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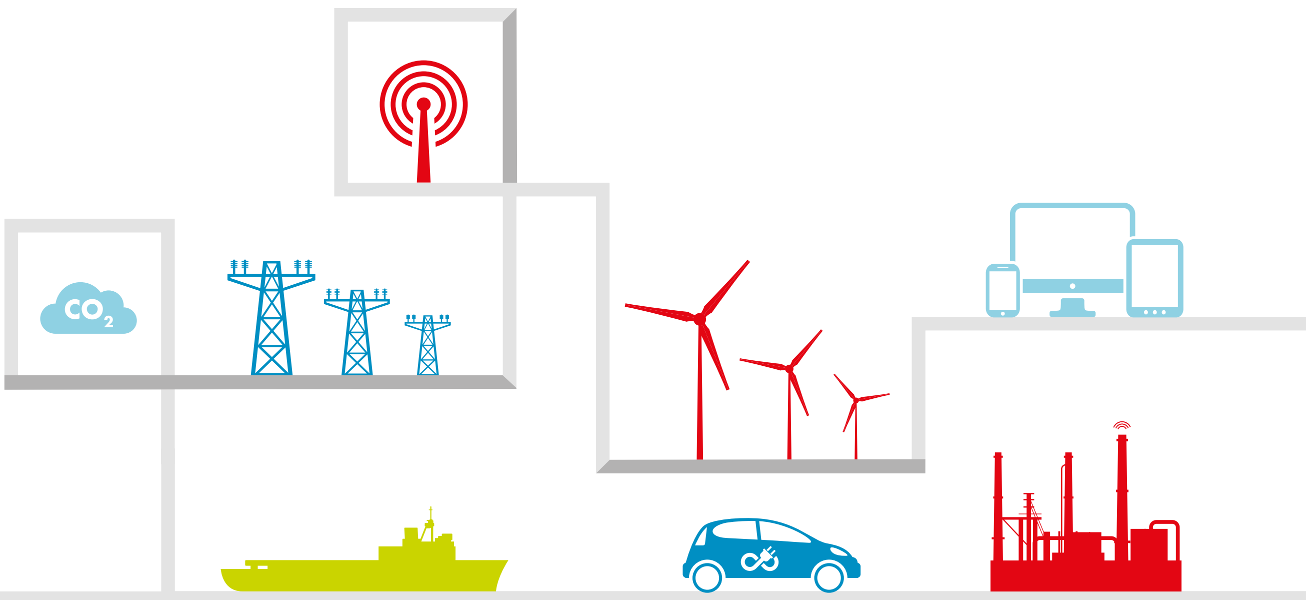

PREPARING FOR THE DISRUPTIONS THAT LIE AHEAD

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Over the last four decades, refiners have had to adjust to a relentless stream of changes in product demand patterns and ever-more-stringent environmental regulations. Making the adjustment takes time and requires a good assessment of the potential future scenarios.

We had the unleaded gasoline mandate, followed by the introduction of oxygenates to gasoline. Next, came the trend for ultra-low levels of sulphur in diesel. Then, over the last 10 years or so, the momentum in dieselisation, changing crude slate and the need for tighter integration with petrochemicals have given refiners even more new things to think about.

Each time, refiners have displayed remarkable flexibility in reconfiguring their facilities and operating strategies.

And now, further challenges lie ahead. Two in particular will have a profound impact on refiners.

First, we have the International Maritime Organization's (IMO) MARPOL 73/78 Annex VI (**IMO 2020**) on the horizon, which will cut the allowable sulphur content of marine bunker fuel from 3.5 to 0.5%. Achieving full residue conversion is likely to be extraordinarily capital intensive and might not be necessary anyway, but cost-effectively reducing fuel oil exposure is almost certainly a good idea, as it has a clear link with competitiveness.

Secondly, a global **energy transition** is under way. One element of this is that we are starting to see battery electric vehicles gaining consumer acceptance. Worldwide, about 50% of refinery output is directed towards road transportation fuels, so any substantial moves towards electrification have significant potential to reduce demand for diesel and gasoline.

DISRUPTION #1: IMO 2020

Although clean air concerns have driven the IMO 2020 legislation, it is not necessarily a compliance issue for refiners.

After 2020, ships that are not fitted with scrubbers will not be able to use high-sulphur fuel oil. However, that does not mean that refiners will not be able find outlets for it, especially as about 50% of the current high-sulphur fuel oil market is not marine fuel so will not be affected by the IMO regulations. In addition, there will be a limited number of ships fitted with scrubbers that can process it. Alternatively, other refiners that have spare residue conversion capacity may take it – but at a price.

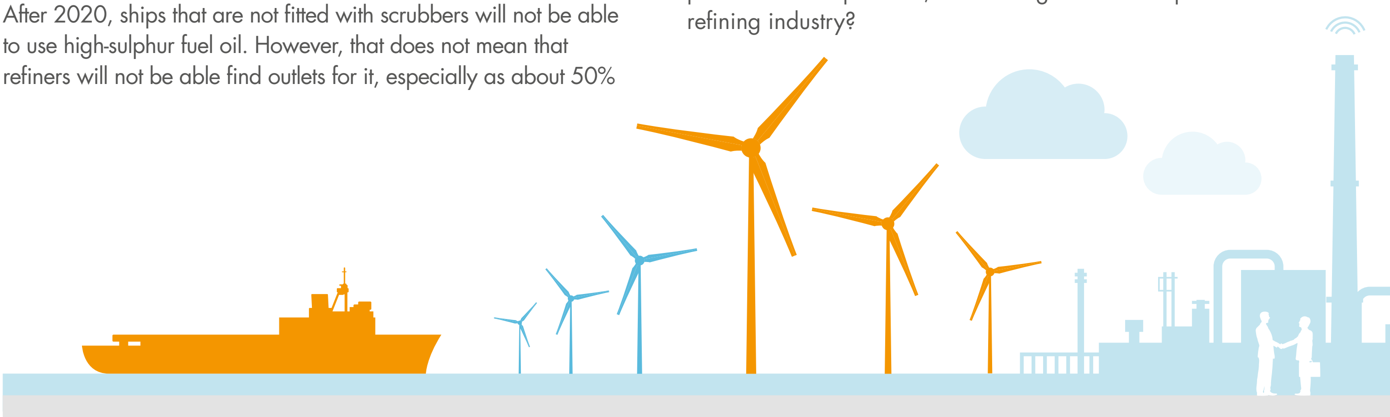
That is why, at Shell Global Solutions, we believe it is better to consider IMO 2020 as a margin opportunity rather than as a compliance issue. The paper on page 4 details some of the technology solutions that can help refiners to take advantage of this. Furthermore, another paper, page 9, details a technology that is seeing a renaissance as IMO 2020 draws closer: visbreaking.

DISRUPTION #2: THE ENERGY TRANSITION AND CHANGES IN THE MOBILITY SECTOR

The energy system of the future is going to look very different; there is no doubt about that. And of course, we need it to.

We know the world needs more energy, but we must emit much less carbon dioxide. So, renewable energy and diversified supplies are key, and that includes solar power, wind farms and biofuels. We also now see politicians under increasing pressure to improve air quality, particularly in urban areas. Some analysts argue that this factor now has a greater influence on transport policy decisions than the wider concerns about climate change.

But when could the arrival of new mobility options such as battery electric vehicles, which are an important and growing part of the transport mix, cause a significant disruption for the refining industry?



The timeline is highly uncertain and there is a wide range of predictions. Shell's view is that the internal combustion engine will continue to power most vehicles over the next couple of decades. The lack of sufficient charging infrastructure and electric engine and battery manufacturing capacity provide some reasons to anticipate a relatively slow pace of change globally, as does the current perceived high cost of the vehicles. The existing world fleet of passenger cars is also unlikely to be replaced through consumer choice alone unless there are incentives or penalties to encourage a switch.

And we are not alone in this view. The International Energy Agency believes that, even by 2040, only 7.5% of the two billion cars that will be on the road will be electric.

And then there are trucks, ships and jet planes. It appears unlikely that any of these will be running on batteries any time soon.

So, it seems that the world is going to continue to need gasoline, diesel and jet fuel for some time. Furthermore, demand for petrochemicals remains robust and, of course, petrochemical facilities need refineries.

ALTERNATIVE POINTS OF VIEW

There are other points of view, however. Some, for example, suggest that as ride-hailing fleets adopt increasingly affordable electric car technology and self-driving technology becomes more common, global demand for oil will start dropping in as little as three or four years from now. In this extreme scenario, it is predicted that some 95% of people will not own a private car by 2030.

Although Shell expects a relatively orderly transition, which would give refineries a couple of decades of relatively slow-changing demand patterns, it does not have all the answers. There are other possible, credible futures to which refiners should remain open. Consequently, on page 6, we have invited David Hampton, an independent strategy consultant with particular experience in energy, to provide an external view on how the energy transition could affect the refining and petrochemical sectors over the next 10–15 years, and beyond.

RESPONSE OPTIONS

In our experience, nearly all refineries have untapped potential. Naturally, those with older technologies generating suboptimal yields or that have poor reliability often have improvement potential. But, we also often find that pacesetting refineries can still achieve higher margins with smart investments.

We believe, therefore, that many refiners will be able to adjust their operations to meet the dynamics of the future markets better without major capital expenditure. Latest-generation catalysts will be key and many promising opportunities centre around revamps, so this issue also explores some of the latest thinking, and technology developments, for revamping some of the principal technology blocks (pages 9–15).

IMO 2020 and the energy transition could both have a major impact on an ill-equipped refiner's profitability. As with the changes that the industry has overcome over the years, from unleaded gasoline to dieselisation, businesses will need to rise to the challenge again. We hope the pages that follow provide insights to help you to do that.

KEY TAKEAWAYS

- IMO 2020 is on the horizon, the global energy transition is under way, renewables are on the rise and electric cars are an important and growing part of the transport mix.
- Refiners that develop the best responses can optimise the opportunity to enjoy a sustainable and profitable future.
- There are many bottom-of-the-barrel upgrading options to choose from, but there is no one-size-fits all solution.
- Revamps, applying state-of-the-art catalysts and thermal conversion technologies are likely to provide compelling responses, especially as they can require less capital expenditure than other options.

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KEY STEPS FOR REFINERS AHEAD OF IMO 2020

The reality is that many refiners remain unprepared for the International Maritime Organization's (IMO) MARPOL 73/78 Annex VI (IMO 2020). These regulations, which will substantially tighten the global cap on the maximum sulphur content of marine fuel oil, could have a major impact on an ill-equipped refiner's profitability. Fortunately, it is not too late; they could implement several low-cost solutions over the next two years to safeguard their competitive position.

Because of these regulations, from 2020, refiners can expect demand for high-sulphur fuel oil (HSFO) to fall, demand for low-sulphur fuel oil (LSFO) to increase and a corresponding price differential between the two to open up.

This is because ships will only be able to continue using HSFO if they are fitted with on-board scrubbers, but on-board scrubbers are costly and it will only be possible to convert a modest percentage of the world's fleet before the new global cap comes into force. Liquefied natural gas conversions are inappropriate for most ships, so most will turn to LSFO from 2020.

Fortunately, the LSFO–HSFO price differential is likely to close partially over time as scrubber technology improves and conversion facilities are built. Consequently, there will still be a market for HSFO and refiners do not necessarily need to eliminate their HSFO exposure, but they would be well advised to reduce it to retain their competitiveness.

How should you respond? There is a wide range of technology options available, but a rigorous evaluation study must be done to find the most cost-effective option for each refinery. Some of these options are shown in Figure 1. Should

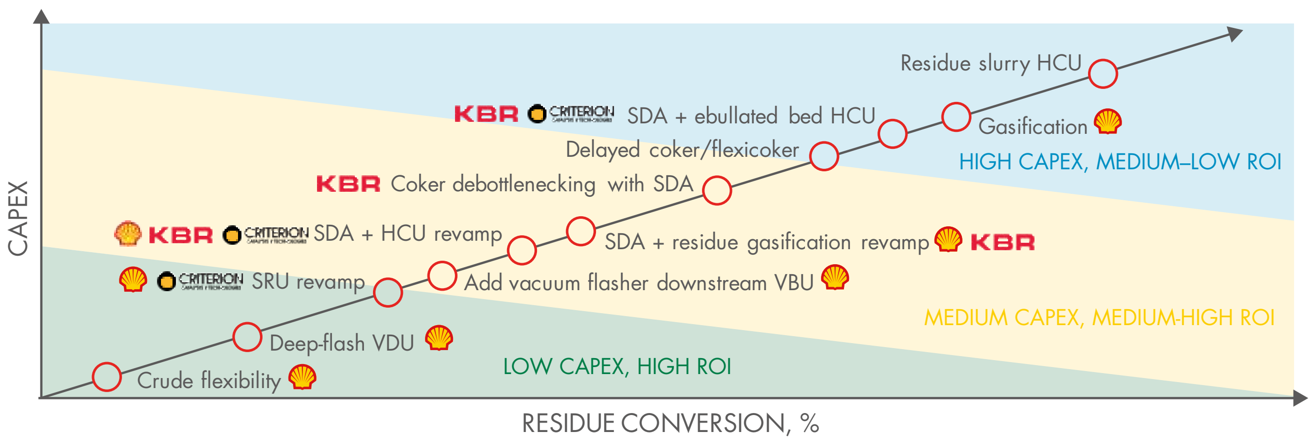

Figure 1: Some of the technology solutions that can help refiners to respond to IMO 2020.

> THE BUSINESS CASE FOR SOME OF THE INTEGRATED SOLUTIONS, WHICH OFTEN INVOLVE REVAMPING EXISTING PROCESS UNITS, HAS TENDED TO BE FAR STRONGER THAN THAT FOR INSTALLING NEW HIGH-RESIDUE-CONVERSION TECHNOLOGY.

you install one of the highest-residue-conversion technologies, for example, ebullated-bed residue hydrocracking or slurry-phase residue hydrocracking? For many refiners, these options may not provide the optimum solution, in part because they are extremely capital intensive.

At Shell Global Solutions, we have been using our experience to help identify the best responses. The business case for some of the integrated solutions, which often involve revamping existing process units, has tended to be far stronger than that for installing new high-residue-conversion technology.

For example, a solvent deasphalting (SDA) unit can be added for comparatively moderate capital expenditure (capex). Simultaneously revamping the hydrocracker can help to reduce HSFO production by almost 50%, increase middle distillates yield and improve crude flexibility.

The combination of SDA and deasphalted oil hydrocracking, or SDA and thermal conversion, which is another moderate-capex response option, has another important advantage: it retains high levels of crude flexibility. This is becoming an increasingly important profitability driver for refiners. There are large opportunities for refiners to increase margins by including lower-priced, opportunity or niche crudes in their diet, so you should always evaluate the effect that your investments will have here.

Another crucial consideration is the refinery's back end. When increasing the level of residue conversion, by either revamping process units or installing new ones, the treating and utility systems and logistics infrastructure can often be key constraints. Additional capacity is likely to be required for sour water strippers, wastewater treatment plants and, particularly, sulphur recovery units. Fortunately, the state of the art has recently advanced here with the development of Shell's next-generation tail gas treating process, Shell Claus off-gas treating (SCOT[1]) ULTRA, which offers a performance step change for minimal investment (see page 14).

Of course, the gestation period of all such projects is likely to extend beyond 2020, so it may be too late to initiate such a response now to reap the benefits of the expected LSFO–HSFO price differential. They may remain options for the long term however, although refiners who have not already committed to this type of long-term, high-capex investment are likely to delay making an investment decision until at least 2019 when the supply, demand and economic implications of IMO 2020 should become clearer.

What changes could you implement before 2020? Among the low-capex, quick-win solutions that have scored highly in our analyses is Shell's deep-flash technology, which can help to lift more and better quality vacuum gas oil (VGO) from the vacuum distillation unit and reduce HSFO production (see page 9). Another popular solution is installing latest-generation reactor internals and catalysts, which can enable the hydrotreating and hydrocracking of heavier and more difficult feeds such as deasphalted oil, heavy VGO and visbreaker VGO, and increase conversion capability.

Another quick-win opportunity is to change the crude diet to include a proportion of opportunity crude. For a typical 200,000-bbl/d refinery, the inclusion of 10% of an opportunity crude with a relative discount of $1/bbl could increase the gross refinery margin by some $7 million a year. This will typically require no capex.

The importance of first developing a robust investment plan tailored to your specific circumstances cannot be overemphasised. You can only identify the optimum solution by taking into account your specific constraints, such as refinery configuration, local factors and available capital, and by using tools such as scenario planning to help you take a view of the future market in which you will be operating.

KEY TAKEAWAYS

- IMO 2020 will cause a price gap to open up between LSFO and HSFO that only the best-prepared and equipped refiners will benefit from, and this gap will close partially over time.
- To reap the benefits of this price gap, a refiner would need to have already invested in a medium- to high-capex solution that suits their particular circumstances.
- Those that have not could focus on what they can achieve ahead of 2020. From installing deep-flash technology and revamping with latest-generation catalysts and reactor internals through to including low-cost opportunity crudes in the refinery diet, there are many steps for strengthening competitiveness ahead of 2020.

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[1]SCOT is a trademark owned by the Shell group of companies.

THE EVOLVING MOBILITY MIX – POTENTIAL IMPACTS ON REFINERS

From climate change, air quality concerns and the growth in electric vehicles through to the emergence of smart cities and autonomous vehicles, a complex mix of interrelated factors is changing conventional patterns of energy supply and demand – and at a faster rate than most industry managers recognise. What are the implications for refiners and how could they respond?

There continues to be a sharp focus on the Paris agreement on climate change, and rightly so, as this global agreement to decarbonise the economy will be a key long-term driver of the energy transition. Meanwhile, there are many other developments happening at a much faster rate that could affect refiners more quickly and more dramatically.

Take air pollution, for example. The understanding of the health impacts and costs of air pollution has changed significantly in the past 10 years. National and city governments worldwide are under enormous pressure to tackle air-quality concerns and they have autonomy to take decisions on this front. Consequently, we have recently seen cities around the world introducing various initiatives for decreasing congestion and tackling traffic pollution, including vehicle emission standards, low emission zones and public transport improvements.

In addition to regulations, there are numerous fast-moving business-, technology- and consumer-led trends such as the growth in electric vehicles, improvements in battery technology, car manufacturers' plans to electrify their fleets and autonomous vehicles. Furthermore, vehicle efficiency is continuing on its upward trend and there is potential for even more aggressive efficiency improvements.

Collectively, the above factors could reinforce each other and increase the pace and extent of change in the energy landscape.

WHAT DOES ALL THIS MEAN FOR REFINERS?

At Irbaris, we believe that business-as-usual projections for future market size will, in many places, miss critical aspects of the changing mix in demand and will prove an overestimate of actual demand. This is highly significant because even a small reduction in demand for transport fuels could have a profound impact on refiners' economics.

This becomes clear when one crunches the numbers. We modelled a plausible projection of the 2030 market that would be consistent with a 2.5% per annum gain in new vehicle efficiency across the petrol and gasoline fleet, and a 25% share of new vehicle sales for electric vehicles. In such circumstances, total refinery product volume falls by 8% compared against the current business-as-usual projections. More important than the absolute volume impact is the impact on product mix. (Please note that this is not a forecast and it is also not an extreme scenario by any means.)

As shown in Figure 1, we modelled two options available to refiners. Option 1 would be to rebalance the barrel: find other options for the molecules otherwise directed to road diesel and gasoline. Some may not consider an 8% demand decline to be dramatic, but the fact that it only affects specific pieces of the product slate makes it highly significant. In fact, road diesel demand would see a 20% cut while gasoline demand would fall by 17%. The impact in some regions could be even more pronounced.

Finding other uses for those molecules would probably require reconfiguring a refinery or adjusting its operating strategy. One might consider directing the gasoline-bound naphtha to petrochemicals; however, the naphtha market would soon be long. Moreover, even if a refiner could sell its naphtha, it would take an economic hit because sales of naphtha have a lower value for refiners than gasoline.

So, rebalancing the barrel could present a major technical challenge. However, I know that Shell Global Solutions' consultants have lots of ideas here.

Option 2 would be to cut output. Although this might be more straightforward technically, operating at lower utilisation rates would likely change the profitability of some refineries.

Of course, not all refineries would be affected equally. There will be regional variations and those with a strong connection to a petrochemical business would probably be relatively robust, as would those with intrinsically low costs or strong feed and product flexibility.

Likewise, the scale, global footprint and diversified interests of the bigger players should provide some protection for their businesses. The impact may be more marked for individual refineries and smaller companies. Paradoxically, the impacts could be most significant in markets expecting the fastest growth and where there are plans for substantial refinery capacity expansion.

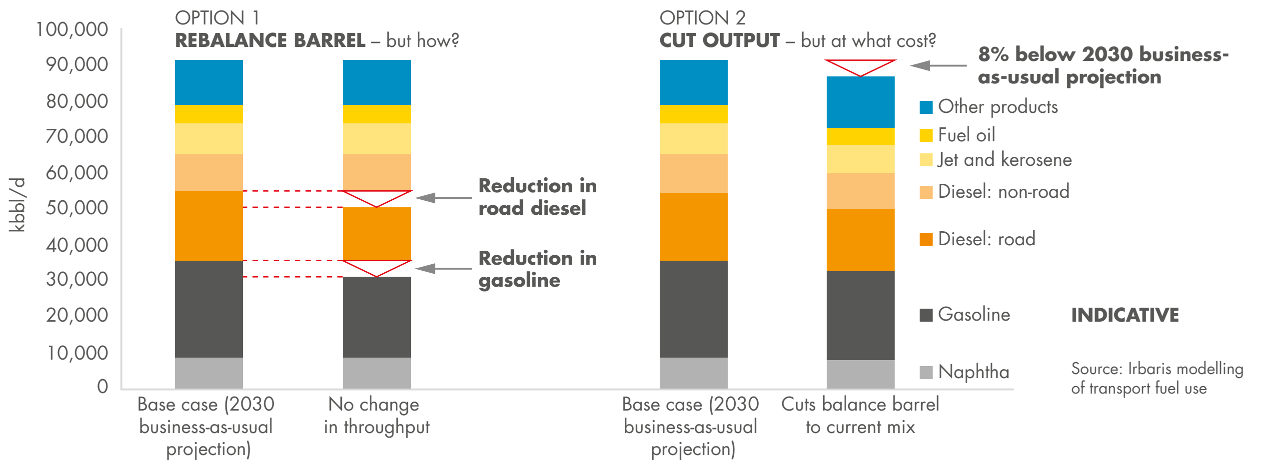

Figure 1: The impact on refiners of changes in road transport. With even modest assumptions about the changes in transport, refiners face a significant mass balance or throughput challenge.

> FINDING WAYS TO IMPROVE CRUDE AND FEEDSTOCK FLEXIBILITY COULD ALSO BE IMPORTANT, WHILE INCREASING PRODUCT SLATE FLEXIBILITY COULD PROVE HIGHLY VALUABLE.

RESPONSE OPTIONS

Refinery managers looking to safeguard their competitiveness have a limited set of options. One of the most important may be to reduce the breakeven point at which they run the refinery. They may be more used to looking for debottlenecking opportunities, but a smart mindset now might be to ask: what options do we have to run our assets at a slightly lower utilisation level and still make money? I understand that there are some interesting technical ideas emerging in this space.

Finding ways to improve crude and feedstock flexibility could also be important, while increasing product slate flexibility could prove highly valuable in terms of a refiner's ability to respond to the mass balance challenge that I outlined earlier.

Portfolio owners could explore additional options, from optimising their portfolios in terms of geography and investment timelines, for example, or looking for rationalisation and strategic partnering opportunities.

The key here is being able to figure out which of those options actually make sense to their specific technical and market circumstances. For example, the most appropriate responses for a state-owned national oil company are likely to be very different to those for a small independent refiner.

STRATEGIC MONITORING

There is a substantial flow of news about developments affecting the energy transition. Some will be important, some hype, and some not actually news at all; it may be difficult for refiners to identify which are important "signposts" of the future pace and direction of change. Energy executives do not traditionally monitor some of the key indicators, which may cut across industry boundaries; however, these executives would be well advised to develop mechanisms to help figure out which developments are important to their business and which are not.

A wholesale oil demand revolution will not be necessary for new threats and opportunities to emerge. And, frankly, most refinery executives are not aware of this yet. The refining industry is clearly not going to disappear overnight, or even over several decades, but the opportunities to make money could change much more quickly.

KEY TAKEAWAYS

- The energy transition creates new threats and opportunities that could have a profound effect on refiners. These changes are already happening more rapidly and in more ways than most industry managers recognise.
- Quite small changes from the business-as-usual projections for transport fuel demand could have profound impacts on refining economics and the competitive landscape.
- The impacts will vary by region and company, although operations with scale, flexibility, complexity and close integration with petrochemicals could be better placed to withstand the changes that lie ahead.
- Managing the risks and opportunities requires monitoring of a wider range of issues than most refining companies have traditionally considered.
- Ensuring that investments in capacity and in performance improvements deliver profits and business resilience requires both leading-edge technical solutions and greater understanding of how the energy transition will affect the individual refinery in the coming decade.

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SEEING THE INTEGRATED PICTURE

Finding ways to minimise the amount of bottoms sent to the bunker fuel pool has become a strategic priority for many refiners. Although many technical solutions are available, the optimum response for a specific refiner depends on individual circumstances. Refiners that already have a visbreaker unit (VBU) and are capital constrained may find integrating it with the vacuum distillation unit (VDU), solvent deasphalting (SDA) unit and hydrocracking unit (HCU) or fluidised catalytic cracker (FCC) to be particularly attractive. Here is why.

Visbreaking is a well-established process that has been around for more than 50 years. It has been a particularly popular bottom-of-the-barrel upgrading option in some regions, especially much of Europe and parts of Asia Pacific that have had a strong market for fuel oil. Although a VBU produces lower distillate yields than a delayed coker, it has clear strengths, in particular, a lower capital cost. It can also be revamped easily to achieve higher conversions if there is no need to produce stable fuel oil.

With outlets for fuel oil now diminishing, however, refiners with a VBU must evaluate new bottom-of-the-barrel solutions. Those with an abundance of capital could consider investing in the technologies that provide the highest conversion levels, such as residue gasification, slurry hydrocracking or ebullated-bed residue hydrocracking, but these will be out of reach for most refiners.

However, as a VBU can integrate seamlessly with an SDA unit, which has a low investment cost, there is the opportunity to reduce fuel oil exposure significantly at a low cost.

THE RATIONALE

Before installing any kind of residue upgrading technology, the first step when seeking to reduce refinery fuel oil production should always be to maximise the distillate yield from the VDU (either as a diesel pool component or as a feedstock for a secondary processing unit such as an HCU or an FCC). The production costs for straight-run distillates are lower than those for a thermal cracking or solvent extraction unit are.

This can be done at relatively low cost by revamping the VDU using Shell's deep-flash, high-vacuum technology. Typically, this can generate 1–3% more distillates, with a corresponding reduction in short-residue (SR) yield.

Next, how to deal with the SR? Some refiners consider putting an SDA unit upstream of the VBU. Shell Global Solutions' view is that cracking SR in a VBU before sending it to the SDA unit is preferable, as it leads to a smaller and, therefore, less-expensive SDA unit.

The quality of the deasphalted oil (DAO) produced from the SDA unit will depend on the unit's extraction depth. A higher extraction depth results in DAO with higher levels of resins, asphaltenes and contaminants. In contrast, the heavy distillates produced by the VBU will be of higher quality. Furthermore, the VBU can be upgraded, also at relatively low cost, by adding a vacuum flasher. This will increase conversion and distillate recovery.

The visbroken vacuum gas oil (VGO) can be routed to the HCU or the FCC, while the high-sulphur vacuum-flashed cracking residue that remains can go to an SDA process such as the residuum oil supercritical extraction (ROSE®) process (see boxed text, KBR's ROSE SDA technology) that can handle such difficult feedstocks. The extraction depth achievable is decided by the quality of the pitch (asphalt) that is produced and its intended use.

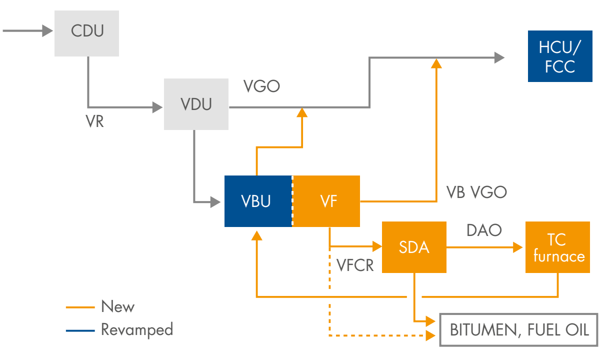

Figure 1: An integrated VDU–VBU–SDA–TC DAO–HCU/FCC line-up. The key is to first maximise the straight-run distillate that is extracted from the vacuum column before treating it first by cracking and then by SDA.

In turn, the SDA unit will produce paraffinic DAO with a high hydrogen content that is, therefore, suitable for further cracking. The pitch that remains, which contains most of the residue's contaminants, can be routed to bitumen blending or for pelletising. A possible line-up is shown in Figure 1.

The DAO produced can be cracked in a Shell thermal distillate conversion (TC) unit. The conversion of DAO into distillates takes place in a heater. The advantages here are that DAO is cracked to distillates without using a catalyst or hydrogen, and the investment costs are significantly lower than those for catalytic conversion processes. When the distillate cracking unit is integrated with a VBU, the cracked feed is routed to a combined fractionator. Additional processing, usually hydrotreating, is required to make final products. Adjusting the heater operating conditions maximises the overall yield of distillates (520 minus) to as high as 75 wt%.

With its low capital cost, reasonably high conversion and wide flexibility in feed quality, such a line-up could be ideal for refineries with capital constraints in revamping secondary processing units.

> IT WOULD PROVIDE AN INCREMENTAL BENEFIT FROM UNIT TO UNIT: THE VDU REVAMP LIFTS MORE DISTILLATE, SO, FEWER BOTTOMS ARE PRODUCED; THE VACUUM FLASHER FURTHER INCREASES DISTILLATE RECOVERY; AND THE FUEL OIL THAT IS PRODUCED BY THE VBU IS REDUCED FURTHER BY THE SDA UNIT.

PHASED INVESTMENT OPPORTUNITY

Increasingly, refiners are keen to avoid regret investments; a line-up such as this would support such an objective. For example, if they later wanted to install one of the highest residue upgrading technologies, the SDA unit would continue to be relevant.

In terms of bottoms reduction, it would provide an incremental benefit from unit to unit: the VDU revamp lifts more distillate, so, fewer bottoms are produced; the vacuum flasher further increases distillate recovery; and the fuel oil that is produced by the VBU is reduced further by the SDA unit that follows.

Consequently, such a line-up could be attractive to refiners worldwide and, with the International Maritime Organization's global fuel oil sulphur cap (IMO 2020) on the horizon, might provide a much-needed low-capital cost option for residue conversion.

KEY TAKEAWAYS

- An integrated VDU–VBU–SDA–TC DAO–HCU/FCC scheme could be particularly interesting for a refiner that has a VBU, wants to respond to IMO 2020 and is capital constrained.
- Although a VBU can integrate seamlessly with an SDA unit to reduce bottoms at low cost, simultaneously sweating the VDU substantially enhances the benefit.
- As an SDA unit can also integrate with other residue upgrading technologies, such a line-up would not be a regret investment.

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KBR'S ROSE SDA TECHNOLOGY

One of the leading SDA technologies on the market is ROSE technology, which is licensed by the technology and engineering firm KBR. The DAO it produces contains very low quantities of metals, asphaltenes, sulphur and Conradson carbon residue, and is an excellent feedstock for processing in conventional refinery units such as fixed-bed VGO hydrotreaters and FCCs. It can also be processed in high-pressure HCUs and TC units.

The increased hydrogen content and lower contaminants of the DAO relative to the residue, together with the low investment and operating costs, often makes ROSE technology an economical option for producing good-quality feed from residue for secondary processing units. According to KBR, the ROSE process is also highly efficient and requires up to 60% less energy than other technologies.

KBR is one of Shell Global Solutions' alliance partners, so when customers receive a Shell-designed revamp that includes the addition of a ROSE SDA unit, all the units are optimised to work together. This includes, for example, the feed specifications and the battery limit conditions.

VDU AND THERMAL CONVERSION TRACK RECORD

Shell Global Solutions has developed numerous pioneering process configurations in response to emerging business needs and has accumulated vast expertise on how to integrate the technology blocks, whether they are VDUs, VBUs, SDA units, TC units processing unconventional feedstocks such as DAO or asphalt, HCUs, cokers or hydrodesulphurisation units.

Shell accounts for about 40% of all worldwide thermal conversion capacity and Shell Global Solutions has licensed more than 115 units, mostly for the visbreaker process. It has also licensed Shell deep-flash VDU technology in 26 revamped and 24 grassroots units since 1985.

HOW INNOVATIONS IN FCC FEED NOZZLE TECHNOLOGY

CAN HELP IN RESPONDING TO THE BUNKER FUELS CHALLENGE

Few refiners will respond to the International Maritime Organization's global fuel oil sulphur cap (IMO 2020) with a single, major investment that will eliminate the bottom of the barrel. Most will implement several low-capital-expenditure solutions that partially reduce it. One relatively inexpensive option that may be particularly attractive is an innovation in fluidised catalytic cracking (FCC) feed nozzle technology, previously thought to be a mature technology. Recent developments here provide the opportunity to increase slurry oil conversion through better atomisation and to, therefore, reduce this heavy, high-sulphur stream, which traditionally goes to the marine fuel oil pool.

In recent years, FCC feed nozzles have seen only small incremental design improvements and conventional analysis techniques have provided few insights into improving their performance further.

However, after a major Shell Global Solutions research and development programme into feed nozzle technology using new analytical techniques, the organisation has developed upgraded feed nozzle technology that is pushing the boundaries for feed atomisation and enhancing unit reliability.

Consequently, refiners can use this technology to increase the conversion of slurry oil, the heavy aromatic by-product that is the lowest-value stream produced by an FCC unit, to higher-value products.

FCC unit performance at two Shell refineries, Deer Park in the USA and Sarnia in Canada, has significantly improved after installing the new feed nozzle technology. Additional feed nozzle upgrades are planned at other Shell refineries, and the technology is available for licensing for non-Shell sites.

DEVELOPMENT 1: FEED ATOMISATION

When atomised sprays are discharged from feed nozzles they transition from liquid sheets to non-spherical ligaments of poorly atomised agglomerations of liquid and then, ultimately, to droplets. However, atomised spray distributions that include non-spherical droplets and ligaments present a challenge to most spray characterisation methods, which tend to rely on spherical and near-spherical liquid droplet distributions.

Looking to improve feed atomisation, Shell tested a range of droplet measurement techniques including phase Doppler and laser diffraction. Finding that non-spherical droplets and ligaments could be improperly characterised, Shell questioned the validity of these methods and sought a more-appropriate spray characterisation technique.

Key to Shell's innovation was the decision to use the shadowgraph particle image velocimetry (PIV) technique. The shadowgraph PIV data the organisation collected for a wide range of commercially implemented feed nozzle designs indicated an opportunity to improve feed atomisation. This programme also provided considerable insights into feed nozzle performance, which Shell leveraged to develop its latest-generation technology.

Crucially, the upgraded technology reduces the quantity and size of globules in the spray. Globules are defined as large droplets plus poorly atomised ligaments; collectively, these can take substantial time to vaporise in the riser.

DEVELOPMENT 2: RELIABILITY AND INTEGRITY

Globules in an atomised spray can lead to coke deposition along the riser wall, throughout the reactor internals, along the overhead vapour line wall and at the main fractionator inlet. Fouling of the slurry system can also result. This deposition and fouling negatively affect the pressure balance, the unit capacity, the catalyst circulation and the slurry heat removal. These effects become progressively worse as the unit gets further into its operating cycle.

As the latest-generation feed nozzle technology can reduce spray globules and improve slurry conversion and liquid yield, it also helps to mitigate these reliability threats.

Two mechanical upgrades supplement the process design improvements. The first is a tapered sleeve design that enables easier extraction of the feed nozzles during unit turnarounds, thereby reducing the time required for feed nozzle replacement. The second is a proprietary, shield-like sacrificial shroud that covers most of the nozzle tip surface yet allows the feed injection to pass through while minimising tip erosion from the flowing catalyst in the riser.

CASE STUDY: DEER PARK REFINERY

In 2015, Shell Global Solutions evaluated Deer Park's FCC unit. Shadowgraph PIV identified opportunities to improve the droplet size distribution and to reduce the globule content, which would increase the number of droplets and reduce the feed vaporisation time.

So, during its 2016 FCC unit turnaround, Deer Park refinery installed the improved feed nozzle technology. Evidence of improved feedstock atomisation is a dramatically lower riser mix zone temperature at a constant riser temperature. By improving the feed atomisation, the new feed nozzle design has reduced the apparent existence of varying local catalyst-to-oil ratios and increased the effective riser residence time. The net effect is a boost in bottoms destruction (slurry) and additional gasoline and light cycle oil (LCO) production (see Table 1).

YIELD SHIFTS, VOL% FEED	AUDITED
Conversion	1.1
Bottoms	(1.2)
Dry gas + coke	0.4
Gasoline + LCO	1.5
LPG + gasoline	0.9
Volume gain	0.2

Table 1: Deer Park feed nozzle yield shift audit.

CASE STUDY: SARNIA REFINERY

Sarnia refinery also installed the improved feed nozzle technology during a 2016 turnaround.

Unit monitoring data is showing measureable yield improvements with a lower dry gas yield. A shift in the mix zone riser temperature profile (Figure 1) for the same riser top temperature demonstrates the improvement in feed atomisation and vaporisation consistent with observations from Deer Park. Furthermore, the success of the feed nozzle shroud in protecting the feed nozzle head has provided the site with confidence that it will achieve another five years of exceptional feed nozzle performance.

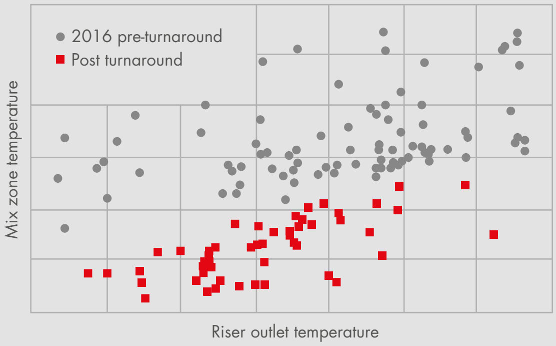
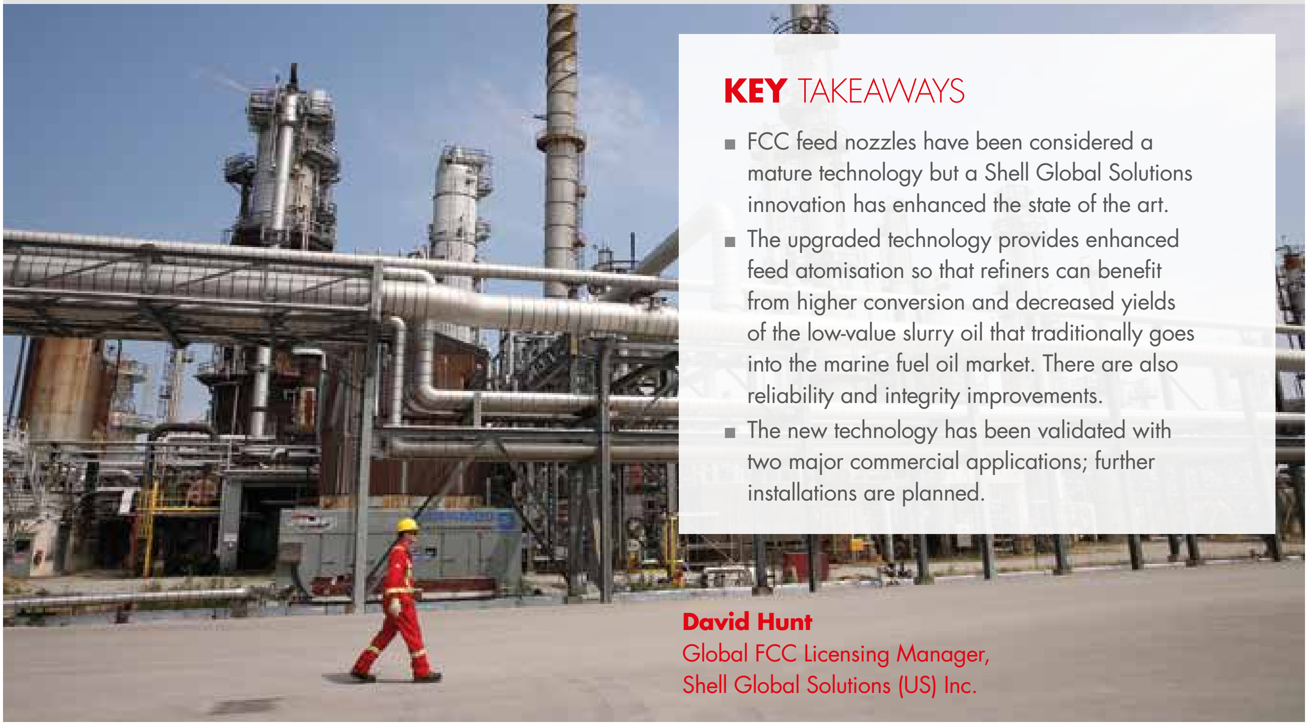


Figure 1: Riser temperature above the mix zone for pre- versus post-turnaround operations.



KEY TAKEAWAYS

- FCC feed nozzles have been considered a mature technology but a Shell Global Solutions innovation has enhanced the state of the art.
- The upgraded technology provides enhanced feed atomisation so that refiners can benefit from higher conversion and decreased yields of the low-value slurry oil that traditionally goes into the marine fuel oil market. There are also reliability and integrity improvements.
- The new technology has been validated with two major commercial applications; further installations are planned.

David Hunt
Global FCC Licensing Manager,
Shell Global Solutions (US) Inc.

TURNING IMO 2020 TO YOUR ADVANTAGE WITH THE SCOT[1] ULTRA PROCESS

Time to prepare for the new marine fuel sulphur specifications is rapidly running out for refiners. Many residue conversion options are available, including quick-win solutions. For example, the Shell Claus off-gas treating (SCOT) ULTRA process offers the potential to increase sulphur recovery unit (SRU) capacity by up to 30% quickly and without capital expenditure, while cutting tail gas treating unit operating costs by up to 50%.

Few shipping operators are investing in expensive bulky on-board sulphur scrubbers with their associated sludge retention and disposal facilities. Instead, they are expecting refiners to provide fuels that will meet the International Maritime Organization's (IMO) global 0.5% cap for sulphur content in marine fuel set to come into force in 2020. Compliance will be a major disruptive change, one that could be either a threat to the profitability of your refinery or, with the right preparation, an opportunity.

There are many ways to reduce the sulphur content of the bottom of the barrel. You could process lower-sulphur crudes or blend in high-value distillates, but these options are economically unattractive. Burning high-sulphur fuel oil on-site in utility boilers is another option, but this creates local emission challenges. That leaves a range of technology solutions for increasing residue conversion (see page 4). The question is how can you take sulphur out (i.e., increase sulphur processing) in an affordable manner and before 2020?

Time, cost and plot-space constraints may preclude some new-build and revamp options, but there are low-cost solutions that you could implement quickly to safeguard your competitive position.

In this article, we consider enhancing capacity in an existing SRU by increasing the front-end pressure (Option 1); through increased oxygen enrichment (Option 2); or a combination of both (Option 3). We will only consider the SRU and assume that the solvent flow system has an additional 10% capacity and that an oxygen supply for low (up to 28%) oxygen enrichment is achievable.

Our example uses the SRU feed gas composition and parameters from a Shell refinery.[2] The SRU line-up includes indirect heating (steam reheating) with two Claus catalytic reactors; the SCOT unit uses a formulated methyl diethanolamine (MDEA) solvent. The SRU has a thermal incinerator that operates at 650°C and uses a Shell sulphur degassing system to achieve a <10-ppmw hydrogen sulphide (H_2S) specification in liquid sulphur.

Options 1 and 2 are feasible for a high (250-mg/Nm^3) sulphur dioxide (SO_2) emissions regime, but not Option 3, as it demands more than the assumed maximum solvent flow (Table 1). Option 2 achieves 120% SRU capacity. The modest (102%) solvent flow increase is because the oxygen enrichment also means less volumetric flow through the SCOT absorber with lower nitrogen content and, consequently, only a minor H_2S column load increase. Only Option 2 remains feasible when a low (150-mg/Nm^3) SO_2 emissions limit is applied, and gives 120% SRU capacity with 105% solvent flow.

However, the development of the Shell SCOT ULTRA next-generation tail gas treating process can transform the situation by offering a performance step change with minimal investment.

In most cases, you only need a simple swap to the highly selective JEFFTREAT[3] ULTRA solvent, which was developed jointly by Shell and Huntsman Corporation, and a change to Criterion Catalysts & Technologies' C-834 high-activity, low-temperature SCOT catalyst, without hardware alterations. The new solvent can achieve deep decreases in H_2S emissions while maximising CO_2 slippage; absorbs H_2S at higher temperatures compared with MDEA, which eliminates the need for a solvent refrigeration system; and provides robust

OPTION	VARIABLES	CAPACITY, % BASE	SO_2 EMISSIONS: 250-MG/NM^3		SO_2 EMISSIONS: 150-MG/NM^3	
			SOLVENT FLOW, % BASE	FEASIBILITY	SOLVENT FLOW, % BASE	FEASIBILITY
1	Increase front-end pressure	110	110	Yes	113	No
2	Low-level oxygen enrichment	120	102	Yes	105	Yes
3	Both 1 and 2	130	115	No	118	No

Table 1. Upgrade option feasibility.

OPTION	VARIABLES	CAPACITY, % BASE	SO_2 EMISSIONS, MG/NM³	SOLVENT FLOW, % BASE	FEASIBILITY
1	Increase front-end pressure	130	250	72	Yes
2	Low-level oxygen enrichment	110	150	73	Yes
3	Both 1 and 2	130	150	75	Yes

Table 2. Upgrading with the SCOT ULTRA process.

performance compared with formulated MDEA, even with line burner/fuel gas co-firing designs, as it handles CO_2 better. The new catalyst increases the destruction of organic sulphur compounds at low operating temperatures.

In this example, Option 1 with the SCOT ULTRA process achieves 130% SRU capacity with only 72% of the solvent flow for the high SO_2 emissions regime (Table 2). Option 3 is also feasible with 130% SRU capacity and 75% solvent flow for the low SO_2 emissions regime.

Further analysis shows that using the SCOT ULTRA process in a new tail gas treating unit for a Middle East SRU has the potential to cut a 25-year life-cycle cost to 71% of the equivalent cost using formulated MDEA without cooling.[4] In this case, operating costs are halved.

The SCOT ULTRA process is one of a suite of technical solutions with the potential to help turn IMO 2020 to your advantage. If you have not already begun to prepare, the SCOT ULTRA process may represent a quick way to boost sulphur recovery while cutting operating costs.

KEY TAKEAWAYS

- IMO 2020 specifications mean that high-sulphur fuel oil may soon be worth less than crude oil.
- A suite of bottom-of-the-barrel sulphur recovery options is available, including a range of brownfield solutions for increasing sulphur-processing capacity.
- The Shell SCOT ULTRA process is a solution that can be implemented quickly through a solvent and catalyst swap, without hardware changes in most cases, to help you to debottleneck SRU capacity with low oxygen enrichment.
- The Shell SCOT ULTRA process can cut solvent circulation to 70–75% of the base design, which can potentially reduce operational costs by 50%, mostly through lower reboiler duty (steam consumption).

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[1]SCOT is a trademark owned by the Shell group of companies.

[2]Amine acid gas at 50°C, 0.75 barg and 100 t/d, composed of 95.5 mol% H_2S, 4.05 mol% carbon dioxide (CO_2) and 0.45 mol% hydrocarbons, and sour water stripper acid gas at 80°C, 0.8 barg and 15 t/d, composed of 62.4 mol% H_2S, 2.4 mol% CO_2, 34.4 mol% ammonia and 0.8 mol% hydrocarbons (dry basis).

[3]JEFFTREAT is a registered trademark of Huntsman Corporation or an affiliate thereof in one or more, but not all countries.

[4]Analysis based on a Middle East refinery with a 220-t/d capacity SRU that needs a new tail gas treating unit with a 25-year life to handle an absorber feed gas with 2.5 mol% H_2S and 0.8 mol% CO_2. The treated gas must have <200 ppmv H_2S to meet a 500-mg/Nm³ SO_2 emissions limit. Low- and high-pressure steam costs \$3.6/t and \$5.8/t respectively, and power costs \$0.035/kWh. The cost of cooling the solvent from 60 to 42°C is \$0.05/m³.

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