CONDENSATE

An EPRINC PRIMER

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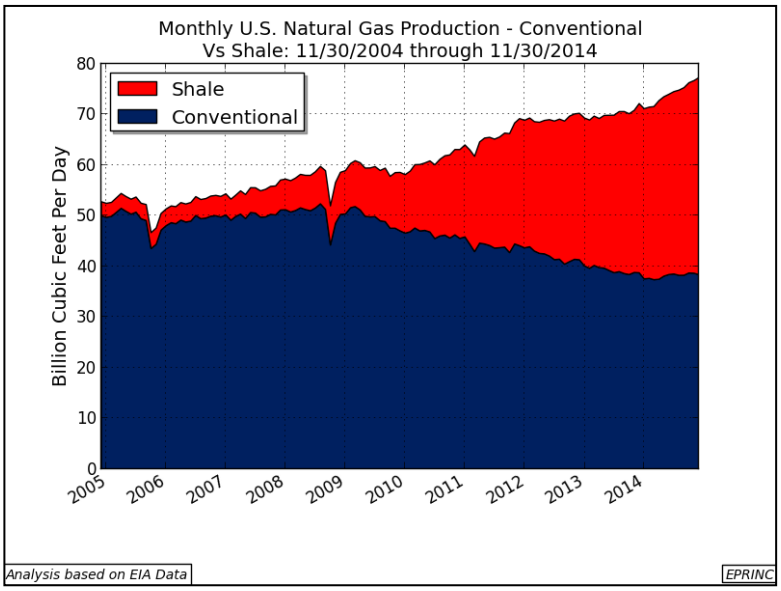
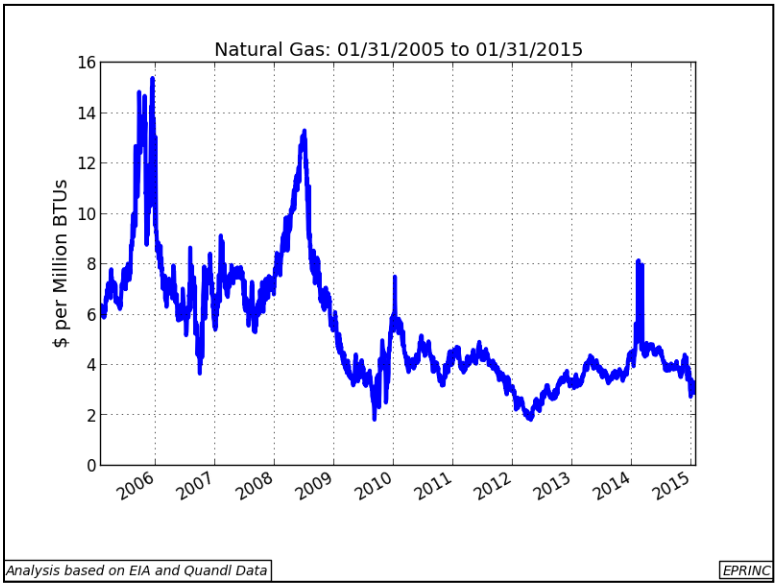
Introduction

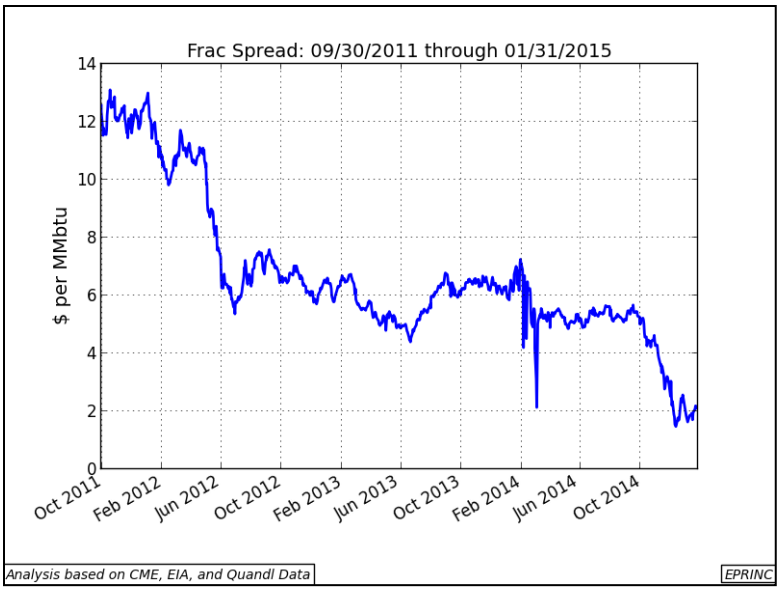
In 2006 after a long, slow period of decline, US natural gas production reversed this trend and started to surge. This was due to two factors: (1) the implementation of horizontal drilling and hydraulic fracturing technologies applied to relatively impermeable, subsurface shale formations; known as **unconventional production**; and (2) high US natural gas prices: 2005's average natural gas price was $9.01/MMBTU contrasted with 2012's $2.75 and 2013's $3.73. By easing the permeability, hydrocarbons (primarily gas but more recently liquids) that were not yet accessible became economically extractable.

Total US dry gas production has gone from an approximate low of 52 billion cubic feet per day (BCF/D) in 2006 to over 72 BCF/D in 2014. Viewing the same phenomenon in relative terms, unconventional natural gas production contributed less than 4% of US dry gas production in 2006 contrasted with over 47% thus far in 2014.





Initially natural gas production was the goal, but with declining natural gas prices more valuable liquids-related products were sought to raise and maintain production profitability (the primary metric for this is the Frac Spread, a measure of the implied profitability of liquids in the natural gas production stream, including condensate, extracted from gas production). As a result, unconventional production created a surge in the affiliated production of the set of entities known as Natural Gas Liquids (ethane, propane, butane, and plant condensate associated with natural gas processing, collectively known as NGLs), lease condensate (collected at the gas wellhead), as well as crude oil.



Conventional wisdom in 2006 saw rising deficits of domestic natural gas supply and NGLs, and rising import requirements. there are now challenges to finding markets for domestic production and a well supplied market from domestic production is expected to continue for the foreseeable future.

The quick solution is to seek export markets for the glut of new supply. Some regulatory constraints have been removed permitting exports and new infrastructure quickly is being completed and set to be commissioned to export natural gas production in the form of LNG from the US Gulf Coast (USGC) beginning as early as 2015. Yet one question remains: what to do with all of the other byproducts of this unconventional production?

Relative to condensates and ethane, propane and butane are more manageable in both storage and disposition. These NGLs can be applied to residential and commercial heating, industry needs, petrochemical requirements, and some transportation uses; in addition, there is ready infrastructure and no significant regulatory hurdles to deliver these to demand centers, be they domestic or foreign.

Ethane is an unwieldy NGL that is only deliverable by pipeline or cryogenically by ship; its greatest value is derived as a petrochemical feedstock to steam crackers. However, the surge in ethane's production is in the Marcellus and Utica shales of western Pennsylvania, eastern Ohio, and West Virginia. These are geographically mismatched with the location of North American steam crackers: Sarnia, ON and the USGC.

Condensate has faced several unique limitations in finding markets. It has several unique properties: once it is out of the ground, it remains a liquid, requiring no pressurization or refrigeration like other NGLs, therefore simplifying handling. Its applications are multiple: diluent for heavy crudes (notably Canadian, and potentially Venezuelan), petrochemical feedstock for steam crackers, refinery and blending feedstock (like crude oil) for further transformation, and even boiler feed in final use.

In refining scenarios condensate can be transformed not only by full-fledged refineries, but also by a type of facility known as a condensate splitter. While akin to an oil refinery in its premise, the technologies in a condensate splitter are simpler involving only atmospheric distillation. Therefore they can be constructed more quickly and at considerably less cost than conventional refineries when compared on a barrels-per-day processing metric.

Condensate has challenges that include definitional/specification and regulatory issues that impede its attractiveness. The other NGLs can be described in terms of particular molecules (ethane, propane, and butane); these specifications are easy to control. Condensate is an assembly of components with the lightest being made up of five-

carbon molecules. The subsequent set of determinants is its accepted API gravity range (generally around 50 degrees or above) and its sulfur content (described similarly to crude oil using a sweet-sour designation). Last, a condensate's assay, or composition, can vary: distilled, its derivatives are different combinations of naphthas, kerosene, and distillates. The skew of a condensate's derivatives presents more value for petrochemical producers, or fuel blenders. Adding to the definitional conundrum is labeling: the condensate derived from gas processing is known variously as plant condensate, natural gasoline, pentanes plus, and paraffinic naphtha.

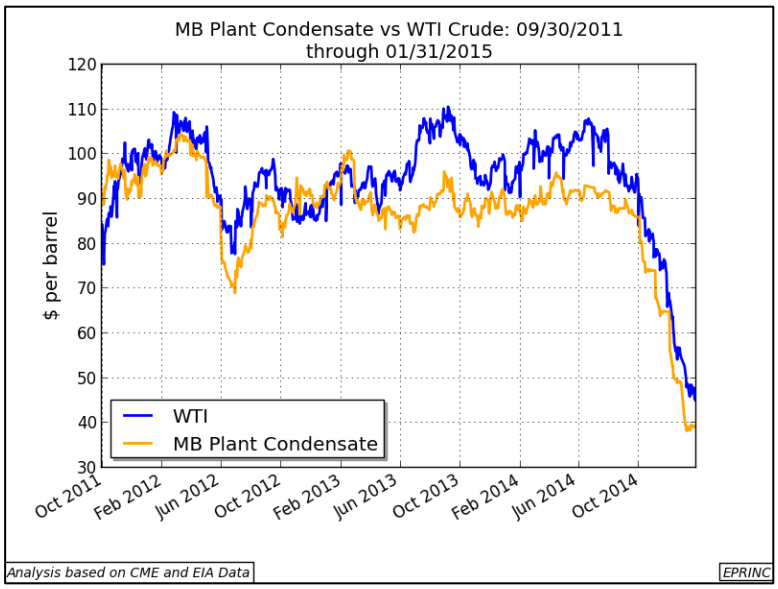
The regulatory challenge is derived from a condensate's origin: either wellhead or plant. The former is considered to have been produced without processing, and therefore, the equivalent of crude; the latter is derived from processing, and hence, from a US regulatory perspective, a product. Furthermore, wellhead condensate is also known as lease or field condensate. Regardless of the origin, the target applications are the same: refining/blending, petrochemical feedstock, diluent, or direct use.

With the accelerated production coming from shale, producers have tried to blend (or spike, in jargon terms) more and more of the lease condensate coming out of these formations directly into the associated crude oil streams. This is the case in particular in the Eagle Ford and Bakken plays. This spiking has served to raise the API gravity level of the crude oil delivered to refineries, and produce a new crude stream label - light tight oil (LTO). However, because refineries are maintained and configured to accept particular types of crude oil based on API gravity and sulfur content, not all spiked shale-produced crude oil/LTO can be easily processed.

To relieve the US condensate surge, producers are borrowing from the US natural gas playbook; in particular, they are seeking ways to accelerate condensate exports. The combination of a large amount of available overseas-based condensate-splitting capacity and depressed US condensate prices have attracted a lot of participants to the potential market seeking swift arbitrage.

One critical impediment has been the regulatory one: lease condensate is considered unprocessed and therefore subject to US legal prohibitions that were put in place in 1974 on the export of any crude oil or crude-equivalent product. In June 2014 two firms, Enterprise Products and Pioneer Natural Resources, received permission from the US Department of Commerce to export condensate after it had been "stabilized" (removing the ethane, propane, and butane, along with impurities such as hydrogen sulfide and nitrogen). By analogy, it is akin to tapping a glass that has some stray carbonation to remove the gas. Since the ruling, there have been at least seven cargoes, approximately 450,000 barrels each in size, that have been shipped to destinations such as Rotterdam and South Korea.

Despite the rapidity of change from shale production and the haste of arbitrageurs, it is important to assess the politics, economics, and market dynamics of processing increasing amounts of US condensate production for domestic utilization versus shipping it overseas. Using the prompt month Mont Belvieu Natural Gasoline contract as a proxy for condensate prices, in 2011 condensate traded at an average premium of $2.50/bbl above the price of WTI Crude. In 2012, condensate averaged at a discount of $3.70 to WTI, and this discount has only deepened since. In 2014, the discount was $9.60, and in January 2015 the discount has averaged $8.60. This implies that there is considerable margin available to be gained from refining condensates into premium products.



Increased domestic utilization could come in the form of running more US condensate through the existing fleet of US refineries. Possibly as much as 10% of refineries in their current configuration could be reapportioned to accept condensate without entirely reconfiguring the refinery. However, with the increased condensate runs refining towers get overloaded and adjustments have to be made to overhead pipes and cut points. Other de-bottlenecking actions must be taken, all of which are non-trivial capital expenditures.

An alternative is to build condensate splitters to produce more light products for things such as gasoline. Currently, the US has one dedicated 75 MB/d condensate splitter operated by BASF/Total located in Port Arthur, TX. Kinder Morgan has plans to be build a 100 MB/d condensate splitting facility on the Houston Ship Channel for $370 million that will be fully operational by the second half of 2015. There are several other similar projects in the USGC area planned or under construction by Targa Resources, Magellan, and Kinder Morgan.

The critical point here is that either adapting existing refineries or building separate condensate splitters are investments projected in the low hundreds of millions of dollars versus several billion for a comparable sized refinery. While exploiting condensate arbitrage through the identification and delivery to overseas destinations is undoubtedly lucrative, medium-term and long-term economic benefits of increased US domestic condensate utilization should be investigated quickly in order not to miss the potential positive benefits of this opportunity.

Regulation Legacy and Definitions

US laws governing definitions of hydrocarbons and their respective trade have moved with various cycles: occasionally in all encompassing waves, but more often incrementally, either increasing or decreasing in their scope of coverage, enforcement, and obligation. The critical legislation on which practitioners are currently focused is the Energy Policy and Conservation Act of 1975 (EPCA). EPCA was developed and enacted in response to the 1973 OPEC-led embargo on oil shipments to the United States. EPCA's focus was to prevent any US exports of crude oil and petroleum products. Until the embargo, US crude oil and petroleum products exports were unrestricted; the rationale for EPCA's legislation was to direct all US production of crude oil and petroleum products towards US consumption, thereby limiting anticipated shortages and price increases. There was other legislation in subsequent years that was enacted with the aimof curtailing exports of petroleum-related materials following EPCA's passage. EPCA was the centerpiece and is critical to current debates.

EPCA was fully enforced until the first month of the Reagan administration. From that point on, EPCA's coverage was gradually loosened or removed at least six times of important consequence over the next fifteen years. These included the removal of quantitative restrictions on the export of petroleum products in October 1981, the removal of restrictions on the export of crude oil to Canada in 1985, and the 1995 allowance to export Alaska North Slope crude oil. Everything else that is produced in the US that qualifies as crude oil is not allowed to be exported.

Condensate is derived solely from natural gas production. It can be sourced at the wellhead: after emerging in gaseous form it is then exposed to atmospheric pressure and temperatures it condenses, or precipitates, into liquid. It can also be derived from natural gas fractionation, the process where raw, or feed, gas, is separated, or stripped, into its hydrocarbon components: methane, propane, normal and iso butane, and condensate. By API gravity, condensate is generally 48 degrees or higher while its sulfur is very low.

Furthermore, the composition of condensate extends across a range of different molecules: the lightest molecules consist of five carbon atoms and progress to heavier ones suitable for distillate production. Generally, at least 50% of a condensate stream can be distilled into naphthas, with the balance a combination of kerosene and distillate. Condensate is referenced by a variety of industry jargon, notably the encompassing one of C5+ (pronounced "cee-five-plus"). Condensate produced at the wellhead is primarily known as lease condensate. Plant condensate is derived from the fractionation process. Plant condensate also has somewhat exotic and/or location-specific names: in the U.S. it is also known as natural gasoline; in Canada, as pentanes plus.

Under the provisions of EPCA, condensate intersect at the point of production: wellhead condensate is considered to be raw like crude oil, not having been passed through a distillation tower. Plant condensate is a product of the fractionation process. EPCA deems the latter condensate is exportable while the former is not.

Until very recently, disposition of lease condensate was not an issue. In 2006, total U.S. condensate production was approximately 710 MB/d, of which lease was almost 500 MB/d. In 2014, total U.S. condensate production is estimated to be 1,420 MB/d, of which lease is 1.08 MB/d. With this swell, disposition of lease condensate has become a major concern. The forecasts for lease condensate alone projects 2018 production to be approximately 1,600 MB/d.

As mentioned previously, condensate has a full array of applications: splitting/distillation; blending/spiking heavy crudes in order to either raise their pipeline flow rate or API gravity; petrochemical feedstock; or direct use. Given the availability of only one current operating condensate splitter in the US, the abundance of ethane for petrochemical uses, and no possibility of lease condensate export except to Canada, lease condensate producers have pushed their production in the direction of spiking, the expedient alternative. This, in turn, has raised the API gravity of certain US crudes to levels that are unattractive economically to many US refineries to utilize unless these crudes are discounted considerably.

The apparent constraints in market outlets for condensate, has raised debate on exports with the view that very soon the U.S. will not be able to absorb its own lease condensate production. Other alternatives, including the construction of new condensate splitters, have been proposed in order to convert lease condensate into products that can either be sold domestically or exported. However timelines to completion for some are uncertain. Therefore the current, most expedient alternative for producers is to spike crude oil.

There is also an irony here: OPEC quotas incentivize condensate segregation; conversely, US regulations incentivize blending/spiking. Because OPEC quotas only place limits on crude oil production, OPEC members have considerable motivation to segregate, and hence monetize their condensate production. Because of the U.S. ban on lease condensate exports, blending is the increasingly preferred channel for disposition.

From the regulatory side, there is policy complication and a lack of clarity and coherence on how to optimally proceed. The accelerated pace of production is not being symmetrically met politically.

Nevertheless, there has been activity on two fronts. First, the Energy Information Administration (EIA), because of the rapid rise of unconventional production, recognized the definitional dilemma of not only condensates but also other NGLs and refinery-produced gases. In June 2013, the agency released its "Proposed NGL Realignment Statement," new "Proposed Definitions for Natural Gas Liquids," and began soliciting comments on the proposed revisions. A definitional transformation would also require a variety and considerable changes to the way the EIA collects and publishes its data. These proposals merit serious attention because of considerable reliance on EIA data, not only in the US but also internationally.

Definitions critical to the condensate discussion are shown in adjacent table. Notably regarding lease condensate, the following two points are made: "Lease Condensate [is]currently considered an NGL, but is mixed with and sold as crude oil. [It is] to be re-categorized as crude oil because it never reaches NGL markets." Ironically, this is in contrast to the purpose of the new proposed definitions, which is to align "...the supply and market point of view..." While lease condensate can be richer than plant condensate in kerosene and distillate cuts depending on the marketed condensate stream (see Exhibit 1 in the Appendix for a list of representative condensate streams and their distillation compositions), both lease and plant condensate share the same, full array of applications, some of which are not available to the handling of crude oil.

EIA's Proposed Definitions for Natural Gas Liquids-June 14, 2013

Term	Current Definition	Proposed Definition	Note
Lease condensate	**Condensate (lease condensate):** A natural gas liquid recovered from associated and non associated gas wells from lease separators or field facilities, reported in barrels of 42 U.S. gallons at atmospheric pressure and 60 degrees Fahrenheit.	**Lease condensate:** Light liquid hydrocarbons recovered from lease separators or field facilities at associated and non - associated natural gas wells. Mostly pentanes and heavier hydrocarbons. Normally enters the crude oil stream after production.	Includes lease condensate as part of the crude oil stream, not an NGL.
Plant condensate	**Plant condensate:** One of the natural gas liquids, mostly pentanes and heavier hydrocarbons, recovered and separated as liquids at gas inlet separators or scrubbers in processing plants.	**Plant condensate:** Liquid hydrocarbons recovered at inlet separators or scrubbers in natural gas processing plants at atmospheric pressure and ambient temperatures.	Mostly pentanes and heavier hydrocarbons, equivalent to pentanes plus.
Pentanes plus	**Pentanes plus:** A mixture of hydrocarbons, mostly pentanes and heavier, extracted from natural gas.	**Pentanes plus:** A mixture of liquid hydrocarbons, mostly pentanes and heavier, extracted from natural gas in a gas processing plant (i.e., plant condensate) or from crude oil in a refinery. Natural gasoline is the largest component of pentanes plus.	Explicitly includes natural gasoline. A supply term.
Natural gasoline	**Natural gasoline:** A term used in the gas processing industry to refer to a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane.	**Natural gasoline:** A commodity product commonly traded in NGL markets, which comprises liquid hydrocarbons (mostly pentanes and hexanes) that generally remain liquid at ambient temperatures and atmospheric pressure.	A subset of pentanes plus.

The other point concerning lease condensate is that the proposed definition underscores its composition as "... mostly pentanes and heavier hydrocarbons." No timeline has been set for concluding receipt of comments and finalizing the new definitions.

On the second front, there have been EPCA exemptions given in June 2014 to Pioneer Natural Resources and Enterprise Products regarding lease condensate exports. Both firms have utilized stabilizer technology to remove lighter gases and impurities. While there has been discussion and hope that this would lead to a general waiver of the export ban, especially on lease condensates, the U.S. Department of Commerce's Bureau of Industry and Security (BIS), the governing agency, has not determined that stabilization is the equivalent distillation.

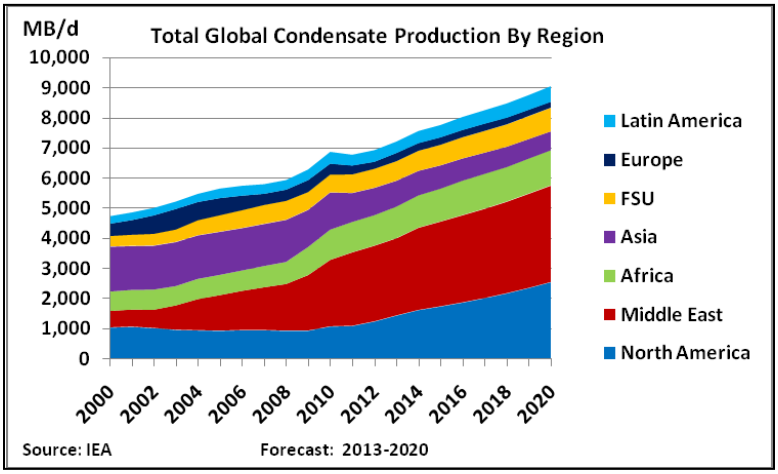
Lastly, there are geographical mismatches between lease condensate and LTO production and demand centers. The two critical plays where lease condensate and LTO production has been rapidly growing are the Texas Eagle Ford formation and the North Dakota Bakken formation. While 40% of U.S. refining capacity is along the US Gulf Coast (USGC), including Texas, USGC refiners are configured to more economically process heavier crude blends; US refining capacity that is more suited for Eagle Ford and Bakken production is located in the eastern and northeastern coastal United States. Pipeline capacity from the plays is limited, so other modalities would need to be utilized to move the material either by water or by rail to these refiners. However, existing federal regulations have created challenging and often insurmountable transportation barriers.

The Merchant Marine Act of 1920, generally known as the Jones Act (for its sponsor Senator Wesley Jones), requires that the direct transport of goods or passengers between two U.S. ports be done by U.S. flagged vessels on U.S.-built ships with U.S. crews. The Jones Act intent was in the meritorious spirit of national defense. But it has fostered a US merchant marine that is currently very costly. In today's markets, it is three times less expensive to

move waterborne hydrocarbons from the USGC to Canada's Nova Scotia, than it is to move them from the USGC to coastal eastern U.S. refineries because of Jones Act requirements. Some lease condensate and LTO is waterborne from the USGC to the East Coast, but producers are quick to underscore that far more could be shipped if it weren't for the Jones Act's restrictions. Nevertheless, lease condensate and LTO producers are first looking to change EPCA's export restrictions before amending the Jones Act; the latter has an entrenched and defensive constituency and has proven to be considerably resistant to any amendment of its rules.

Supply Trends

Using a variety of sources, including the IEA, EIA, and other estimates, global condensate production is projected to grow to 9.1 MMB/d in 2020 from 7.2 in 2013, at an annualized rate of 3.2%. From the beginning of the unconventional production boom, total global incremental growth has been 3.1 MMB/d from a base of 5.8 MMB/d in 2006. Proportionally, lease condensate has generally been between 82% and 84% of total condensate production and is expected to remain in this range through 2020 (See Exhibit 1 in the Appendix for detail on Global Condensate Production).



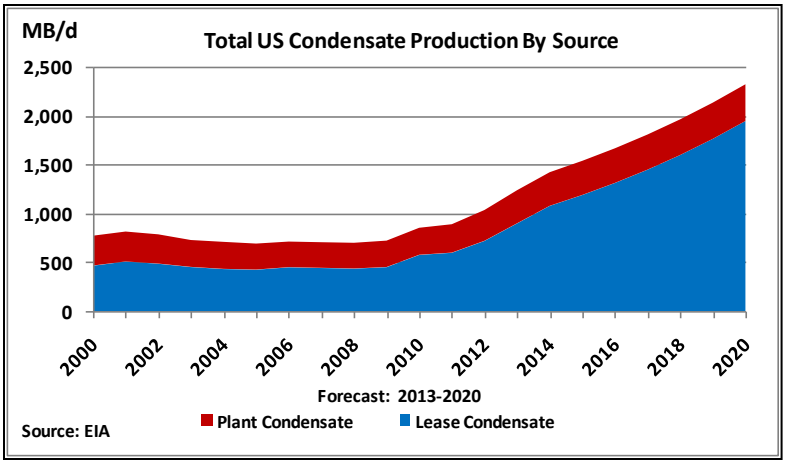
Regionally, the largest incremental condensate growth to 2020 is expected in North America at 1.1 MMB/d, an annualized rate of 8.4% from 2013. Clearly, the U.S. will a be dominant condensate producer. This will be followed by the Middle East with a projected rise of 640 MB/d, or 3.2% yearly. Qatar will be the dominant producer followed by Saudi Arabia and United Arab Emirates; 2020 volumes are forecast to be 1.2 MMB/d, 800 MB/d, and 545 MB/d with yearly growth of 1.7%, 3.1%, and 1.4% respectively, from 2013.

Smaller incremental increases are projected for Latin America, Africa, and the FSU of 140, 135, and 120 MB/d to 520, 1,170, and 785 MB/d in 2020, respectively. Africa will continue to rely on Algeria and Nigeria; the FSU on Russia and Kazakhstan; while Latin America's upside will come from Peru and Trinidad.

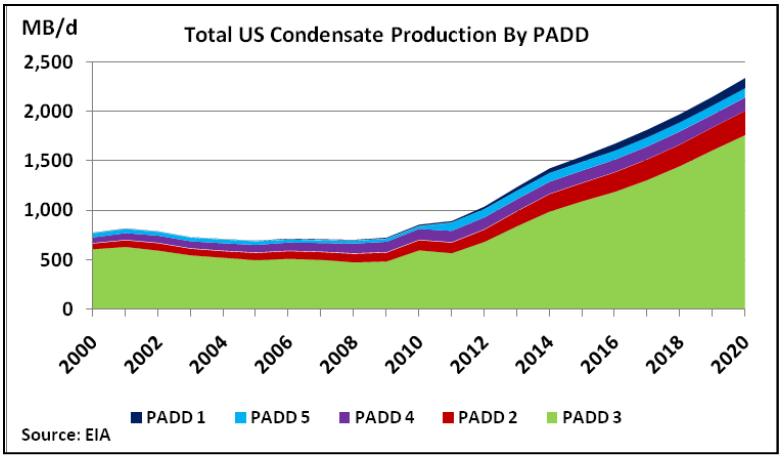
The greatest regional declines will be seen in Asia, decreasing by 229 MB/d, or 4.4% yearly, to 630 MB/d in 2020. This will be primarily driven by Malaysia and Indonesia, and only partially offset by new production in Australia. Europe is also expected to see a collective decline of 78 MB/d because of the continuing depletion of the legacy North Sea fields.

North America - US and Canada

Until 2006, the portion of North America's condensate production generated at the wellhead/lease had been approximately 60%. However with the unconventional production boom, this has begun to rise and is projected to be 84% by 2020. Clearly, the lease counterpart will be dominant in the realm of condensate production. Of the five PADD districts, PADD 3 will dominate total condensate production, delivering volumes from the Eagle Ford and Permian formations and is expected to show 925 MB/d in incremental growth reaching 1.8 MMB/d in 2020. This will be an annual rate of 13%. Behind PADD 3 volumes, at some distance but still very respectable, is PADD 2 production driven by Bakken formation, recording annual increases of 9.3% to 246 MB/d in 2020.



The Eagle Ford formation is located in the southwestern portion of Texas. It is about 50 miles wide and stretches for approximately 400 miles from an area to the northwest of Houston to the Texas-Mexico border in a southwesterly direction. The first Eagle Ford volumes were produced in 2008 by Petrohawk Energy (owned by BHP Billiton since 2011). Other producers quickly began developing the area and total liquids production has jumped from almost nothing to over 1.4 MMB/d. While estimates of current Eagle Ford lease condensate volumes vary, the most conservative place them at about 600 MB/d. The southern flank of the Eagle Ford is generally dry, producing almost all gas. Liquids production becomes more intensive as the area is traversed to the north.



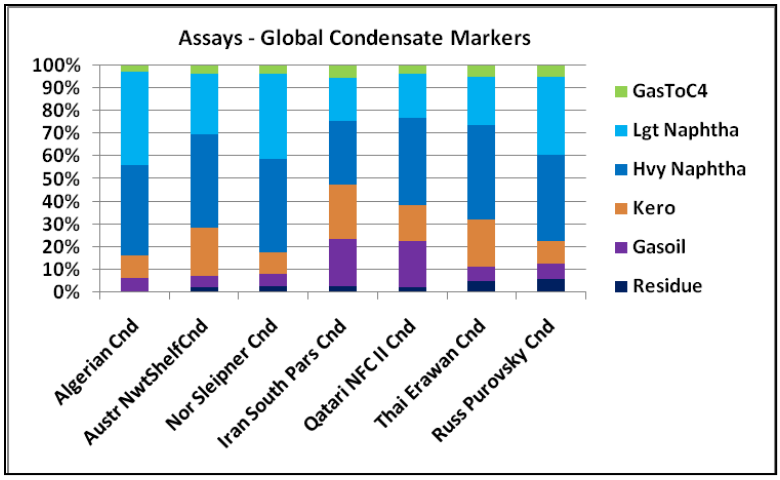
However, the quality of Eagle Ford production varies considerably: API gravities vary in a range from 38 to 60, and some streams are exhibiting high metals content. Critical to the development of the Eagle Ford are consistent crude grades. Some operators have begun to this, labeling and posting prices for their particular streams.

The Bakken play straddles the US-Canadian portion with the majority of it located in North Dakota. Between 1999 and 2006, various efforts tried to draw attention to the sizeable estimates of area reserves. However, it was only in 2007 that the area began to gain interest from exploration and production companies. The Bakken breakout year was 2009 when liquids production reached 300 MB/d from 100 MB/d in 2007. Current Bakken production is about 1 MMB/d. Of this, about 100 MB/d is estimated to be lease condensate. Unlike Eagle Ford where there is extensive pipeline capacity and within proximity to the USGC, the Bakken formation is somewhat isolated with limited access to pipelines. Therefore, Bakken producers are increasingly reliant on the use of rail transport to get their production to demand centers. About 700 MB/d or 70% of Bakken liquids production moves by rail.

Contrary to the United States, Canada's total condensate production is projected to be flat through 2020 at a steady rate of approximately 210 MB/d. This is because condensate volumes are a function of natural gas production, and Canadian natural gas demand is dropping because of US' rapidly declining need for Canadian gas exports.

Assay/Distillation Yields

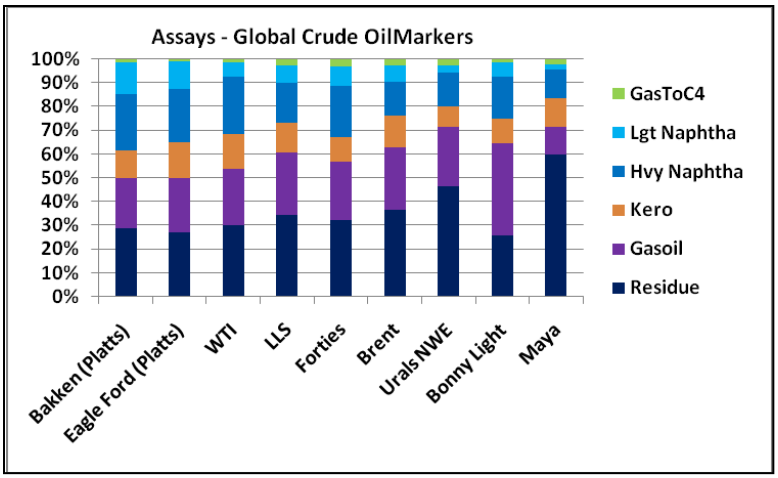
Like crude oil, condensate quality is variable both by composition and by location. Its primary compositional measures are API gravity and sulfur content; this is followed by its core assay that describes the yield of naphthas, kerosene, distillates, and atmospheric residue. Exhibit 2 in the Appendix lists the assays for six primary global condensate markers, Canadian condensates, along with several primary crudes and the two key US Mid-Continent LTOs.



Overall while the lower API threshold is 48 degrees, the key condensate markers average over 60 degrees, and sulfur is very low. Naphtha yields average 60% but are highly variable and can be further broken down into light and heavy ones in varying proportions. Kerosene and gasoil generally occupy a smaller percentage. However, Middle East condensates, in particular Qatari NFC II and Iranian South Pars condensates, yield considerable amounts of middle distillates, while Algerian and Norwegian condensates have little. Lastly, there is a minimum atmospheric residue (averaging 2.5%), making them unattractive to a refiner having considerable secondary capacity.

These different attributes are key elements in a condensate's appeal to either a petrochemical producer or a refiner.

Compared to the crude markers that are also shown in the exhibit, the difference in condensate and crude assays is vivid, especially in crude's lower gravity and higher proportion of middle distillates and atmospheric residue. It is important to note the assays of the two LTOs (Bakken and Eagle Ford as described by Platt's) with their higher gravities and naphtha yields.



There is limited information on the condensates that have been shipped from the USGC. While there is nothing resembling a marker assay yet, some information has been gleaned and published. In particular, one of the cargos that has been shipped was described as having a typical yield of 62% naphthas, below average yield of middle distillates, but high, atypical atmospheric residue of almost 10%. The economics of moving this sort of condensate through a splitter could be challenging.

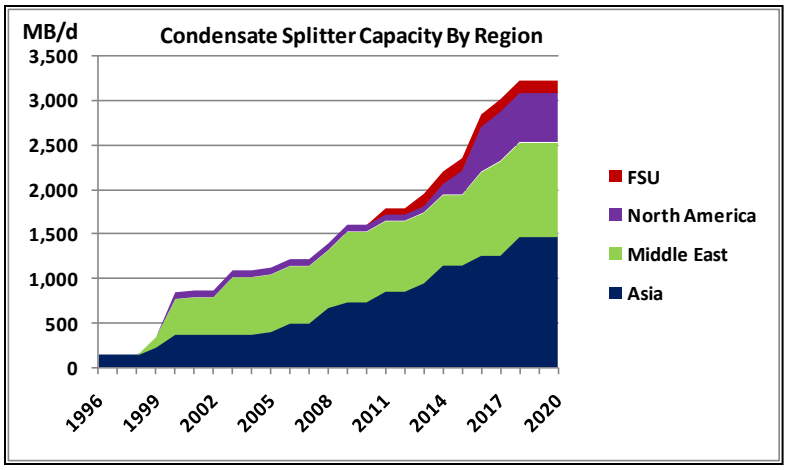
Additional reports in news services assert that Asian importers of US condensates claim that their cargoes were of varying and unsuitable quality for use in their facilities. Until there is more clarification and consistency the importers will refrain from seeking more US cargoes.

Future condensate marketing efforts should take cues from the Middle East and Norwegian condensate markers cited previously: in particular, the clarity and transparency of their assays.

Demand Trends

With approximately 1.8 MMB/d of new global condensate production, it is important to assess the disposition of all of this new supply. As mentioned previously, there are four sectoral areas for condensate disposition. This section will focus on two of the more important ones: refining/blending and diluent.

--Refining/blending



Unlike the US, many condensate producing Middle Eastern and North African countries have marketed condensate as a separate stream for a long time. This has led to the adoption and increase in the use of condensate stabilizers and splitters at demand centers, first in Asia and then the Middle East. A stabilizer is the simpler of the two types of facilities: it removes any hydrocarbons lighter than condensate and other impurities. A splitter is essentially a simple refinery, consisting of an atmospheric distillation unit and storage tanks; no other secondary processing, such as hydroskimming, is done, and the production yield focuses on premium products.

Facility costs vary. Recent reports peg an 80 MB/d stabilization facility at $190 million, while a 100 MB/d splitter at $370 million. On a unit cost basis, a splitter has a capital cost that is 50% higher than stabilizers. However, splitters deliver products that are not subject to the U.S. export ban.

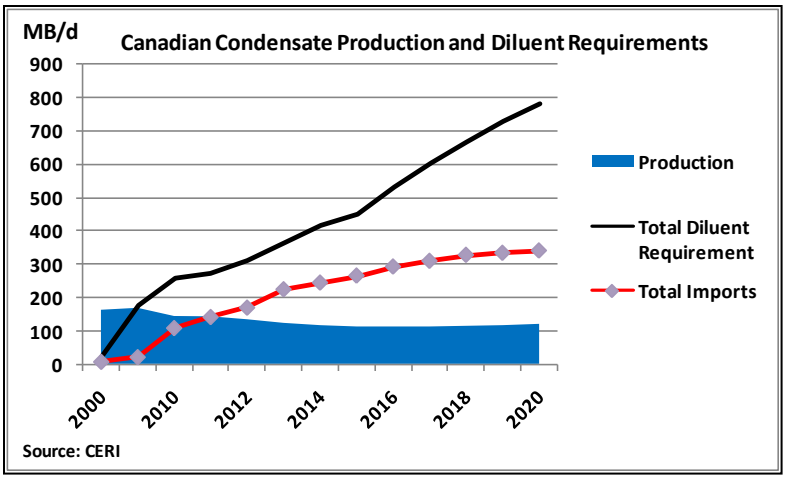
Total global condensate splitting capacity has grown from 140 MB/d in 1996 to 1,960 MB/d in 2013. Based on the development of current committed projects, this is projected to reach 3,230 MB/d in 2018 showing incremental growth of 1,270 MB/d. Asia committed first to splitters in 1996 with two 70 MB/d units: one in Thailand, one in Taiwan. Asian capacity stood at 950 MB/d in 2013, and is set to be 1,470 in 2020. South Korea and China were the dominant Asian condensate demand centers in 2013 with total splitting capacity of 230 MB/d and 220 MB/d, respectively. China is set to expand to 490 MB/d by 2018, while South Korea is committed to reaching 440 MB/d in 2015.

The Middle East currently has 790 MB/d set to expand to over 1 MMB/d by 2018. Many Middle East condensate producers are OPEC members. Given that their crude oil output is subject to quotas and their condensate production is not, these producers have considerable incentive to segregate and market as much condensate as possible. In 2013, the United Arab Emirates was the largest regional condensate splitter with capacity of 420 MB/d with no future expansions planned. Qatar is set to double its capacity to 292 MB/d in 2016, making it the second largest regional splitter.

Until 2013, the US only had one 75 MB/d splitter that was operating: the BASF/Total facility at Port Arthur, TX. With uncertainty over the repeal of the US export ban that is corralling a considerable amount of U.S. condensate production, this is set to change rapidly through the end of the decade. Currently, there are six projects in the USGC that, when commissioned, will add another 485 MB/d by 2017 for a total of 560 MB/d. In the event that there is only incremental and selective allowances of lease condensate exports, these investments will produce products that when combined can be either marketed domestically or delivered as exports depending on demand (See Exhibit 3 for details on global condensate splitters).

-- Diluent

"Diluent" is the general term that is used to describe the use of one hydrocarbon stream to mitigate the viscosity and density of a much heavier one in order for the latter to be transportable via major pipelines. Condensates, given their general profile of being light in API gravity and having easy handling characteristics, qualify for this role. Countries such as Venezuela and Canada with heavy crude production and limited access to indigenous condensates would seek these new volumes out.



With declining demand for Canadian natural gas exports by the U.S., Canadian gas producers are set to curtail their future production to a steady level through 2020. Given that condensate is produced in association with natural gas, level gas production implies that Canadian condensate production will show no change through 2020 also, and will remain at approximately 210 MB/d in this same period.

Growing Canadian bitumen and conventional heavy crude oil (HCO) production will require diluents in Alberta, and with flat-lining Canadian condensate production, increasing diluent import requirements are expected. As a percentage of base volume, diluent requirements vary: HCO requires about 21% additional condensate; bitumen's needs are about 41%.

In particular, Canada produced about 1.4 MMB/d of bitumen and HCO that required diluent; the total 2013 diluent requirement was 365 MB/d of which 200 MB/d was imported from the US. The Canadian Energy Research Institute (CERI) forecasts that Canada's 2020 diluent-requiring bitumen and HCO production to be 2.3 MMB/d; in 2020, the total diluent requirement will be 780 MB/d of which 380 MB/d is expected to be U.S.-sourced.

Canada is also considering using synthetic crude oil (SCO) as a possible additional diluent. However, the availability of SCO for future diluent purposes is uncertain. If SCO were unavailable then there would be higher import condensate requirements. Either way at this time, Canadian diluent supply is not expected to be sufficient for projected bitumen and heavy crude production. There are also overall economic considerations: use of SCO works best when blended in a 50/50 ratio, compared to approximately 30/70 for condensate to crude/bitumen. The critical constraint on Canadian imports is transport availability, both pipeline and rail.

Transport availability is the critical bottleneck for delivering sufficient condensate quantities to Alberta. Some rail transport from the North Dakota Bakken formation became available in September 2012; it delivers about 30 MB/d of condensates. However, pipelines are key for the large volume requirements.

Enbridge's Southern Lights 180 MB/d pipeline was commissioned in 2010. It carries condensate from Chicago area terminals to Alberta,due to increasing requirements Enbridge announced in mid-2013 to 275 MB/d. In addition, Kinder Morgan's Cochin pipeline, running also from the Chicago area to Alberta, was reversed in July 2014 moving

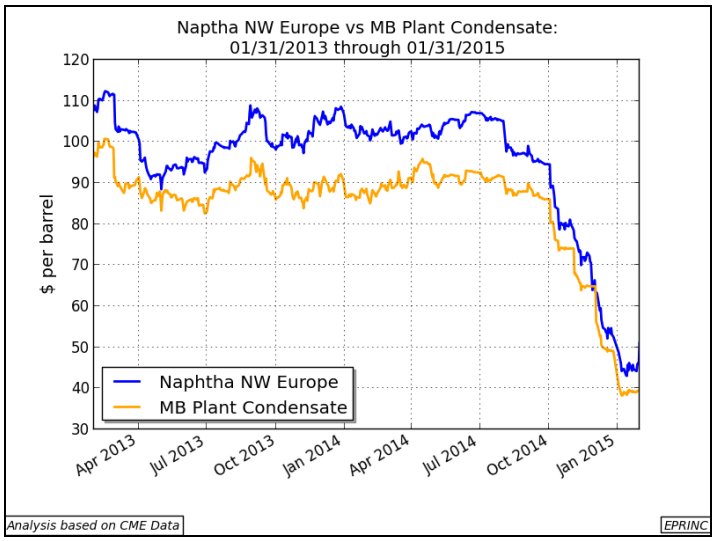
condensate at a rate of 95 MB/d. However, that largest portion of US condensate production is in southwestern Texas; the challenge there is to move it to Chicago terminals so that it can continue on Enbridge and Kinder Morgan's systems. The Explorer pipeline, running from the Houston and Port Arthur areas to Chicago, provides that leg of the Alberta-bound condensate trip. Of its 660 MB/d capacity, 250 is allocated for moving condensate northward.

Last, Alberta producers are expecting to commission the Enbridge Northern Gateway system in the middle of 2017. Its twin pipelines would run east from the Pacific coast at Kitimat British Columbia to Edmonton, with one of the pipelines dedicated to diluent transport. The diluent source would be a combination of Kitimat production and waterborne deliveries. The projected capacity for the Northern Gateway is 193 MB/d.

The high volumes of U.S. lease condensate would be perfectly applicable as a diluent to Venezuela's heavy crudes. But under current U.S. regulations, only Canada can be a beneficiary of U.S. condensate exports.

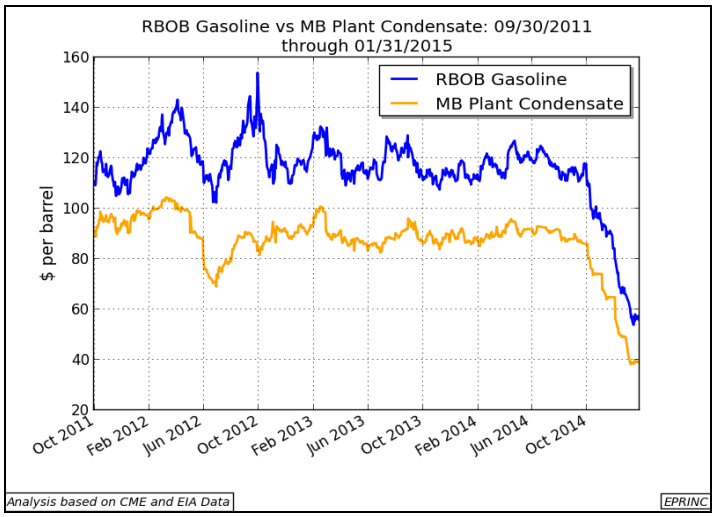
Pricing

In theory, condensate pricing should reflect the value of the products that can be produced from it, or its applications, as in the case of diluent. Since there is no one consistent accepted pricing regimen in place, it is important to know the ones that are in use, especially regionally.



In moving condensate volumes from Qatar, Iran, and Saudi Arabia, two benchmarks are generally used to determine price. More often, condensate cargoes transported to East Asia are priced against Dubai crude, usually in a range of $5 above or below the benchmark. Less often, prices are negotiated against Brent crude at a discount of up to $8.

In the case of Alberta's requirements for diluents, condensate imports are tied to the price of West Texas Intermediate (WTI). In recent years, delivered US condensate was priced as much as $25/barrel over the price of WTI. However, its premium generally trends between $5 to $10/per barrel, with some occasions where it drops to a $3 discount.

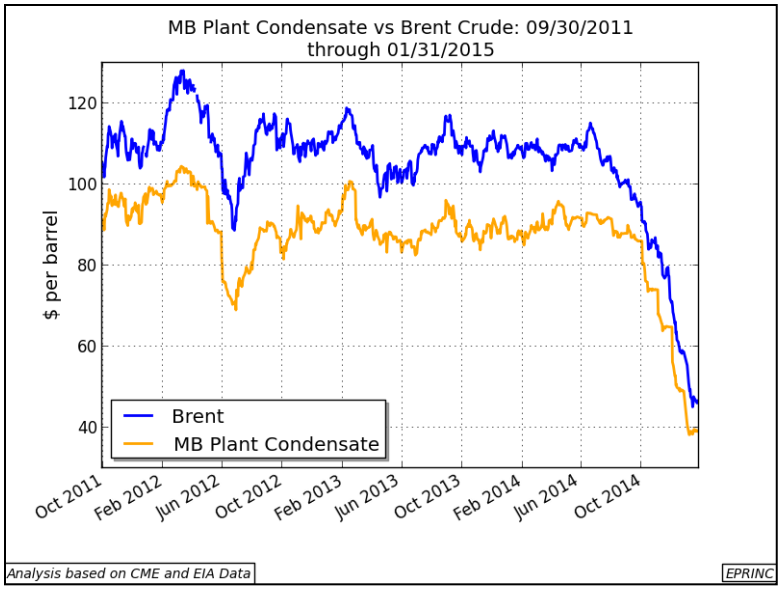


In east Asia and Northwest Europe, the focus is on the value of naphtha from condensate; in the United States it is determined by gasoline's premium. Profitability is key for naphtha and gasoline producers. So it would make sense to show product prices relative to those of condensate.

Using the front month Mont Belvieu Natural Gasoline contract as a proxy for US condensate prices and mapping it against the prices of Naphtha in Japan and Northwest Europe, spreads can be derived to produce an implied margin; this will give some preliminary notion of

margin. Looking at Naphtha-NW Europe vs. MB Plant Condensate barrel-to-barrel (1-1) for the last two years, the average spread for the last two years is $11.80, the high is $20.22, and the low is $4.00. Similarly, Naphtha-Japan vs. MB Plant Condensate (1-1) margin, the average is $13.85, the high is $19.95, and the low is $6.40.

While freight and other logistics have not been incorporated here, this indicates that there is considerable value to be gained from the use of US produced condensates.



Similarly, looking at US RBOB Gasoline vs. MB Plant Condensate (1-1), the spreads are considerable. Over the last two years, the average has been $27.80, the high has reached $41.82, and the low $19.10.

Spreads also offer support for the blurred distinctions of reporting Eagle Ford condensates and crudes, the reason why there is such a strong incentive to spike Eagle Ford and Bakken crude production with condensate. Again, using the front month MB Natural Gasoline as a proxy for US condensate prices, and mapping it against API 40 degree WTI and Brent, condensate prices have averaged $8.40 for the last two years below those of WTI, and $17.85 below Brent.

Modeling for further analysis

In recent years, there have been several studies published on the subject of the U.S. EPCA crude oil export ban, and its effects on the U.S. economy and energy prices. Of these studies, notably, the recently published collaborative effort by the Brookings Institution and NERA has done considerable work isolating factors (lifting the ban completely, or selectively on either condensate or crude oil; timing of any easement in the ban: immediately or at different points in the future), combined with using multiple economic scenarios (base case, high growth, low growth). The summary conclusions published by both organizations favor a repeal, complete rather than incremental, sooner than later.

Conclusions

Focusing exclusively on U.S. lease condensate issues relating to the EPCA export ban, there are several points of resolution that are required.

Primarily, U.S. lease condensate assays need to be clarified, consistent, and published. Just as Statoil, BP, Total, Iran, and Qatar circulate information on the critical attributes of their marketed condensate production, so too, should US lease condensate producers. It would add greater stability, predictability, and marketability to their production. Second, regulators should clarify governmental definitions of not only lease condensate but all gas-related hydrocarbons so that they are consistent with those definitions used elsewhere. It is commendable that work was begun in this area in 2013. However the proposed definition for lease condensate makes it closer to crude oil rather hydrocarbons produced in association with gas production.

Appendix - Additional Exhibits

Exhibit 1: Global Condensate Production (Source: IEA; Forecast: 2012-2020)

	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Africa	642.6	672.4	1,004.5	1,008.9	1,011.8	1,048.5	1,074.7	1,089.5	1,144.7	1,156.9	1,146.7	1,163.1	1,170.9
Asia	1,487.3	1,425.5	1,233.2	958.7	905.8	857.8	812.8	773.2	737.5	705.3	676.6	651.0	628.4
Europe	410.1	570.5	365.9	299.2	236.5	275.9	258.5	250.9	245.9	244.2	226.9	211.5	197.9
FSU	359.1	556.2	593.2	619.2	634.6	650.7	667.5	685.0	703.2	722.2	742.1	763.0	784.9
Latin America	251.3	320.1	396.8	362.7	388.9	384.8	405.5	414.4	437.8	450.2	476.7	492.6	523.4
Middle East	545.9	1,177.7	2,205.5	2,436.6	2,510.1	2,559.4	2,726.0	2,811.5	2,893.2	2,960.8	3,035.8	3,123.1	3,198.3
North America	1,049.9	943.1	1,085.4	1,104.3	1,251.3	1,449.2	1,631.5	1,751.6	1,881.8	2,026.6	2,186.5	2,365.4	2,559.0
Total	**4,746.2**	**5,665.6**	**6,884.6**	**6,789.6**	**6,939.2**	**7,226.3**	**7,576.5**	**7,776.0**	**8,044.1**	**8,266.3**	**8,491.4**	**8,769.8**	**9,062.8**

Exhibit 2: Assays

Condensate Markers

Condensates	API	Sulfur	GasToC4	Lgt Naphtha	Hvy Naphtha	Kero	Gasoil	Residue	Avg Daily Vol MB/d
Algerian Cnd	68.6	0.0	2.5	41.5	39.6	10.0	5.9	0.5	445
Austr NwtShelfCnd	63.0	0.0	3.4	26.8	41.3	21.2	4.9	2.4	82
Nor Sleipner Cnd	61.4	0.0	3.7	37.3	41.5	9.5	5.3	2.7	56
Iran South Pars Cnd	58.4	0.3	5.5	19.0	28.0	24.0	21.0	2.5	300
Qatari NFC II Cnd	68.0	0.2	3.7	19.5	38.5	15.8	20.4	2.4	50
Thai Erawan Cnd	59.0	0.0	5.0	21.0	41.8	20.8	6.0	5.1	100
Russ Purovsky Cnd	64.1	0.0	5.0	33.8	37.5	10.1	6.3	6.0	200

Crude Markers

				Assays					Avg Daily
Crudes	API	Sulfur	GasToC4	Lgt Naphtha	Hvy Naphtha	Kero	Gasoil	Residue	Vol MB/d
Bakken (Platts)	41.0	0.2	1.1	13.6	23.5	11.9	21.1	28.7	900
Eagle Ford (Platts)	47.0	0.1	1.0	11.6	22.4	15.0	23.0	27.0	1000
WTI	40.0	0.3	1.5	5.7	24.1	14.9	23.5	30.2	340
LLS	35.8	0.4	2.5	7.6	16.6	12.4	26.4	34.5	300
Forties	40.3	0.6	2.9	8.5	21.4	10.6	24.5	32.2	570
Brent	38.1	0.4	2.7	6.8	14.4	13.3	26.1	36.7	240
Urals NWE	35.8	0.2	2.6	3.0	14.3	8.9	25.2	46.8	1000
Bonny Light	35.1	0.2	1.2	6.1	17.6	10.7	38.7	25.9	495
Maya	21.1	3.3	2.0	2.4	12.0	12.0	11.9	59.7	2390

Canadian Condensate

				Assays					Avg Daily
Canadian Condensates	API	Sulfur	GasToC4	Lgt Naphtha	Hvy Naphtha	Kero	Gasoil	Residue	Vol MB/d
Sable Island Cnd	62.8	0.0	5.5	38.3	45.7	8.3	2.0	0.3	
Peace River Cnd	57.4	0.1	2.2	13.5	13.8	15.4	43.3	11.6	
Fort Sask Cnd	76.2	0.1	2.8	24.5	23.4	17.9	27.5	3.9	
Pembina Cnd	54.8	0.1	3.1	4.0	6.5	11.8	52.7	19.6	

Exhibit 3: Global Condensate Splitters

	1996	2000	2005	2010	2015	2020
Asia	**140**	**374**	**404**	**738**	**1,151**	**1,471**
Brunei						
Seria						30
China						
Fujian					93	93
Huizhou				85	85	85
Tianjin					30	30
Zhejiang						180
Indonesia						
Tuban				10	10	10
Japan						
Kashima				35	35	35
Mizushima				64	64	64
Korea						
Daesan				140	140	250
Incheon					100	100
Onsan					90	90
Malaysia						
KR-2A		74	74	74	74	74
New Zealand						
Maui		25	25	25	25	25
Singapore						
Jurong					100	100
Pulau Bukom		70	70	70	70	70
Taiwan						
Kaohsiung	70	70	70	70	70	70
Thailand						
Ban Laem			30	30	30	30
Map Ta Phut	70	135	135	135	135	135
FSU					**140**	**140**
Russia						
Ust-Luga Complex					140	140
Middle East		**400**	**645**	**791**	**791**	**937**
Iran						
Persian Star						120
Qatar						
Ras Laffan				146	146	292
Saudi Arabia						
Ras Tanura			225	225	225	225
United Arab Emirates						
Dubai		120	120	120	120	120
Fujairah			20	20	20	20
Ruwais		280	280	280	280	280
North America		**75**	**75**	**75**	**275**	**560**
United States						
BASF/Total PetChem		75	75	75	75	75
Castleton-CorpusChristi					100	100
KM Condensate Splitter					100	100
Magellan-Corpus Christi						100
Martin Midstream-CC						100
Targa-Channelview						35
Trafigura-Corpus Christi						50
Grand Total	**140**	**849**	**1,124**	**1,604**	**2,357**	**3,108**

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