



Troubleshooting Hydrotreater Performance: Part II

A comprehensive review of operating parameters and performance issues affecting ULSD hydrotreater

David Krenzke, Advanced Refining Technologies

In Part I of Troubleshooting Hydrotreater Performance (see *Refinery Operations* Vol. II, No. 9), the following factors affecting unit performance were examined:

- Impact of feed contaminants on catalyst performance
- SOR activity evaluation
- Key operating parameters
- Loading and sulfiding guidelines
- Temperature response
- Mercaptan recombination.

Part II examines the effects of H₂ availability, liquid maldistribution, radial temperature spreads, feedrate response, flow rate tests and feed contaminant effects on hydrotreater performance as summarized from the Spring 2011 ART Webinar on “Troubleshooting Hydrotreater Performance.”

H₂ Availability

In a case study where H₂ availability was an issue, the unit’s start-of-run (SOR) WABT was 10-15 °F higher than expected. There were also concerns destined to cause problems that should have been addressed at SOR. For example, the refiner instead selected catalyst sock-loading instead of recommended dense-loading. ART and most other catalyst suppliers don’t recommend this technique due to the relatively poor control of the amount of sulfur converted to H₂S. To compensate, the unit may need to be run at a somewhat higher temperature to convert the required amount of sulfur to H₂S. So, in most cases some amount of catalyst activity is lost by feed only sulfiding. Light coker gas oil (LCGO) processing was also begun

immediately upon startup. As previously mentioned in Part I of this article, this will cause premature and excessive coking on the freshly sulfided catalyst.

All of these factors (i.e., sock loading, feed-only sulfiding & LCGO processing) will cause a lower SOR activity. The temperature response was also lower than indicated and the calculated apparent activation energy was only about 15 kcal/mole, which should typically be greater than 25 kcal/mole. An extremely high deactivation rate was also observed when producing less than 0.04 wt% (i.e., less than 400 ppm) sulfur.

Figure 1 (on page 2) shows plots the required temperature vs. days on stream to produce less than 400 ppm sulfur. The graph shows the loss of a huge amount of activity between 65 and 78 days on stream. **Figure 2** (on page 2) shows a similar plot except over a much wider period of time. The actual deactivation rate led to the observation that the H₂/Oil ratio was much lower than expected. The expected 1000 scfb H₂ consumption noted in the Intent to Bid (ITB) document was actually only about 500 scfb.

The hydrotreating “rule of thumb” (ROT) is that the H₂/Oil ratio should be about 3-4 times greater than H₂ consumption when producing low sulfur diesel. This ratio should be even higher for ULSD at about 5-6 times greater than H₂ consumption. The very high deactivation rate and poor temperature response between days 65-78 meant that hydrogen circulation needed to be improved (i.e., only 2.2 H₂/Oil-to-H₂ consumption ratio). Activity was regained and processing performance was improved at 4.3 H₂/Oil-to-H₂ consumption ratio. There was

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nonetheless still a debit for SOR activity due to previously noted issues with sock loading and processing cracked stocks very early in the cycle.

Feedrate response should then be investigated if and when temperature response meets expectations (Figure 3 on page 3), including bed channeling, feed maldistribution and bypassing.

Liquid Maldistribution

Non-uniform liquid/gas flow (i.e., maldistribution) leads to poor catalyst utilization, resulting in lower than expected activity and cycle length. Beginning at the very top of the reactor, the oil and gas is not uniformly distributed over the catalyst bed, effectively increasing space velocity. Potential causes include:

- Lack of liquid distribution tray, which is not very common (except for [perhaps] naphtha units)
- Poor distribution tray operation, such as with a tray incorrectly installed (not level), not properly cleaned or in poor condition, as there are places for oil and gas to leak around the tray. In some cases, an older styled tray does not provide efficient oil and gas distribution and the refiner should consider replacing with modern trays that provide very high levels of catalyst utilization
- Poor catalyst loading demonstrated by variable loading densities or non-uniform void space in reactor beds, along with these beds not being level, can lead to poor distribution in the catalyst beds. For example, variations in loaded density lead to non-uniform void fractions and the oil and gas will chose the pass of least resistance --- seeking the lowest density, highest void fraction sections of the bed to flow through, meaning that section will experience a much higher severity operation whereas other more densely packed sections will experience very little oil and gas mass transfer. A similar scenario is repeated if the catalyst bed is not level

where oil and gas mass transfer will occur through the shallow section of the uneven catalyst bed due to lower pressure drop as opposed to the high side of the uneven catalyst bed

- Low flow rates (<0.5 psi/ft ROT) indicates there are potential problems with flow distribution (i.e., channeling)
- Low liquid mass flux (minimum = 2000 lbs/ft²-hr [2.7 kg/m²-sec]) leads to ineffective catalyst utilization due to operating well below the turn-down ratio of the reactor design
- Uneven coking usually resulting from poor distribution where there are “pockets” of low amounts of catalysts and high levels of oil and gas moving through and generating more heat that leads to coke build up. The flow pattern is then further disturbed due to this build up of “coke balls” in the interstitial spaces between the catalyst particles where the gas and oil flow around this disturbance
- Objects left in catalyst beds during loading that went un-noticed, providing another mechanism for poor flow distribution.

Signs of non-uniform flow (maldistribution) include hot spots, uneven radial

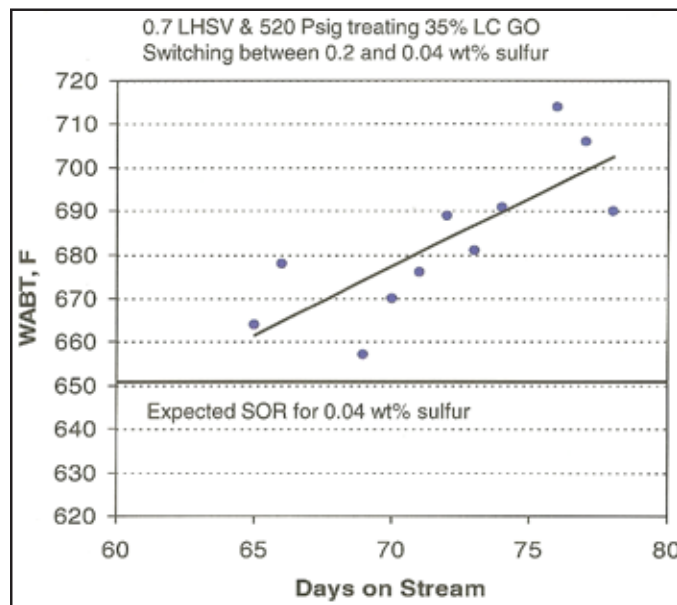


Figure 1. H₂ Availability: Activity Loss Over 65-78 Days on Stream

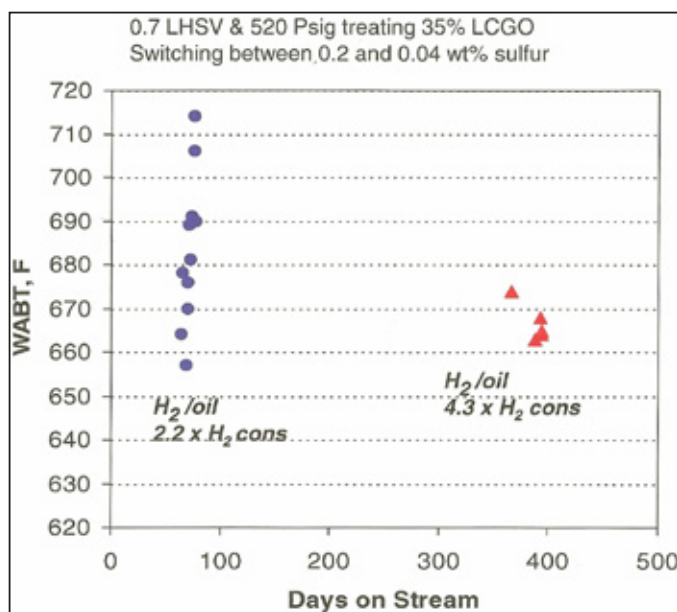


Figure 2. H₂ Availability: Actual Deactivation Rate Over 65-400 Days on Stream

temperature spreads (> 10°F or 5°C) and poor catalyst activity, especially with older hydrotreaters. Sufficient thermocouple coverage than can be utilized to detect hot spots don't exist in many older units, or there may not be enough thermocouples at a given catalyst bed level to properly determine radial temperature spreads.

Potential solutions include increasing gas rate to improve distribution; consider dense loading catalyst (much more uniform that sock

Cont. page 3

loading); change (reduce) catalyst size provided that the unit can tolerate somewhat higher pressure drop; improve reactor internals design and/or installation; reduce upsets and improve emergency responses such as with unplanned shutdowns where oil may remain in the catalyst bed at elevated temperatures, forming the previously noted coke balls and resulting poor distribution once the unit is restarted; employ an activity grading catalyst system, such as when processing cracked feedstock with a significant amount of olefins.

These olefins release a very high amount of heat for the amount of hydrogen they consume. This will result in a very high temperature increase over a relatively short interval of bed depth, such as when only a high activity catalyst layer is loaded at the top of a reactor. Moreover, the unreacted olefins will polymerize and form a polymer at these high temperatures leading to poor distribution and ultimately pressure drop issues, which is why ART recommends loading a lower activity catalyst at the top of the reactor followed by activity grading to spread out the exotherm.

Radial temperature spreads in excess of 10 °F are an indication of catalyst distribution problem. Reactors designed with adequate thermocouple coverage at each bed level provide a more accurate determination of radial temperature spreads. For example, one hydrotreater unit showing very poor catalyst performance fortunately had sufficient thermocouple coverage for determining radial temperature spreads at each of the unit's six catalyst beds. The first two beds were determined to be within the 10°F radial temperature spread limit, whereas the temperature spreads beginning with Bed 3 were outside the 10°F range (e.g., Bed 5 > 20°F). The unit was revamped after these distribution problems were observed for a couple of cycles.

Increasing the feedrate reduces the effect of flow maldistribution or channeling. A feedrate response test can be conducted if flow maldistribution or channeling is suspected. In feedrate response testing, flow distribution performance is compared at two feedrates (LHSV) while holding temperature,

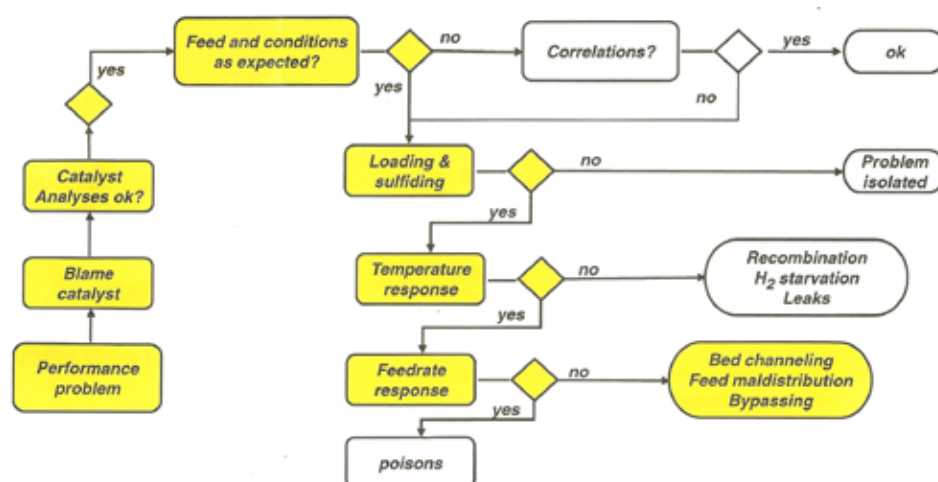


Figure 3. Unit performance strategy

$$\frac{\text{LHSV}_1}{n-1} \left(\frac{1}{S_{\text{Prod}_1}^{n-1}} - \frac{1}{S_{\text{Feed}}^{n-1}} \right) = \frac{\text{LHSV}_2}{n-1} \left(\frac{1}{S_{\text{Prod}_2}^{n-1}} - \frac{1}{S_{\text{Feed}}^{n-1}} \right)$$

Solve the above equation for n, and if n>2 then flow maldistribution is likely

Figure 4. Feedrate response test

Table 1. ULSK unit case study: Expected and actual feed and operating conditions.

	Expected	Actual
API	44	46
Sulfur, ppm	2500	1100
LHSV, hr-1	1.75	1.47
H2/Oil, scfb	870	930
Product Sulfur, ppm	10	11
SOR WABT, °F	575	623

H₂/oil ratio and feed quality constant. The rate constant for each feedrate is calculated as shown in **Figure 4**, where the equation is solved for n. Since the temperature is constant, the rate constants should be equal. Note that the value n in the equation indicates reaction order. Almost all chemical reactions occurring in hydrotreaters have reaction orders less than or equal to 2.0 (i.e., n ≤ 2.0). The typical range of reaction orders in commercial hydrotreaters is 1.0 to 1.5.

Unit Case Studies

In a ULSK (ultra-low sulfur kerosene) case study, the unit SOR temperature was nearly 50°F lower activity than expected. The catalyst lots were

satisfactory and catalyst loading and sulfiding had proceeded smoothly. Feed and conditions were actually easier than expected as shown in **Table 1**. The actual 623°F SOR temperature was significantly higher than the expected 575°F SOR.

Sulfur speciation results on feed and outlet product showed the presence of “easy” sulfurs including mercaptans. The easy sulfurs in the product suggest a maldistribution or channeling problem. The mercaptans disappeared when temperature was increased, indicating that recombination was not an issue in this case. In addition, product distribution of easy sulfurs was different from that of the feed and

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was probably not due to an exchanger leak. Otherwise, there would be raw feed leaking into the exchanger and the feed and product sulfur distribution would be similar.

The unit also showed unusually low pressure drop despite having dense loaded the catalyst, suggesting that there was a bypassing or maldistribution problem. A subsequent flow rate test indicated a reaction order of 4.3 compared to the expected range of 1.0 to 1.5. The 4.3 reaction order indicates that 25-30% of the catalyst is not being utilized due to maldistribution.

At this point, it is important to note the increasing amount of feedstock contaminants (poisons) in the 200 crudes currently available on the global market. Feed contaminants such as Si, Na, Ca, As, Pb, P, Ni + V, Fe and C₇ insolubles (microcarbon residue [MCR]) can be remedied if the refiner works with the catalyst supplier in applying the most effective remedy (e.g., improved desalting, better feed distillation, catalyst guard bed, bed grading, Fe-traps, etc.).

Case Study: ULSD Unit

In a ULSD unit that started up consistent with expectations, it quickly experienced rapid activity loss that resulted in a shut down after only a few months compared to the expected one-year cycle length. Refinery personnel indicated that current and prior cycle feed and operations were not significantly different. Other important considerations included:

- The lot analysis for the catalyst were well within specifications and similar to other successful lots
- Loading and sulfiding proceeded as expected
- Operational issues could not be excluded (H₂ partial pressure potentially low, only sporadic feedstock endpoint data)
- Caustic contamination from upstream disulfide vessel was possible
- Sulfur speciation on feed and product indicated no exchanger leaks.

The cycle ultimately came to an early

end. The catalyst had to be dumped and reloaded with fresh catalyst. Examination of the spent catalyst in this unit showed significant contamination, with the top of the bed containing a lot of powder along with the catalyst. The contaminants were examined at various levels, beginning with the top guard beds and into the layers containing the active catalysts. The first layer of active catalyst was contaminated with a significant amount of arsenic (0.13 wt% As₂O₃), along with very high levels of iron (0.91 wt% Fe₂O₃), sodium (2.24 wt% Na₂O) and phosphorous (5.24wt% P₂O₅).

In a coker naphtha unit, the SR/coker blend being processed started up with the expected activity but then began to experience higher than expected deactivation part way through the cycle. Increases in temperature resulted in decreases in product sulfur, but the unit eventually reached its maximum inlet temperature limit.

Feed and operating conditions were typical with anti foam usage being similar to previous cycles. Loading and sulfiding both went fine. The unit's temperature response indicated that recombination was not occurring. Sulfur speciation on feed and product showed no easy sulfur species in the product, eliminating the possibility of an exchanger leak. Poisoning was suspected, but analytical testing on the feedstream was inconclusive. Upon further examination, the spent catalyst analysis showed significant contamination due to silica (Si) and arsenic (As), such as with the previous ULSD case. Although Si contamination was expected, As was not expected.

Troubleshooting Recommendations

In summary, troubleshooting hydrotreater performance requires a systematic approach. It should first be verified if there really is a catalyst performance issue while simultaneously verifying that current feed and operating conditions have not changed. If there are changes, correlations should be used to ascertain if the changes explain the performance difference. In addition, the loading and sulfiding procedure should be reviewed to confirm if anything

unusual occurred.

To determine the cause of performance issues, test runs should also be performed, including evaluation of the unit's temperature response and checking for potential maldistribution with feedrate response testing.

Collection of a sufficient number of (corresponding) feed and product samples is critical. The suppliers laboratory tools should be used to verify internal analyses and to have analyses completed, which may not be available at the refinery. Finally, the experience of the catalyst supplier should be utilized.

Editor's note: *Refinery Operations* extends its appreciation to Advanced Refining Technologies (ART) and Grace Davison for supplying this information on hydrotreater performance guidelines. For further elaboration, the reader should contact Dr. David Krenzke or Woody Shiflett, Ph.D., Ch.E, Director of Global Marketing at ART (wosh@chevron.com; +1 1510 242 1166).

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PROCESS OPERATIONS

Risk Based Inspection in Refinery Operations

Meridium Inc. Describes the Business Case for RBI at the BPCL Kochi Refinery

BPCL is a leading player in the Indian petroleum sector, with gross sales of about RS 1,216,840 million and four refineries, including:

- Kochi refinery: 9.5 million mtpy (192,000 bpd)
- Mumbai refinery: 12 million mtpy (242,000 bpd)
- Numaligarh refinery: 3 million mtpy (60,000 bpd)
- Bina grassroots refinery: 3 million mtpy (60,000 bpd).

Project involved implementation of Meridium's core functionality as well as inspection management and thickness monitoring (corrosion analysis) functionalities. The Phase 1 functional design specification (FDS) was completed in November 2008, followed by conference room pilot (CRP) and training in February 2009 and achievement of the "go-live" milestone in March 2009.

The Phase 2 RBI pilot focused on the Kochi facility's fluid catalytic cracking and downstream gas concentration units (FCC/GCU), with the following components:

- FCC/GCU corrosion study
- RBI methodology and software training

In cooperation with engineers at the Kochi refinery, Meridium proceeded with BPCL's Asset Integrity Management System (AIMS) Project in 2008 (Figure 1). Phase 1 of the AIMS

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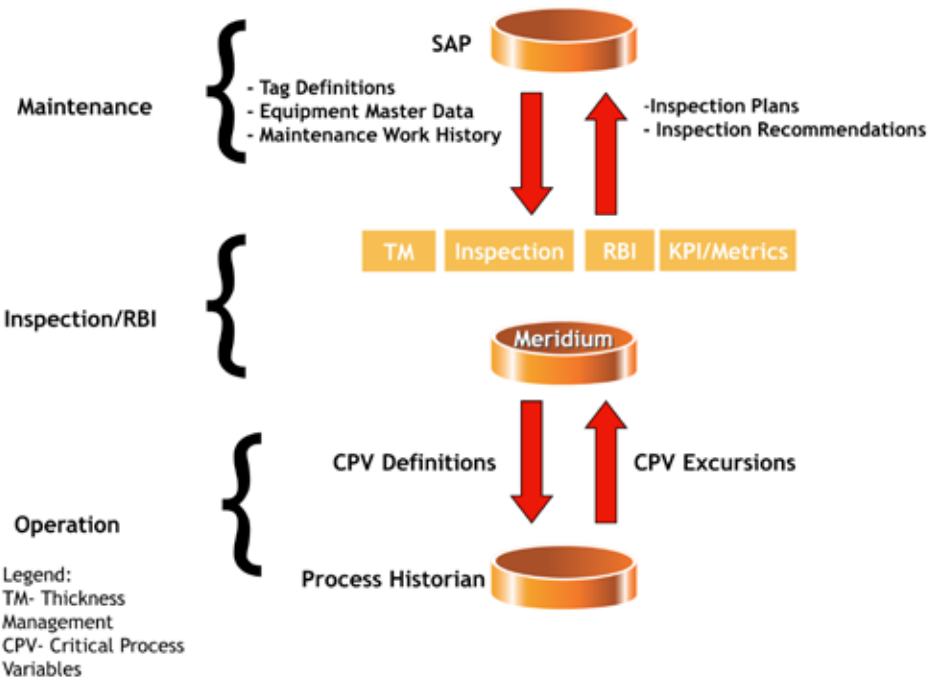


Figure 1

Table 1. RBI Work: Inspection Optimization Benefits.

Equipment	Existing Inspection Plan	RBI Based Inspection Plan
FE3A – Main col. bottom raw exchanger	Inspect every T/A – Visual & UT thickness measurements (int. corrosion inspection only – no ext. corrosion inspection)	Bundle inspection – 10 yrs Shell & channel inspection for int. & ext. corrosion – 7.5 yrs
FV13 – Raw oil charge drum	Inspect every T/A – Visual & UT thickness measurements (int. corrosion inspection only – no ext. corrosion inspection)	Vessel inspection for int. & ext. corrosion – 10 yrs
Piping – Main col. FV9 bottom to main column raw oil exchanger tube (I/L)	Inspect every T/A – UT thickness measurements (int. corrosion inspection only – no ext. corrosion inspection)	10 in. new line – inspect 2012 T/A Existing lines: UT inspection – 10 yrs CUI inspection – 15 yrs

- Meridium RBI software implementation
- Limited RBI facilitation
- Data collection and loading
- Data audit
- RBI finalization and 2012 turn-around (T/A) inspection planning.

The top down approach to the FCC/GCU corrosion study provided a common understanding of these two process units (74 corrosion loops combined) and asset integrity. This ensured consistency in assignment of potential degradation mechanisms and RBI process and design data. The ability to assess the impact of process excursions on asset integrity and reliability was also ensured, including assessment of unmitigated risks for 1084 degradation mechanisms linked to 190 equipment and piping systems with 408 RBI components.

Lessons learned in the RBI work demonstrated the importance of data quality, predicating the need for data audit procedures and tools. RBI procedures need to be standardized with inspection confidence, production loss and inspection documentation guidelines. The need for a training and skills program was also identified.

To emphasize the importance of data audit procedures and quality data, an independent data audit uncovered a variety of inconsistencies. For example, these inconsistencies included missing internal corrosion data, which prevented the refiner from having a clear understanding of corrosion rates and metal loss. A “faulty” RBI

analysis with missing input data leads to incorrect results for determining probability of failure for internal corrosion. Meridium suggested that BPCL should correct the input data and re-run the RBI analysis.

Identifying the Benefits

Preliminary benefits in the RBI work included risk reduction and inspection optimization. Addressing the top 10 risks resulted in more than 50% risk reduction. Key degradation mechanisms contributing to high risk were identified. A few sample RBI based recommendations indicated that more inspections were performed for internal corrosion. Inspection resources could instead be reassigned for other degradation mechanisms, such as external corrosion and wet H2S cracking. **Table 1** shows inspection optimization benefits.

Based on the success of the RBI implementation initiatives that began in November 2008, future plans include:

Establishing RBI procedure/guidelines for production loss consequence evaluations; strategy rule sets standardization and inspection documentation guidelines

- Plant-wide RBI implementation
- Complete SAP integration
- Mentoring of BPCL inspection engineers by RBI veterans
- Comprehensive risk-based program.

Editor’s Note: A detailed discussion of the stepwise implementation of Meridium’s proprietary AIMS methodology is beyond the scope of this discourse and should be deferred to Meridium experts

such as Vinay Nihalani (vnihalani@meridium.com; +1 281 920 9616; ext. 2215). This article is based on a more detailed discussed prepared by Roopesh Modathiyalath, Deputy Manager at the BPCL Kochi refinery and Vinay Nihalani, at the 2011 NPRA Annual Meeting in San Antonio, Texas, USA (refer to NPRA paper: AM-11-09). ■

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Vinay Nihalani, P.E. VP, Mechanical Integrity Solutions,

INDUSTRY NEWS

Oil Exports from US?

According to an investigative report announced by Esa Ramasamy on June, the US could resume exporting some of its domestic crude oil production in 2012 when the output from Eagle Ford Shale in Texas ramps up. Eagle Ford shale crude's gravity ranges from 42 API to 60 API with very low sulfur content, which in the US Gulf Coast refining terminology is considered a super light crude. But that's the problem for US refiners: they aren't built to process that type of crude. So the highest value for it may be outside the country.

Current Eagle Ford production stands at around 100,000 bpd or more. Valero's 100,000 bpd Three Rivers refinery in Texas is currently consuming about 40,000 bpd currently and expects to hike this to 60,000 bpd by the end of this year, according to Valero spokesman Bill Day. Valero is also refining Eagle Ford crude at its 340,000 bpd Corpus Christi refinery.

In addition to Valero, Flint Hills is

also processing Eagle Ford shale crude at its 300,000 bpd Corpus Christi refinery. There are other refiners in the Houston area with heavy conversion capacity that also have refined Eagle Ford crude. But others with less conversion capacity have not.

Light crudes are not preferred by Gulf Coast refiners because they have invested heavily in secondary units and by running light or very light crudes, they would be under-utilizing their secondary units and this affects their margins," said Tom Hogan of Turner, Mason consultants.

Light crudes tend to produce more light ends (naphtha, gasoline) and distillates (diesel and jet fuel) with little residual fuel oil. But Gulf Coast refiners with coking capacity are designed to take that residual fuel and turn it into transportation fuels. "The lack of larger quantities of residual oil in Eagle Ford Shale is why Gulf Coast refiners may not run this crude in large volumes,"

noted Hagan. "If they did run Eagle Ford Shale it would be to blend down a very heavy sour crude."

That Gulf Coast refiners like heavier crudes, and are built to process them, is evident in the data on their prevailing run rates. According to the US Energy Information Administration, US PADD III (Gulf Coast) refineries ran crudes with an average API of between 29 degrees and 30 degrees with sulfur ranging from 1.50-1.70 ppm between 2000 and March 2011. Prior to 2000, Gulf Coast refiners ran crudes with an API ranging from 31.3 to 33 degrees. The shift was able to occur as new coking units and other heavy oil treatment facilities were brought on line, designed specifically for a world crude market that was projected to get heavier.

So if the Eagle Ford crude would not be preferred by existing refiners, that leaves non-US refineries. By mid-2012, Eagle Ford Shale crude production is expected to rise sharply. ■

Motiva Refinery will Run Solely on Saudi Crude

A Dow Jones Newswire reported on June 10 that Saudi Arabia will be the sole supplier of crude oil to Motiva Enterprises LLC's refinery in Texas after the facility finishes expanding its capacity to 600,000 bpd next year, a person familiar with the matter said. The expansion of the Port Arthur, Texas, refinery, a joint venture between Royal Dutch Shell PLC and Saudi Arabia's state-owned oil company Saudi Arabian Oil Co., is scheduled for completion in the

first quarter of 2012. The boost in its intake of Saudi crude oil would coincide with Saudi Arabia's pledge to boost its oil production despite opposition from fellow members of the Organization of Petroleum Exporting Countries.

About half of the fuel at the 285,000 bpd facility is currently refined from Saudi crude oil, the source said. Motiva will increase the number of oil shipments it accepts every month to 27 ships after the expansion, up from seven, the

source said. Each ship brings in about 600,000 barrels of oil.

Motiva spokeswoman Marti Powers said in an interview that the company would be looking at "several supply options" for the Port Arthur refinery after its expansion. Powers said Motiva would look for the easiest and most cost-efficient source of crude oil. In addition to the Port Arthur facility, Motiva also owns refineries in Norco and Convent, Louisiana. ■

Asian Refiners Reassured of Ample Saudi Crude Supplies

Asian refineries are confident Saudi Arabia will ensure no shortage of oil supply to meet rapidly rising demand this year despite OPEC's failure to agree on an output increase in early June. But

demand in the region could suffer in the long term if the failure of the producer group to send a clear signal to markets keeps oil above \$100 a barrel.

Asia is driving the global increase

in oil consumption, so higher Saudi supply would benefit regional refiners. The Paris-based International Energy Agency (IEA) expects Asia to burn 900,000 bpd more oil

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in 2011 than 2010, over 70% of the 1.29 million bpd global demand growth forecast for the year.

"We are not concerned about a shortage of supplies," said a Chinese crude

trader at a big state-run oil refiner. "Our demand has been met over the past two years even when OPEC cut supplies and changed crude grades they supplied."

Saudi Arabia is China's top supplier,

and in the first four months of 2011 is already up over 27% on the year at 1 million bpd. China is expected to bring online around 500,000 bpd of new refining capacity this year. ■

Omsk Refinery Continues to Expand

The Omsk oil refinery, part of the Gazprom Neft group, recently processed its billionth tonne of crude oil since its opening in 1955. This makes the refinery the first in Russia to reach this goal. The landmark billionth tonne was processed at AVT-7 Production Plant. The capacity of the Omsk Oil Refinery, one of the world's largest oil processing facilities, now stands at 20 million tonnes per year. In 2010 the volume of oil refining at the facility was around 19 million tonnes, with the refining depth of 83.27%, one of the highest in the Russian refining industry.

Today, the Omsk refinery produces around 50 types of product. The facility occupies the leading position in Russia in terms of motor fuel production. A significant proportion of the production structure at the plant is devoted to aromatic hydrocarbons: benzene, paraxylene, orthoxylene, all raw materials for the petrochemical and organic synthesis industries. The modernised technological process at the aromatics complex allows for the production of orthoxylene of up to 99.6% purity, benzene of up to 99.98% purity and paraxylene of up to 99.95%

purity – the highest ratings in the world.

Alexander Meling, the General Director of the Omsk Oil Refinery, said: "Today the Omsk Oil Refinery is one of the most state-of-the-art oil processing facilities in Russia. To have reached a billion tonnes is the result of over half a century of plant operation and contributions to the development of the enterprise from the Gazprom Neft group. With their support we have been able to move toward a common goal – to achieve market leadership in terms of volume and depth of oil refining, and the range and quality of products."

Currently the Omsk Oil Refinery continues to implement the medium-term investment program, which provides a number of modernization projects. Under this program last year the plant saw the opening of Russia and Europe's largest facility for the isomerisation of the light gasoline fraction Izomalk-2, with a capacity of 800 thousand tonnes per year. The Izomalk-2 complex produces isomerizate, a high-octane component of modern motor fuels with zero sulfur content, aromatic and unsaturated hydrocarbons, which in 2011 enabled the plant to begin manufacturing

high-octane gasoline of the 4th environmental class.

Today under the modernization program the Omsk Oil Refinery is constructing a catalytic cracking and hydrotreater with a capacity of 1.2 million tonnes per year and a new diesel fuel hydrotreater with a capacity of 3.0 million tonnes per year. Once commissioned, these units will produce motor fuels of the 4th and 5th environmental classes respectively.

Out of all projects aimed at increasing industrial and environmental safety at the facility, the main ones are: upgrading the nitrogen-oxygen station; construction of a new farm for dark petroleum products, a feedstock farm for the production of bitumen and coke, a condensed petroleum gases farm, and the renovation of water treatment plants.

The volume of investment directed towards the development of the Omsk refinery until 2020 on the part of Gazprom Neft amounts to 100 billion roubles. The volume of financing of the medium-term investment program in 2011 amounts to 19 billion roubles. ■

Design and Preliminary Engineering Services Proceeding for Nigerian Refinery

KBR has been awarded a contract by Houston-based FPR Inc. to provide Design and Early Engineering Services for the development of the Araromi Refinery Project in the OK Free Trade Zone (OKFTZ) in Nigeria.

KBR will execute the Design and Early Engineering Services for a low complexity 160,000 bpd grass roots

refinery and marine facility estimated in excess of US\$3 billion. The refinery will produce motor gasoline, automotive gas oil, kerosene and jet fuel. This work will be executed primarily in the Republic of South Africa and the United States.

This award marks the first contract awarded under a Memorandum of Agreement (MOA) under which the

two firms anticipate executing various phases of the project which include EPC-GM and Operation and Maintenance. The Araromi Refinery Project will be developed in phases, with an ultimate capacity of 320,000 bpd with a full petrochemical complex. ■

Petrobras Going Forward with Abreu e Lima Refinery Project

Petrobras has the resources to complete the refinery being built in northeast Brazil with partner PDVSA alone if the Venezuelan state-owned oil giant decides to pull out of the project, company executives said.

"The project is not going to be halted and there is not going to be a shortage of resources to complete it if PDVSA leaves the partnership," Petrobras director of downstream operations Paulo Roberto Costa said in an early June press conference at the headquarters of the Abreu e Lima binational refinery project. Petrobras commenced the refinery's construction at the port of Suape, located a few kilometers from Recife, the capital of Pernambuco state, without any assistance from the Venezuelan oil company, Costa said.

"About 35% of the project has been executed and the refinery is expected to start production in 2013," the Petrobras executive said. The refinery will have the capacity to process 230,000 bpd of petroleum. Petroleos de Venezuela, or PDVSA, has until August to decide whether it wants to continue the partnership because the funding provided by Petrobras ends this month, Costa said. Venezuelan Construction of the \$16.25 billion refinery was started with a \$6.25 billion loan that Petrobras obtained from the state-owned BNDES development bank, Costa said. "As of now, we have used nearly 7 billion reais (about \$4.38 billion) of this loan and, since all the work was already contracted for, the funds run out in August," the Petrobras executive said.

"August is the deadline that PDVSA has to decide if it wants to contribute its share, which is 40% of the refinery, and whether it is going to continue providing resources so we can move ahead with the construction," Costa said. "We have set aside some resources so we can continue the project without stopping the work in case we have to take over 100% of the refinery," the Petrobras executive said.

Negotiations on the refinery project dragged on for several years due to differences over what each party's final stake would be, and Petrobras decided to start construction on its own due to PDVSA's failure to assume its share of the BNDES loan. ■

New Iraqi Oil Refinery

Iraq hopes to complete negotiations with European investors to build a new oil refinery in the city of Karbala [Kerbala], the country's Deputy Prime Minister, Hussain al-Shahristani said in early June. The projected 140,000 bpd Kerbala refinery is part of a plan to build four new refineries, adding around 750,000 bpd of refining capacity at an estimated cost of more than \$20 billion, according to Reuters.

"We hope to finish negotiations with European investors regarding the Kerbala refinery and to begin work this year,"

Deputy Prime Minister Hussain al-Shahristani, who has responsibility for Iraq's energy affairs, told reporters.

He said the Kerbala refinery was expected to be completed in three to four years. Shahristani said that with the planned additional refining capacity, on top of the country's existing refining capacity of 500,000-550,000 bpd, Iraq would turn from an importer into an important exporter of refined oil products.

According to the OPEC website, Iraq produces about 453,000 bpd of refined

products and uses 589,000 bpd.

Last month, Deputy Oil Minister Ahmed al-Shamma said Italy's ENI had expressed interest in the Kerbala refinery project, which was valued at \$4-\$4.5 billion. The other three new refining facilities in the national refinery expansion plan would be located at Nassiriya in south Iraq, in the northern oil city of Kirkuk and at Maysan in the south. Shahristani said Iraq was also upgrading its existing 140,000 bpd Basra refinery. ■

Future of Russia Oil & Gas Research Report Ready

Reportlinker.com announces that a new market research report is available in its catalogue: The Future of Russia Oil and Gas Industry to 2020: "The Future of Russia Oil & Gas Industry to 2020: Forecasts of Supply, Demand, Investment, Companies and Infrastructure"

covers the entire value chain of the industry. It analyzes and forecasts each of the oil and gas segments in Russia including upstream sector, pipeline, refinery, LNG and storage sectors. The report also gives detailed analysis of investment opportunities in each sector,

highlighting the growth potential and feasibility of projects. It also identifies the key challenges, drivers and restraints in the country's oil and gas industry and the impact of these metrics on the industry. ■

Wastewater Treatment Contract at Chinese Refinery

Siemens reported on June 16 that it will supply wastewater treatment at the Sinopec Anqing refinery in Anhui Province, China. The contract includes a powdered activated carbon treatment (PACT) system, a Zimpro wet air regeneration (WAR) hydrothermal unit, and a Hydro-Clear sand filtration system. The system will be used to treat salty and oily wastewater from refining and petrochemical production activities from existing and upgraded units.

The 1,000 m³/h Anqing system will also help Sinopec discharge a cleaner effluent and also generate approximately 500 m³/h of reusable water. The refinery will reuse the water in its cooling tower

system, which will help to offset the strain on China's surface water bodies.

The wastewater also needs to meet the Chinese specifications for surface discharge. The Sinopec refinery discharges its treated wastewater into the Yangtze – the third largest river in the world and the largest in China. Preserving and maintaining this major waterway's water quality and ecosystems is one of the Chinese government's main environmental initiatives.

Siemens's PACT system combines biological treatment and carbon adsorption into a single, synergistic treatment step to remove organics. The solids are pumped as slurry to the Zimpro WAR

unit where the carbon is regenerated and biological solids are destroyed. The WAR system will generate virtually no sludge that requires landfill disposal or incineration. The Hydro-Clear filter system makes it possible to filter large volumes of water and return it to the cooling circuit, resulting in large savings in the amount of fresh water required. The entire wastewater treatment system has a smaller footprint design to help reduce land requirements.

The new wastewater treatment system is the seventh project that Siemens Water Technologies has worked on with Sinopec Corp. The system will become operational in 2012. ■

French Oil Major Content with One US Refinery

Oil major Total, France's largest company, will not acquire or build any additional US refineries, its chief executive said in early June, preferring to look instead to markets where gasoline demand is expected to grow. Christopher de

Margerie said in an interview that the company was content with its single US refinery – the 232,000 bpd Port Arthur facility in Texas, which completed an extensive modernization earlier this year. De Margerie said Total has no

interest in adding another refinery in the US. "No chance," he said. "If we have to develop new refineries, (they) have to be developed in countries where there is access to growth ... the Middle East, or China or maybe India." ■

Croatian Government Pushing for Overhaul of two MOL Refineries

The Croatian government wants MOL Nyrt. to raise oil reserves at INA Industrija Nafta d.d. and overhaul its two refineries as part of demands to get back more influence in the Hungarian

oil company's local unit, as reported by the Bloomberg news agency on June 3. The government said on June 2 that it intends to review 2003 and 2009 agreements that gave MOL control rights

over Croatia's largest refiner. MOL has 47.47% of INA, while the government holds 44.84%. ■

Calendar of Events

SEPTEMBER

22-23, *Russia & CIS Refining Technology Conference & Exhibition*, Euro Petroleum Consultants, Moscow, Russia, +44 (0) 20 7357 8394, www.europetro.com.

OCTOBER

9-12, *NPRA Q&A and Technology Forum*, San Antonio, Texas, +1 292 457 0480, www.npra.org.

NOVEMBER

Nov. 29 – Dec. 1, *ERTC 16th Annual Meeting*, Barcelona, Spain, +44 (0) 207 484 9700, conf@gtforum.com, www.gtforum.com.

EDITORIALLY SPEAKING

Expanding Maintenance Work Scope

Adhering to added hydrotreater unit maintenance work scopes requires resources and diligence for tracking and reviewing to ensure that the equipment under scrutiny is inspected by operations personnel. This takes into account scheduled work and extra work that should be listed and checked off for proper line-up.

Concerns with hydrotreater safety

with operating hydrotreaters against a wide envelope of operating conditions and process objectives (e.g., FCCU feed pretreatment, LCO upgrading to ULSD, etc.). For example, at one refinery, a hydrogen leak occurred from a one-inch gate valve on a makeup gas line in a gas oil hydrotreater.

When the leak was discovered, the

months earlier after a company ownership change occurred and had undergone recent maintenance and testing prior to activation for operation. A post-event investigation determined the likely cause of the hydrogen leak was that the one-inch gate valve was not completely closed prior to the start of operation. The investigation determined that a possible scenario for the loss of the valve bull plug was expansion and contraction during hot and cold cycling of the unit combined with vibration from a nearby reciprocal compressor over the 18 months since re-commissioning.

Processing unconventional hydrocarbons through the newest hydrotreaters requires more hydrogen, higher conversion temperatures and higher overall unit (and plant) complexity to yield clean transportation fuels at the other end. In between the front end and back end of the plant, higher amounts of corrosion and fouling are to be expected with the types of heavy crudes that are being added to the refinery crude diet, such as the higher percentages of heavy Canadian crudes being processed by Midwestern refiners in the U.S.

It therefore stands to reason that oil companies will be compelled to increase their downstream capital and operating budgets to accommodate whatever types of low quality crudes that they can get. Looking at budget outlays of refiners that that many of us have access to, it looks like 2012 looks to be neither a bumper year, nor one of drought, in terms of downstream capital expenditures for adding process complexity to refinery operations. ■



Rene Gonzalez, Editor
Refinery Operations



Figure 1. The BP Kochi refinery recently expanded its risk based inspection (RBI) process. Photo courtesy of Meridium, Inc.

and reliability (**Figure 1**) are increasing as more units come on line and are operating across a wider range of operating parameters, including higher H₂ partial pressures and higher temperatures towards end-of-run (EOR). Cognizance of these maintenance and operations procedures with these constantly modified units must involve plant operations and health/safety personnel to develop an operational mechanical integrity checklist to ensure that all mechanical equipment components are addressed.

While no two gas oil hydrotreaters are alike, many of these procedures and checklists have evolved from experience

gas oil hydrotreater unit shutdown procedures were immediately implemented and emergency response was requested. The gas oil hydrotreater unit was fully shut down after about 30 minutes. Shutdown consisted of sufficiently depressurizing the unit and adding nitrogen to allow safe closing of the leaking one-inch gate valve and installation of the associated missing bull plug.

During this event, the one-inch gate valve was found to be open roughly 10% with no bull plug in the valve, allowing the hydrogen to leak to the atmosphere.

The hydrotreater involved in this incident had been re-commissioned 18

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