Assessment of the Cost and Scale of Refinery Capacity Additions Necessary to Absorb Projected US Light Tight Oil Increase

October 2014

Turner, Mason & Company ("TM&C") has evaluated the potential impending surplus of domestic light crude oil and how the petroleum industry might respond to this event in several recent engagements which we performed for both upstream and midstream clients. In these engagements, we analyzed the potential responses the industry would likely employ under a variety of scenarios regarding both crude production levels and crude export policy assumptions, and how these responses would impact both investment and domestic crude oil prices and differentials. To support the studies being carried out by Columbia University's Center on Global Energy Policy, in collaboration with the Rhodium Group, and by the Center for Energy Studies at Rice University's Baker Institute for Public Policy, we relied upon this work to examine the potential impacts of three specific interpretations of the current export ban and three differing outlooks for domestic oil production, as defined by the authors of the reports.

Regulatory Scenarios

Regulatory Scenario One envisions a "loose" interpretation of the current export policy that would allow export of domestic crude oil that is processed in a distillation tower designed to remove a small percentage of light material. This scenario assumes that recent Bureau of Industry and Security (BIS) private rulings, which allow for export of similarly processed condensate, are applied to crude oil. A simple stabilizer, as this type of distillation tower is sometimes called, removes a mixture of ethane, propane, butane and pentanes-plus by distilling it from the crude oil (or condensate). Depending upon crude oil quality, this mixture (also called "NGL" or "Y-grade") typically represents 5% to 10% of the feed to the stabilizer. The bottoms product would be an exportable stabilized crude oil, although it will still physically and chemically resemble many light-to-medium crude oils banned from export. A simple flow diagram of a simple stabilizer is shown in Figure 1.

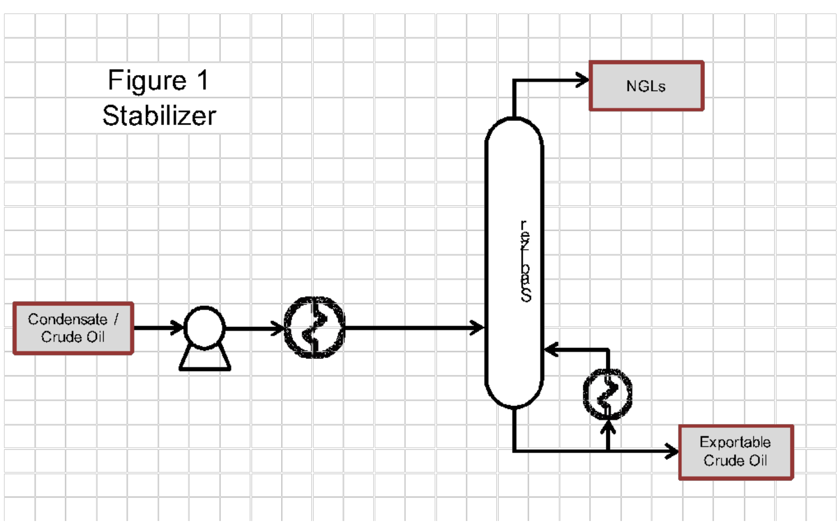
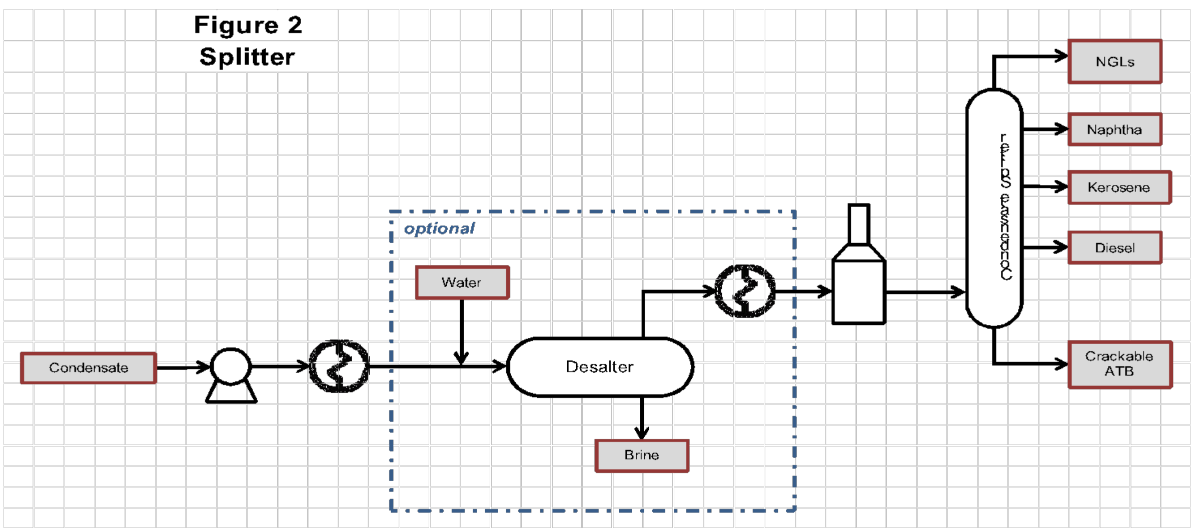


Figure 1
Stabilizer

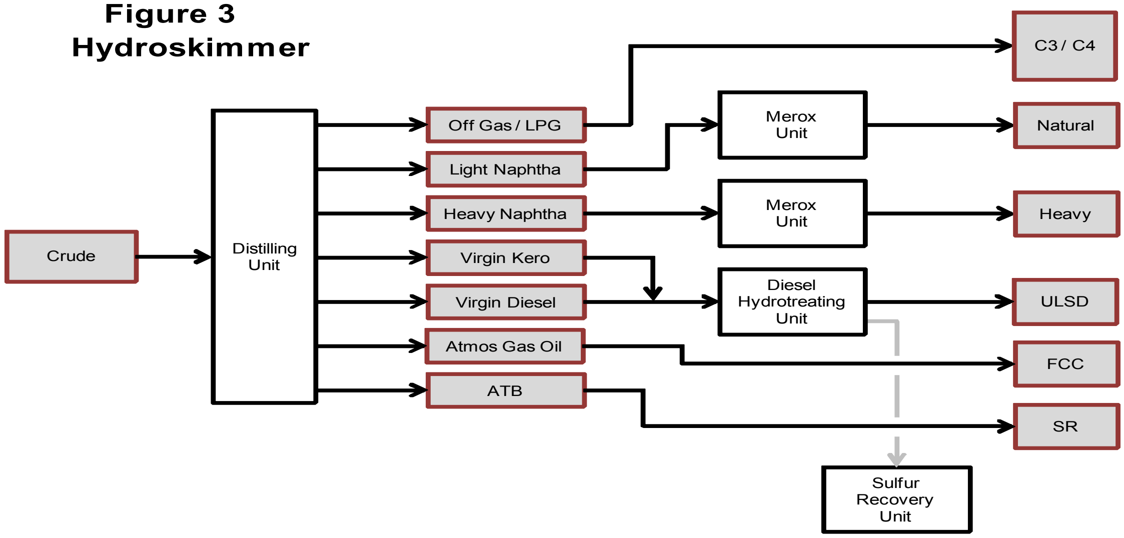
Regulatory Scenario Two assumes stabilized condensate can be exported, but not crude oil. This scenario is consistent with the current BIS "clarifications" made in the Enterprise and Pioneer private rulings. Stabilized condensate is typically lighter than crude oil, has a low percentage of heavy bottoms material and can resemble certain intermediate or unfinished product streams that are currently exportable (such as plant condensate). Thus, condensates would likely be directed to simple stabilizers, but crude oil would need to be more fully processed in order for the products to be exportable. There has been recent speculation of the possibility of allowing the export of condensate (but not crude) directly, without the requirement that it be stabilized. Because significant volumes of condensate will be stabilized in any case, to facilitate proper storage and transport, and because the investment and operating costs of stabilization are relatively small, such a case would not result in substantively different results.

Regulatory Scenario Three assumes a "strict" interpretation of the export ban and requires all domestic crude oil and condensate be more fully processed in a facility that resembles a refinery crude oil distillation unit. Facilities similar to the USGC condensate splitters currently under construction are assumed to qualify as crude oil distillation in that they fractionate their feed into multiple unfinished product streams. A simple flow diagram of a splitter is shown in Figure 2.



Depending upon the ultimate volume of surplus, additional downstream processing may be required. In those instances, a hydroskimming facility designed to produce ultra-low sulfur diesel ("ULSD") may be preferable to a splitter that produces little or no finished product. A block flow diagram of a ULSD hydroskimmer is shown in Figure 3.

Figure 3
Hydroskimmer



Crude Oil Production Outlooks

For each regulatory scenario, we were asked to analyze the potential outcomes associated with three possible outlooks for domestic crude oil and condensate production. The first production outlook is the *2014 AEO Reference Case* which assumes production will peak 9.6 million of barrels per day ("MM bpd") in 2019. The 2014 AEO also has a *High Resource Case* which assumes production will continue to gradually rise through 2030 to a high of 12.85 MM bpd. The third production outlook, the *Upper Bound Case*, assumes a more rapid growth in production with volumes reaching 13 MM bpd by 2020 and peaking at 14.3 MM bpd in 2026.

Potential Downstream Reponses

As the growth in domestic production has risen refiners and midstream players have begun to respond with various investments. For the most part, these announced projects have more to do with quality differences between the new domestic production and the imports being displaced and/or economic opportunity. We are unaware of any projects currently underway solely in response to a potential surplus of domestic crude oil. However, that "Day of Reckoning" is rapidly approaching and we suspect a new round of projects will be announced and that these investments will be tailored to convert crude oil and condensate into products that are exportable.

While there are a number of ways to process crude oil, from the simple stabilizers previously mentioned all the way to new grassroots, highly complex full conversion refineries, we believe most of these new investments will be limited to what is the minimum level of simple processing needed to making something legally exportable. Our opinion is rooted in several fundamental views:

- *The potential for a total relaxation of the export ban, which if done would strand investments made solely to circumvent the current regulation and cripple the incremental economics associated with increasing refinery utilization to produce finished products for export markets;*

- *The emergence of midstream players, whose experience operating complex refining processes is limited, as owner/operator of these new facilities;*

- *The surplus of Western Hemisphere heavy crude oil, which limits the economic attractiveness of revamping heavy oil refineries for light oil to displace these imports;*

- *The shorter execution time needed to engineer and construct simple facilities compared with more complex refineries; and,*

- *The likely oversupply of domestic gasoline and the finite volume of gasoline exports the U.S. can expect to economically place in the world market.*

While we feel a few economics-driven projects that go beyond this "minimum investment" approach will get built, we believe the majority of the investments will involve stabilizers, splitters and/or hydroskimmers. Stabilizer projects require the least amount of investment, are the easiest to permit and can be usually executed with 24 months. In contrast, a ULSD hydroskimmer features much more process equipment with longer lead times, a more difficult permitting pathway and can take up to four years to execute from conception. Which of these options becomes the dominant route to dealing with the light crude oil surplus will be dictated by the ultimate interpretation of the export regulations.

We believe that most of the new "crude-to-product" facilities will be located along the Texas Gulf Coast. This will be driven by two factors – (1) the majority of future production increases will come from Texas (primarily the Eagle Ford and Permian basins) and ultimately be "piped" to the Gulf Coast and (2) because of the need to segregate exportable streams from non-exportable crude, the processing facilities will need to be proximate to export facilities. Our own outlook on production, which closely resembles the *2014 AEO High Resource Case*, envisions an increase in crude production from PADDs II and III (from 2013 year average levels) on the order of 4 MM bpd. Approximately 2.2 MM bpd is from the Permian Basin and Eagle Ford basins alone. Therefore, we believe any crude oil surplus will be mostly comprised of these barrels which are easily shipped to major Texas ports such as Corpus Christi, Freeport, Texas City, Houston and Port Arthur. Thus, we conclude the majority of new investments will be geared to processing crude oils and condensates from these basins and that the facilities will be near major ports.

Regulatory Scenario One – "Loose" Interpretation

Assuming both crude oil and condensate can be exportable by stabilizing these material in a simple facility presents the easiest, cheapest and fastest solution to a domestic surplus of light crude oil. While the world market for crude oil and hydrocarbon feedstocks will ultimately set the price for stabilized crude oil, we believe it is reasonable to assume the relative value of the stabilized crude will be higher than its unstabilized predecessor by an amount that reflects the increased value to a buyer by removal of the low-valued NGLs and any water. Thus, the economic "penalty" for having to stabilize crude oil should be its associated operating cost and a reasonable return on the newly invested capital. Table 1 depicts the expected yield of NGLs and stabilized crude oil from three likely feedstocks and Table 2 shows the expected composition of the NGL streams.

TABLE - 1

Stabilizer Material Balances - MBPD

	WTI	Eagle Ford	EF Cond
Crude Oil Feed	230.0	170.0	100.0
Products			
Y-Grade Mix	11.5	11.4	10.0
"Stabilized" Crude	218.0	158.2	88.3
Total Products	229.5	169.6	98.3
Loss*, %LV	0.22	0.22	1.70

"*" Estimated loss includes an assumed 0.2% water in feed

TABLE - 2

Estimated Y-grade Compostion* - %LV

	WTI	Eagle Ford	EF Cond
Ethane & Lighter	1	1	5
Propane	13	8	24
Butanes	52	47	40
Pentanes & Heavier	34	44	31

"*" Actual composition will be highly dependent on crude oil quality

Table 3 lists the approximate investment for stabilizer complexes. Table 4 details the projected operating costs.

TABLE - 3

Stabilizer Complex Investment - $MM

	WTI	Eagle Ford	EF Cond
Crude Oil Stabilization	95	80	65
Tankage	80	70	60
Docks	45	40	35
Other Infrastructure	130	110	90
Total (USGC basis)	350	300	250
MBPSD Capacity	*240*	*180*	*105*

TABLE - 4

Stabilizer Operating Costs - $/B

	WTI	Eagle Ford	EF Cond
Fixed Cost	0.25	0.29	0.41
Variable Cost	0.14	0.15	0.07
SG&A/Int. on Working Capital	0.08	0.10	0.12
Capital Recovery	0.71	0.82	1.16
Total Cost	**1.19**	**1.37**	**1.78**
Throughput, MBPCD	*230*	*170*	*100*

If production growth is similar to that found in the *2014 AEO Reference Case* then no surplus will materialize. The current level of capacity additions and refinery utilization increases, coupled with existing stabilized condensate that will qualify for export, will easily absorb a maximum domestic crude oil production level of 9.6 MM bpd. As a result, there will be no discernible impact on crude oil prices.

If production growth is similar to that found in the *2014 AEO High Resource Case* then an eventual surplus of 2.5 MM bpd will materialize by 2030. This will require approximately 11 to 15 stabilizer complexes to be built. The number of new stabilizers could be a bit lower if more existing condensate stabilizer capacity has its stabilized products approved for export. The initial surplus will start to appear in 2017, so the planning for new investment will need to begin soon. Based upon the projected rate of growth, approximately one of these new stabilizers will need to be built each year. The probability of new facilities coming online as production builds is quite high; therefore, we do not believe major price disruptions will occur. Based on stabilizer full cost, we expect the impact on crude oil prices be $1.00-$1.50 per barrel. There is a chance for new capacity to outpace production growth. In this event, the impact on price could be as little as $0.50 per barrel, which is equal to the incremental operating cost of the stabilizer facility.

If production growth is similar to that found in the *Upper Bound Case* then the expected surplus will start to occur in 2016 and will grow to over 4 MM bpd by 2026 when it peaks. This will require approximately 18 to 24 stabilizer complexes to be built. Under this outlook, planning for new investment will need to have already begun. Based upon the projected rate of growth, approximately three of these new stabilizers will need to be built each year through 2021. After that, the rate of growth tapers off the point where one new stabilizer per year is needed. The probability of new facilities coming online as production builds is much lower under this outlook; therefore, we believe major price disruptions could occur. While we still believe the ultimate impact on crude oil prices will be $1.00-$1.50 per barrel, there is a good chance new capacity will lag production for several years – perhaps until 2022. In this event, the impact on price could be significant. An inability to stabilize crude oil could prompt short-term discounts on the order of $5-$6 per barrel, the level we believe needed to increase refinery utilizations in PADDs I and V.

Regulatory Scenario Two – "Status Quo" Interpretation

Making the assumption that condensate can be made exportable by simple stabilization, but not crude oil, will substantively increase the investment required to produce exportable products from any domestic light crude oil surplus. The results below are largely the same if one assumes that condensate could be exported even without stabilization, as noted above.

While we believe there will be almost 1.4 MM bpd of condensate produced once production peaks, much of this volume is already being produced or will have a "home" once several announced projects are completed. Thus, while production could perhaps grow by 2.5 to 4 MM bpd, we believe new condensate will be only 0.3 to 0.4 MM bpd of that amount. Therefore, condensate stabilization can only put off the inevitable surplus by a year or two. Thus, more complex processing will be required under a "status quo" interpretation to convert light crude oil into exportable products. While this will require more investment per barrel, it will also take significantly greater lead time for project execution. Similar in effect to more rapid production growth, longer equipment and permitting lead times also increases the probability that production growth can outpace new facilities and create short-term imbalances that will require greater price discounts to correct until new facilities are built.

As we previously stated, we believe the "price setter" facility for this scenario will be a WTI ULSD hydroskimmer. While different facilities could go in, we believe this configuration will be the most common and that its economics will ultimately dictate the long term price impact on domestic light crude oil. Table 5 depicts the expected hydroskimming yields from the three most likely feedstocks.

TABLE - 5

Hydroskimmer Material Balances - MBPCD

	WTI	Eagle Ford	EF Cond
Crude Oil Feed	170.0	130.0	100.0
Hydrogen, MSCFD	13.0	8.0	7.0
Products			
LPGs	5.0	4.2	6.6
Light Naphtha	14.5	16.0	11.5
Heavy Naphtha	36.5	34.0	30.5
Jet Fuel	0.0	13.0	10.0
ULS Diesel	61.0	32.0	23.8
Gas Oil	5.0	0.0	0.0
ATB	47.0	30.0	12.0
Total Liquid Products	169.0	129.2	94.4
Product Yield, %LV	99.4	99.4	94.4

TABLE-6

Hydroskimmer Complex Investment - $MM

	WTI	Eagle Ford	EF Cond
Process Units	360	250	210
Tankage	110	90	80
Docks	60	50	40
Other Infrastructure	470	410	270
Total (USGC basis)	1,000	800	600
MBPSD Capacity	*180*	*140*	*110*

TABLE-7

Hydroskimmer Operating Costs - $/B

	WTI	Eagle Ford	EF Cond
Fixed Cost	1.05	1.12	1.10
Variable Cost	0.85	0.95	0.63
SG&A/Int. on Working Capital	0.26	0.31	0.29
Capital Recovery	2.74	2.87	2.79
Total Cost	**4.93**	**5.29**	**4.86**
Throughput, MBPCD	*170*	*130*	*100*

As shown, hydroskimmers produce significant volumes of unfinished naphtha, gas oil and ATB. While some of this volume will displace imports of similar oils and may find markets in the Caribbean, as hydroskimming activity grows, many of these barrels will need to move to Asian markets. In this event, there will be further downward pressure on domestic crude oil prices. However, there is a possibility that the industry could overbuild hydroskimming capacity, which could make it more difficult for downstream processors to extract discounts equal to their full cost.

Table 6 lists the approximate investment for these facilities and Table 7 details the projected operating costs for hydroskimming. Table 8 compares the relative net margin of hydroskimmers with alternative dispositions for light crude oil. We believe the difference in net margin between a

TABLE-8	
Light Crude Oil Processing Options - $/B of Relative Margin	
USGC Refinery Incremental Barrel (WTI)	base
Increased USGC Utilization (WTI)	(0.40-0.80)
USGC Greenfield Simple Stabilizer	(1.20-1.80)
USGC Refinery "Add-On" Hydroskimmer (USGC pricing)	(1.50-2.50)
USGC Refinery "Add-On" Hydroskimmer (Export pricing)	(3.50-5.00)
Increased USWC Refinery Utilization (Pipeline crude)	(4.00-5.00)
Increased USAC Refinery Utilization	(4.50-5.00)
USGC Greenfield WTI Hydroskimmer (USGC pricing)	(4.50-5.00)
USGC Greenfield WTI Hydroskimmer (Export pricing)	(6.00-7.00)
Increased USWC Refinery Utilization (Rail crude)	(6.50-7.00)

WTI hydroskimmer and a USGC refinery's incremental WTI runs will mirror the expected discount to pre-surplus WTI that is needed to facilitate these investments.

As in Regulatory Scenario One, if production growth is similar to that found in the *2014 AEO Reference Case* then no surplus will materialize and existing (and planned) capacity will absorb the maximum domestic crude oil production level of 9.6 MM bpd (which is only 1.0 MM bpd above current levels). As a result, there will be no discernible impact on current domestic crude oil prices.

If production growth is similar to that found in the *2014 AEO High Resource Case* then the eventual surplus of 2.5 MM bpd will require approximately 3 or 4 new condensate stabilizer complexes. However, if more existing condensate stabilizers are qualified for exporting their stabilized product, this would reduce the amount of new stabilizer capacity. More importantly, approximately 13 to 15 crude oil hydroskimmers, or other facilities of equal capacity, will need to be constructed to deal with the projected surplus by the time it starts to build in 2017. Given the lead time for new stabilizer investment, planning activities for the first of these facilities will need to begin now if they are to come online with the expected surplus. Based upon the projected rate of growth, approximately one or two of these new stabilizers or hydroskimmers will need to be built each year. The probability of new facilities coming online as production builds is reasonably good, but not high. Therefore, some price disruptions could occur. Based on relative hydroskimming economics, including return on investment, we expect the long term impact on crude oil prices be $5.00-$6.50 per barrel. Since the economics for hydroskimming are highly sensitive to naphtha and ATB netback prices, the first hydroskimmers may have better margins during the period when imports of these unfinished oils are being replaced by hydroskimmer volumes. However, that may only serve to lessen (or off-set) the short-term "hit" to domestic crude oil prices if production growth initially exceeds new capacity. Still, it is likely that naphtha and ATB from hydroskimming operations will eventually exceed domestic demand and need to be exported if the surplus reaches 2.5 MM bpd.

If production growth is similar to that found in the *Upper Bound Case* then initial surplus beginning in 2016 and the eventual peak surplus of 4 MM bpd will likely create problems for the downstream industry if hydroskimmers are required. Under this outlook, 4 to 6 condensate stabilizers will still need to be built, but the real challenge will be a) to get design and construction of the first group of hydroskimmers needed by 2016-2017 underway and b) to build 18 to 20 hydroskimmers between now and 2022. In total, 30 to 35 stabilizer and/or hydroskimming complexes will be required if domestic production grows to 14.3 MM bpd. Given the current petrochemical construction boom on the USGC, it is doubtful, in our opinion, that this many new facilities can be built at a rate equal to this level of production growth. Even if the financing for these facilities was readily available, we doubt permitting agencies would be capable of moving this quickly and it is likely the domestic EPC industry and its equipment suppliers would be overwhelmed given the large aggregate investment required, as shown in Table 9.

TABLE-9			
Aggregate Industry Investment - $ Billions			
Interpretation:	"Loose"	Status Quo	"Strict"
AEO Reference	0	0	0
AEO High Resource	3-5	13-16	14-17
Upper Bound	6-8	26-31	27-32
Upper Bound (150%)	n/a	39-46	41-48

In the past, such an environment has caused refining and petrochemical investments to increase in cost by as much as 50% over their expected "steady state" cost. While we still believe the long-term impact on crude oil prices will be similar to the $5.00-$6.50 per barrel if production growth was lower, it is impossible to predict how far domestic crude oil prices would fall in this scenario until the imbalance in supply was corrected. The short-term situation would be similar, in our opinion, to periods when crude oil was "bottled-up in Cushing, OK, North Dakota and Alberta due to limited transportation avenues. In these scenarios, discounts of $10 to $15 per barrel were not unusual. While large discounts would prompt increased utilization by refineries in PADDs I and V, these facilities could realistically accept no more than 0.2 MM bpd of additional oil, thus providing no real help. Such a large drop in prices could well serve to slow down production growth to levels more consistent with the *2014 AEO High Resource Case* if no reasonable outlet exists for the incremental crude oil barrel. Certainly, if production growth was being stifled by the export ban, we would expect increased pressure on regulators (and Congress) to grant temporary export exemptions and approve other allowable activities like crude oil swaps to encourage domestic production.

Regulatory Scenario Three – "Strict" Interpretation

If the BIS's rulings regarding stabilized condensate were reversed and condensate needed to be further processed, there will be very little difference to the outcomes described in Regulatory Scenario Two. Instead of condensate stabilizers being built, condensate splitters or hydroskimmers would be required. This will add to the Regulatory Scenario Two alternatives in this way:

- For *2014 AEO Reference Case* production levels, no real difference

- For *2014 AEO High Resource Case* production levels, new stabilizer complexes would become hydroskimmers instead. Existing stabilized condensate would require splitting and eventually hydroskimming, so a few additional hydroskimming complexes would be needed at an incremental cost of $1 billion in the aggregate. The probability for a short-term "hit" to crude oil prices would go up since these additional hydroskimming would require longer lead times, but overall long-term impact on crude oil price would be about the same.

- For *Upper Bound Case* production levels, the required condensate hydroskimmers would only serve to "pile on" the Regulatory Scenario Two short-term crisis. Given the magnitude and duration of the potential 4 MM bpd surplus and its impact on crude oil prices, it is difficult to quantify the impact of the relatively small increase in process facilities that the elimination of stabilized condensate exports would prompt.

Conclusions

It appears to us that the production levels envisioned by the *2014 AEO Reference Case* creates no need for crude oil exports and if it eventually did (perhaps due to reduced refinery utilization) the downstream industry would quickly adjust to absorb any surplus. Thus, various interpretations regarding current export regulations are a moot point. Any impact on domestic crude oil prices would be negligible and difficult to separate from the typical market variations in the price for WTI.

If production levels mimic the *2014 AEO High Resource Case* outlook, then the downstream industry will need to respond with significant investment, short of an outright repeal of the export ban. The degree of investment will be dependent on the ultimate interpretation of the regulation's clause regarding "processing in a crude distillation unit". If stabilization of both condensate and crude oil is regarded as "distillation", then the downstream requirements to make a 2.5 MM bpd surplus created over 15 years into exportable, stabilized crude will be reasonable and will likely keep pace with the growth in production. The expected impact on domestic crude oil prices will be somewhere between $0.50 and $1.50 per barrel of reduction to the WTI price. If stabilization is not allowed, then hydroskimming will most likely be employed and the expected reduction in price will grow to $5 to $7 per barrel. Further, wider short-term discounts could occur if hydroskimmer construction lags production growth.

If production levels reach those found in *Upper Bound Case*, then there is a significant chance that the downstream industry will not be able to construct facilities at the pace needed to prevent a glut of crude oil on the USGC. If stabilization of both condensate and crude oil is allowed, then there is a chance these short-term imbalances will be manageable, but crude oil discounts of $5 to $6 per barrel could occur during the rapid growth years between 2016 and 2022. Beyond that time period, we would expect the imbalances to be corrected and the large discounts to shrink back to long-term values around $1.00 to $1.50 per barrel. If stabilization is not allowed and hydroskimming required, it is almost guaranteed the downstream industry will not keep pace with this level of production growth. The supply imbalance will be greater, and its duration longer, compared with a ruling allowing stabilization. While long-term discounts will be $5 to $7, short-term discounts over the period leading up to peak production in 2026 could easily exceed $10 per barrel on a regular basis. It is also feasible that domestic crude prices could fall to a level where production growth is negatively impacted.