Result of high acid crude oil refining Disparity within high acid crude oils match Difference between crude oil currently processed and design quality of crude	Enhance sewage water processing capability to elevate electric desalting drum flexibility: • Add solid wetting agent • Add asphalt dispersants

Table 9

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Maximisation of VGO through deep-cut distillation for refinery margins

Appropriate choice of crude and/or crude oil blends as feedstock and a vacuum tower revamp enable higher production of vacuum gas oil for secondary processing

RAJEEV KUMAR, CHITHRA V, SHALINI GUPTA, SONAL MAHESHWARI, PEDDY V C RAO and N V CHOUDARY
Bharat Petroleum Corporation Ltd, India

Over the years, improvements to distillation towers have delivered better separation and higher yields.[1,2] Vacuum towers have been improved by the introduction of packing designs that deliver better mass transfer and separation. Packings have the advantage of lower pressure drops compared with trays, reducing, for instance, flash zone pressures and the overall column pressure drop.[3,4] Thus, more efficient vacuum tower operation meets the current demand for processing heavy crude oils and delivering high heavy vacuum gas oil (HVGO) yields.

Traditional vacuum towers deliver a HVGO/residue cutpoint of approximately 520–565°C.[5] Deep-cut operation starts when cutpoints are increased by 50°C (see Figure 1). In this way, an increase in product recovery by up to 2–5 wt% is possible. However, vacuum column operations present an arduous environment for efficient fractionation, which makes upgrading product from bottoms to distillate more difficult. Shifting of delta initial boiling residues to vacuum gas oil (VGO) is the real challenge for a deep-cut VGO maximisation process to meet the design feedstock criterion of the secondary units.[6,7]

In the current refining climate, processing opportunity crude oils in atmospheric units[8] and vacuum towers in deep-cut mode operation can provide economic and operational benefits to the refiner. To obtain deep-cut yields, a revamp of the vacuum unit is required, and a proper design and engineering study is essential. This should include crude type, exchanger, furnace, tower, ejector system and so on, to optimise capacity, low-pressure capability and overall revamp cost. However, a simplified analysis can benefit the project's initial feasibility study. Accurate feed characterisation and effective process simulation are key factors in evaluating deep-cut options.

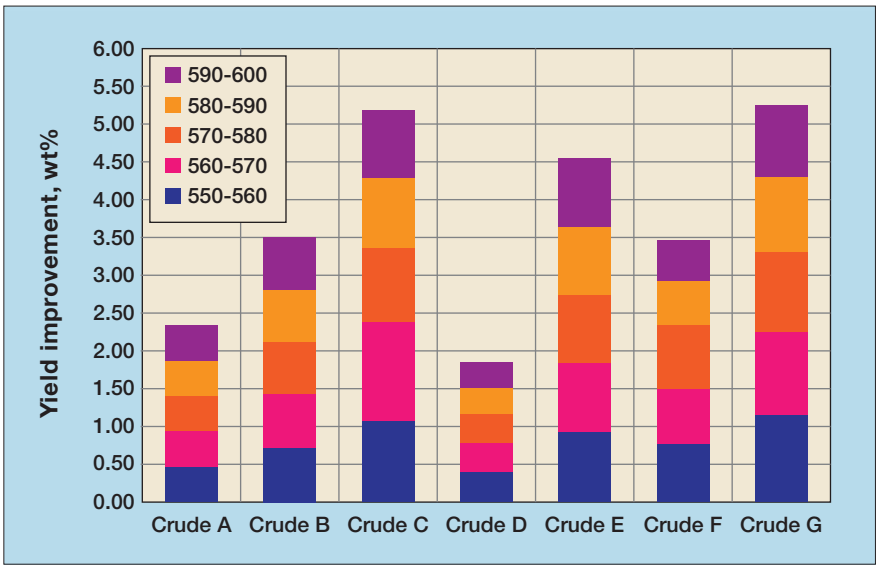


Figure 1 Yield improvement for crude oils

A technical evaluation of deep-cut maximisation has been included in the present work. The evaluation includes a study on: selection of the crude basket; true boiling point distillation for deep cuts at each 10°C cut for analyses and endpoints; feed characterisation to meet the criterion for secondary units; and an economic analysis. Thus, increasing the demand for feed enhancement in HVGO yields can provide a large economic incentive per barrel, reducing residue production and so improving the gross refining margin.

Challenges in processing deep-cut VGO

VGO from the vacuum tower is a feedstock to secondary units — HCU/HDS and FCC units — for maximising distillates production. The endpoints of VGO processed in these units are generally 520–565°C and vacuum residues (VR) are used for producing low-value products such as fuel oils, low-sulphur heavy stock and bitumen. Extending the endpoints of VGO up to 600°C can be further utilised for conversion to high-value distillates in the secondary processing units. The diversion of deep-cut VGO (520–600°C) from VR means up to 2–5 wt% more of the crude feedstock is available to the secondary units. This can result in more distillates and fewer low-value products.

To obtain deep-cut VGO, vacuum tower operations are quite severe, which causes changes in VGO composition. In such conditions, the

Feedstocks for deep-cut processing

Crude oils properties	A	B	C	D	E	F	G
Origin	Algeria	Thailand	Azerbaijan	India	Qatar	Nigeria	Abu Dhabi
Density at 15°C, kg/L	0.8055	0.8096	0.8490	0.8320	0.8750	0.8550	0.8590
SG at 60/60°F	0.8061	0.8102	0.8499	0.8329	0.8757	0.8554	0.8597
°API gravity	44.1	43.2	35.1	38.5	30.2	33.9	33.1
Total sulphur, wt%	0.11	0.04	0.15	0.13	2.15	0.12	1.74
TAN, KOH/gm	0.08	0.02	0.20	0.16	0.09	0.21	0.09
Pour point, °C	-37	23	-4	24	-15	-3	-27
KV @ 40°C, cSt	1.09	3.56	6.46	2.90	9.10	3.90	8.51
MCCR, wt%	0.73	1.21	1.50	1.10	4.60	1.20	4.42
Asphaltene, wt%	0.032	0.022	0.066	0.310	1.200	0.159	1.720
Basic nitrogen, ppm	100	89	400	210	305	290	330
Metal, V, ppm	0.84	0.07	0.10	0.17	21.00	0.77	8.77
Metal, Ni, ppm	0.34	0.62	3.00	3.40	7.20	4.20	6.90

Table 1

Specifications for deep-cut VGO to secondary units

Specifications	CCR	Asphaltene	V	Ni	V+Ni
Units	wt%	ppm	ppm	ppm	ppm
Secondary unit feed (VGO)	<0.5	<500	<1.0	<1.0	<3.0

Table 2

primary concerns are production of increased levels of Conradson carbon residues (CCR), larger quantities of high molecular weight polycyclic aromatics and asphaltenes in VGO, which could lead to higher coke make in the secondary units, and metal contaminants that could poison the catalysts. All secondary units are vulnerable to these factors, which could lead to a heavy penalty through catalyst poisoning and effect on run length. The real challenge for a deep-cut VGO maximisation process is to meet the design feedstock criteria of secondary units for parameters such as CCR, C_7 insoluble asphaltenes, nitrogen and metals. Not only has distillation technology improved, but conversion units are also better equipped to handle heavier gas oil feeds. A methodology has been designed to debottleneck these units by deep-cut characterisation for each 10°C cut range. This will help to restrict the maximum cutpoint for HVGO and increase conventional yields.

Selection of crude oil feedstock

A crude oil basket was selected from various parts of the world. For the most part, high and medium °API crude oils were selected for the study. Feedstock characterisation for critical properties was carried out by standard ASTM methods and the results are shown in Table 1.

TBP distillations for deep cuts

True boiling point (TBP) distillation (atmospheric) was carried out in a batch set up of 15 theoretical stages, in accordance with ASTM D2892, up to 360°C cuts. The residue was transferred to a pot still for vacuum operation at 0.5–0.1 mm Hg, in accordance with ASTM D5236. The composite (atmospheric and vacuum) distillations were carried out up to AET 600°C cuts. The yield profile is shown in Figure 2.

Deep-cut characterisations and secondary units

VGO drawn from the vacuum column is used as feed to secondary processing units. The extent of deep cut and its endpoints from the vacuum column is determined by CCR, metals content (V, Ni) and C_7 insoluble asphaltenes in the VGO. Generally, secondary units are designed for a feedstock with Ni <1 ppm, V <1 ppm, and C_7 insoluble asphaltenes at 500 ppm (maximum). However, the composite metal content (Ni+V) can be up to 3 ppm (maximum), with a penalty in run length.[5] In view of this, crude characterisation studies are necessary to determine the cutpoint at which VGO can be extracted for study. Thus, the metals content for VGO cutpoints up to 600°C (that is for every 10°C rise from 550 to 600°C), along with CCR and C_7 insoluble asphaltene content data, are required to revamp the existing vacuum column to decide the endpoint for VGO cut. To understand the deep cuts and endpoints for processing in the secondary units, small cuts beyond 550°C have been made, such as 550–560°C, 560–570°C, 570–580°C, 580–590°C and 590–600°C. These cuts were characterised for their physico-chemical properties to meet the criteria as feedstock for secondary processing (see Table 2). The primary concerns here are high levels of CCR and asphaltenes in VGO, which could cause higher coke make in the secondary units, while higher metals content could poison the catalysts. These critical parameters were characterised for varying VGO endpoints for various crude oils (see Figures 2–6).

Results and discussion

Feedstock selection is one of the criteria for deep-cut maximisation through the revamp of vacuum towers and operations. In order to establish the cut-off temperature for deep cuts, the initial physical properties of crude oils were studied. Various crude oils of differing origins were selected and characterised (see Table 1). It was observed that high °API crude oils are low in CCR, asphaltenes and metals when compared to medium °API crude oils. In this regard, the cut-off for deep-cut VGO would be more critical for medium and low °API crude oils. Initial characterisation of crude oils will be helpful in the selection of suitable quality feedstock.

Distillation of various crude oils was studied and the studies revealed that the yield profile of high °API crude oils was higher compared to medium °API crude oils. However, the yields of deep cuts are found to be higher for

medium-density crude oils compared with low-density (high ° API) crude oils (see Figure 1). However, processing lower °API crude oils is more beneficial with regard to feedstock flexibility and thus offers more incentives, provided it meets the specifications of the deep cuts.

Since deep-cut operations are severe, the HVGO obtained contains high CCR, asphaltenes and poisonous metals (V, Ni). Thus, HVGO obtained from selected crude oils (A–G) was characterised for CCR (see Figure 3), asphaltenes (see Figure 4), vanadium (see Figure 5), nickel (see Figure 6) and V+Ni (see Figure 7) respectively. Based on the feed specifications for secondary units, the endpoint will be the cut-off for HVGO deep cuts.

It was observed that crudes E, F and G contained higher levels of CCR and so 580°C would be the maximum endpoint for these crude oils. However, crudes A, B, C and D can have cuts up to 600°C (see Figure 3). The asphaltene contents of crudes E, F and G are found to be higher and so their cutpoints would be 560, 590 and 560°C, respectively. However, crudes A, B, C and D can go up to 600°C deep cuts.

The vanadium content of crude E was observed to be the highest, hence 560°C would be the maximum endpoint for this feedstock. However, crudes A, B, C, D, F and G can be processed for cuts up to 600°C (see Figure 5). The nickel content of crude E was also observed to be the highest, hence 590°C would be the maximum endpoint. However, crudes A, B, C, D, F and G can be processed for cuts up to 600°C (see Figure 6). The vanadium plus nickel content of crude E was observed to be highest, hence 580°C would be the maximum endpoint. However, crudes A, B, C, D, F and G can be processed for cuts up to 600°C (see Figure 7).

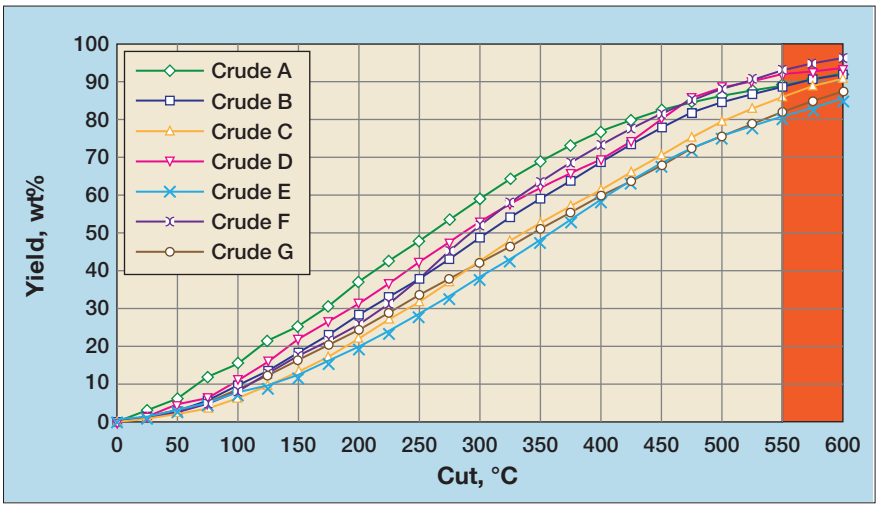


Figure 2 TBP yield profile up to 600°C cuts

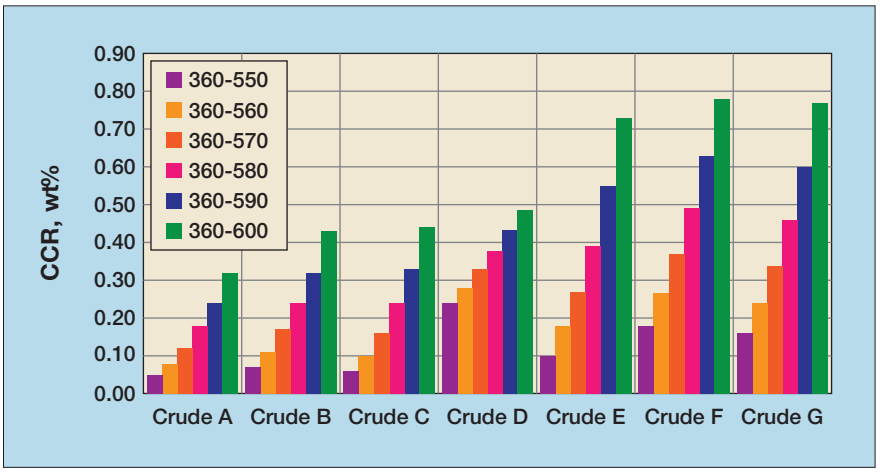


Figure 3 CCR profile for deep cuts

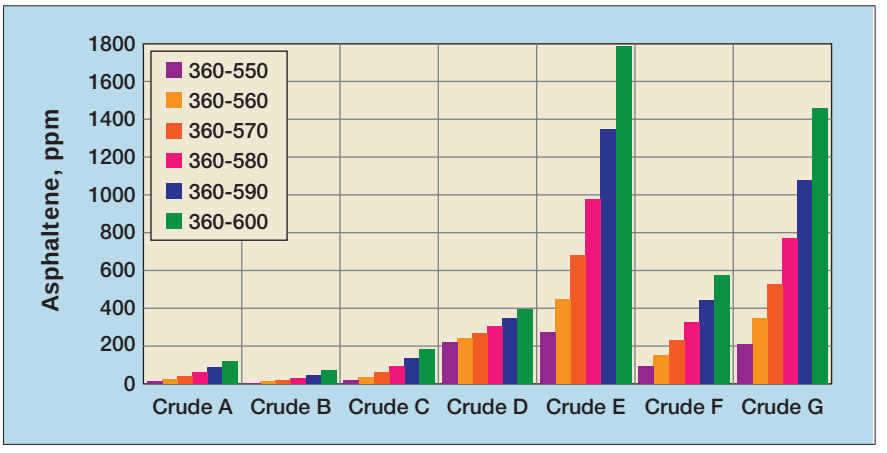


Figure 4 Asphaltene profile for deep cuts

Revamp of vacuum towers for deep-cut operations: a case study

In the current refining climate, various options have been followed for improving margins, such as processing opportunity crude oils, blend optimisations and residue valorisations. The idea presented here, to explore the possibilities for the maximisation of deep-cut VGO yields for extra distillates, in this way reducing residue yields, has been taken up for implementation. In order to employ this concept, it is necessary to understand the detailed engineering required, the hardware and feedstock needed for deep-cut VGO, deep-cut VGO characteristics, and endpoints for processing limits. More data on the properties of heavy crude oils will be useful for examining feedstock flexibility.

In the field, deep-cut mode operations are severe. Thus, a revamp of the vacuum tower is

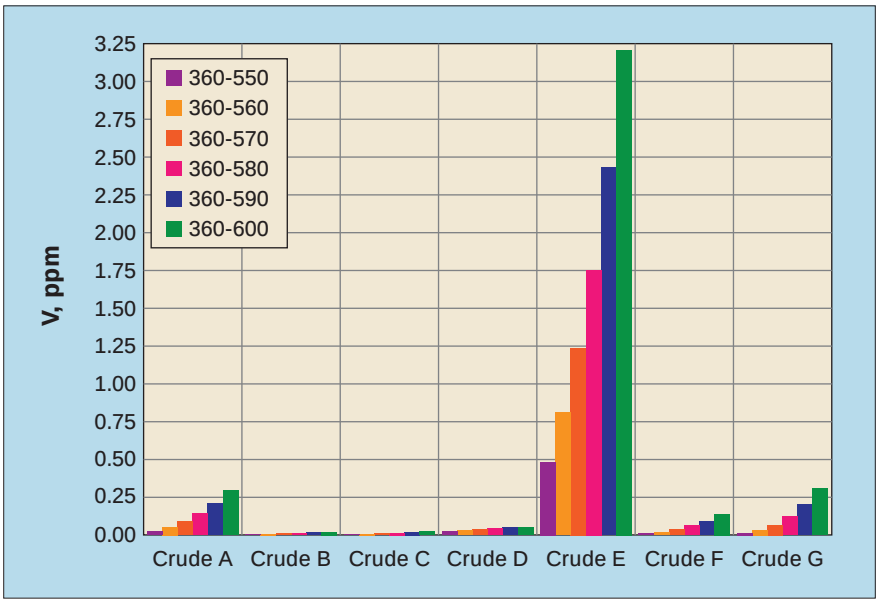


Figure 5 Vanadium (V) profile for deep cuts

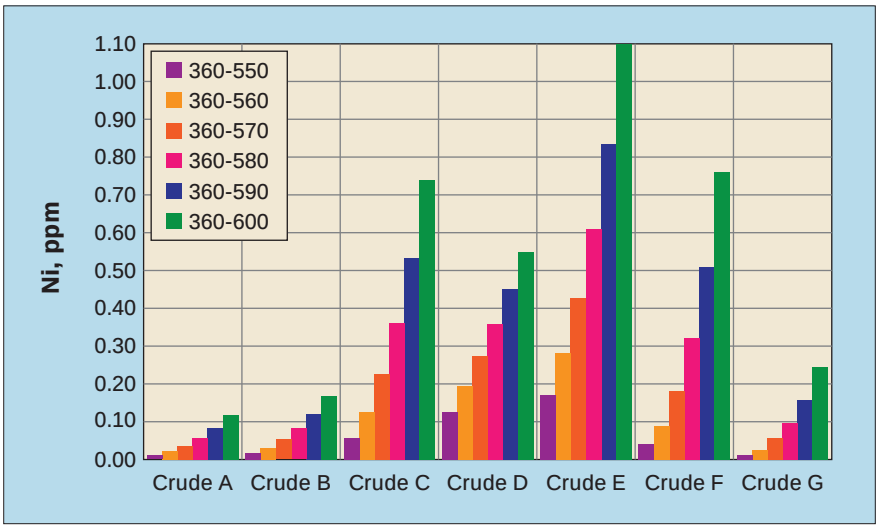


Figure 6 Nickel (Ni) profile for deep cuts

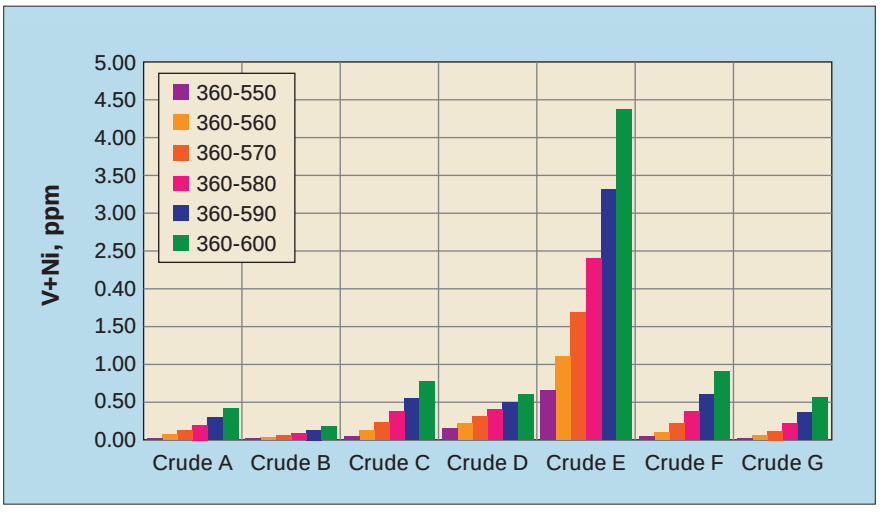


Figure 7 V+Ni profile for deep cuts

essential prior to their implementation. Since vacuum tower system configurations vary from refinery to refinery, a detailed engineering study is needed. To implement the idea fully, a turnaround has to be identified for hardware modifications. This will include inspection of furnace design, flash zone conditions, wash oil section design, low pressure drop draw-off trays and spray sections, all crucial parameters for the implementation of deep-cut mode operations.

To investigate low-capex opportunities, a review by an experienced revamp engineering team of the existing unit and equipment is essential. Pre-revamp analysis can lead to the correction of underperforming systems, which saves extra costs and can reduce the overall investment in a revamp. A detailed engineering and process simulation study can be envisaged to fully evaluate the benefits.

Considering all of these aspects, selection of the engineers to carry out a pre-revamp study has been made and one of BPCL's refineries has been considered for the revamp of a vacuum tower during an upcoming turnaround.

Economic analysis

The expected benefit by deep-cut distillation of VGO up to 50°C for processing in secondary units has been estimated based on per-barrel crude throughput. Increasing the HVGO cut means 2–5 wt% of extra feed (see Figure 1) for distillate improvement at the secondary units, rather than being downgraded as VR. Conversion in the secondary unit is 70% (assumed) and the remaining 30% can be taken as VR. The refinery gate price for distillates and residues is taken as ~$0.5 per litre and ~$0.3 per litre, respectively. Thus, the expected benefit is estimated to be in the region of $0.3–1.0 per barrel of crude throughput.

Conclusions

Initial feedstock characteristics have the greatest influence on deep-cut properties and so have an effect on the operation of secondary processing units. Processing medium °API crude oils is better than processing high °API crudes for obtaining higher yields of deep cuts. However, there is a wide variation in the characteristics of the deep cuts near their final boiling points,

and thus an understanding of deep cuts at intervals of 5–10°C is essential for obtaining endpoints. Based on the characteristics of deep-cut VGO and its specifications, the endpoint varies, depending on the feedstock crude and/or crude oil blends.

A vacuum tower revamp is essential for operation in deep-cut mode. By revamping the unit for deep-cut mode operations, the yield can be improved by 2–5 wt%. Deep-cut incentives for typical light and medium crudes are estimated to be ~$0.3–1.0 per barrel of crude throughput.

Acknowledgement

The authors express their sincere thanks to BPCL management for constant encouragement and support. Also, special thanks to S Ramanathan and Muzaffar Ahsan for their support.

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Rajeev Kumar is a Deputy Manager (R&D) with Bharat Petroleum Corporation Ltd, India, specialising in the development of new processes in crude areas, crude compatibility, resid upgrading, biodiesel and biolubricant processes. He holds a master's degree in chemical engineering from Indian Institute of Technology, Kanpur, India.
Email: rajeevkumar@bharatpetroleum.in

Chithra V is a Senior Research Scientist (R&D) with Bharat Petroleum Corporation Ltd, specialising in crude evaluations, fuel characterisations and new product development. She holds a master's degree in chemistry.
Email: chitrar@bharatpetroleum.in

Shalini Gupta is a Senior Research Scientist (R&D) with Bharat Petroleum Corporation Ltd, specialising in bio-lubricants, metal recovery from spent catalyst, resid upgratation and analytical sciences. . She holds a master's degree in chemistry.
Email: guptashalini@bharatpetroleum.in

Sonal Maheshwari is a Senior Research Engineer (R&D) with Bharat Petroleum Corporation Ltd, specialising in bitumen and resid upgrading. She holds a master's degree in chemical engineering from Indian Institute of Technology, Delhi, India.
Email: maheshwaris@bharatpetroleum.in

Peddy V C Rao is a Senior Manager (R&D) with Bharat Petroleum Corporation Ltd, and has 24 years' experience in the petroleum, biofuels and petrochemicals industry. He holds a doctorate in chemistry from Indian Institute of Technology, Bombay, India.
Email: raopvc@bharatpetroleum.in

N V Choudary is a Chief Manager (R&D) with Bharat Petroleum Corporation Ltd. He has 26 years' research experience in petroleum refining, catalysis, adsorption and thermodynamics and holds a doctorate in chemistry.
Email: choudarynv@bharatpetroleum.in

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Renewable fuels and biofuels in a petroleum refinery

Sound judgement of the process environment, logistics and product properties are necessary to process both fossil and bio-derived raw materials on a single site

JUKKA KEYRILÄINEN and MATTI KOSKINEN
Neste Jacobs

Bio-based raw materials and associated process technologies form an entirely new engineering challenge for integrated petroleum refineries. The composition variation of raw materials, including trace components, various logistical problems and the difficulty of coming up with the right integration approach compared to conventional engineering of fuel refineries using petroleum feedstocks, needs new types of skills and experience. The fundamental engineering challenge is to combine existing advanced petroleum process technologies with various aspects of the problems faced in renewable fuels process engineering and to come up with the optimal design approach that enables the implementation of biomaterial streams to the highly integrated process environment of a petroleum refinery.

Introduction

Renewable fuels have been one of the hottest topics so far in this millennium's energy debate. The reason for the growing interest is obvious: the ever-increasing concern about CO_2 release to the atmosphere and its impact on global warming. Another significant factor is political instability in the areas where crude oil is produced. And thirdly, local agricultural economics and trade deficits, partly due to historically high crude oil prices, provide an additional driver to get more energy from domestic sources among quite a few of the leading consumers of petroleum.

During past centuries, flora has been the source of fuel as well as many valuable and vital substances and constituents. In the oil era, many of those products became cheaper and performed better when derived from fossil feedstocks. For renewable fuels, the sustainable way would be to encourage benefiting first from the value chain of the biomass constituents and to produce fuel only from the residues, or from an entirely different feedstock such as algae — not part of the food chain or the traditional green industry. This method of switching from pollution to solution is already on the research agenda of many enterprises.

The simplest and cheapest way to process renewable feeds in an existing refinery, as co-feeds, is not necessarily the most economical one

Petroleum refinery as a platform for renewable fuels production

Petroleum refineries are natural locations for renewable fuels production. They are, after all, built for the production of advanced fuels by the most cost-effective means to deliver appropriate products for surrounding societies. Refiners are very experienced with their raw materials and equipment, which is mainly due to the fact that they have been utilising them for a long enough time to gain thorough knowledge on all relevant issues. Typically, the refineries also have an extensive knowledge of product and fuel markets, albeit for petroleum-based fuels only. The processing of biofeedstocks means entering an unknown territory. One could say, from a traditional viewpoint, that anything "bio" means additional problems by way of fouling, decreased efficiencies or an additional work burden. Biomaterials are living organisms containing and producing a multitude of compounds. In traditional applications, the smaller scale impurities might not be relevant or even recognised due to relaxed requirements, but they can be of paramount importance in petroleum refineries with regard to catalyst activity or when accumulating within equipment.

Another important issue is that the simplest and cheapest way to process renewable feeds in an existing refinery, as co-feeds, is not necessarily the most economical one. Also, the available trading specifications for renewable feed materials resemble merely the key factors for present applications, while a complete description of biomaterial properties is lacking. Only experience will reveal the significant factors and surprises.

However, in current circumstances, "bio" also means a premium in product value, which changes the picture, not least in the current economical climate, wherein refinery margins are low or non-existent. The engineering challenge is to do the integration correctly, when bioprod-

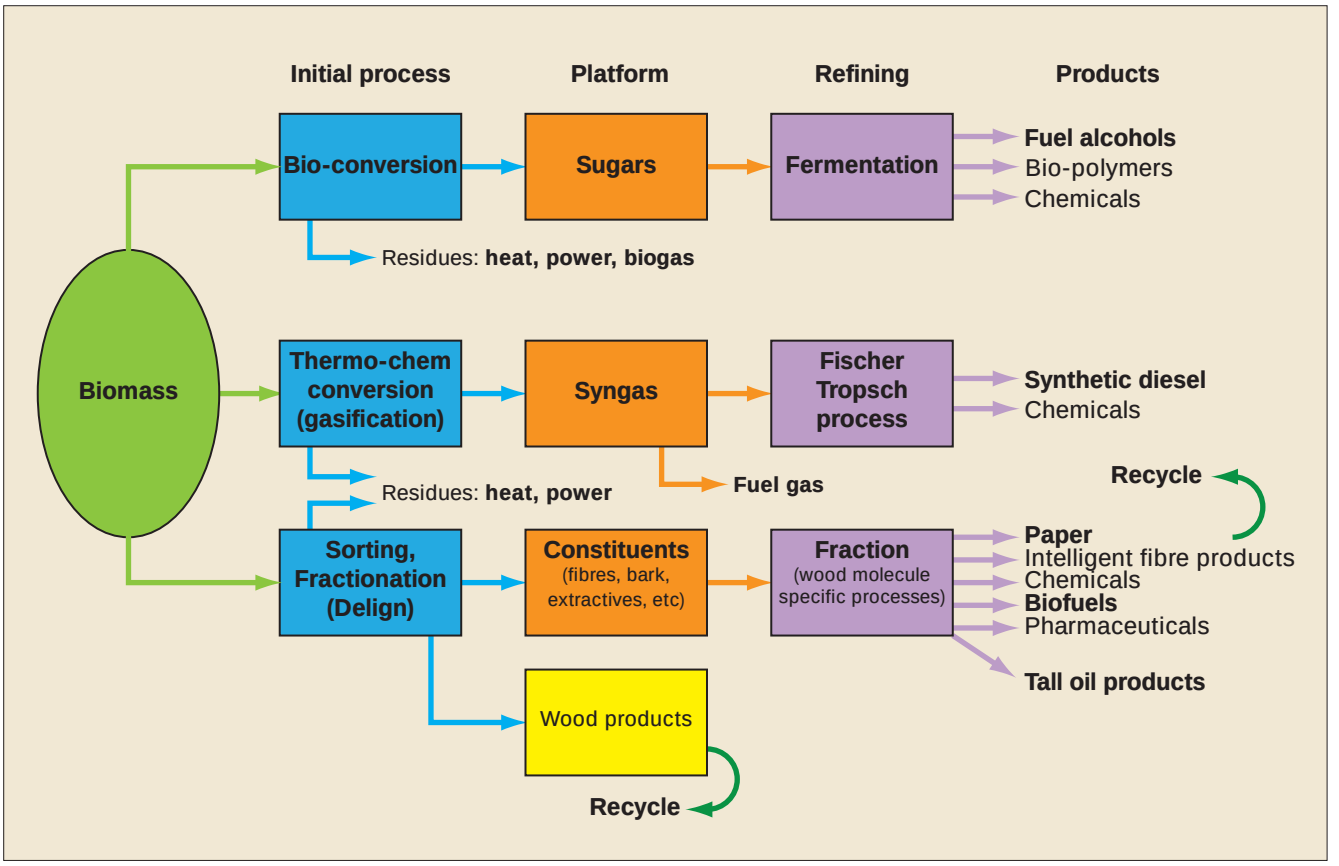


Figure 1 Biorefinery platforms

ucts are manufactured in a petroleum refinery. Moreover, the key is to create molecules as similar as possible to existing fuel molecules in their structures.

Conventional petroleum refineries can be modified to process bio-basestocks into renewable fuels.

Routes to renewable fuels

A biorefinery concept could be built on three main initial platforms to promote different product slates (see Figure 1). The sugar platform is based on biochemical conversion processes and focuses on the fermentation of sugars extracted from biomass, including lignocellulosic material. This platform requires strong know-how of bio- and genetic engineering and chemical engineering, because the conversion is done by micro-organisms.

The syngas platform is based on thermochemical conversion processes and focuses on the gasification of variable biomass feedstocks. It can use almost any organic feed and produces synthesis gas that can be converted to components other than fuels. Although the syngas platform seems to consist of known technology blocks that are proven in other applications, there are many challenges that are not simple to overcome. Some of the technology blocks were designed originally for other purposes and applications and, often, quite a few must be redesigned and adapted for this specific application. Also, bio-based feedstocks contain small quantities of components that are different to those of fossil origin, which, of course, requires experimental demonstration.

A biorefinery concept could be built on three main initial platforms to promote different product slates

The constituent platform, based on fractionation processes, focuses on the separation of valuable biomass constituents for further processing. The residues may be utilised by bioconversion or thermochemical means.

Perhaps the best example of a biorefinery is a traditional pulp mill, a constituent platform, where a primary product, fibres, is separated from chemical constituents using chemical or thermomechanical processes. From the chemical fraction, multiple products may be produced, including commodities, fine chemicals, functional food and pharmaceuticals. Volume-wise, the main by-products so far are different biofuels in liquid or solid form. However, other routes do exist (see Figure 2).

The fats and oils route is currently widely practised in FAME production. It generates a commercial product, which, however, has significantly compromised properties, resulting in blending limitations in normal diesel use or dedicated automotive equipment. The emerging hydroprocessing route provides far superior products and is currently practised in the NExBTL process, with two operating references in Neste Oil's Porvoo refinery and a third unit

currently being started up. The biomass route depicted in Figure 2 is yet to be fully commercialised.

Technology challenges

Proving the credentials of various biorefinery and renewable fuels production concepts in petroleum refineries requires innovation networks and teamwork among different research institutes. One key issue is determining the concept of plant ownership. For a pulp mill or an ethanol plant, the main investor may be self-evident. But the more diverse the mix of expected value-added products, the more complex it is to initiate an organisation or a particular network to promote and finance the project.

The syngas platform requires a reliable logistics chain for raw material feeds where the volumes are huge. For example, a 100 kt/a Fischer-Tropsch (FT) product unit would require more than one million cubic metres of forest residue calculated as solid wood. And the FT product capacity is in most cases too low to be profitable. Today, such logistic chains in high enough volumes are non-existent or at least rare. Partnerships with the forestry industry to secure raw material availability may be more than justified.

Crude FT product is a wide mixture of alkanes, oxygenates and olefins in typically two product streams: condensate and wax. Specific treatment is often necessary for different crude FT product streams, which, of course, adds to the total engineering burden. Co-feed to existing petroleum refinery streams may be one possibility, but it may not be a value-creating solution, because the product of bio-origin is easily diluted in huge amounts of fossil products. In general, a thorough understanding of current oil refining technology and integration skills is required to achieve a viable solution.

Specific treatment is often necessary for different crude Fischer-Tropsch product streams, which adds to the total engineering burden

Another challenge is the tremendous variation in raw material qualities. Even for a single tree, the constituent of material changes significantly from base to top or from older branches to buds. Then again, trees from different parts of a single forest or of geographically diverse origins contain different compositions of sulphur, nitrogen and chloride compounds, to name but a few. And things do not ease with farmed raw materials, given the incoherence of the farming industry in general.

Yet another formidable challenge is the management of catalyst cycle length and lifetime, and the required pretreatment know-how and analytics. Clearly, robust processes are required.

Process development for renewable fuels

Advanced process modelling is a necessity for the development of processes. This is challenging in view of the lack of property data for natural substances. Therefore, extensive testing of unit operations and unit processes, combined with modelling, gives a reliable base for the process design.

Modelling can be utilised from chemistry to proven technology, by determining the kinetic parameters of reactions, interpreting test results and dimensioning thermal and mass transfer units and emissions management, up to the operational optimisation of the plant. The traditional methodology is illustrated in Figure 3.

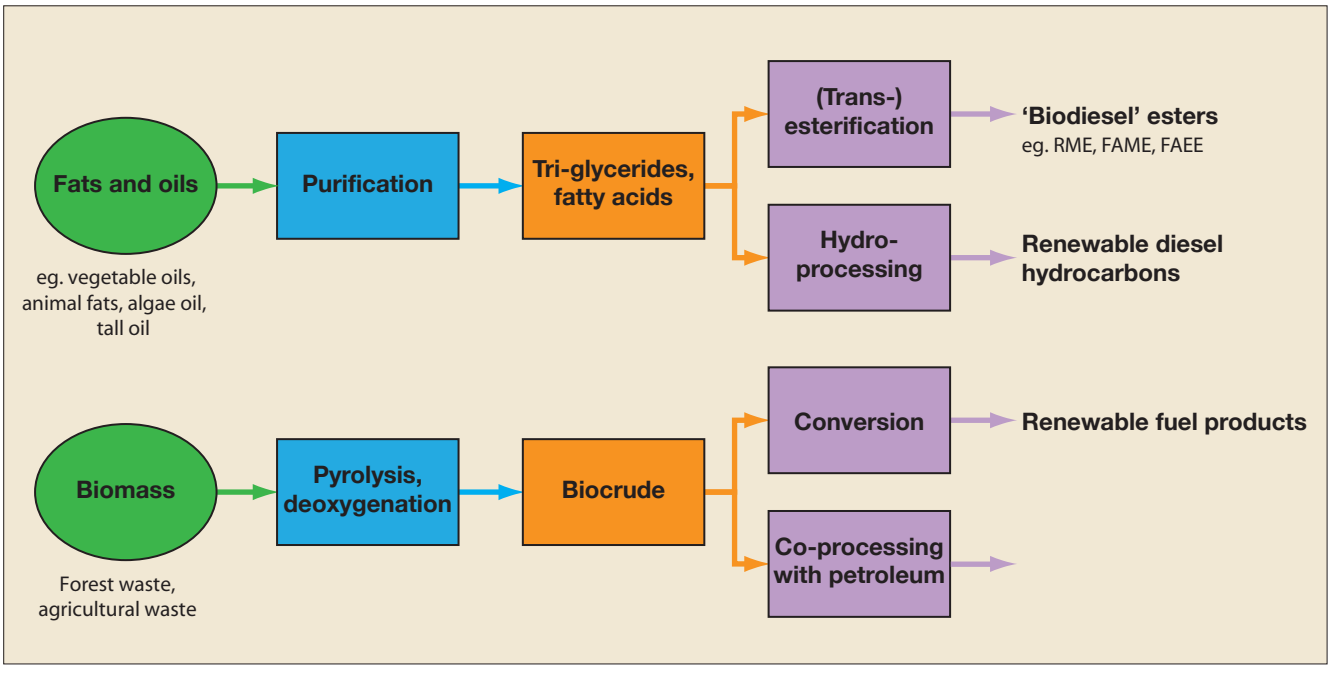


Figure 2 Other routes to renewable fuels

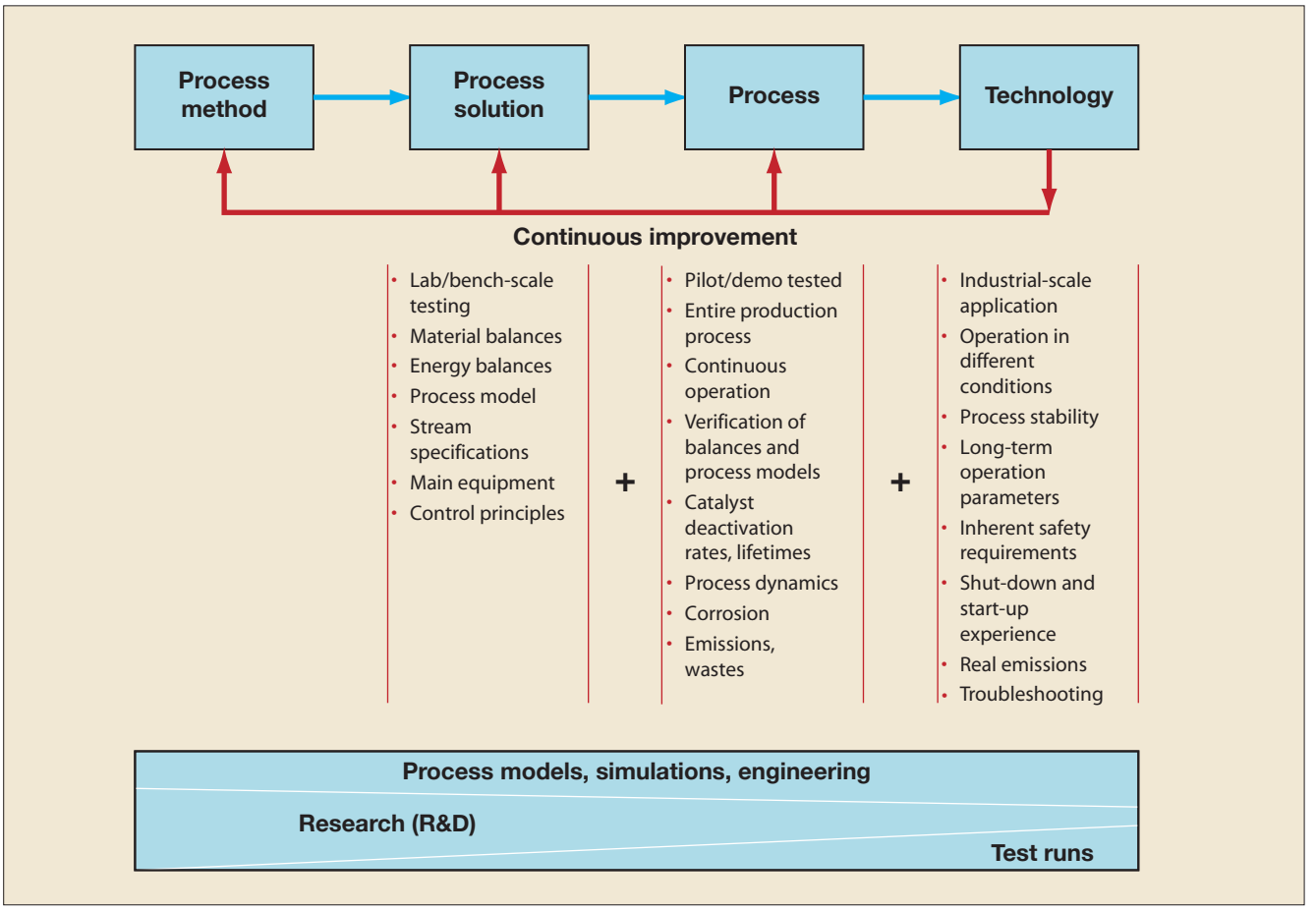


Figure 3 Process development

However, if advanced modelling technologies and modern chemical engineering tools are used rigorously, significant savings in overall time schedules can be attained (see Figure 4). In practice, the NExBTL process was developed without any conventional pilot plant stage, which cut the time for designing and building facilities to zero and helped to push technology development forward significantly, enabling the first unit to be started early, resulting in greatly improved NPV for the project. The modelling effort requires time and skills, which, of course, means additional money spent at the front end.

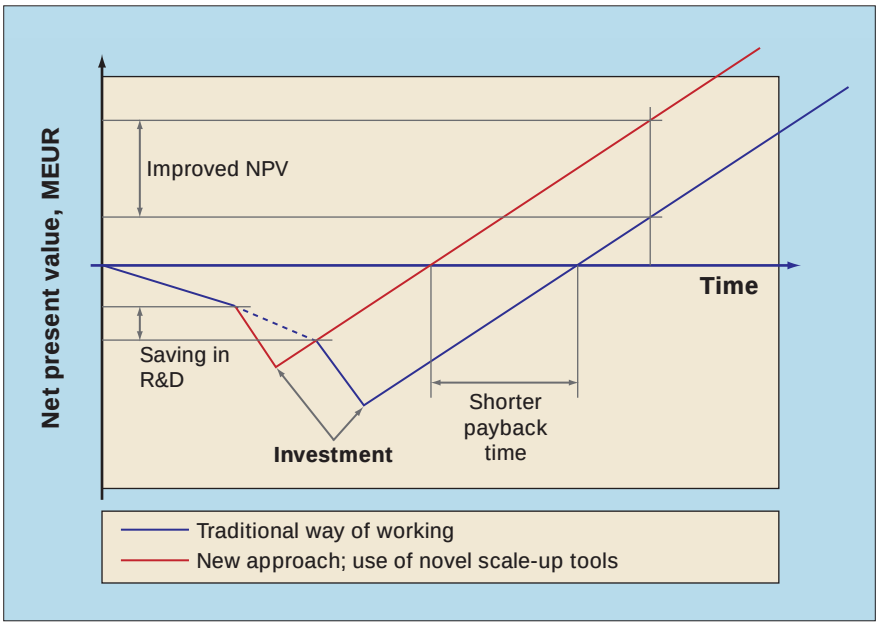


Figure 4 Process development enhancement through modelling

Partnership is the key

The ultimate payout with the successful application of modelling can be considerable, as renewable fuel production may be started a year or more before, with no costs associated with piloting. The difference with regard to conventional oil refining and fuel production is that the solutions available might not be tailored to existing needs, but some additional research and engineering is all that is needed to fit the pieces together. A key issue then is to identify suitable partners or resources that are capable of handling this task, since biomaterials have gained a lot of public interest. Many companies would like to participate in the bio-business and are keen to form close relationships and partnerships in the renewables industry. It can be puzzling to have several contestants claiming to be able to handle the task better than anyone else, with no grounds to verify this, since it is outside tradi-

tional modes of operation. Also, the pros and cons of forming close partnerships must be weighed against whether there truly is potential for mutual benefits (see Figure 5).

An investment project in a petroleum refinery normally means purchasing one or a few licence packages from one or several technology suppliers and finding an engineering contractor who will then put the packages together for the detailed design, construction and purchasing activities. The task is fairly simple, since licence package suppliers are aware of the environment in to which their product is going to be fitted. For renewable fuels processing, a lot is required of the engineering contractor in order to glue together the often misaligned pieces stemming from different industrial practices.

The renewable fuels process can be made to work, but the contractor must step up with a clear vision and fill in the blanks left by technology vendors who could be earning their living in a totally different field of industry, say, with animal feeds.

Generally speaking, for the successful execution of investment in renewables, it is essential to recognise open items in the knowledgebase and to find the right partners to piece the process together. This means managing the whole vendor chain effectively.

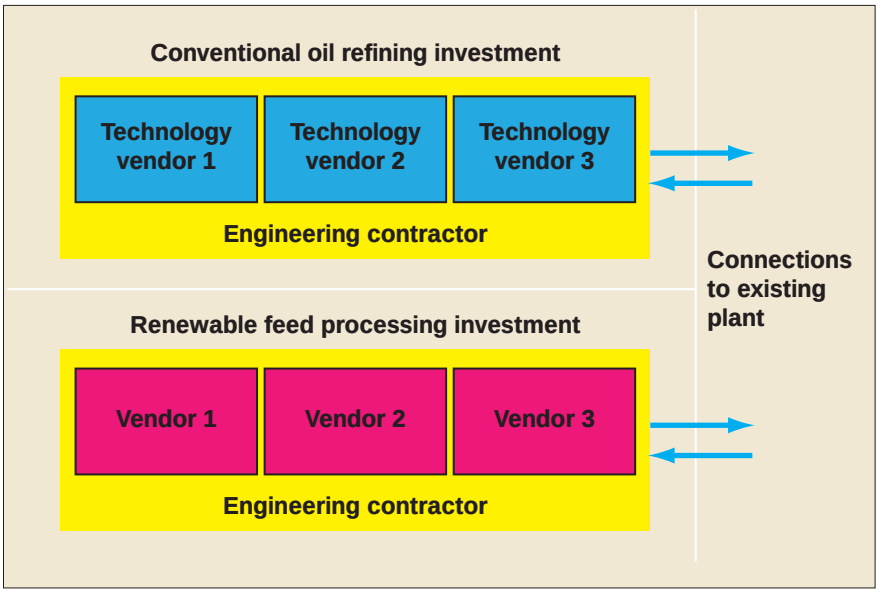


Figure 5 Engineering contractors for conventional and renewable processes

Biomaterials in petroleum refining units

A wide variety of components is typical for raw materials from natural sources, since living organisms require a multitude of nutrients and minerals for their digestion, which in turn produces a broad spectrum of, say, effluents. Surprisingly, many of the smaller scale impurities and trace components may not even be familiar to the users of present applications if there has not, for one reason or another, been particular interest in them. Often the principle of "if it causes no problem, it is not there" is applied to the variety of impurities. This lack of interest may actually be justified from the producer's economical viewpoint, but the downside is that the effects of those possibly existing impurities to a different applications cannot be anticipated and they might be revealed only by experience if there has not been previously gained knowledge on their existence and behaviour. Therefore, caution should be applied when studying the specifications for commercially available raw materials — they are by no means complete, and are more likely to incorporate only the properties and parameters that are significant to the present applications of said materials.

For the successful execution of investment in renewables, it is essential to find the right partners to piece the process together

Handling the logistical challenges

Having said that, renewable raw materials contain a broad spectrum of components in various concentrations, and an experienced refiner might think straight away that it is exactly the same with crude oil, and they would be right. But it must also be noted that even conventional refineries are actually very versatile, with possibly tens of different production units and feed-blending capabilities, while renewable fuels production, especially when integrated into an existing process plant, may consist of a single production unit and a few storage tanks. If so, there should be no false expectations of the unit being capable of processing "any" of the types of raw material chosen to be utilised.

When the basis of design is agreed for a new renewable fuels process, the natural variation in raw material quality can be addressed in two ways. The first is, obviously, to specify all of the possible variations of raw materials as suitable feeds for the process, but this can end up raising the complexity of engineering, which unfortunately applies to costs as well. Another approach would then be to limit the number of raw materials to a few representative cases and compensate for variations by designing the logistics as flexibly as possible. In practice, this would mean providing enough storage capacity and routing possibilities in order to keep some fractions separate, to blend fractions intentionally and for the intermediate storage of fractions that require severe processing.

Purification of oils and fats

Since the purification of oils and fats is a common task in the food

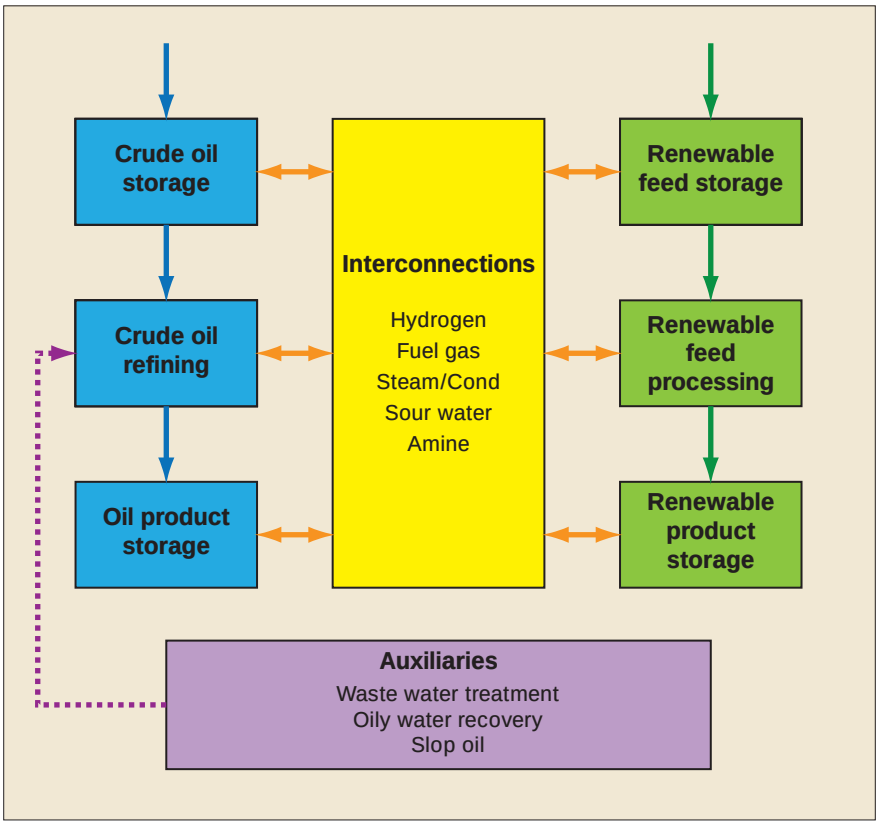


Figure 6 Production segregation

industry, there are several well-developed processing methods commercially available, including degumming, bleaching, deodorising and dewaxing. Some can be alternatives to one another, while others are connected in series to achieve best results.

The choice of suitable purification method depends very much on the quality and source of the oil to be purified. Some seed oils may need additional steps to reach the required levels of purity. But it is also good to recognise that the processing conditions within one purification step can vary with different feedstocks.

When designing a new processing unit for renewable fuels production, it can be tempting to make the range of possible feedstocks as wide as possible. By considering what was stated above, it becomes obvious that the purification system, whatever the combination of steps chosen, must be flexible in terms of utilising the processing steps. If some feedstocks require less purification, maybe one step can be completely bypassed. The possibility then is not only for an actual bypass pipeline over one processing step, but also the ability to store feedstocks with different requirements separately.

Gasoline properties

	High octane	Low RVP	Low olefins	Low benzene	Low aromatics	Driveability (distillation)
Butanes	Yes	No	Yes	Yes	Yes	Yes
Alkylate	Yes	Yes	Yes	Yes	Yes	No
Isopentane	Yes	No	Yes	Yes	Yes	Yes
C_6 isomerate	No	Yes	Yes	Yes	Yes	Yes
Light FCC gasoline	Yes	No	No	No	Yes	Yes
Heavy FCC gasoline	No	Yes	Varies	Yes	No	No
Reformate	Yes	Yes	Yes	No	No	No
ETBE, TAEE	Yes	Yes	Yes	Yes	Yes	Yes
Ethanol	Yes	No	Yes	Yes	Yes	No

Table 1

The size and frequency of certain feedstock shipments must be taken into account when designing the storage facilities if blending is not desired. On the other hand, having some blending and buffering capacity in between processing steps might be advantageous, because it allows intermittent operation of one processing step while securing homogenous feed quality for the next.

Flexibility can be greatly increased with logistical solutions. Processing units in general tend to be designed for a certain capacity, which then can vary to some extent between given turndown and over-design percentages. With properly designed logistics, the virtual turndown or operating window of processing steps can be significantly improved.

Managing by-product and waste streams

Integrating the renewable fuels process into an existing refinery can result in the co-processing of raw materials from fossil and renewable sources. But it may also turn out to be beneficial to keep these two fractions separated for legislative and / or economical reasons; for instance, in the search for a premium margin.

In principle, separation is very simple; it is all about nominated storage tanks, pipelines and processing units. The real challenge of integration, however, is how to manage all of the side products, waste streams, drains and spills without introducing a threat to the existing plant operations (see Figure 6). A good example is handling wastewater from a process using renewable raw materials. Due to their composition and biological source, the trace amounts of raw materials in water effluents can create order of magnitude greater BOD readings compared to common oily waters. In addition, the biological compounds are often more easily digested by the fauna in active sludge treatment and, therefore, the species in sludge used to digest biological wastewater are often different from those used for fossil organic waters. It can be easily understood that there is a

good potential to mess up or overload the wastewater facility without proper knowledge. A seemingly small issue may become a very large one when the whole facility has to be run down because of malfunctioning wastewater treatment. A similar issue could be the transportation of renewable raw material trace components to another fossil unit via, for instance, a minor utility line, which could appear after a time as mysterious corrosion or plugging.

Product compatibility

All products coming from a petroleum refinery pipeline must comply with existing specifications and simultaneously ensure future product improvement. However, this is not the case depicted in Table 1, which shows some key gasoline components and their key quality parameters.

As can be seen, compared to common fuel components, the existing biocomponents perform quite well, although only ETBE and TAEE bring considerable advantages in upgrading gasoline blending. The situation with diesel material is even worse, as fatty acid methyl esters have provided many problems due to poor product stability, cold properties and challenges in engine performance (deposits and corrosion in fuel systems, engine oil dilution or polymerisation, phosphorous, ash). These problems can be overcome by hydrogenated vegetable oils and animal fats, such as the product from Neste Oil's NExBTL process, which simultaneously yields superior product with improved cetane and lower emissions. The key is to create molecules, be they in gasoline or diesel boiling range, which are as similar as possible to existing fuel materials in their structure.

Both biorefining and renewable fuels production in petroleum refineries pose many challenges

Conclusions

Both biorefining and renewable fuels production in petroleum refineries pose many challenges. As both are strongly emerging ways to produce fuels, the underlying engineering skills requirements combined with sound judgement of process environment, logistics and respective product properties and values will dictate the overall feasibility of such operations.

The engineering challenge is to combine existing advanced petroleum process technologies with various aspects of the problems faced in biorefinery engineering and to come up with process simulation tools that allow the implementation of biomaterial streams to the highly integrated process environment of a petroleum refinery. Besides process modelling, a sound understanding of related material requirements and corrosion engineering, as well as advanced process control and on-line analyser technologies permit the steady-state operation levels required in a modern petroleum refinery. The resulting most viable solution is the one entailing the best economic results.

Matti Koskinen is Sales Manager for Neste Oil clean fuel technologies with Nest Jacobs Oy. Formerly a Process Design Engineer with Neste Engineering, he holds a master's degree from Helsinki University of Technology.
Emai: matti.koskinen@nestejacobs.com



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Protection analysis in refining

Independent pilot plant testing can serve as an independent protection layer to reduce the technical risks of new process technology

ROBERT ABSIL
Intertek PARC

Factors contributing to technical risks when implementing new process technologies in the refining industry include the complex compositions of crude oil fractions and of heterogeneous catalysts used in the conversion of those fractions to marketable products. Furthermore, reactor hydrodynamic performance and operational issues can pose significant technical risks. The approach proposed in this article is to use layer of protection analysis, which has its origin in the process plant safety field, to mitigate these technical risks. The motivation behind this approach is to semi-quantify the risks that are associated when implementing new process technologies so that they can be controlled, with decisions being made based upon objective evidence. To illustrate this approach, one operational issue — plugging of reactor beds — is analysed and a risk mitigation programme is proposed. Furthermore, independent pilot plant testing is proposed as an independent protection layer to reduce technical risks.

Number of isomers as a function of carbon number[1]

Carbon number	Boiling of n-paraffin, deg°C	Number of isomers
5	36	3
8	126	18
10	174	75
12	216	355
15	271	4347
20	344	$3.66 * 10^5$
25	402	$3.67 * 10^7$
30	449	$4.11 * 10^9$
35	489	$4.93 * 10^{11}$
40	522	$6.24 * 10^{13}$
45	550	$8.22 * 10^{15}$

Table 1

Refinery process implementation risks

Feedstock risks

When considering technical risk in the refining industry, the crude oil feedstock is one major contributor. Conventional crude oil is a complex mixture of hydrocarbons that boil over a wide range of temperatures. Reaching beyond the maximum cutpoints of vacuum-packed column distillation (~1040°F, 560°C) and high-vacuum, short-path distillation (~1300°F, 700°C), sequential elution fractionation indicates that the maximum atmospheric equivalent boiling points (AEBP) of crude oils can exceed 2500°F (1370°C). The hydrocarbons include paraffins, cycloparaffins, aromatics, resins and asphaltenes. They also contain heteroatoms, such as sulphur, nitrogen and oxygen, in their structures. Furthermore, crude oils contain metals, such as vanadium, nickel, iron and copper. In addition, crude oils contain salts, which are dissolved or suspended as crystals in very small water droplets emulsified in the crude oil.

To illustrate the complexity of a crude oil or its fractions, Altgelt and Boduszynski listed the number of isoparaffins that can exist as a function of carbon number (see Table 1).[1] Similar structural variations exist for cycloparaffins, aromatics, resins and asphaltenes at a given carbon number.

Moreover, hydrocarbons may contain one or more heteroatoms in their structures. Sulphur exists, for example, as mercaptans, sulphides, disulphides, thiophenes, benzothiophenes and dibenzothiophenes; oxygen as phenolics and carboxylic acids; and nitrogen as indoles, pyridines, amines and quinolines.

The technical risk associated with the complexity of feedstock composition is that the potential outcome of a process technology implementation involving a new feedstock may not be completely known, since no two crude oils are the same. Altgelt and Boduszynski pointed out that a complete compositional analysis of heavy fractions — and thus also of the crude oil — is impossible and that simplifications must be made.[1]

Instead of focusing on individual compounds, groups or lumps of compounds that fall into similar chemical classifications have been used with success.[2] However, the less is known about the feedstock, the greater the technical risk and the higher the probability of failure on demand of the programme.

Catalyst risks

Another important factor affecting risk assessment is the heterogeneous catalyst used in the conversion

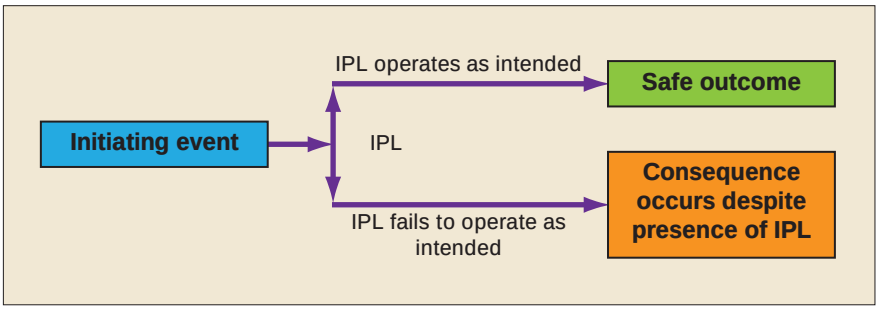


Figure 1 Effectiveness of an independent protection layer[6]

process. The composition of a solid catalyst can be complex; the catalyst is often dual-functional, in that the acidic function provided by the zeolite catalyses cracking and isomerisation reactions, and the metal function catalyses hydrogenation reactions, as is the case with hydrocracking catalysts. Moreover, a binder, such as alumina, is used as support or to give the solid catalyst particle mechanical strength. Although substantial advances have been made in understanding heterogeneous catalysts, factors such as diffusion limitations, poison sensitivity, limited understanding of reaction mechanisms and of the structure of the active sites contribute to technical risk.

Again, the technical risk associated with catalyst complexity is that the potential outcome of new process technology involving a new catalyst is not completely known.

Reactor hydrodynamic performance risks

In a trickle-bed reactor, the ideal flow pattern is that the liquid flows as a continuous film over the catalyst particles, with the hydrogen flowing through the remaining void space and diffusing through the liquid film to the catalyst surface. However, commercial trickle-bed operations have been shown to be non-ideal and are affected by, for example, liquid and gas maldistribution and mass transport limitations.[3]

Since no actual statistics were given in the McGovern report,[3] a probability of failure on demand cannot be calculated. However, for the sake of argument, if 10 out of the 50 hydrotreaters started up industry-wide were not able to meet the performance predicted by properly packed pilot plant units, the probability of failure on demand of the commercial trickle-bed processes in this application would be 0.2.

Operational risks

Another risk often overlooked is associated with operational issues, which are due to problems pertaining to the operation of an existing refinery unit, such as a co-current, trickle-bed reactor, and can play a key role on whether the implementation of a new process technology is a success. These include issues related to plugging of reactors, excessive wear of control valve stems or unanticipated corrosion of equipment. Switching to processing feedstocks other than conventional crude oil may lead to unanticipated operational problems. Early reports indicated that hydroprocessing of residues was affected by reactor bed plugging due to fines, such as dirt, sand, salt and corrosion products.[4] Hydrotreating of gas oil to produce ultra-low sulphur diesel was impacted by fines accumulation.[3] Plugging of hydrotreating catalyst beds by colloidal and non-colloidal fines has been reported in the processing of oil sands-sourced gas oil.[5]

The less is known about potential operational problems, the greater the risk and the higher the probability of failure on demand of the process

Again, the less is known about potential operational problems, the greater the risk and the higher the probability of failure on demand of the process.

Independent protection layers

Process plant safety

The concept of risk and risk mitigation measures are well developed in the field of process plant safety to evaluate the hazard potential of installations or changes to installations. Risk mitigation measures can be categorised according to the degree of quantification. The well-known hazard and operability (HAZOP) and what-if studies are purely qualitative. Simplified quantitative methods, such as the Chemical Exposure Index (CEI) and the Fire & Explosion Index (F&EI), use relative rankings of hazards. Full quantitative methods, such as chemical plant quantitative risk analysis (CPQRA), completely quantify the risks associated with an event. Moreover, layer of protection analysis (LOPA) identifies independent layers of protection that reduce risk. An independent protection layer (IPL) is defined as "...a device, system, or action that is capable of preventing a scenario from proceeding to its undesired consequence independent of the initiating event or the action of any other layer of protection associated with the scenario."[6] An event tree showing the effectiveness of an IPL is illustrated in Figure 1.

The PFD is defined as the probability of failure on demand of the IPL. Thus, if out of 100 initiating events or demands the IPL in Figure 1 fails to operate once, the probability of failure on demand is 1 out of 100 or 10^{-2}.[6]

Passive and active IPLs

Two types of IPLs have been identified. A passive IPL is "...not required to take an action in order for it to achieve its function in reducing risk."[6] Passive IPLs include dikes, underground drainage systems, open vents, fire-proofing and inherently safe

design. An active IPL is "...required to move from one state to another in response to a change in a measurable process property."[6] Active IPLs include instrumented systems, such as a continuous pressure controller that regulates, for example, unit pressure at a specified set point and generates continuous feedback to the operator that it is functioning normally. A state controller is also an active IPL. It takes pressure measurements and executes on-off changes to alarm indicators and to process valves. A basic process control system (BPCS) is a control system that continuously monitors and controls the process in day-to-day operation. Some typical ranges for PFDs are shown in Table 2. Note that the BPCS is a relatively weak IPL for reasons of little redundancy, limited built-in testing capabilities and limited access security.[6]

Probabilities of failure on demand for several IPLs[6]

Type of IPL	Device	Industry range PFD	Typical PFD
Passive	Dike	$1 * 10^{-2}$ to $1 * 10^{-3}$	$1 * 10^{-2}$
Passive	Open vent	$1 * 10^{-2}$ to $1 * 10^{-3}$	$1 * 10^{-2}$
Active	Relief valve	$1 * 10^{-1}$ to $1 * 10^{-5}$	$1 * 10^{-2}$
Active	Rupture disc	$1 * 10^{-1}$ to $1 * 10^{-5}$	$1 * 10^{-2}$
Active	Basic process control system	$1 * 10^{-1}$ to $1 * 10^{-2}$	$1 * 10^{-1}$

Table 2

Application of LOPA to ULSD hydrotreating

Risk assessment in ULSD production

Consider a refiner deciding to implement ultra-low sulphur diesel (ULSD) process technology. A tabulation of potential risks is shown in Table 3. The refiner or plant operator in the general case has to ask systematically what the risks are and whether these risks can be accepted. As a first approximation, the financial impact of failure to meet each criterion will be assumed to be the same. The main risks are whether the refiner will be able to produce ULSD that meets ATSM specifications using the catalysts available on the market and using the existing trickle-bed reactor.

The approach proposed here can be used for each of the items listed in the checklist in Table 3. It consists of the following steps:

- Identification of each potential technical risk
- Examination of the fundamentals associated with each risk using in-house, literature or patent data. Only documented evidence can be used
- Semi-quantification of each risk
- Mitigation of each risk by installing IPLs.

This approach is illustrated for an operational technical risk; namely, reactor plugging. This topic was chosen because it does not involve any proprietary information. Moreover, the open literature has a number of references to plugging of trickle-bed reactors.

Trickle-bed reactor plugging

In the following, the term "particle" refers to the catalyst and the term "particulate" to the material in the feedstock that is responsible for plugging of the reactor bed.

Sources of particulates in a refinery

A particulate balance performed around the refinery shows that particulates responsible for reactor bed plugging can either enter the refinery with the crude oil or can be generated in equipment or process units inside the refinery. Categorised according to source, these include:

- Particulates entering with the crude oil or unconventional resource:
  - Suspended solids, such as very fine sand, clay and soil particles, iron oxides and iron sulphide particles. These are picked up from pipelines, tanks and tankers during transportation to the refinery
  - Salt and fines carryover from the desalter due to improper operations. Total suspended solids removal should be greater than 60%, with 80% removal of particles greater than 0.8µ
  - Clays entrained during distillation in case the feed is not properly desalted
- Particulates generated within the refinery:
  - Corrosion products from process equipment and piping
  - Coke generated on the hot surfaces of heaters, furnaces and heat exchangers

Risk assessment for ULSD reactor bed operations

Input variable	Output variable	Risk assessment
Feed rate, bbl/day	Product rate, bbl/day	How much LCO can be charged with diesel?
H_2 make rate, scf/bbl	H_2 bleed rate, scf/bbl	
Inlet H_2 composition, vol%	H_2 tower rate, scf/bbl	What is impact on performance?
H_2 recycle rate, scf/bbl	H_2 consumption, scf/bbl	Can H_2 be supplied?
Inlet pressure, psig	Outlet pressure, psig Pressure drop, psig/L	Is pump capacity correct? Is reactor plugging an issue?
Temperature range, deg F		What is cycle length? Can catalyst be regenerated?
Catalyst		Has optimal catalyst been selected?
Reactor dimensions, L/D Liquid distributor configuration		What is catalyst contacting efficiency? Is distributor operating properly?
Reactor/tower integrity		Are vessels rated for operating pressures? Is equipment integrity status known?
Feed composition	Product composition	Can ASTM D-975 be met?

Table 3

- Particulate (catalyst fines) carryover from FCC units
- Particulate (coke) carryover from cokers
- Gum and coke precursors in cracked feedstocks.

Types of plugging mechanisms

Analysis shows that the pressure build-up is from an accumulation of debris in the reactor in the inter-particle void space. This build-up can either be in the top layer of the bed or extend deeper into the bed. Plugging can thus be categorised into two groups as to cause:

- Plugging due to retentive screening[14]
- Plugging due to deep bed filtration.[11]

Plugging by retentive screening

Plugging by large particulates is due to retentive screening, meaning that the particulates in the feedstock are so large that they actually cannot penetrate deeper than the top layer of the catalyst bed due to physical constraints. To illustrate order-of-magnitude effects, two arrangements will be considered first, using spherical catalyst particles and spherical particulates. As a rule, the term "particle" is used for catalyst and the term "particulate" for material other than catalyst that leads to pressure build-up. Next, the impact of catalyst particle distribution, catalyst shape and catalyst bed loading procedures will be discussed.

Ideal packed bed with one constriction diameter[14]

The particle stacking configuration affects the extent of retentive screening. First, the most open or maximum voidage packing of a bed of uniform spheres with diameter D occurs when the particles are arranged in a square array, with each layer directly above the other (see Figure 2). Then, the minimum diameter of the particulates, defined as d, that will be retained are defined by the following equation:

$$D/(d + D) = \cos 45°$$

For a 1mm-diameter sphere, the minimum diameter of the particulate that will be retained by the bed is 414 microns. The diameter d can also be called the constriction diameter. Particles can be arranged in equilateral triangular pitch too (see Figure 3). The particles are in an array, with each layer directly above the other. Then, the minimum diameter of the particulates with diameter d that will be retained are defined by:

$$D/(d + D) = \cos 30°$$

For a 1mm-diameter sphere, the minimum diameter of the particulate that will be retained by the bed is 154 microns.

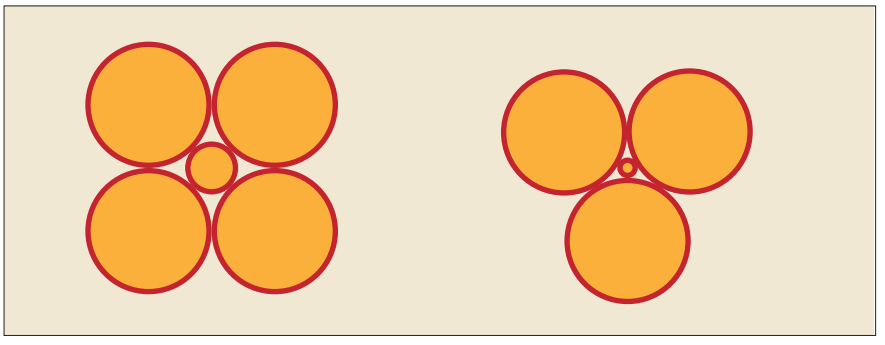


Figure 2 Square packing of spheres

Figure 3 Equilateral triangular pitch

Factors affecting constriction diameter distribution[14]

Actual trickle-bed reactors have a distribution of constriction diameters affected by particle shape, particle size distribution and loading procedure.

Catalyst particle shape

The shape of particles can affect the retention of particulates in the feed on top of the catalyst bed. If the particles are shaped as cylindrical extrudates or shaped extrudates, like trilobes, they can lie parallel to each other and significantly reduce the accessible openings.

Catalyst particle distribution

Catalyst particle distribution also plays a key role. While a conventional hydrotreating catalyst has a nominal extrudate size, such as 1mm-diameter extrudate, they exhibit a particle size distribution. Small particles and fines are generated by attrition during handling. If the distribution of the particles is sufficiently broad, the smaller catalyst particles or catalyst fines may be able to nest within the interstices between the larger particles. This then reduces the diameter of the particulates that can pass through the top layer of the bed.

Catalyst loading procedure

Wooten[8] compared two types of procedures for loading catalysts in commercial fixed-bed reactors. The sock-loading method uses a canvas tube to transport the catalyst from the reactor inlet manway to the bottom of the reactor, with the sock discharging the catalyst upon the bed surface. The catalyst cylinders are randomly oriented in this method and are not allowed to find a stable, horizontal rest position. This leads to bridging of the cylinders and void spaces that tend to collapse during operation. The dense-loading method, on the other hand, uses a vertical pipe that extends into the top of the reactor, with the catalyst being horizontally propelled using either air-propelled or kinetic propulsion systems. The main difference is that in the dense-loading method the catalyst cylinders fall onto the bed surface and are able to assume a horizontal rest position before being impinged by other catalyst cylinders. Most of the catalysts reach terminal velocity after falling 10–15ft. The cylinders, thus, pack horizontally, thereby minimising bridges and settling during operations. The dense-loading method can increase catalyst bed densities by as much as 17%. While the dense-loading method initially gives pressure drops greater by a factor of 1.5–2.5 than

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those with sock-loading, they can be lower later in the run. Wooten pointed out that sock-loaded catalyst beds have higher void space and are thus able to better handle particulate matter in the feedstock. One would expect the dense loading method to sieve out smaller particulates, increasing the likelihood of plugging on the top layer of the bed with particular feeds.

In the examples shown in Figures 2 and 3, the catalyst spheres were stacked, with each array directly on top of each other. This generates vertical channels. Actual catalyst packing configurations are substantially more complex and the required particle configurations to retain the particulates may not be present in the particulate's flow path in the first catalyst layer, but may be present in a subsequent layer. Regardless, Narayan *et al*[9] reported that a bed of hydrotreating catalyst comprised of pellets of diameter of 1–2mm will strain out particulates of the order of 100 microns in size.

Plugging by deposition

Plugging due to deposition is caused by the very fine particles that are small enough that they will not be physically retained by the catalyst in the reactor, but are rendered insoluble during processing and deposit on the catalyst's external surface. Fine particulates, such as kaolin clay, can have their surfaces stabilised by insoluble organic materials, such as asphaltenes, making it very difficult to separate them from bitumen.[10] However, their surface properties can be modified by the hydrotreating process due to a combination of desorption of asphaltenes at higher temperature or asphaltene conversion. The asphaltene coating is then progressively removed and increased deposition results down the length of the bed. This has been observed in the hydrotreating of gas oil that contains asphaltene-coated clays, with the greatest deposition of the fine particulates being toward the exit of the reactor.[11] Furthermore, iron sulphide with its surface-modified asphaltenes deposited rapidly because the asphaltenes were desorbed or thermally decomposed from the iron sulphide surface.[10]

The impact of a reactor plugging event will depend on the pressure control system configuration

Water produced by hydrodeoxygenation reactions destabilised the asphaltene-coated kaolin clay particulates by reducing the surface coating. Neither ammonia nor quinoline affected particle deposition. Deposit testing with 8µm carbon black in kerosene on a packed bed of glass bead or hydrotreating catalyst at room temperature showed that the pressure drop increased with specific deposit. The carbon



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black was observed to be deposited along the entire length of the bed; the axial pressure drop profile increased along the length of the bed. The pressure drop increase was attributed to pore restriction and to particulates attached to the particles to increase their hydraulic radius. The initial interaction was due to electrostatic attraction between the carbon black and the glass bead, and then by particulate-particulate interactions.[9]

Unit design considerations

One problem often encountered in process plant — refinery scale as well as pilot plant operations — is plugging of the trickle-bed reactor when converting certain types of feedstock. This plugging can lead to high pressure drops at the inlet of the bed or across the entire bed, depending, as previously discussed, on the plugging mechanism. What happens to the plant depends on how the pressure control system is configured. The pressure is typically controlled by a control valve in the bleed line of the high-pressure separator. The pressure-measuring device can be located upstream, for example, in the hydrogen line prior to combining with the liquid feed line, or downstream of the reactor, for example, in the bleed offline.

The impact of a reactor plugging event will depend on the pressure control system configuration. If the inlet pressure is controlled, an increase in pressure drop will result in a decrease in the reactor outlet pressure and part or most of the reactor will operate below the design pressure. This will have a significant effect on catalyst performance. If the outlet reactor pressure is controlled, the inlet reactor pressure will increase. The advantage with the latter design is that most of the catalyst bed will be at design pressure. However, it does permit operation at higher inlet pressures than were initially intended. Intertek PARC's hydrotreaters are configured to control the reactor inlet pressure.

In the case of a large pressure drop due to a drastic reduction in the available open cross-sectional area in the reactor, the pressure may increase rapidly; the pressures in the reactor and the feed system will quickly increase, potentially exceeding the maximum allowable operating pressure. The issue is whether the risk of overpressure will be accepted. Obviously, this risk is unacceptable and therefore a means of reducing this risk must be implemented. To protect the reactor from overpressure, a rupture disc is installed in the reactor inlet line after the hydrogen line. This disc will rupture when its set pressure is exceeded. Furthermore, the pump will have a rupture disc in a pump-around so that if rupture disc pressure is exceeded the pump will continue pumping without building up pressure. It is important to have a check valve in the line between the pump outlet and the hydrogen line. One reason is that when the pump rupture disc ruptures, the check valve prevents the unit from depressurising through the feed system. Special precautions must be made to ensure that the material used to make the check valve seal is compatible with the feedstock. This is the configuration used in Intertek PARC's pilot plants.

The various means of preventing bed plugging can all be considered IPLs, in that they prevent an undesired consequence

Douwes *et al*[4] mentioned that the possibility of plugging of the reactor has to be taken into account by judicious selection of the design pressure of the equipment and by protecting the upstream and downstream low-pressure systems. To protect the upstream system, special safeguarding equipment needs to be installed to prevent backflow of material.

Impact of reactor plugging

First, reactor plugging increases pressure drop and, depending on the pressure control system configuration, can lead to reduced performance, increased ageing of the catalyst and inability to meet product specifications. If the pressure in the low-pressure region is adjusted to meet the specified pressure, the impact on catalyst performance should not be significant. If the pressure in the low-pressure region is not adjusted to the specified pressure, catalyst performance will be reduced and product specifications may not be met.

In a 2005 report, McGovern *et al*[3] reviewed the performance of hydrotreating units and outlined possible solutions to mitigate their under-performance compared to pilot plant reactors. The major contributor to sub-par performance of commercial HDS units is liquid maldistribution, requiring higher start-of-run temperature and greater catalyst deactivation rates. Maldistribution occurs at two levels: macro- and micro-scale. Macro-scale maldistribution refers to the initial liquid distribution, while micro-scale maldistribution refers to the flow pattern over a distance of several particles. Two types of micro-scale flow have been recognised. In film flow, the ideal case, the liquid flows as a film over the catalyst surface down the catalyst bed. In rivulet flow, the liquid flow coagulates and forms rivulets of liquid that are several particles thick. Micro-scale maldistribution was stated to be present in all trickle-bed reactors, while macro-scale distribution was reduced by using high-efficiency liquid distributors, but could not be eliminated. Fines at the top of the bed impact liquid maldistribution, with increasing accumulation progressively increasing liquid and thus gas maldistribution.

Mitigation of reactor plugging

Bos[7] provided an extensive list of methods to reduce particulate formation, including:

- Storage of cracked feedstocks under a nitrogen blanket
- Limited storage time
- Corrosion control in upstream equipment
- Temperature control to avoid hot

spots in heaters, furnaces and heat exchangers.

However, if particulates cannot be eliminated at source, they must be dealt with. The following means can be identified:[7]

- A feed filter using either disposable filters, automatic backwash filters or automatic back-flush filters with filter micron ratings of >5 micron, 10–500 micron and 0.5–50 micron, respectively
- A staged catalyst bed with a guard layer and/or internals for trapping the particulates and providing storage capacity for the particulates
- A guard bed reactor located upstream of the reactor with a pretreatment catalyst for trapping the particulates, with bed being replaced as needed.

Examples of IPLs in mitigation of reactor bed plugging

The rupture disc at the inlet of the reactor is intended to prevent system overpressure and is an example of an independent protection layer. The probability of failure on demand of a rupture disc is 1 out of 100 (see Table 2). If previous experience has shown that the probability of overpressure is 1 out 100, then by installing the rupture disc the risk of tank overpressure is reduced by a factor of 10^{-2} to 1 out of 10 000.

The various means of preventing bed plugging can all be considered IPLs, in that they prevent an undesired consequence. Thus automatic backwash and backflush filters are active IPLs, while guard bed catalysts with a macroporous structure to trap very small particulates can be considered passive IPLs. Furthermore, installation of a guard bed that can be replaced further reduces the risk. Thus, if the probability of failure (for instance, rapid plugging of the top of the bed) during the lifecycle of the catalyst is 1 in 10, or 0.1, then for the sake of argument the probabilities of failure on demand for the filter and the replacement guard bed are 1 in 100, and the probability of failure can be reduced depending on the particulate size in the feedstock. In the event of retentive screening, either one of the IPLs would reduce the probability to $1*10^{-3}$ and both IPLs in series would reduce the probability to $1*10^{-5}$. Actual PFDs should be determined on an industry-wide basis and should include vendor input.

Pilot plant testing as independent protection layer

Prior to implementing new process technology, the refiner or plant operator must address each item in their risk assessment list and go through a procedure similar to that used in the reactor plugging case.

An independent protection layer often used in the refinery and chemical industries to reduce technical risk associated with implementing new process technology is independent pilot plant testing.[12,13] A pilot plant is a unit that simulates the operation of a refinery unit on a substantially reduced scale. Pilot plants can cover



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non-hydroprocessing refinery units, such as delayed cokers, deasphalters and visbreakers. Pilot plants can also simulate operations of fixed-bed reactors used in hydrotreating, hydrocracking, reforming and isomerisation. Independent testing means that confidential testing services are provided by the company whose only revenues are from the pilot plant services provided. Moreover, the company does not compete with its clients nor owns technology that it markets itself. Recall that the definition of an IPL is "...a device, system, or action that is capable of preventing a scenario from proceeding to its undesired consequence."[6]

The pilot plant is considered an IPL because it is a system that can prevent an undesired consequence from occurring, such as not meeting product specifications in commercial operations. As such, it must have a probability of failure on demand. It is only through open lines of communication between the pilot plant service provider and its clients that the PFD can be determined and used to improve the quality of the pilot plant testing services provided. The pilot plant is used to determine the performance of the catalyst using the actual feedstock. The catalyst to be used in the testing will be the same as the one used to load the commercial reactor and will be activated using the same procedure as that which will be employed commercially. The products generated in the pilot plant testing can be evaluated to determine if they meet product specifications. By doing pilot plant testing, feedstock and catalyst risks are substantially reduced. Risks associated with meeting product specifications are also substantially reduced. Furthermore, any operational issues will be identified and addressed.

The technical risks associated with feedstock complexity, catalyst complexity, trickle-bed performance and operational issues can be addressed using independent pilot plant catalyst testing. In each of these cases, if an existing trickle-bed reactor is used for new process implementation, the catalyst currently loaded in the commercial reactor must be part of the catalyst screening or feedstock evaluation to assess the hydrodynamics of the commercial reactor.

McGovern *et al*[3] pointed out that "...[t]he most reliable method to identify poor commercial HDS reactor performance is to simulate the commercial unit operations in a small-scale...[pilot plant]...unit. If the same feed and catalyst are used with the same start-up and operating conditions, then the primary difference between the two operations is the hydrodynamic or mass-transport characteristics of the two unit. If these tests are performed correctly, they can identify differences as small as 10°F... The key to the success of these tests is good lab unit operation with very small inerts."

By doing pilot plant testing, feedstock and catalyst risks are substantially reduced. Risks associated with meeting product specifications are also substantially reduced

Conclusions

Factors contributing to technical risks when implementing new process technologies in the refining industry include feedstock complexity, catalyst complexity, reactor hydrodynamics and operational issues. As suggested by the layer of protection analysis used in process plant safety, independent pilot plant testing services can serve as an independent protection layer to reduce these risks. Examples are shown in an actual case how layer of protection analysis can be applied to mitigate the risk of reactor bed plugging due to particulates. The motivation of this approach is to semi-quantify the risks that are associated when implementing new process technology so that they can be controlled. Decisions are made on objective quantified evidence so that risks can be minimised.

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Robert Absil is General Manager of Intertek PARC, Pittsburgh, Pennsylvania, USA. He has over 25 years of experience in the refining industry, focused on pilot plant testing, and holds a BS degree in chemical engineering from the Illinois Institute of Technology and MS and PhD degrees in chemical engineering from Northwestern University, Evanston, Illinois.
Email: robert.absil@intertek.com
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Improving crude unit operation

Most crude and vacuum units present an opportunity for improvement using modern process control systems

TIM OLSEN and GARY HAWKINS
Emerson Process Management

The reliability and operating flexibility of a refinery's crude unit has a material impact on the profitability of the entire refinery due to its importance to the overall process by distributing intermediate streams as feedstock to the downstream workhorse conversion units that create higher value products. Many refinery managers and operations personnel want the crude unit to just run and not cause any trouble. However, it can be a source of increased energy usage, reduced productivity, lower intermediate product quality, high maintenance costs and increased safety risks. This is because crude units are often among the most neglected parts of any refinery, with all the infrastructure issues of ageing facilities. Today, nearly every crude unit faces major operating challenges of energy inefficiency, poor unit utilisation and asset unreliability, as well as safety, health and environmental issues.

Unexpected pump failures, accelerated coking on fired heater tubes, overhead column vapour not condensing and unreliable measurement of high-viscosity fluids are among the everyday occurrences. Energy issues are often related to heat exchanger tube fouling and poor heat transfer efficiency, an inability to optimise fired heaters and inadequate temperature measurements needed to optimise crude unit operation.

But improvement is possible. In the words of one official of a large US refinery: "Selective application of advanced technology can help a crude unit overcome built-in deficiencies and actually improve its performance to the point of becoming an industry top tier benchmark."

Besides their improvements in accuracy and long-term stability, modern microprocessor-based field instruments provide lots more information on their status and condition than the simple process measurements of older instrumentation. These technologies enable more efficient operations, decreasing costs and increasing profit levels.

Effective crude unit operations depend on achieving excellence in the areas of energy efficiency, day-to-day reliability, asset utilisation and safety

Emerson calls this the Smart Refinery — a place where personnel are better informed about process performance, faulty field assets and the root causes of existing or imminent problems. In the Smart Refinery, console operators receive information relating to critical control applications, maintenance technicians are made aware of impending maintenance needs, and the safety engineer is notified of safety instrumented system (SIS) issues.

Effective crude unit operations depend on achieving excellence in the areas of energy efficiency, day-to-day reliability, asset utilisation and safety. Each of these can be improved by implementing modern technologies that are often lacking in older units.

Modernisation

The crude unit can be eliminated as a sore spot for the refinery and made a star performer by modernising control systems and adopting digital field architecture. Investments in technology enable efficiency, reducing the impact of crude unit disruptions on the downstream refinery operations. Existing facilities can start small and gain experience through upgrade programmes at a measured pace, with benefits from early installations paying for the later stages.

Replace older legacy control systems

Modern automation technology is faster, more powerful and with features that enable information management beyond the simple process variable, setpoint and output. Embedded advanced process control (APC) tools are easy to use and maintain, require no additional hardware or software, and can shorten implementation schedules dramatically.

Digital automation architecture gives refiners the ability to safely operate closer to process and equipment constraints without violating them, while monitoring the condition of many assets in real-time. Information from this smart technology helps personnel address the long-standing uncertainty as to whether observed problems are the result of instrument degradation or, indeed, are process problems.

For refineries with frequent crude oil switching, disturbances in crude unit operations often propagate into bigger issues downstream. It only makes sense to diminish such disturbances at their source to achieve effective and reliable operations throughout the refinery.

Managing the change from one incoming crude to another requires a regulatory control layer with the dynamic performance necessary to respond quickly and precisely to setpoint changes. Yet, the importance of the regulatory control layer is often overlooked in older systems. For example, energy consumption and material balance must be re-established following a switch to bring the intermediate products within specifications. Advanced process controls shift the burden of managing crude switching from the operator to a fractionator optimisation package that minimises the chance for human error, hastens the transition time and mitigates crude unit disruption during switching.

It is also important to effectively use the levels in crude unit process vessels as a disturbance buffer. This may require a shift in thinking for operators to allow intermediate levels to fluctuate from 25–75% full and not try to maintain a given setpoint such as 50%. If disturbances are absorbed in the crude unit, the intermediate feedstocks can be processed more effectively in downstream units.

Install digital instrumentation

Digital instrumentation improves asset reliability and utilisation of crude unit production equipment. Smart field devices produce a great deal of useful information that is easily accessed and stored by advanced asset management software. With the availability of near real-time information on the condition of measurement instruments, final control elements and other assets, refiners can predict when these assets will require attention and fix them before the process is adversely affected. In addition, unnecessary maintenance is avoided on those assets that do not need immediate work. This predictive maintenance strategy keeps the unit operating and minimises spurious process tripping. As a result, unscheduled slowdowns and shutdowns are reduced or eliminated, and the unit operates reliably within safe limits, thereby improving profitability.

Not all changes require large capital investments to deliver fast and lasting returns. For example, adding missing measurement points to aid optimisation, adding smart, microprocessor-based instruments for asset health information and advanced process control can be implemented on key operating parameters at minimal expense to produce a significant ROI in a short time.

Benefits of technology

Without question, the application of advanced technologies can improve the performance of most crude units in today's refineries with respect to energy efficiency, reliability, utilisation and safety.

Smart field devices produce a great deal of useful information that is easily accessed and stored by advanced asset management software

Energy efficiency

Significant energy savings can be achieved by reducing the amount of excess combustion air to the crude and vacuum heaters. The challenge is to minimise excess combustion air while maintaining a sufficient air supply for full, safe combustion. If combustion air is not sufficient, after-burning can take place in the upper parts of the heater, resulting in higher temperatures than designed for that section. This can damage the heater tubes, tube supports and firebox structure. In extreme cases, the fuel mixture in the firebox can become explosive.

Measurements of oxygen and carbon monoxide/combustibles from the flue gas composition analysers located in the radiant section of the heater firebox indicate when there is enough combustion air for safe operations. Smart analysers with health-monitoring capabilities support console operator confidence in the accuracy of flue gas measurements. As a result, fuel-to-air ratios can be optimised safely by trimming costly excess combustion air to the heater.

Advanced process controls can be employed to optimise the heater operation for maximum energy efficiency. Modern digital process control systems with embedded APC functionality allow for faster implementation, easier maintenance and greater uptime than traditional methods of implementing APC.

Optimum energy efficiency typically requires more measurements than provided for in the design of most crude units. For example, temperature measurements around each heat exchanger bundle are often acquired manually only when preparing for an upcoming turnaround to determine which exchangers need to be cleaned. Today's wireless technology makes it easy and cost effective to add measurement points to obtain the missing measurements needed to monitor heat exchanger performance.

Another important area for consideration is the transfer of heat from hot downstream products to preheat incoming crude, because heat exchanger tube fouling negatively impacts the effectiveness of the heat transfer. A 10% decrease in heat transfer efficiency in the preheat exchanger train will require a commensurate increase of energy for the crude heater. Further reductions in crude preheat exchanger performance will cause the crude heater to reach its firing limit, making it necessary to reduce the throughput of crude oil.

Reliability

The asset failures that cause many process slowdowns or total shutdowns can be greatly reduced through the use of the diagnostics

produced by smart field instrumentation and digital valve controllers. This data is easily accessed by advanced asset management software and presented for use by refinery personnel. When one of the monitored devices begins operating outside its normal parameters, an alarm is raised, indicating that point needs to be evaluated. In addition, detailed information on every asset on the control network is maintained in a database for use in various routine maintenance tasks, including loop checkout, configuration, calibration, troubleshooting and accurate documentation of maintenance performed.

Most non-critical rotating machinery is monitored periodically by technicians using vibration data analysers along pre-established routes to develop a view of the operating condition of motors, pumps, fans, compressors, turbines and the like. Those assets that are most likely to fail can be identified by changes in vibration levels due to poor shaft alignment, worn bearings, loose or broken foundation mounts, a cracked impeller or cavitation. Critical machinery can be monitored continuously online using permanently installed sensors. For essential assets not currently wired, wireless vibration transmitters are available to greatly reduce the cost barriers to continuous monitoring. Even second- and third-tier rotating assets can be continuously monitored, enabling maintenance personnel to identify and act on developing problems.

These advanced monitoring and analysis technologies are capable of raising alarms if field assets develop symptoms of failure, so corrective action can be taken to prevent a shutdown and potential safety or environmental incidents. It is also possible to determine which repairs can be delayed until a scheduled maintenance period or other appropriate time. This is the essence of cost-effective predictive maintenance — an important factor for increased equipment reliability and greater unit utilisation.

Utilisation

Smart digital technology not only provides accurate measurements of process conditions such as vibration, temperature, flow, pressure and desalter interface levels, it also gives refinery personnel insight into the health of the field assets. Root cause information enables people to be well prepared before they ever go into the field. Maintenance based on field-generated information is the least costly type of maintenance and contributes substantially to maximum utilisation of refinery assets.

The SmartProcess fractionator optimisation package, for instance, can be applied to improve crude unit yields and flexibility, especially with smart field devices capable of responding rapidly to setpoint changes. Such devices also aid in detecting the onset of fractionator flooding so that operators can take appropriate actions in a timely manner. These solutions serve to improve crude and vacuum unit utilisation, and reduce excess energy consumption.

Safety

Safer operating conditions can be achieved through modern automation functions and features, including operator training simulation, smart instrument health monitoring and smart safety logic solvers with automated partial stroke testing of safety shutdown valves. Training simulations provide console operators with realistic scenarios to practise infrequent events such as startup, shutdown or sudden emergencies. With deeper knowledge and more familiarity with standard operating procedures, operators are able to react immediately, properly and confidently when required by an infrequent but rapidly evolving situation.

The diagnostic capabilities of smart instruments can also improve both the availability and reliability of safety instrumented systems (SIS). These diagnostics give refinery managers confidence that the SIS function is performing properly. They also help avoid unnecessary shutdowns by indicating when maintenance is required (as described above).

Partial stroke testing of safety shutdown valves verifies the capability of valves to move upon demand while minimising operating disturbances to operations. However, verification of movement does not guarantee a safety shutdown valve will stroke fully when required. Safety shutdown valves that may not actually move for years could have a build-up of precipitated salts, scale or corrosion on the valve stem, preventing full travel when needed. Documented comprehensive partial stroke testing provides both verification of movement and how much the valve is capable of travelling — a valuable tool for safety instrumented system life cycle management.

Conclusions

Nearly all crude and vacuum units present an opportunity for improvement. Modern process control systems with embedded APC functionality continuously monitor loop performance, identify issues and proactively address loop-tuning issues. Digital instrumentation generates a vast amount of information that can be used to drive automatic alerts, predictive maintenance, diagnostic data archives and environmental reports. This diagnostic technology greatly reduces the amount of time required for tasks such as configuration, loop checkout and commissioning, instrument calibration and troubleshooting compared to analog instrumentation connected to conventional control systems.

Tim Olsen is a Refining Consultant within the PlantWeb global refining industry group of Emerson Process Management where he supports Emerson's technical and business strategy. He is a Vice Chair of the AIChE National Fuels & Petrochemicals Division (FPD), has a BS in chemical engineering from Iowa State University, with emphasis in industrial engineering and process control, and an MBA from the University of Iowa.

Email: Tim.Olsen@Emerson.com

Gary Hawkins has been a Global Refining Business Consultant for Emerson Process Management since 2007. Prior to joining Emerson, he worked for UOP for nearly 31 years developing the UOP Standard Specifications for process control and managing the instrumentation and controls group in UOP's engineering department. Gary holds a BS in chemical engineering from the University of Illinois, Urbana-Champaign.

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Energy modelling at Gdansk refinery

Energy management systems at Grupa Lotos's Gdansk refinery in Poland have been integrated into a single model developed with Soteica. The model is available plant-wide and has widened the understanding of the impact of process variables on energy performance.

Grupa Lotos is a vertically integrated oil company engaged in crude oil production and refining, as well as the distribution of oil products. Gdansk refinery's throughput capacity is 6 million t/y of crude oil. An expansion is currently under way to achieve a throughput capacity of 10.5 million tonnes of crude oil annually. Its energy system is based on several steam pressure levels, with a set of fired boilers producing high-pressure steam, a set of steam turbo generators producing electricity and a set of process heaters that can run with fuel gas and fuel oil.

Different economic trade-offs provide many challenges to operate the site-wide energy system at minimum cost. For instance, the trade-offs among electrical power, steam and fuels networks. In addition, ash, NO_x and SO_2 emissions limits must be taken into account.

The project has enabled an understanding of all the decision variables and the associated constraints, which sometimes are hidden or ignored

A detailed model of the steam, fuels, electricity, boiler feed water and condensates systems has been built, including all of the interactions among these systems, real plant constraints and the degrees of freedom of their operation. Such a model is scheduled to perform automatic executions of the optimisation of the entire system and is continually populated with validated live data from the process. A calculation of equipment efficiencies is done as part of the performance monitoring activity of the model. Other monitoring aspects include the continuous audit of the energy system so that the data can be relied upon for evaluating the value of energy production and usage, and waste can be eliminated.

Recommendations given by the model are taken into account by operations on a daily basis. The same model used for online, real-time optimisation is also used in standalone mode, populated with either current or historical data, to perform case studies for planning or to evaluate alternatives for better operation of the energy system.

As a result of the project, the information of the refinery energy system has been organised into one model and a single environment to which everyone has access. Furthermore, the project has enabled an understanding of all the decision variables and the associated constraints, which sometimes are hidden or ignored. Additionally, centralisation of the responsibilities for the energy system's optimal operation has been achieved.

Multi-unit coordination supports diesel programme

Implementation of a multi-unit coordination tool at the Chevron Pembroke refinery in south Wales has supported a successful programme for the improvement of diesel production by enabling operators to be more responsive to changes in operating conditions.

The Pembroke refinery blends middle distillates directly from the process unit to hydrotreaters. The day-to-day operation of the two downstream hydrotreating units is challenging as the throughput has to be maximised subject to a variety of process constraints and the availability of the various feed components, which include kerosene, several straight-run gas oil streams and FCCU product streams such as HHCN and LCGO. The decision-making process for these blends involves several refinery areas and console operators in different control rooms across the site.

Hence, as part of the improvement programme, a new large-scale multi-unit coordination tool was implemented. The GDOT software supplied by Apex Optimisation is used within Chevron Pembroke for medium-term optimisation problems. This system, which is basically an on-line refinery linear programming model, is running in closed loop and has been in service at Pembroke with essentially 100% utilisation even during significant changes in crude slates.

There are essentially 18 variables available to control the production rates and the qualities of the three middle distillate products of the refinery: kerosene, diesel and gas oil. One of the important challenges is to train the CDU, cracking and VDU operators so that they are more aware of the operating objectives and constraints of downstream units when making moves on their units. In large and complex refineries, operators traditionally control to the targets that have been specified for their particular unit and are not necessarily aware of operational constraints on downstream units and any opportunities to minimise giveaway on

the product rundown lines. The training required for the console operators is mainly related to an understanding of the concept of on-line coordination of multiple process units, intermediate product flow rates and quality targets. The GDOT tool can significantly improve this decision-making process, making sure that the upstream units are optimised in a coordinated manner, keeping all units within acceptable operating ranges. This enables the operators to work better together and achieve an improved overall performance.

Chevron has selected the GDOT tool for coordination of production areas such as the diesel system. It is important to note that the system does not require any specialised staff and is maintained by the same process control engineers who are responsible for the multi-variable predictive control (MPC) applications.

GDOT provides an on-line console interface for engineers and operators. For this project, however, it was decided to let the console operators use the interface of the 12 MPC controllers (based on DMC-plus) instead. It was also configured to track the status and the limits of the MPC variables. By using the existing interface, operators did not need to be retrained, resulting in a smoother transition and faster operator acceptance. However, the user interfaces of the individual MPC controllers could obviously not give the complete picture of the current optimised solution for the entire diesel production system. Hence, customised database displays have been made available to operations and production planning staff.

Process data and models available from the existing MPC systems were sufficient to develop most of the models required for GDOT

Process data and models available from the existing MPC systems were sufficient to develop most of the models required for GDOT. This meant that the project was able to proceed with minimum impact on the refinery operation. The preparatory site work included the installation and configuration of a server on the process control network.

The diesel production improvement project has been a great success, with overall benefits valued at $10 million, including a large increase in diesel production. The main benefit of the GDOT system is that it enables operation instructions and strategies to be consistently implemented, minute by minute, driving the units towards more profitable operation and improving the competitive position of the refinery. The system deals with daily operational issues. The modelling approach, using dynamic, non-linear models, is capable of adapting to all expected and unexpected operating scenarios and has proven to be very robust.

The ULSD improvements project did not require any major unit upgrades or revamps and took nine months from start to finish. Payback was achieved in a few weeks. Another conclusion from this project, according to Chevron, is that multi-unit coordination systems should be considered as one of the next logical steps for a refinery to improve operation further with an existing configuration.

Keeping emissions balance at deeper partial burn

By installing a lance-based technology that injects heated oxygen into the flue gas duct between the regenerator and the CO boiler or heat recovery boiler, a refinery was able to keep its NO_x emissions levels at their current level when operating its FCC unit deeper in partial burn for enhanced production of motor fuels.

The refinery had been struggling to control NO_x from the FCC regenerator and was taking a significant penalty to keep emissions below permitted limits. However, an increase in flue gas CO of 0.75% would increase the yield of motor fuel products by about 0.5%. The yield improvement is based on operating at a higher catalyst-to-oil ratio at a constant reactor temperature allowed by the lower regenerator temperature. However, the higher CO levels also bring higher levels of NO_x precursors and ultimately higher stack NO_x emissions. Applying Praxair's $CONO_x$ technology would enable them to go deeper into partial burn to achieve the yield benefit without exceeding the NO_x limits.

FCC regenerator flue gas is one of the larger CO and NO_x emission sources in the refinery and will continue to be regulated heavily in attempts to minimise the refinery's environmental impact. The reported low capital cost of implementing $CONO_x$ means that the technology can be used in conjunction with other emissions control devices to achieve larger reductions in emissions.

The technology is based on a specialised lance that injects heated oxygen into the flue gas duct between the regenerator and the CO boiler or heat recovery boiler. It delivers a high-velocity jet of heated oxygen that rapidly mixes with process gases. The lance also creates high concentrations of free radicals, enabling rapid reactions at lower bulk temperatures. Due to the jet-mixing characteristics and the free radicals achieved, the technology is said to be more effective at initiating low-temperature reactions than a standard oxygen jet.

In partial-burn regenerators, the lance is operated such that the flue gas remains deficient in oxygen after all oxygen from the lance is consumed, resulting in significant reductions in NO_x precursors; namely, ammonia and hydrocyanic acid.

By reducing the availability of NO_x precursors in the duct prior to conversion to NO_x in the CO boiler, stack NO_x can be reduced considerably. Consequently, the technology can be used to debottleneck operations due to CO boiler or NO_x limits.

SGS, Praxair form NO_x-cutting partnership

Shell Global Solutions and Praxair are introducing technology designed to reduce nitrogen oxide (NO_x) emissions from fluid catalytic cracking (FCC) units in refineries. According to the partners, the technology helps refiners address increasingly stringent regulatory requirements while providing operational flexibility and lowering capital and operating costs.

The technology, called $CONO_x$, is a high-velocity, highly reactive oxygen jet with mixing capabilities that enable rapid reactions of carbon monoxide and NO_x precursors at typical flue gas temperatures. A reduction in NO_x emissions of up to 60% can be achieved in both full- and partial-burn regenerators, say the developers. With a low cost of implementation, the $CONO_x$ system can be combined with other control technologies to achieve even larger reductions in NO_x emissions.

The $CONO_x$ system creates a high-temperature, reactive, oxygen-rich stream that can be integrated into existing flue gas duct work with minimal modifications. Shell Global Solutions will be involved in marketing $CONO_x$ and will also work with Praxair to update and improve the technology. Praxair will carry out process design engineering in concert, provide the $CONO_x$ lance and gas flow control equipment, and participate in safety reviews, start-up and optimisation.

Emerson takes petrochems control contract

Petrobras has selected Emerson Process Management to provide process automation technologies and services for the Petrochemical Complex of Rio de Janeiro (Comperj) in Brazil. As main automation contractor for Comperj, Emerson will deliver engineering services and technologies for process automation and systems integration of the refining unit, selected utilities and offsite operations.

The Comperj complex will be able to process 165 000 barrels of heavy crude per day when its first refining unit begins operations in 2013, and the same amount in a second unit expected five years later. This investment in Brazil's refining capacity will help support the country's expanding oil production. The project is also expected to generate more than 200 000 direct and indirect jobs during construction.

The Comperj project is one of the first in Brazil to use a main automation contractor, which aims to improve coordination of projects involving multiple suppliers and contractors. Emerson will provide a broad scope of automation products and services. In addition to systems for process control, safety, fire and gas detection, machinery monitoring, and management of process and maintenance information, the company will supply measurement instruments, control valves, pressure regulators, and other related products and services.

With a low cost of implementation, The $CONO_x$ system can be combined with other control technologies to achieve even larger reductions in NO_x emissions

Engineering work has already begun, with hardware delivery to start in 2011. Automation tasks will be led by a team in Rio de Janeiro and São Paulo. In late 2009, Emerson announced a $35 million expansion of its Sorocaba manufacturing and operations site.

Rosneft's Far Eastern refining giant

Rosneft, Russia's largest oil producer, plans to complete a refining complex at the end of a pipeline across eastern Siberia to the Pacific coast by 2016. Rosneft may look for a partner for the plant, at Nakhodka in the country's Far East. The facility will be able to process 20 million tonnes of crude a year, or 400 000 b/d, and may cost $14 billion.

Albemarle, Petrobras sign catalyst plant deal

Albemarle Corporation and Petrobras have signed a memorandum of understanding to build a world-scale hydroprocessing catalyst production plant on the site of their existing joint venture, Fabrica Carioca de Catalisadores, in Santa Cruz, Brazil. The new facility will complement existing production of fluid catalytic cracking (FCC) catalysts.

The plant will be constructed ahead of significant demand growth for hydroprocessing catalysts, as Brazil begins to implement more stringent specifications for ultra-low sulphur diesel and as Petrobras begins to introduce new hydrotreaters to existing and new refineries over the coming years.

Albemarle will provide Fabrica Carioca de Catalisadores with its technology for the manufacture of hydroprocessing catalysts, enabling the production of Stars products, which serve the market for production of low-sulphur fuels in North America, Western Europe and Japan. The plant will supply equivalent markets in South America.

Petrobras and Albemarle are also taking part in a joint technical cooperation aimed at the further development of hydroprocessing catalysts. Petrobras says that by 2016 its requirement for catalyst is expected to be five times higher than its current consumption. This development is particularly important to guarantee market-

competitive sourcing over the long term.

CNOOC invests for LNG and petrochems production

China National Offshore Oil Corp. (CNOOC) has begun construction of a new petrochemical refinery in southern China's island province of Hainan. The industrial park in Dongfang City is scheduled to begin production of LPG and chemicals using petroleum from the South China Sea by December 2012.

Spending in phase one of the project will total $650 million. The company plans to spend a comparable amount for phase two of the project, which will produce vinyl products by April 2013.

China's largest oil and gas producer, CNOOC's production reached 48 million tonnes of oil equivalent, and its refinery and chemical output was 32 million tonnes.

Technip's revamp award for North Africa

Technip has won a contract worth $908 million to revamp and expand an Algerian refinery. The refurbishment of existing installations owned by Sonatrach, Algeria's national oil company, will raise refining capacity to 3.6 million tonnes annually from a current 2.7 million tonnes, according to Technip.

The new units will enable the refinery to produce gasoline to specifications similar to those needed for Europe.

In addition to the Algeria tender, Technip says that it is also studying tenders in Brazil for new vessels, in the Middle East for "selective" onshore projects, especially Saudi Arabia, and in China.

The company also won an order from Total to raise capacity at the Normandy refinery in Gonfreville, France. The project, which will enable the facility to make more diesel and kerosene, will cost $132 million.

CNPC ramps up gasoline production

China National Petroleum Corporation has started up its 10 million tonnes refinery in Jilin province.

Investment in the refinery totalled CNY 2.55 billion. The refinery will increase the annual crude oil processing capacity of CNPC Jilin subsidiary from 7.5 million tonnes to 10 million tonnes. It is expected to contribute sales revenue of CNY 7.7 billion per year.

CNPC Jilin subsidiary will increase production of chemical materials by 860 000 tonnes annually and increase the proportion of high-standard gasoline production to 70% of its total production from the current 50%.

HPCL opts for small footprint

India's state-owned Hindustan Petroleum Corp. Ltd (HPCL) plans to invest $6.7 billion to set up an 18 million t/y refinery in the state of Maharashtra. The new refinery was intended to make up for space constraints at HPCL's existing Mumbai refinery. The 6.5 million t/y Mumbai refinery is situated in a plot measuring just 350 acres compared with a standard requirement of over 2000 acres of land for a refinery of this size. Currently, 1800 acres of land is available with Maharashtra Industrial Development, and the company has asked for an additional 1000 acres between Ratnagiri and Raigad.

Engineers India has been appointed to carry out a feasibility report on the proposed refinery. The options are for a single unit of 18 million t/y or two units of 9 million t/y capacity each.

NYC grows algae to save wetlands

New York's Department of Environmental Protection (DEP) is building a pilot project at its Rockaway Waste water treatment plant that includes conversion of algae into biofuels. Wastewater from the plant currently produces excess nitrogen, which is eventually discharged into Jamaica Bay near the city.

Although nitrates have been damaging local saltwater marshlands, the pilot scheme would use the same waste water to grow algae that would be converted to biofuels.

The plant will have two 100-metre metal troughs and will mimic an ecosystem through varying flow currents and using sunlight to promote algae growth, according to the DEP. Nearly 40 gallons of waste water will be poured a minute into the machine to grow the algae.

The algae, grown in 10- to 14-day intervals, will then be removed and shipped to a chemical plant at the University of Arkansas, where it will be converted into biofuels.

Jamaica Bay has been losing large amounts of its wetlands over the last 70 years due to excess nitrogen releases and the city has pledged hundreds of millions of dollars over the next decade to stop the decay. Future upgrades to the waste water treatment plants located around the bay will ensure less discharge.

Coking project in La Plata

Foster Wheeler's Global Engineering and Construction Group has been awarded a contract by YPF for a new delayed coking unit to be built at YPF's Complejo Industrial La Plata in Argentina. Foster Wheeler's scope of work includes detailed engineering, procurement services and support to construction and plant start-up.

The unit will use Selective Yield Delayed Coking (Sydec) technology. The new facility will have a capacity of 28 000 b/d and will produce anode coke to be used in the aluminum industry. Foster Wheeler has been working with YPF since 2008 to develop coking technology for the Complejo Industrial La Plata.

Foster Wheeler's Sydec process is a thermal conversion process used by refiners to upgrade heavy residue feed and process it into transportation fuels and coke products for fuel and metallurgical markets. The process can be designed to maximise clean liquid yields while minimising fuel coke yields, or to minimise heavy gas oil yields or produce specific grades of coke for industrial use.

Neste merges business areas

Neste Oil has reorganised its operations now that its renewable fuels business is entering an advanced phase following two major investment projects. The Oil Products and

Renewable Fuels business areas have been merged to create Oil Products and Renewables. Matti Lehmus, currently Executive Vice President, Oil Products, has been appointed Executive Vice President, Oil Products and Renewables. The change took effect in late December 2010. Neste Oil's financial reporting will remain unchanged, however. Oil Products and Renewable Fuels will continue to form separate reporting segments.

According to Neste, the reorganisation will bring greater operational efficiency and clear benefits. By integrating the businesses, the company wants enhanced cost efficiency.

Neste Oil recently commissioned the world's largest renewable diesel plant in Singapore and is moving towards completion of a similar-sized plant in Rotterdam, due to come on stream at the end of the first half of 2011. The first plant based on the company's NExBTL biofuels process was built at Neste Oil's Porvoo refining site. Completion of these investments means that renewable fuels-related activities will shift into a normal business model.

Socar's refiners make two into one

State Oil Company of Azerbaijan (Socar) plans to build a refinery in Baku by 2020, replacing the company's two existing plants. The company plans to build a plant with an annual capacity of 10 million tonnes.

The new refinery, to be built in the city's Karadakh area, will produce only Euro-5 standard fuels, the strictest category of European fuels. The Novo-Bakinskiy plant, formerly known as Azneftyanajag, will close once the new plant is completed. Batinskiy, the second plant formerly known as Azeneftyag, will also shut down around the same time. The Novo-Bakinskiy plant has 212 000 b/d processing capacity, while Batinskiy can refine 230 000 b/d.

Sunoco 2 PBF 3

Sunoco aims to sell its oil refinery in Toledo, Ohio, to PBF Holding for about $400 million. The deal is subject to regulatory approval and was expected to close in Q1 2011.

PBF is owned by the private equity firms The Blackstone Group and First Reserve Corporation. The property is the third refinery PBF acquired in 2010, for a total production capacity of about 530 000 b/d. The Toledo plant can produce about 170 000 b/d.

The new operating company, called Toledo Refining, will pay $200 million cash and a $200 million two-year note for the property. An additional payment of up to $125 million based on the future profitability of the plant is also part of the deal.

Toledo Refining will purchase the crude oil and refined product inventory at the refinery at the time of the closing at market prices. Sunoco expects pre-tax cash proceeds from the sale of those products of about $200 million. The sale will leave Philadelphia-based Sunoco with two refineries.

UOP processes for max diesel in Brazil

Petrobras has selected UOP to provide all of the process technologies for two new maximum diesel refineries to be built in Brazil. UOP's hydrocracking and hydrotreating technologies will be used to produce diesel fuel from Brazilian national crude oils at two new refineries. Petrobras plans to construct a two-train 600 000 b/d facility in Maranhao, Brazil, to be known as Premium I, and a single-train 300 000 b/d facility in Ceara, Brazil, to be known as Premium II.

Basic engineering for the refineries is currently under way. Commissioning of the first train at the Premium I site is planned in 2014, and of the Premium II facility in 2017.

According to OPEC, global demand for diesel fuels is expected to grow from 24.5 million bpd to 34.2 million bpd by 2030, driven by an increasing share of diesel cars in developing regions around the world. Diesel production is projected to account for 60% of the rise in oil demand expected over the next 20 years.

Both refineries will employ UOP's Unicracking hydrocracking process and the Unionfining hydrotreating process to upgrade feedstocks to ultra-low sulphur diesel. Selective Yield Delayed Coking technology provided by Foster Wheeler USA will also be employed to maximise diesel production by converting the residue portion of the crude oil to an intermediate product used in diesel production. UOP will also serve as the front-end engineering design (FEED) contractor to provide a basis for procurement and construction at the site. Design of the crude and vacuum systems in the refineries will be provided by Process Consulting Services through a partnership with UOP.

3D training for refinery workers

Invensys Operations Management and Eni Refining and Marketing have launched a 3D simulation training service for refiners. The service features training kiosks fitted with Invensys's SimSci-Esscor Eyesim software and employing Eni's refining expertise. Field operators are trained on generic and specific process tasks in the kiosks so that safety and productivity can be improved. A pilot project will be installed at Eni's Gela refinery on the Southern coast of Sicily. The kiosks will then be deployed at other Eni sites.

The kiosks integrate SimSci-Esscor simulation software with games console controllers. Using 3D navigation techniques, trainees and plant personnel can learn process operations and procedures from an interactive tutorial. They can also score their performance.

The development aims to reduce risk in refineries. According to the two companies, Eyesim is the first industrial virtual reality training system. Engineers and operators are able to see and safely interact with the plant and the processes they control. It is based on first-principle simulation and augmented reality.

Eyesim uses and applies gaming and other skill sets. Employees who are new to engineering and plant, working alongside experienced engineers, are expected to use the system.

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