## Q&A FORUM

If you would like to submit any questions to the panel you may do so from the floor or alternatively you may submit them in writing and hand them to the conference staff.

### Oct 25 AM session: Climate change bill and opportunity crudes supply outlook

Section 1

1. As Canada strives to increase the value of the oilsands, should refiners expect to see a trend of bitumen-derived crude being upgraded to a greater degree upstream in the future?
2. If more regions switch to taking a life cycle (well-to-wheels) approach for regulating GHG emissions from transportation fuels, like California's Low Carbon Fuel Standard (LCFS), will this greatly impact the appeal and use of opportunity crudes? How will this impact refiners that have already upgraded to handle low quality crude?
3. In light of the climate bill and LCFS requirements, which processing route—carbon rejection or hydrogen addition—is right for refiners?
4. Will the market price opportunity crudes according to the $CO_2$ emission propensity in the future?
5. Carbon tax vs. carbon cap and trade. EC president Jose Manuel Barroso on July 2 said that he is in favor of a broad tax although the European Union has been implementing Emissions Trading Scheme (ETS) for many years. Is Europe changing its approach to fight climate change and how does it affect the US and the rest of the world? Which option is favored by environmental legislators in the world at this moment and in the future and why?
6. How do Canadian bitumen-derived crudes compare to other opportunity crudes from say, South America, in terms of the quantity and ease of middle distillate production? Other than API are there any key crude properties to consider when trying to increase middle distillates?
7. To what extent are the tightening regulations for bunker fuels expected to impact the profitability of processing heavy crudes? What upgrading options are available for minimizing this fraction of the crude?

### Oct 25 PM session: Crude quality, distribution, and management

Section 2

1. What are potential miscibility problems when Canadian syncrudes are blended with paraffinic crudes in Asia as oilsands producers are eyeing the Far Eastern market?
2. What are potential miscibility problems when Brazilian heavy oil and Venezuelan bitumen are blended with paraffinic crudes in Asia as Latin American producers are eyeing the Far Eastern market?
3. The gasoil fraction of Canadian syncrudes is known to have poor cetane quality, is any work being done to address this problem?
4. Naphthenic acid (NA) is known to cause corrosion in refinery equipment. There are some developmental works to decarboxylate NA in a hydrotreater. What is the development status?
5. There are a few theories of asphaltene fouling. Can anyone offer a clearer picture of fouling formation? Also, is there any pretreating approach ahead of the desalters?
6. What strategies have been most effective for reducing fouling in bottom-of-the-barrel conversion units (i.e., antifoulants additives, online cleaning methods, novel heat exchangers, etc.)?

7. For crude blends prone to excessive fouling, how does the expense of heat exchanger cleaning (online or traditional methods) compare to the cost of using additives to reduce the rate of fouling (and to increase time between cleanings)?
8. What strategies are available to prevent instability in visbreaker and coker products? Specifically, many refiners have had issues with di-olefin polymerization in visbreaker and/or coker naphtha?
9. How much of the current world production of crude is considered to be acid crude? Would acid crudes be crudes with a Total Acid Number (TAN) greater than, say, 0.5 or 1.0 mg KOH/g?
10. What approximate percentage of refineries (or number of refineries) in the world can process these acid crudes? What is the typical maximum TAN capability of most these refineries, e.g. <2 mg KOH/g or <5 mg KOH/g? What is the typical maximum TAN capability of the best of these refineries, e.g. <10 mg KOH/g?
11. What are the main methods employed by refineries to enable them to process acid crudes? What is the recent or emerging trend in processing methods employed by refineries to enable them to process crudes with higher content of acids?
12. What are some of the problems refiners have encountered as a result of additives/treatments used in upstream production or in the pipeline? What options do refiners have for mitigating these problems?

## Oct 26 AM session: Innovations in downstream processing I

Section 3

1. Has any refinery or high acid crude production company tried to build a processing unit dedicated to destroying or reducing acids in crude to conventional levels first to allow the treated crude to be processed in conventional refinery processing units thereafter?
2. In Japan, ExxonMobil and Petrobras plan to bow out from the refining business because of a new rule forcing refiners to raise the proportion of gasoline and gasoil they produce from residues. The upgrades (i.e., installation of delayed cokers and RFCCU) appear to be very expensive. Are there any alternatives?
3. Rare earth materials are know to maintain hydrothermal stability of FCC catalysts, particularly in residue upgrading; however, rare earth supply is tight and demand is expected to skyrocket due to novel technical applications (i.e., hybrid cars). Are there any alternatives to rare earth oxides being considered in FCC catalyst formulation for processing conventional and/or resid feeds?
4. What modifications are necessary when applying coking, visbreaking, and/or solvent deasphalting in upstream heavy oil upgraders as opposed to a conventional refinery setting? Are additional opportunities available to utilize the low value resid byproducts (e.g., coke, pitch, asphalt, etc.) in HOU plants vs. refiners?
5. What are the benefits of integrated SDA-delayed coking schemes for a refiner looking to process increasing quantities of opportunity crudes? Can any other integrated schemes involving bottom-of-the-barrel conversion technologies—such as Coking, SDA, visbreaking, resid hydrocracking, etc.—provide similar benefits?
6. In delayed coking, several companies have targeted the selective production of high quality coke to enhance the value of the byproduct, other companies have discussed the selective production of shot coke to alleviate the burden of decoking; in your opinion, what morphology is most desirable? How does the coker process configuration and operating conditions impact coke morphology?
7. What considerations must be made when utilizing extra heavy and/or high TAN opportunity crudes with the delayed coking technology while preventing operation problems, such as fouling and corrosion? Are

any modifications needed to the standard licensed technology to improve operations when processing these low-cost feeds?

8. Is it possible to cofeed biomass into a coker unit? If so, how does the modified feed impact coke morphology?
9. Can you comment on the installation of SDA technology as a grassroots unit vs. a revamp project? Do you have any experience installing SDA technology as a revamp of a subcritical solvent deasphalting unit? What is the primary motivation/benefits of the revamp? Can you discuss the energy savings/$CO_2$ emissions reduction that may be provided?
10. Can you comment on the recommended outlet for the asphalt bottoms from the solvent deasphalting process (e.g., disposal as waste, coker feed, gasifier feed, fuel oil blend component, etc.)? Some techniques are available to convert de-oiled asphalt streams into solid, pelletized asphalt products, can you indicate the benefits of this action in regards to potential end-use of asphalt?
11. Can you provide a comparison on the available outlets for visbroken residue to the potential outlets for asphalt and/or petroleum coke?
12. In light of future MARPOL Annex VI sulfur specifications on marine bunker fuels, many refiners are considering option to limit or eliminate the production of high sulfur fuel oil; however, the installation of alternative technologies (e.g., resid hydrotreating, resid hydrocracking, etc.) requires a significant capital expenditure. What low-capital techniques are available to refiners currently operating visbreaker units to lower the sulfur content of residual fuel streams to meet product specifications?
13. With the price of rare earth metals rising worldwide, are there any alternative materials that can be utilized in resid FCC catalysts to provide the hydrothermal stability benefits necessary that allow these catalysts to withstand the severe regeneration conditions on a RFCCU?

## Oct 26 PM session: Innovations in downstream processing II and carbon management

Section 4

1. Heavy, dirty opportunity crudes require more processing (and therefore more energy) to obtain high quality products than required light, sweet crudes. How can refiners handle/mitigate the associated increase in $CO_2$ emissions?
2. Which carbon capture technology has the most potential to be adopted by refiners? Are any refineries that have implemented carbon capture?
3. Upstream vs. downstream. Which place is the most economical to reduce $CO_2$ emissions on a life cycle basis?

# NOTES