James A. Baker III Institute for Public Policy
Rice University

Shale Gas and Tight Oil

By

Al Troner

President
Asia Pacific Energy Consulting (APEC)

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Chapter I. Introduction; Setting the Stage/Upstream

At the end of July 2014, a crude oil tanker began the long journey to a buyer in South Korea—the first unrestricted sale, outside of Canada, of unrefined American oil since the 1970s. Bureaucratic and political decisions now being weighed in Washington will decide the future of the US shale revolution and indeed could reshape the panorama of international energy.

Over the course of 2013-14, the shale revolution has broadened and accelerated, reshaping the fundamentals of the US, and the global energy panorama. The continued buildup of US tight oil, shale gas, and parallel natural gas liquids (NGLs) production is restructuring world energy trade, balances, and prices. In less than a decade, the US flipped from its decades-long role as a major oil importer to a major exporter of oil products, natural gas, NGLs—and sooner than many realize—an exporter of crude oil, even if initially to a very limited extent.

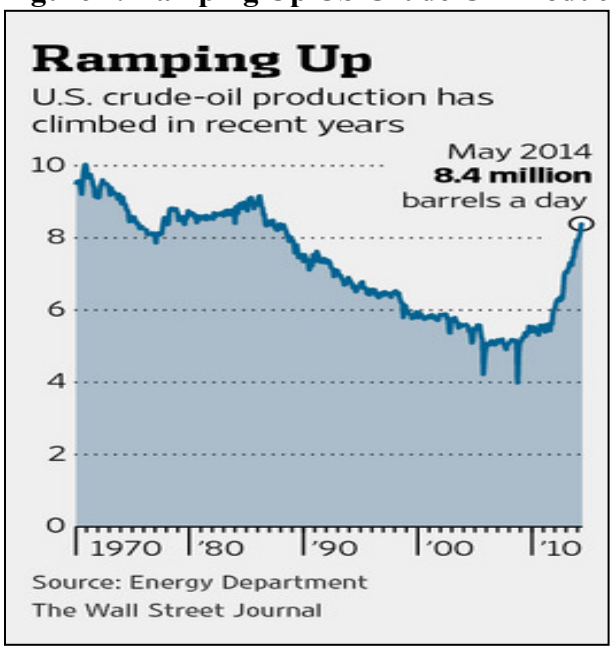
In APEC's initial work for the Baker Institute on "Natural Gas Liquids in the Shale Revolution" in April 2013, we focused on the pivotal role of NGLs in the emerging shale revolution. The purpose of the current study is two-fold: to review, analyze, and track the substantial changes that have emerged in US oil and gas over recent years and to survey the implications and possible outcomes resulting from the modification or full abolition of the decades-long US crude oil export ban. This second topic is no longer simply a matter of intellectual speculation, as the US Department of Commerce's Bureau of Industry and Security (BIS) in June 2014 approved the first application for the sale of field condensate—until then considered black oil and so banned from export—to foreign markets, with three cargoes earmarked for summer loading, two to Asian buyers.

The US in recent years has emerged as a global leader in refined product sales, in liquid petroleum gas (LPG) exports, and will soon add liquefied natural gas (LNG) sales abroad in big volume. Since US crude output began to rise steadily in 2009, after four decades of decline from its 1970 peak, increased oil production has not only backed out foreign crude imports, but underpinned a surge in American refining. In July 2014, crude processing volumes hit a new high, the largest volume of oil refined in this market since the EIA began record-keeping in

1982. This too was in part due to US crude export restrictions. Since the end of 2011, US oil production has risen nearly by half to reach about 8.4 MM B/D as of mid-year. Any shift in federal policy that allows for increased crude exports—currently allowed in only a limited fashion, with Canada the main buyer—has worldwide implications for oil and oil product balances.

We therefore focus on shifts in recent Washington energy policy and the direction and implication of changes in US oil exports patterns and their impact on global energy. It must be underlined that this is a situation in flux and that, since changes in US energy policy involve both national politics as well as bureaucracies in at least three separate US departments—Commerce, Energy, and at times the US Treasury—progress will be slow and policy changes often unclear. As this paper will show, this has been particularly the case in the Department of Commerce (DOC) June rulings, which remain shrouded in secrecy and vague in both wording and intent. Further, we will detail and analyze current export policy, in particular the apparent contradiction between government actions and the opaque decision-making surrounding oil export policy. President Barack Obama in early 2013 claimed that "This is the most transparent administration in history." Despite such declaration, the oil and gas industry has significant difficulty understanding what official policy changes—if any—have taken place or may be implemented in the near future. Billions of dollars of investment in exploration, field development, downstream refinery expansion, and constructing oil/gas infrastructure pivot on this decision-making. Most of all the construction of specialized distillation units to process NGL, known as condensate splitters, hangs on Washington's decisions.

Figure 1. Ramping Up US Crude Oil Production



Source: "Oil Exports Sail Through Loophole," The Wall Street Journal, July 31, 2014, http://online.wsj.com/public/resources/documents/print/WSJ_-B001-20140731.pdf.

Before moving to a more detailed analysis, we think it is useful to point out some basic trends that have characterized the changing US shale revolution in 2013-14:

- Higher, Faster, Larger: Tight oil production has continued to rise at far higher than anticipated rates of increase. Forecasts from the Department of Energy's (DOE) Energy Information Agency (EIA) have been consistently behind the curve in predicting the increase in US domestic tight oil output, despite devoting greater resources to analyzing trends. The Paris-based International Energy Agency (IEA) has been even further off base, and its forecasts regularly lag emerging production reality.

- Official vs. Private Forecasts: Private forecasts have fared only a little better, though generally tend to predict higher tight oil output. In part, this is due to "the nature of the beast" (i.e., the situation is fluid, fast-changing, and production forecasts become rapidly dated). A thorough projection made by the private International Strategy and Investment Group (May 13, 2014) seemed reasonable when released in the spring of this year. Yet, by mid-2014 it has begun to look somewhat dated, as can be seen in the sample below.

Table 1. Changing Viewpoints: Tight Oil Forecast (in MBD)

Field	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19
Eagle Ford (1)	801	1,069	1,319	1,569	1,819	2,069	2,319
Bakken (2)	951	1,211	1,361	1,569	1,819	2,069	2,319
Permian (3)	1,305	1,545	1,795	2,045	2,295	2,545	2,795

Notes: (1) Claims constant 50% condensate
(2) No condensate breakout
(3) Conventional/Unconventional; No condensate breakout
Source: Timm Schneider, "Matters," International Strategy and Investment Group, May 13, 2014.

- Steadily Rising: As forecast, tight oil production has been mainly light and ultralight, with the vast majority of output at 38 API or lighter. And field, or wellhead, condensate (in the US known as lease condensate) continued to make up a substantial portion of tight oil production. Analysts have estimated that about 25% of this oil production is actually condensate, ranging in weight from API 45-70. The composition of tight oil becomes a key factor in the emerging debate on allowing crude oil exports, because the DOC classified field condensate as crude oil and banned it from export. Field condensate precipitates naturally out of gas at wellhead. Plant condensate, stripped directly from gas in the NGL separation/gas cleaning complex, was defined for decades as an oil product and so exportable. For this reason, field operators had no incentive to separate and segregate field condensate from the overall oil pool.

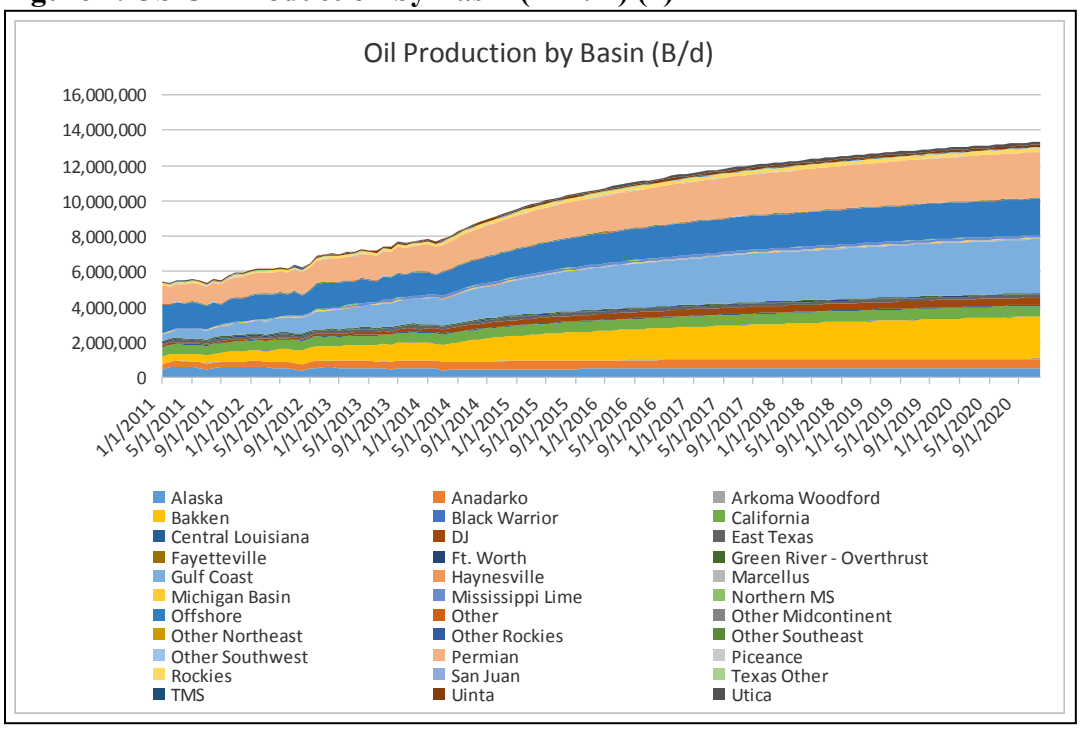
- More From Less: Gas output too has been steadily rising and could increase at an even faster rate if sales outlets could be found for all gas and NGLs output. NGLs range from ethane (C2, containing two carbon molecules), through propane (C3), Butane (C4)—together known as LPG—and concluding with condensate (C5-C5+). All NGLs are liquid hydrocarbons suspended in gas underground, at subsurface temperature and pressure. The Marcellus and Utica gas/NGL basins in the northeastern US have seen output constrained by limits to market absorption. While Marcellus output built quickly in 2013-14—this single gas basin is now producing almost as much gas as Qatar—output could actually rise far higher if ethane produced with gas could be sold as a petrochemical feedstock. In 2Q, 2014, as many as 500 Marcellus gas wells were drilled and capped—the ethylene cracker market could not absorb all potential ethane output, so

rather than just burn ethane output, these completed wells were shut in. This phenomenon of ethane rejection has been the chief restraint on increased gas output. Yet, we expect gas production to still rise steadily. Since wet gas will be produced before dry, this will be paralleled by increased NGL output.

- The Other NGLs: Ethane exports by pipeline to Canada began in late 2013, while ethane/propane seaborne exports to Europe started in early 2014. Yet volumes remain fairly limited. In contrast, LPG sales abroad have built rapidly, as US Gulf Coast (USGC) midstream companies quickly expanded fractionation capacity, which separates NGLs into separate and high-purity products, while also expanding LPG tankage and berthing for exports. Texas alone will have LPG export capacity equal to that of Qatar and Saudi Arabia by no later than 2016, and possibly by next year. It is condensate, though, that is causing major pressure to build on modifying, if not abolishing, the long-standing crude export ban. Eagle Ford's tight oil output has continued to rise. In 2014, field condensate made up about 39% of crude production. As seen by the mid-2014 projection in Figure 2 below by BTU Analytics, a well-informed private consulting firm, Permian output will follow in the second half of this decade, adding to condensate production, all easily accessible to USGC ports.

- Increased Upstream Efficiency: Oddly enough, in part this problem of "ethane rejection" has emerged due to one of the most consistent drivers of the shale revolution improving operational efficiency. From horizontal drilling to the use of multi-well pad drilling to more specialized fracking fluid and better water recovery, tight oil and shale gas operators have consistently been reducing costs and increasing recovery rates. This has exposed one of the underlying and fundamental problems that resulted from greatly increased output: Can the domestic market absorb all incremental oil, gas, and NGL production, and if it cannot, how do upstream companies cope with export restrictions? Longer term, the great question will be whether operating efficiency can continue to grow at the rates of 20-30% p.a. as was the case 2008-13.

Figure 2. US Oil Production by Basin (in B/D) (1)



Note: (1) Actual production statistics through March 2014, with the exception of Mississippi Lime (Oklahoma output) and forecast from June 2014.
Source: BTU Analytics

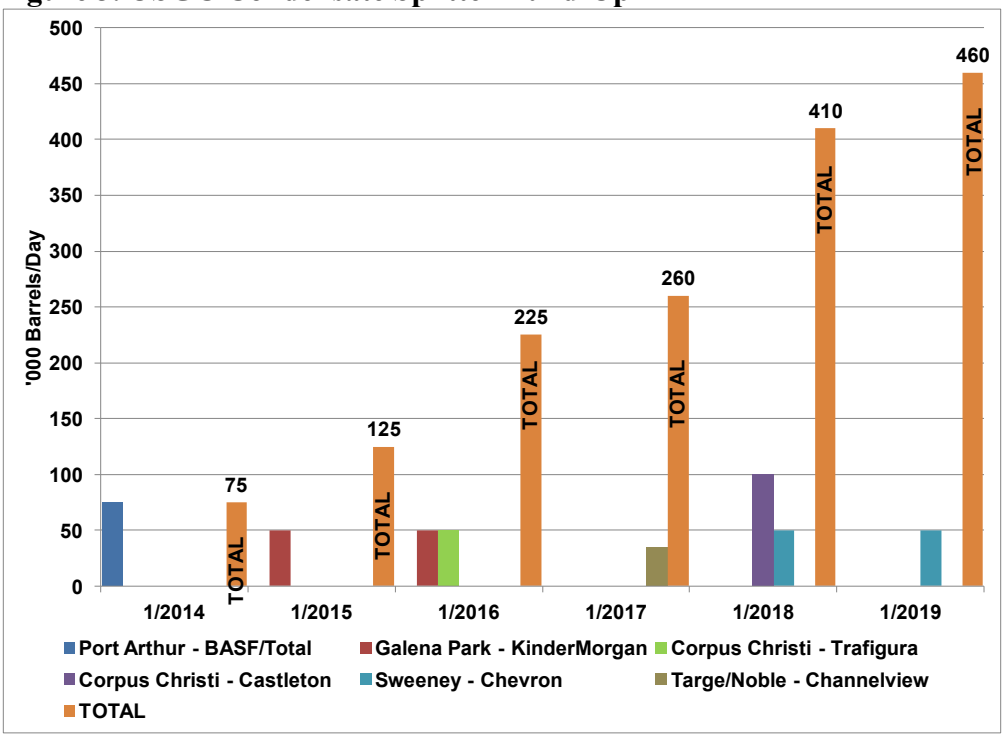
- Demand Growth Minimal: The other half of the coin to rapidly rising crude production has been tepid US demand growth. American oil consumption has been almost static in 2013-14 for a number of reasons: renewable fuels standards had ethanol replacing a portion of oil used in gasoline, mandated greater auto fuel economy, substitution of oil demand by shale-derived gas/NGLs, and the slow and uneven economic recovery.

- Product Exports Surging: US refiners—faced with a growing volume of domestic black oil production that could not be exported as crude and seeing processing costs drop due to cheaper gas supply—increased their utilization rates, not for domestic sales, but for exports. In the week of July 11, 2014, refiners processed a record 16.6 MM B/D of crude—and product exports have risen steadily throughout the 2013-14 period. The US crude ban unwittingly transformed American refiners into major volume oil product exporters.

- A Fundamental Mismatch: The crude that is being produced in ever increasing volume is light, low sulfur (known as sweet) tight oil. USGC refineries, however, have been built around the design concept of running heavy, high-sulfur (known as sour) grades. Refiners invested heavily in severe secondary units to extract the highest percentage of light product from heavy slates and in intermediate units to improve product quality by removing sulfur and other impurities—the latter particularly important in transport fuels. While refiners have made some efforts to modify plants to handle a higher percentage of light crude, overall the refinery investments have been limited.

- Splitter Redux?: It was the midstream companies, such as Kinder Morgan and Magellan, and the independent traders, such as Trafigura and Castleton, who filled the vacuum for refining very light crude and condensate. Initially, investing in a condensate splitter was a move to skirt export restrictions by converting (mainly) condensate into exportable product. A condensate splitter is a simple, purpose-built refinery, designed to handle very light feedstock. Later proposals shifted focus to providing traders with physical barrels to back their paper trade. Yet until the issue of transformation is settled (i.e., at what point is condensate converted from a base material) to an exportable product, many proposals will hang in investment limbo. The first, Kinder Morgan/BP's plant near Houston, is set for a late-2014 startup; the second, Trafigura, is expected to complete construction by 4Q 2014, while a third, headed by Castleton, gained approval of key environment permits in September.

Figure 3. USGC Condensate Splitter Build-Up



- <u>What Constitutes "Transformation":</u> Until the mid-2014 BIS rulings allowing Enterprise Products and Pioneer, two Texas-based mid-stream companies, to export condensate that had been stabilized and "lightly processed," though not fully refined into oil product, the rules seemed straightforward. Field condensate was defined as black oil and could not be exported, other than in certain limited circumstances (such as to Canada), unless a means of transformation (i.e., distillation) converted this base material into refined oil products.

- <u>System Backup:</u> Signs have emerged that growing tight oil production is beginning to back up through the entire USGC downstream sector. Others warned earlier that this would be a result of the continued export restrictions. Maria van der Hoeven, the Executive Director of the IEA, judged that the US must decide soon on whether to overturn its nearly 40-year ban on oil exports or it will cripple output from the shale revolution, tight oil, gas, and NGLs. As van der Hoeven commented pointedly: "As far as I know the United States was always in favor of a free market." In 2013, she first sounded the warning that the US would have to find export outlets to reach its full shale revolution potential. From mid-2013 until the public disclosure of approval for modified

condensate exports in mid-2014, no action was taken by the US government to modify policy.

- Light Ends' Overflow: Rapidly rising oil product exports nearly have filled the Atlantic Basin, as USGC refiners run more light, sweet tight oil grades. Refinery light end exports have been supplemented by sales abroad of LPG, ethane, and plant condensate. Many market analysts puzzle over whether the Atlantic Basin—Europe, Latin America, and Africa—will be able to absorb any further US export volumes.

- Condensate/NGL Trade Moving East: If the BIS June approvals represent a change in export regulations, Asia is eager to buy as much supply as available. The first cargoes sold by Enterprise and Pioneer went to GS Caltex in South Korea and Cosmo Oil, Japan, though this second sale was shifted to Europe due to a lack of shipping. These sales represent only the tip of the demand iceberg. Both are refiners that process condensate by blending it with crude and have no special-built facilities to process condensate alone. Yet SK Energy (98 MBD) and Samsung (142 MBD) in South Korea, Dragon Aromatics (92 MBD) in China, and Jurong Aromatic (106 MBD) in Singapore will all be operating at full by the end of 2014. With Mideast condensate output reaching plateau, it is inevitable that US output will begin to flow to Asia in ever-increasing volume.

Table 2. East of Suez Condensate Splitter Build-Up (in MBD)

Country	Location	Company	By 1/2014	By 1/2017		By 1/2019		Status
			Total	Expansion	Total	Expansion	Total	
MIDEAST GULF			**1,095**	**212**	**1,307**	**894**	**2,201**	
Qatar			**200**	**143**	**343**	**-**	**343**	
	Messaieed	QP	30	-	30	-	30	
	Messaieed	QP	27	-	27	-	27	
	Ras Laffan	QP/ExxonMobil	143	-	143	-	143	Startup 8/2009
	Ras Laffan	QP/Total (1)	-	143	143	-	143	Full operation by 2017
Saudi Arabia			**225**	**69**	**294**	**-**	**294**	
	Ras Tanura	Aramco	225	-	225	-	225	Commissioned 8/2003
	Ras Tanura	Aramco (2)	-	69	-	-	-	Unofficially shelved
UAE			**416**	**-**	**416**	**-**	**416**	
	Abu Dhabi/Ruwais (3)	ADNOC	139	-	139	-	139	
	Abu Dhabi/Ruwais (3)	ADNOC	139	-	139	-	139	
	Abu Dhabi/Ruwais	ADNOC	-	-	-	118	-	Canceled
	Dubai (4)	ENOC	59	-	59	-	59	
	Dubai (4)	ENOC	59	-	59	-	59	
	Fujairah (5)	Vitol	20		20	-	20	Working at full end-2009
	Fujairah	Gulf Petrochemical	-	-	-	49	-	Project shelved
Iran			**254**	**-**	**254**	**894**	**1,148**	
	Arak (6)	NIOC/Sinopec	20	-	20	-	20	Commissioned in 2012
	Assaluyeh	NIGC	59	-	59	-	59	
	Assaluyeh (7)	NPC	-	-	-	68	68	Startup expected 1Q-2017
	Bandar Abbas (8)	NIOC/NICO	-	-	-	118	118	Startup now planned by 3Q-2017.
	Bandar Abbas (8)	NIOC/NICO	-	-	-	118	118	Startup expected by 1/2019
	Bandar Abbas (8)	NIOC/NICO	-	-	-	118	-	Startup expected post-2019
	Bandar Taheri	NPC	-	-	-	59	-	Canceled
	Bouali Sina	NPC	37	-	37	-	37	
	Bourzouyeh	NPC	79	-	79	-	79	
	Bourzouyeh	NPC	39	-	39	-	39	Running at full end-2009
	Lavan	NIOC	20	-	20	-	20	
	Pars (Shiraz)	NIOC	-	-	-	118	118	Startup expected by 1/2019
	Siraf Refining Park, Assaluyeh (9)	NIOC/JV Partners	-	-	-	472	472	Startup expected post-2019.
Iraq			**-**	**-**	**-**	**-**	**-**	
	Komor (10)	KRG Regional Govt/JV partners	-	59	59	-	59	Shelved, but may be revived
	Irbil	KRG/Kargroup (11)	-	15	15	-	15	Shelved, but may be revived
ASIA PACIFIC			**1,257**	**554**	**1,811**	**139**	**1,950**	
South Asia			**22**	**-**	**22**	**-**	**22**	
India			**15**	**-**	**15**	**-**	**15**	
	Hazirah	ONGC	15	-	15	-	15	
Pakistan			**6**	**-**	**6**	**-**	**6**	
	Dhohak, Punjab	Oil & Gas Development Co.	3	-	3	-	3	
	Karachi	Enar Petrotech Services Ltd.	3	-	3	-	3	
Bangladesh			**1**	**-**	**1**	**-**	**1**	
	Chittagong (12)	Super Refinery	1	-	1	3	1	Expansion suspended
SE Asia			**569**	**-**	**569**	**30**	**599**	
Indonesia			**98**	**-**	**98**	**-**	**98**	
	Aceh	Humpuss - Idled 2001	-	-	-	-	-	65 MBD plant morthballed
	Tuban (13)	TPPI	98	-	98	-	98	98 MBD splitter inactive since 2011 and restarted 10/2013; expansion canceled
Vietnam			**16**	**-**	**16**	**-**	**16**	
	Vung Tau	Petrovietnam	5	-	5	-	5	
	Vung Tau	Siam Cement	-	-	-	30	-	Canceled
	Chan Tao (near Vung Tau) (14)	Rayong Purifier	-	-	-	-	-	3 MBD plant idled since 2008 & future status unclear
	Cai Mep	Petrovietnam	11	-	11	-	11	
Malaysia			**74**	**-**	**74**	**-**	**74**	
	Kerteh	Petronas	74	-	74	-	74	
	Pasir Gudong (15)	Honam (LG Caltex)	-	-	-	45	-	Shelved, but may be revived
Singapore			**174**	**-**	**174**	**-**	**174**	
	Pulau Bukom	Shell/PCS	69	-	69	-	69	Expansion possible with QP.
	Jurong Island (16)	Jurong Aromatics	105	-	105	-	105	Finance approved; startup expected by 2014
Thailand			**138**	**-**	**138**	**-**	**138**	
	Ma Ta Phut-I (17)	PTT Aromatics & Refinery PLC (PTTAR)	69	-	69	-	69	Operating for both refining and petrochemicals.
	Ma Ta Phut-II (18)	PTT Aromatics & Refinery PLC (PTTAR)	69	-	69	-	69	Operating for both refining and petrochemicals.
	Ma Ta Phut	Rayong Refining Corp.	-	-	-	59	-	Canceled
Brunei			**-**	**-**	**-**	**30**	**30**	
	Pulau Muara Besar (19)	Zhejiang Hengyi	-	-	-	30	30	Capacity downsized from earlier 98 MBD; Startup delayed to post-2018 or possibly cancelled.
Taiwan			**69**	**-**	**69**	**-**	**69**	
	Kaohsiung	CPC	69	-	69	-	69	Often splits whole naphtha.

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Table 2. East of Suez Condensate Splitter Build-Up (in MBD) – Cont'd

Country	Location	Company	By 1/2014	By 1/2017		By 1/2019		Status
			Total	Expansion	Total	Expansion	Total	
NE Asia			**589**	**554**	**1,143**	**109**	**1,252**	
China			**287**	**-**	**287**	**60**	**347**	
	Huizhou, Pearl River Estuary (20)	CNOOC/Shell	78	-	78	-	78	
	Huizhou, Pearl River Estuary	CNOOC/Shell	-	-	-	60	60	Not approved by NDRC
	Lanzhou, Xijiang	CNPC Petrochina	60	-	60	-	60	Running at full in 2009.
	Metro-Shanghai	Sinopec	-	-	-	65	-	Shelved
	Taizhou, Zhejiang (21)	CNCP/QP/Shell	-	-	-	98	-	Delayed; Startup may slip into 2019
	Tianjin	Sinopec	49	-	49	-	49	Startup during 3Q-2011
	Yanchang	Yanchang Petrochemical	8	-	8	-	8	
	Gulei Port, Zhengzhou, Fujian (22)	Dragon Aromatics	92	-	92	-	92	Commissioned 8/2013
Japan			**119**	**-**	**119**	**-**	**119**	
	Kashima	Kashima Oil/Japan Energy/Mitsubishi Chemical	64	-	64	-	64	Started up 1/2008; with petchem plant and CCR
	Kikuma	Taiyo Oil	20	-	20	-	20	Part of refining complex
	Mizushima	RING (23)	35	-	35	-	35	Commissioned in 8/2009
South Korea			**183**	**554**	**737**	**-**	**737**	
	Daesan	SamsungTotal	-	142	142	-	142	Commissioning by 3Q-2014
	Daesan	LotteChem/Hyundai Oilbank	-	137	137	-	137	Completion scheduled by 1Q-2016
	Daesan	SK Energy	-	98	98	-	98	Commissioned by 3Q-2015
	Daesan	SK Energy (24)	-	98	98	-	98	Start-up scheduled for 2Q-2015
	Inchon	S-Oil (ex-Ssangyong)	36	-	36	-	36	Began operation in 2002.
	Inchon	S-Oil (ex-Ssangyong)	-	-	-	25	-	Suspended
	Onsan	SamsungTotal	147	-	147	-	147	Startup was end-2002.
	Onsan (25)	S-Oil (ex-Ssangyong)	-	79	79	-	79	Startup in 2Q-2014
Russian Far East			**-**	**-**	**-**	**49**	**49**	
	Vladivostok	Novatek	-	-	-	49	49	Startup by 4Q-2017
	Ohka, Sakhalin (26)	Gazprom	-	-	-	89	89	Startup post-2018
Australasia			**78**	**-**	**78**	**-**	**78**	
Australia			**45**	**-**	**45**	**-**	**45**	
	Port Bonython (27)	Santos	45	-	45	-	45	
	Darwin	Darwin Clean Fuels	-	-	-	50	-	Project unofficially shelved
New Zealand			**30**	**-**	**30**	**-**	**30**	
	Taranaki (28)	Shell/Todd	30	-	30	-	30	
Papua New Guinea			**3**	**-**	**3**	**-**	**3**	
	Hides	OilSearch	3	-	3	-	3	
	Niugini LNG (29)	Interoil	-	-	-	8	-	Suspended
GRAND TOTAL			**2,352**	**766**	**3,118**	**1,033**	**4,151**	

Notes:

(1) ExxonMobil has bowed out of the project, and Total is now foreign company leader (10%), with QP taking 84% equity and 6% divided between Idemitsu, Cosmo, Marubeni, and Mitsui. Splitter will have Dist. HDT, VGO hydrodesulfurization and Continuous Catalytic Reformer (CCR).

(2) Project will likely have a reformer of about 24 MBD.

(3) Capacity additions were completed in 2008, but are often underutilized.

(4) Complex additions included 35 MBD CCR, 67 MBD Naph. HDT, and 14 MBD Dist. HDT was completed 2010.

(5) Splitter shares facilities with conventional topper.

(6) Sinopec completed a 64 MBD Naph HDT and a 24 MBD Continuous Catalytic Reformer (CCR) early in 2011; units are shared with the 20 MBD condensate splitter.

(7) Unit feeds 1.4 MM MTA ethylene cracker; it may well be a pretreatment unit rather than a splitter.

(8) Startup dates are tentative and have slipped a number of times in the past. Three units will share common Naph and Dist HDTs as well as a common reformer. Hydrotreating will be completed with the first splitter by 3Q, 2017.

(9) A new grassroots project of 8 x 60 MBD design capacity splitters is to be completed post-2019, with units likely to be commissioned serially. NIOC is proposing this project as a JV with still unsecured foreign investors. Partners will be allowed to export product.

(10) Emergence of tacit cooperation between central and regional governments plus promised South Korean funding have made this proposed condensate splitter realistic. The Kurdish regional government (KRG) desperately needs finished products, particularly transport fuels, while condensate produced by Dana Gas' Komor development has yielded substantial NGL output beyond local power generation needs. A small reformer is part of the project.

(11) Kar planned to raise current 45 MBD capacity at Irbil to 100 MBD by the end of 2012 and to 170 MBD by 2014—in part by adding a splitter unit to the complex, but the latter is now shelved.

(12) Current 1 MBD splitter is running on both condensate and naphtha; new 3 MBD unit will run on condensate only.
(13) Splitter expansion was designed to provide feedstock for ethylene cracker. Olefin complex startup has been delayed until late in the decade and splitter project canceled.
(14) Thai owner Rayong Purifier declared bankruptcy and unit idled in 2008.
(15) Honam is the petrochemical arm of GS Caltex, a refining JV of Lucky Goldstar and Chevron. If splitter goes ahead, output will be coordinated with Singapore trade group.
(16) Estimated capacities include 45 MBD Naph HDT, 25 MBD Dist HDT, 18 MBD CCR, and 29 MBD BTX.
(17) Formerly known as Aromatics of Thailand Corp, (ATC). Now fully integrated with PTT refining facilities, including a 25 MBD CCR.
(18) Now fully integrated with the Rayong refinery.
(19) The $6 billion project will include a 160 MBD processing plant with a 30 MBD splitter to provide feedstock for 1.5 MM MTA of paraxylene, 0.4 MM MTA of benzene. Plant will in large part be based on imported condensate.
(20) Condensate splitter was commissioned in late 2006, ahead of startup of the full CNOOC refinery. Expansion in ethylene cracking will lead to capacity expansion.
(21) Condensate splitter side-by-side with refinery and olefin complex.
(22) Splitter started up in August 2013, but only ran regularly by 2014. Project includes 44 MBD CCR, 30 MBD Naphtha HDT, 40 MBD alkylation, and 70 MBD isomerization. Splitter will run on imported condensate.
(23) Mizushima splitter is owned by Research Association of Refinery Integration for Group-Operation (RING), a consortium of refiners and chemical firms.
(24) SK Energy is converting a CDU design at 200 MBD to run half on condensate.
(25) Splitter works with conventional refinery.
(26) Gazprom proposal tied to Sakhalin-III development and may well be shelved, but company considering expanded commercial activity in Asia. Condensate output in Sakhalin has substantial N+A content, and we assumed plant orientation toward maximizing gasoline. Gazprom is Russia's largest-volume condensate producer.
(27) Plans to mothball plant have been shelved, though plant is running at fairly low utilization rate.
(28) Facility will run through 2016 at minimum, as plans to mothball have been abandoned.
(29) Mitsui withdrawn and project uncertain.
Source: "Condensate East of Suez 2013 – NGL Feedstocks as the Petrochemical Pivot of Asia's Shale Revolution," Asia Pacific Energy Consulting.

- An Emerging Yin/Yang: As we detailed in the April 2013 Baker Institute report on the shale revolution, we believe new trade flow will increasingly dominate supply/demand projections through this decade, in particular for light oil products, condensate, and tight oil output. The US is building a supply overhang that the home market will be unable to fully absorb, and it is questionable whether the entire Atlantic Basin could consume. Asia Pacific, though demand growth rates have slowed, will likely remain the leader of world oil demand growth.

- The "Third Rail": While there is general agreement in the energy sector that some modification of oil export rules—and considerable clarification of current federal policy—is urgently needed, politicians tread warily. American consumers believe strongly that they have the right to cheap gasoline. The US consistently ranks among the

leaders in least expensive retail gasoline prices among Organization for Economic Development and Cooperation (OECD) countries. Any move that would raise gasoline prices would be the equivalent of touching the third rail of an electrified rail line, destroying any office holder's chances of reelection. Yet, it is by no means certain that exporting crude and condensate would raise gasoline prices, any more than exporting gasoline itself.

Chapter II. Shale Gas/Tight Oil Development 2008–2014

A. *Overview*

The shale revolution began as explorers searched for ways to free gas constrained by geology, when reserves were trapped in impermeable shale formations. Operators learned that fracking—using controlled explosions to open impermeable gas and oil reservoirs—combined with horizontal drilling, which allowed greater extraction of liquids with a single drilling, as well as reaching *pockets* of oil that are not easily accessible to vertical wells, opened up new upstream opportunities. Operators then inject water and chemical blends, under pressure, to break open rock paths and force hydrocarbons to the surface. Shale formations have been known for decades, and fracking, in some form, has been used since the beginning of the oil and gas industry some 150 years ago. What is different now is that it is a programmed, systematic application of hydrocarbon recovery and an ever more sophisticated use of horizontal wells. Both its scale and sophistication now is substantially greater than when first experimental efforts began nearly a decade ago and could not have been imagined even by grizzled roughnecks. Systematic fracking in shale projects began as an attempt to exploit unconventional gas reserves that previously were deemed sub-commercial. Yet as marketed gas production began to steadily rise from 2009's level of 59.4 BN CFD of marketed dry gas to reach 82.2 BN CFD as of January 2014, the average price of gas declined—by as early as 2010.

The year 2010 was the turning point. A soft economy reduced gas demand and combined with rapidly building domestic gas output. The result was far less profitable gas production if relying solely on gas sales revenue. As gas prices fell, field operators turned to liquids-rich finds. Explorers began to turn away from dry shale development in the Barnett and Fayetteville basins

(Texas, Arkansas, Louisiana), to liquids-rich prospects. Bakken, an enormous shale reserve covering much of the state of North Dakota and extending far into Canada and Montana, was the first target of opportunity, and black oil production was the driver. Eagle Ford, located in southern Texas and extending well into Mexico, became the second area of tight oil-driven shale development.

Why focus on shale-derived oil? Simply because the revenue that could be gained from crude oil, but to some extent NGLs too, was far greater than natural gas. Traditionally the relationship of gas and oil has been set at the level where the heat produced by burning 1 barrel of crude oil is accounted as 5,800 CF of gas.[1] By 2009, the future price of crude, as measured by WTI to NYMEX gas, had fallen to a ratio of 14.9; by 2010, to 16.2; by 2011, to 23.6; and in 2014, it ranged in the mid-to-low 20s. When a producer had any choice as to which potential reserve to develop first, it was obvious that wet, particularly oil-rich shale formations had top priority.

Bakken oil production began rising rapidly by 2011 and by 2012 pushed North Dakota into third spot as an oil-producing state by volume, behind Texas and Alaska. Eagle Ford followed, as explorers found that it also contained large volumes of NGLs and that in order to maximize profitability all NGL output had to be utilized, with the field condensate making a particular impact on oil output. By October 2012, some 30% of the *crude* produced from Eagle Ford was in reality field condensate.

Once known oil-rich shale gas discoveries began development, upstream operators turned to NGL-rich fields. Drilling began to focus on the Marcellus formation in the Northeast of the US, as well as the underlying Utica shale formation, which is wetter, though smaller in extent, than Marcellus. Other explorers began to appraise and develop wet shale areas in Oklahoma's Cana-Woodford basin and in the Niobrara basin, mainly in Colorado.

[1] Though this standard is used by the US Internal Revenue Department and so adopted in American financial documents, the more common international field practice is a conversion of 6,000 CF to 1 BBL, the famous 6:1 value ratio. This BOE methodology has long been used by the financial sector to account for gas reserves as "converted" to oil, though conceptually it is inaccurate; gas can never be equivalent to oil, as gas generally is burned, while oil—and NGLs—often have a market value far higher than their calorific value.

The liquids emphasis, however, shifted—NGLs became the development target, as the easy and known oil formations were already put into play. Shale gas development is now driven as much by liquids as it is by gas, and the impact on US crude production, a significant proportion of which is actually field condensate, has been noticeable. By January 2014, tight oil made nearly half of US black oil output, while NGL production rose to 2.975 MM B/D, a 57% increase from 2010 levels.

This has also had an impact on the traditional relationships between crude, gas, and NGLs. In 2000, gas was still considered a poor relation of oil and, though regarded as a basic part of US energy use, incremental supply was expected in the form of LNG. As late as in 2008, new LNG receiving terminals were being proposed, and DOE projections showed a steady increase in US gas imports. The shale revolution overturned these assumptions and reshaped the relationship of gas to NGL. Traditionally gas was the dog and NGLs were a by-product tail of that output: one did not increase or decrease gas production from a wet field, because condensate prices rose above crude, or fell sharply. The priority need was to provide gas for the main sales contract. Shale development shifted NGL from a by-product of gas output to a co-product, and increasingly as gas prices appeared to settle in for a long spell of softness, NGLs have become a production driver, just like oil. The tail has begun to wag the dog. Yet, despite the shifted emphasis away from gas production per se, gas output continues to rise. Output of gas in the major shale plays (Eagle Ford, Bakken, Permian, but including Marcellus/Utica and the Haynesville basin) was expected to rise 425 MM CFD in August 2014 to total 40.1 BN CFD—yielding more gas than Qatar and Saudi Arabia combined. And despite pessimists' dire forecasts, it would appear that tight oil output will be higher and possibly far more sustained than earlier predictions.

Table 3. US Tight Crude Production Forecast (in MBD)

Field	2011	2012	2014	2016	2018	2020
Eagle Ford						
Total Crude Oil *	429	733	1,425	2,080	2,250	2,573
Est. Field Cond.	143	265	534	820	968	1,078
%Share Crude	33.3%	36.2%	37.5%	39.4%	43.0%	41.9%
Est. Plant Cond.	32	35	55	80	90	123
%Share Crude	7.5%	4.8%	3.9%	3.8%	4.0%	4.8%
Total Condensate	175	300	589	900	1,058	1,201
%Share Crude	40.8%	40.9%	41.3%	43.3%	47.0%	46.7%
Permian						
Total Crude Oil *	1,024	1,169	1,529	2,069	2,310	2,491
Est. Field Cond.	90	125	176	256	330	329
%Share Crude	8.8%	10.7%	11.5%	12.4%	14.3%	13.2%
Est. Plant Cond.	20	34	59	99	110	141
%Share Crude	2.0%	2.9%	3.9%	4.8%	4.8%	5.7%
Total Condensate	110	159	235	355	440	470
%Share Crude	10.7%	13.6%	15.4%	17.2%	19.0%	18.9%
Bakken						
Total Crude Oil *	416	634	998	1,643	1,953	2,027
Est. Field Cond.	44	67	106	174	223	232
%Share Crude	10.6%	10.6%	10.6%	10.6%	11.4%	11.4%
Est. Plant Cond.	12	24	38	63	93	97
%Share Crude	2.9%	3.8%	3.8%	3.8%	4.8%	4.8%
Total Condensate	56	91	144	237	316	329
%Share Crude	13.5%	14.4%	14.4%	14.4%	16.2%	16.2%

Source: Asia Pacific Energy Consulting

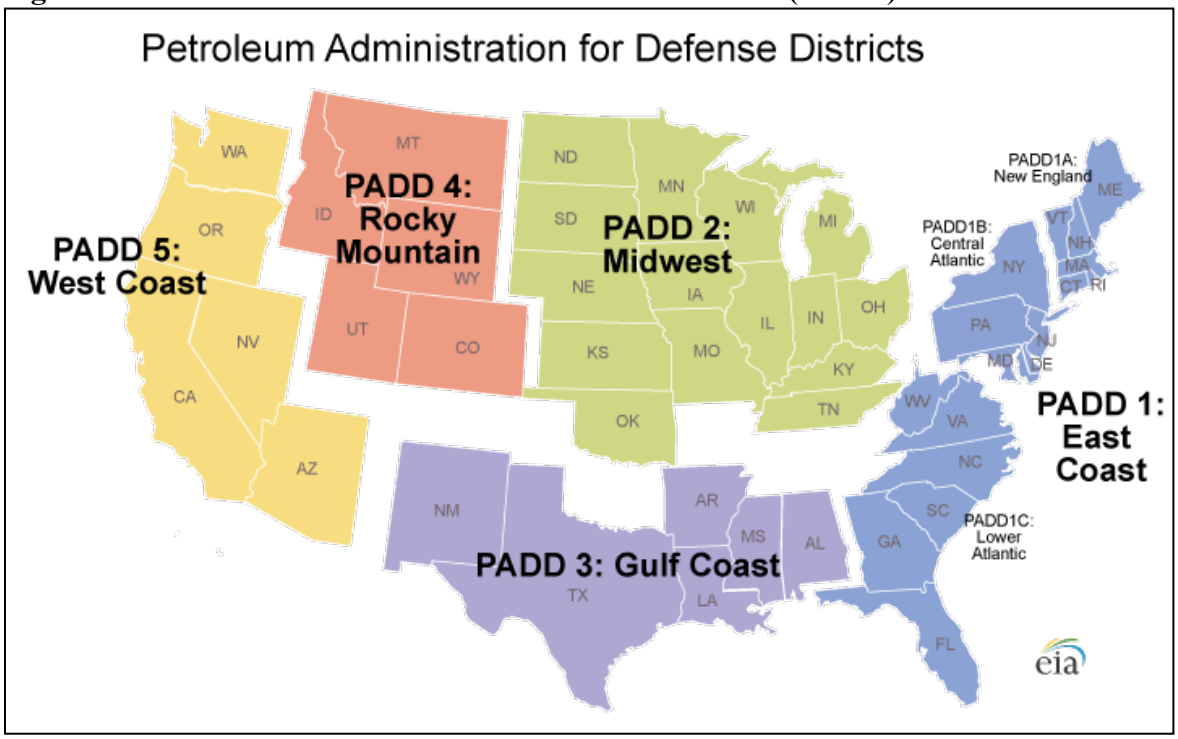
B. *Current Leaders in Gas/NGL and Tight Oil*

It is important first to understand where these shale developments are located, as the geographic distance of tight oil projects to processing plants and demand centers shapes their development. We will be using the federal government's Petroleum Administration for Defense Districts (PADD) system in examining the various regions of the US.

Bakken, the first major tight oil basin to be developed, is mainly in North Dakota (ND), within PADD-2, on the US-Canadian international border. It was distant from most US refining, and upstream developers first had to wrestle with transport as a major problem in developing their find. In contrast, Eagle Ford and the Permian Basin both are located in PADD-3, mainly within Texas, though the former runs well across the US-Mexican international border, and the western wing of the Permian extends well into southeast New Mexico (NM). Eagle Ford is very close to the USGC refinery cluster, running along the Texas-Louisiana coast, which accounts for more than half of national refining capacity, as well as the vast majority of US base petrochemical capacity.

Smaller-volume tight oil production is located in PADD-2—the South Central Oklahoma Oil Province (SCOOP), which makes up the southern portion of the Cana-Woodford Basin—in Niobrara mainly in Wyoming (WY) in PADD-4, and Utica, which straddles PADD-1 and PADD-2, mainly in the states of Ohio (OH), Pennsylvania (PA), and West Virginia (WV). The enormous Marcellus wet gas field overlays Utica and extends further east into New York (NY) as well. Possible future producer Tuscaloosa also is a PADD-3 discovery, mainly in Louisiana, but extending into neighboring Mississippi (MS), with similar proximity to USGC refining as Eagle Ford.

Figure 4. Petroleum Administration for Defense Districts (PADD)



The rise in US output of crude (including NGLs) has been breathtaking and seemingly relentless. Substantial impacts have already emerged in international markets from the growing production of liquids, as the US added 1.1 MM B/D (black oil and NGLs combined, but excluding biofuels) after seeing output rise 1 MM B/D in 2012, according to BP's 2014 Statistical Review.

In the period January 2011 through January 2014, oil production rose 44.5% to reach 7.83 MBD, with most of that gain recorded in tight oil output. Gas production, despite upstream operators focusing on oil and wet gas project, rose 8.9% to reach 82.21 BN CFD.

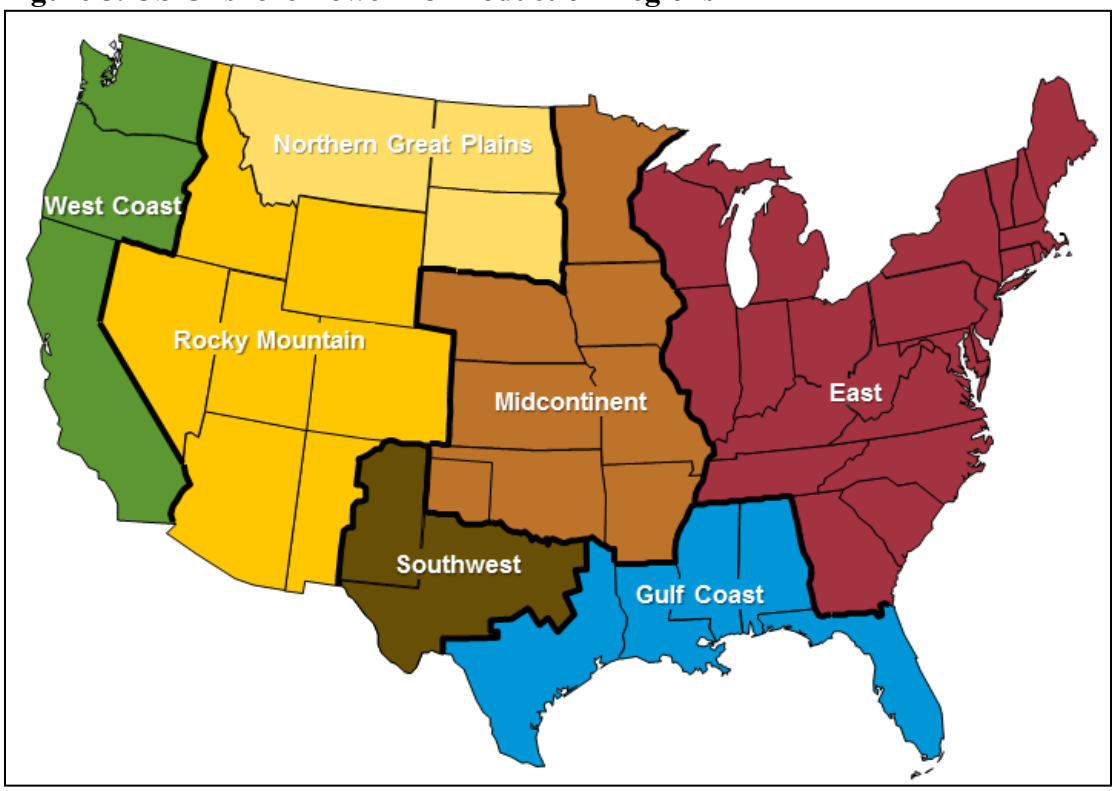
Most important has been the calming effect that rising US production has had on world oil markets over geopolitical jitters due to disruption in Libya, Nigeria, Iraq, and Syria. According to Christof Ruhl, chief economist at BP, oil prices were "extremely stable" and price volatility the lowest since global oil prices were deregulated in the early 1970s.[2]

Most of this continuing rise came from expanding tight oil production, abetted by additional field and plant condensate, derived from oil and gas output. The EIA in its August forecast expected the big rhree of tight oil output—Bakken, Eagle Ford, and the Permian—to rise in aggregate 72 MBD in August alone, bringing their production up to 1.11 MM B/D, 1.45 MM B/D, and 1.63 MM B/D, respectively. It should be noted that 10 years ago there was no tight oil production in Bakken or Eagle Ford. All Permian output then was from conventional oil developments.

There is substantial range of forecasts as to how fast and how high US crude output will rise. For example, using 2019 as the target year, the EIA had 9.6 MM B/D for US oil output in its May base case outlook. Well-respected RBN Energy pegged forecast output higher at 11.0 MM B/D. RBN noted that the EIA tends to under-report both crude and condensate that is over 50 API and has been consistently behind the production curve on Permian incremental production gains. RBN also highlighted—and in APEC's view rightfully so—that the Texas Railroad Commission (TRRC), the state oil and gas agency, while separating field and plant condensate from black oil production, underreports field condensate output. Consultants BTU Analytics, which generally takes a higher-volume production outlook, forecast oil production will rise from 7.83 MM B/D at the beginning of 2014 to 12.68 MM B/D in January 2019. Another established consulting firm, Bentek predicted US production rising at a far slower pace, to total 10 MM B/D by 2019.

[2] "US Record Forecast in BP's 2014 Statistical Review," *Platts*, June 16, 2014.

Figure 5. US Onshore Lower-48 Production Regions



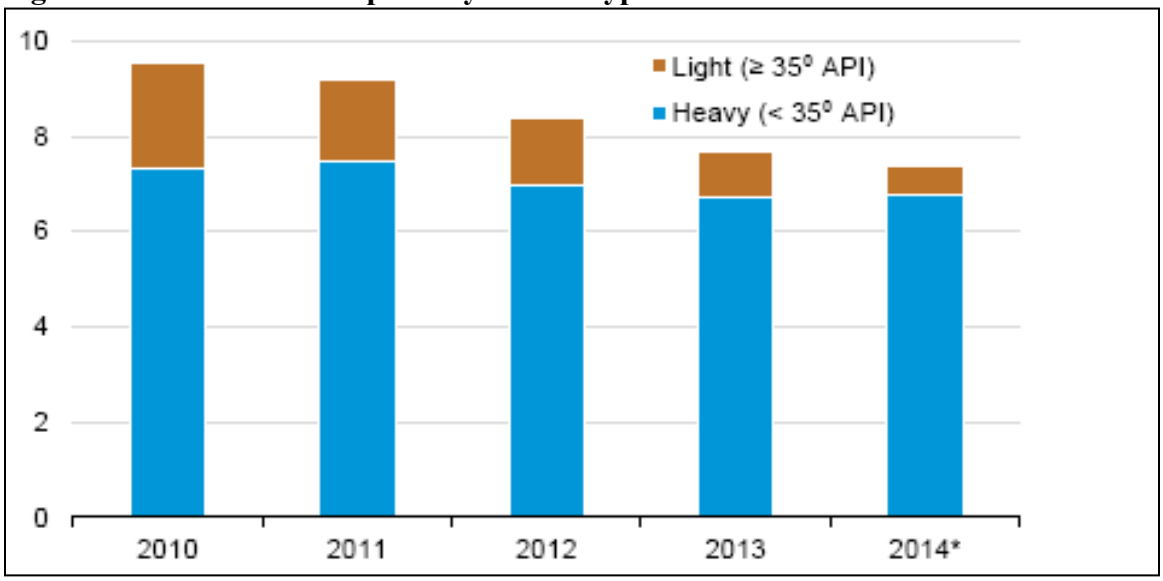
Source: "US Crude Oil Production Forecast–Analysis of Crude Types," US Energy Information Administration, May 29, 2014, 5, http://www.eia.gov/analysis/petroleum/crudetypes/.

All of these projections may be right, or inversely all wrong, but it is clear that US oil production remains on a steady upward trajectory, at least until the end of the decade. APEC's view is that we will reach a plateau period at end-decade, roughly 2018-20, with the gains in tight oil for most the part being balanced by declines in mature production.

The EIA has created a new approach to looking at current and future US oil production, by abandoning the old PADD system and creating a more logical regional breakout of crude and condensate output, often influenced by the emergence of tight oil production in volume. This study will be mainly concerned with the Gulf Coast region (Eagle Ford and Tuscaloosa), the Southwest region (Permian), the Midcontinent region (Cana-Woodford/SCOOP), the Northern Great Plains (Bakken), the Rocky Mountains (Niobrara and Uinta), and Marcellus/Utica within the East region.

This EIA analysis of crude quality and forecast of the impact of tight oil on average crude quality confirmed a point that the industry had long earlier concluded—that light crude imports have been reduced to a minimum and that it is likely that US refiners will buy mainly heavier imports in the future.[3] By January 2014, USGC refiners had more or less completed their back-out of imported light crudes. The main exception was equity barrels by companies with a foreign partner, such as Motiva, a joint venture of Shell and Aramco. Once the US Atlantic Coast refiners (USAC) complete their light crude back-out, most likely in 2015, US refiners will focus on medium-weight grades.

Figure 6. US Crude Oil Imports by Crude Type



Source: "Crude Oil Production Forecast," US Energy Information Administration, 3.

This becomes relevant when considering the other main point of this EIA analysis—that the percentage of condensate in Eagle Ford output has peaked and will steadily decline through the end of 2015. Reinforcing the trend, the EIA forecast, neither Permian nor Bakken will show any significant increase in condensate output for their liquids production.

[3] "US Crude Oil Production Forecast–Analysis of Crude Types," US Energy Information Administration, May 29, 2014.

C. *NGLs and Oil*

As we have detailed in the April 2013 study titled "Natural Gas Liquids in the Shale Revolution," the role of NGLs in energy balances is often woefully underestimated for a number of reasons. First, condensate, the only NGL that does not require containment, is frequently confused with light oil. Using an artificial breakpoint—such as is often the case in US analysis—stating that if a liquid has an API of more than 45, it is a condensate, is both technically incorrect and commercially misleading. Second, the displacement knock-on effects of NGLs influence a wide range of sectors—plant condensate can be used both in building gasoline blends as well as a petrochemical feedstock. Third, since condensate can be blended or spiked into a crude pool, it is often a contributing factor to raising the API of tight oil grades. A change in US export policy could see field operators begin to separate, segregate, and export condensate on a regular basis, which would at least moderately lower the average API for most tight oil grades, but in particular for Eagle Ford. This will make tight oil more attractive to USGC refiners. Finally, there is the displacement factor—a phenomenon often under-appreciated by analysts—if ethane is used in ethylene cracking, it displaced either an oil product—naphtha—or other NGLs, such as condensate (natural gasoline) or LPG (both propane and butane). Crude and oil product exports are shaped by NGLs, which are neither separate nor exclusive in their impact on oil and oil product markets.

If we take an overview by BTU Analytics of mid-2014 as our starting point—and noting the upbeat, though balanced outlook this company has in predicting future output—it is interesting to note that the gas and NGL forecast still is seen as strong, despite upstream companies turning to tight oil and gas liquids production as their priority.

And this consistent increase in gas output occurred despite a large number of wet gas wells shut in, due to ethane rejection in Marcellus development. Marcellus output will rise in 2014 to nearly 13 BN CFD, a more than four-fold increase over 2011 production levels. Other forecasts are just as upbeat, with Bentek in early 2014 predicting that US gas output should rise an average of 3.4 BN CFD through 2019, despite ethane rejection.

Table 4. National Gas Output and Marcellus Production

	2011	2012	2014	2016	2018	2020
US Output	75.51	80.29	82.21	94.47	104.09	105.97
Marcellus Output	2.86	5.52	12.65	17.85	15.02	15.88
%Share US Output	3.8%	6.9%	15.4%	18.9%	14.4%	15.0%

Source: BTU Analytics

And that gas will produce NGLs—one of the reasons that gas development shifted from dry developments, such as Haynesville, to wet gas finds, such as Marcellus, was the revenue from NGLs. Since 2009, NGL output—excluding field condensate—rose from 1.7 MM B/D to 3.0 MM B/D anticipated this year. If field condensate contained with tight oil was included in this production, total NGL output this year would top 4 MM B/D, possibly rising to as much as 4.2 MM B/D. By 2020, excluding field condensate, NGL output should rise to 4.5 MM B/D. This steady expansion of NGL production has been underpinned by a massive construction drive—over the period of 2013-15, some 70 new gas/NGL complexes will be completed, capable of processing almost 15 BN CFD of wellhead gas. The great NGL drive is on and the sustained rise in condensate output will continue to shape oil markets quite directly.

The flip side is that NGL supply has already overwhelmed the US market's absorption ability, as reflected by ethane rejection—both capping wells and simply burning ethane as natural gas—and by sharply growing exports of propane, butane, and plant condensate, as well as gradually increasing ethane sales abroad. This, too, has begun to impact world crude and oil product markets, if only by simple displacement of oil-derived products by gas-derived NGLs.

The chief driver, of course, has been relative values of gas, NGLs, and crude. While NGLs have fallen significantly in price since their most recent peak in 2011, taken as a group, they still sell for more than twice the value of natural gas. And the increased production of tight oil has also added to the NGL production rise, as associated gas produced together with this oil tends to have a high NGL content. Further, while NGL sales prices are far higher than gas values, condensate—both field and plant—sells at a consistent discount to crude oil. Under the long-standing ban on crude exports, field condensate was considered crude—and the higher price of crude compared to condensate encouraged producers to simply blend condensate back into the black oil pool.

If there has been a shift in US condensate policy, as shown by the June export cargoes, this means a new source of refinery and petrochemical feedstock has emerged—with direct impact on Asia Pacific balances. The prestigious Institute of Energy Economics, Japan (IEEJ) forecast that non-OPEC oil supply would rise 1.6 MM B/D in 2015, with 700 MBD in additional production from the US, 400 MBD added from Columbia and Brazil, and 200 MBD from Canada. More significantly, they expect that US field condensate will soon play an important international role in crude supply. "We expect to see US condensates flowing into the Asia market from now on," said Yoshikazu Kobayashi, oil group manager of IEEJ.[4]

D. *What's in the Crude?*

A spate of rail oil tanker accidents in the US and Canada highlighted another aspect of the NGLs versus crude calculation—the presence of more volatile NGLs, in particular butane, in rail shipments of Bakken tight oil. The size and intense heat of fires caused by derailed oil tanker cars led many to suspect that producers were purposefully injecting butane into black oil shipments to increase oil volumes—crude oil sells for some 20-30% more, on a volume basis, than butane, while butane is far more volatile. Hence the suspicion that accidental fires were made worse by the "spiking" of NGL into crude.

Yet, a study released in August 2014 by the North Dakota Petroleum Council (NDPC) concluded that an extensive range of testing of Bakken output showed no evidence of NGL spiking into crude production before rail shipment, refuting claims that the volatility of Bakken shipments was increased by deliberate or accidental addition of NGLs. The study was commissioned to extensively survey, sample, and test a wide range of production streams in North Dakota crude output. Still, the NDPC recommended that all rail shippers of oil classified as Bakken crude use only Packing Group 1 rail tank cars, which now generally haul for hazardous materials.

[4] "IEEJ Sees Non-OPEC Supply," *Platts*, July 10, 2014.

Table 5. Tight Oil Production Forecast (in MBD)

Crude	2011	2012	2014	2016	2018	2020
Eagle Ford (USGC)	397.0	698.0	1,466.0	2,389.0	2,770.0	2,988.0
Permian	1,004.0	1,135.0	1,503.0	2,049.0	2,339.0	2,532.0
Bakken	404.0	610.0	976.0	1,660.0	2,013.0	2,283.0
SCOOP/Cana-Woodford	289.0	341.1	434.0	490.2	507.9	522.5
Niobrara (2)	98.3	107.9	279.0	421.1	497.8	554.3
Uinta	45.0	55.0	85.0	106.0	112.0	120.0
Marcellus/Utica	20.0	23.0	48.0	126.0	216.0	214.0
Tuscaloosa	10.8	10.1	10.7	13.2	14.6	15.7
Total Tight Oil Output	2,268	2,980	4,802	7,255	8,470	9,230
Total US Output	5,423	6,070	7,832	10,752	12,205	13,064

Notes: (1) Generally actual statistics through third month of each year; Oklahoma data actual only through 2013, rest through 2014.
(2) Niobrara includes Powder River.
Source: BTU Analytics

Table 6. Rate of Increase in Tight Oil Production Forecast

Crude	2011-2014	2014-2020	2011-2020
Bakken	141.6%	133.9%	465.1%
Eagle Ford	269.3%	103.8%	652.6%
Perrmian	49.7%	68.5%	152.2%
All US	44.4%	66.8%	140.9%

Source: BTU Analytics

Table 7. Big Three—Share of Total US Production

	2011	2012	2014	2016	2018	2020
Share	33.3%	40.2%	50.4%	56.7%	58.4%	59.7%
Volume	1,805	2,443	3,945	6,098	7,122	7,803
of which:						
Permian	*1,004*	*1,135*	*1,503*	*2,049*	*2,339*	*2,532*
Eagle Ford	*397*	*698*	*1,466*	*2,389*	*2,770*	*2,988*
Bakken	*404*	*610*	*976*	*1,660*	*2,013*	*2,283*
Total US Output	**5,423**	**6,070**	**7,832**	**10,752**	**122,054**	**13,064**

Source: BTU Analytics

The future composition of crude is an important question and a target that keeps on moving, both in the composition of future output, as well as expected production levels. Since tight oil output is highly variable in quality—with crude varying among strata, as well as within as a single stratum—explorers should be more cautious in their outlooks, particularly with basins that have multiple strata, stacked one atop another, such as the Permian.

Yet, selling a new prospect, upstream executives often are relentlessly upbeat. Scott Sheffield, the chief executive officer of Pioneer Resources, suggested to an oil conference in August that US oil production, underpinned by expanding tight oil output, would reach an all-time high in 2016 at roughly 10 MM B/D and top 14 MM B/D before the end of the decade. Pioneer's data pinpointed future Permian production as the key support to the continued rise of American crude output, claiming that the Permian basin contained the recoverable oil reserves of "12-15 Bakkens on top of each other."[5] But what kind of tight oil will emerge and what ultimate plateau production volume will be achieved remain open questions.

E. *Looking at the Tight Oil Plays*

The sustained rise in North American oil output can best be understood in terms of "waves of development." The first wave of development, 2009-14, was based on Bakken, Eagle Ford, and Permian for tight oil. The second wave of tight oil production is coming from fields now rapidly expanding output—though will be unlikely to reach the 1 MM B/D plus production now seen in the Big Three. These include Uinta and Cana-Woodford (SCOOP) basin developments. Further down the road will be the condensate/crude output of projects in Utica (tight oil/condensate), Marcellus (condensate), Tuscaloosa, and possibly Monterey.

APEC expects US success in developing shale gas/tight oil will be first followed by Canada with the Dunleavy development, followed by Canadian Bakken, and Alberta/British Columbia Montney basins will begin to show sizable commercial output by as early as 2018 and will be major producers by the end of the decade. Eagle Ford, as well as Bakken, extends well across the US border and deep into northeastern Mexico. We expect first commercial impacts of shale development there by 2018-20.

1. <u>The Big Three—Eagle Ford, Bakken, and Permian</u>

APEC takes a more conservative forecasting approach than many analysts and tends toward the lower range in its forecasts. We also include in our crude production numbers plant condensate, which is derived from shale gas, as well as associated gas produced with tight oil. Even with a

[5] Jessica Resnick-Ault, "Shale driller pioneer sees US pumping 114 mln bpd," *Reuters*, August 6, 2014.

more conservative approach, APEC's forward look at production in the "big three" will total more than 7 MM B/D by end-decade, including all condensate output.

Table 8. *Big Three* Tight Crude Production Forecast – APEC (in MBD) (1)

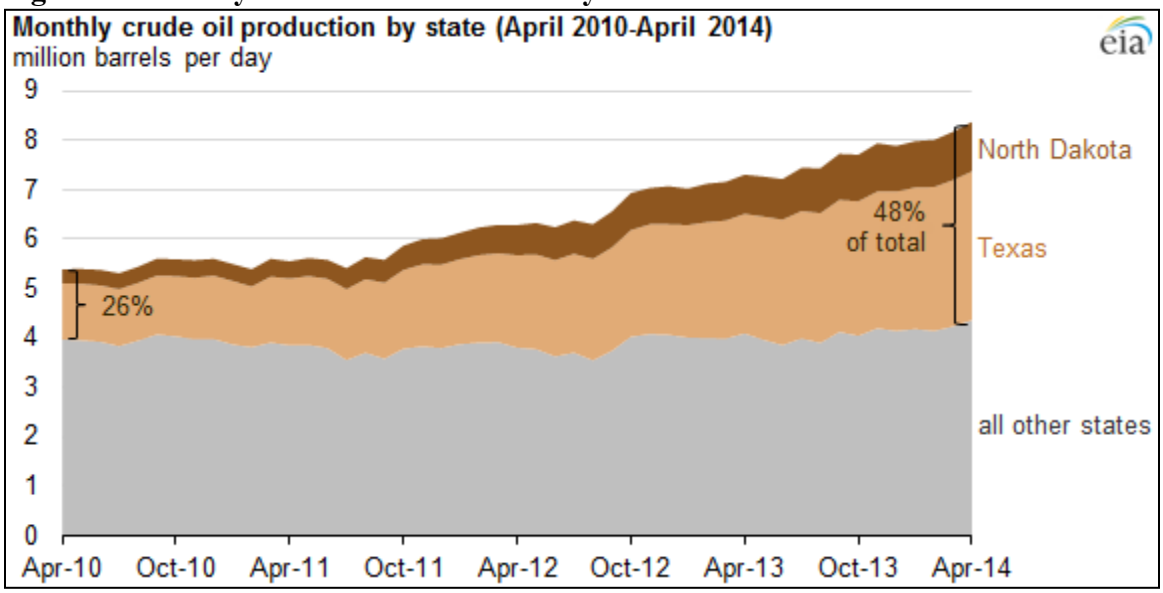
Field	2011	2012	2014	2016	2018	2020
Eagle Ford	429	733	1,425	2,080	2,250	2,573
Permian	1,024	1,169	1,529	2,069	2,310	2,491
Bakken	416	634	998	1,643	1,953	2,027
Total	**1,869**	**2,536**	**3,952**	**5,792**	**6,513**	**7,091**

Note: (1) Total crude includes black oil and field and plant condensate.

a. Tight Oil Impacts

The impact of the big three on US oil production has been substantial; EIA's analysis (see Figure 6 below) showed that two states, Texas (most of Permian and all US Eagle Ford) and North Dakota (Bakken), by April 2014 made up nearly half of all American crude/condensate output. It should be noted that for Permian production most crude in 2010 came from conventional field developments. Gains through April 2014 were for the most part from tight oil output, not only increasing overall Permian production, but making up for declining output from Permian conventional fields.

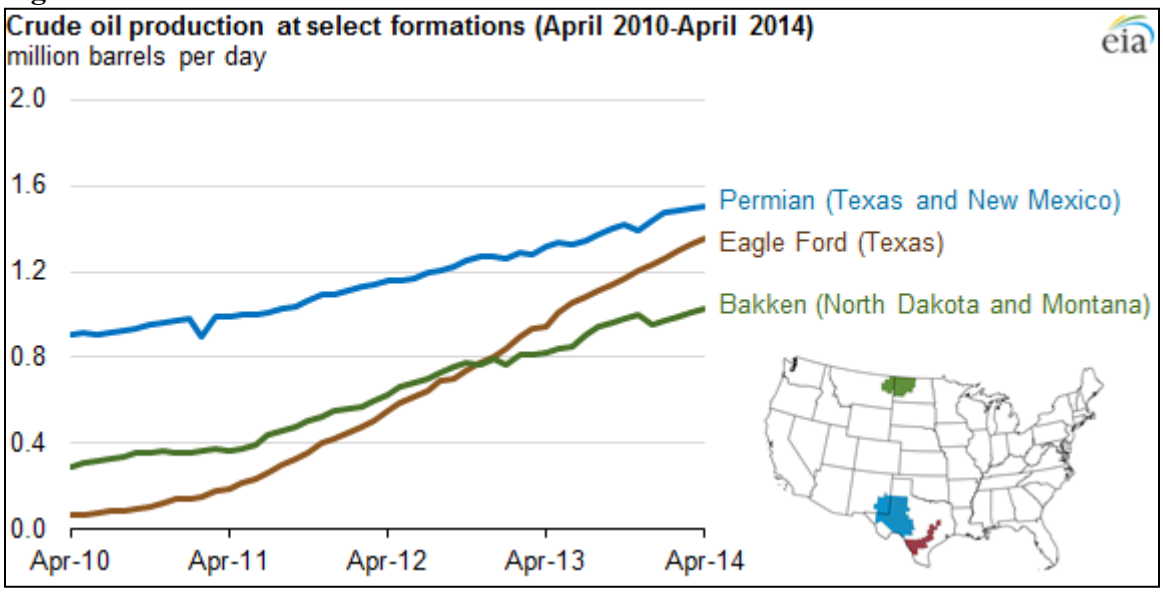
Figure 7. Monthly Crude Oil Production by State



Source: "Today in Energy," US Energy Information Administration, July 1, 2014; North Dakota and Texas now provide nearly half of US crude oil production.

Eagle Ford and Permian accounted for most of Texas oil production of 2.15 MM B/D, excluding plant condensate, according to the TRRC. It should be noted that even though there are serious flaws in the TRRC's methodology and apparent flaws in statistics that it gathers, the commission provides far more detail on condensate production in Texas than national figures by the EIA section of DOE. (Please note that we will defer to TRCC statistics solely for condensate.) Eagle Ford crude output has far outpaced even relatively recent forecasts—we expect that Permian production will rise more sharply in the medium term (i.e., 2014-17), and forecasters have suggested it may well see output expand even further by 2020. But as a jury trial in Scotland can rule, the case is "not proven"—at least yet.

Figure 8. Crude Oil Production at Select Formations



Source: "Today in Energy," US Energy Information Administration.

b. Eagle Ford

Eagle Ford is a tight oil and shale gas basin shaped like a quarter moon, located south of San Antonio and extending far over the US national border into Mexico's Tamaulipas state. The tight oil zone is furthest north of three exploration zones. As drilling extended north, dry gas, wet gas, and then finally tight oil were the main hydrocarbons discovered.

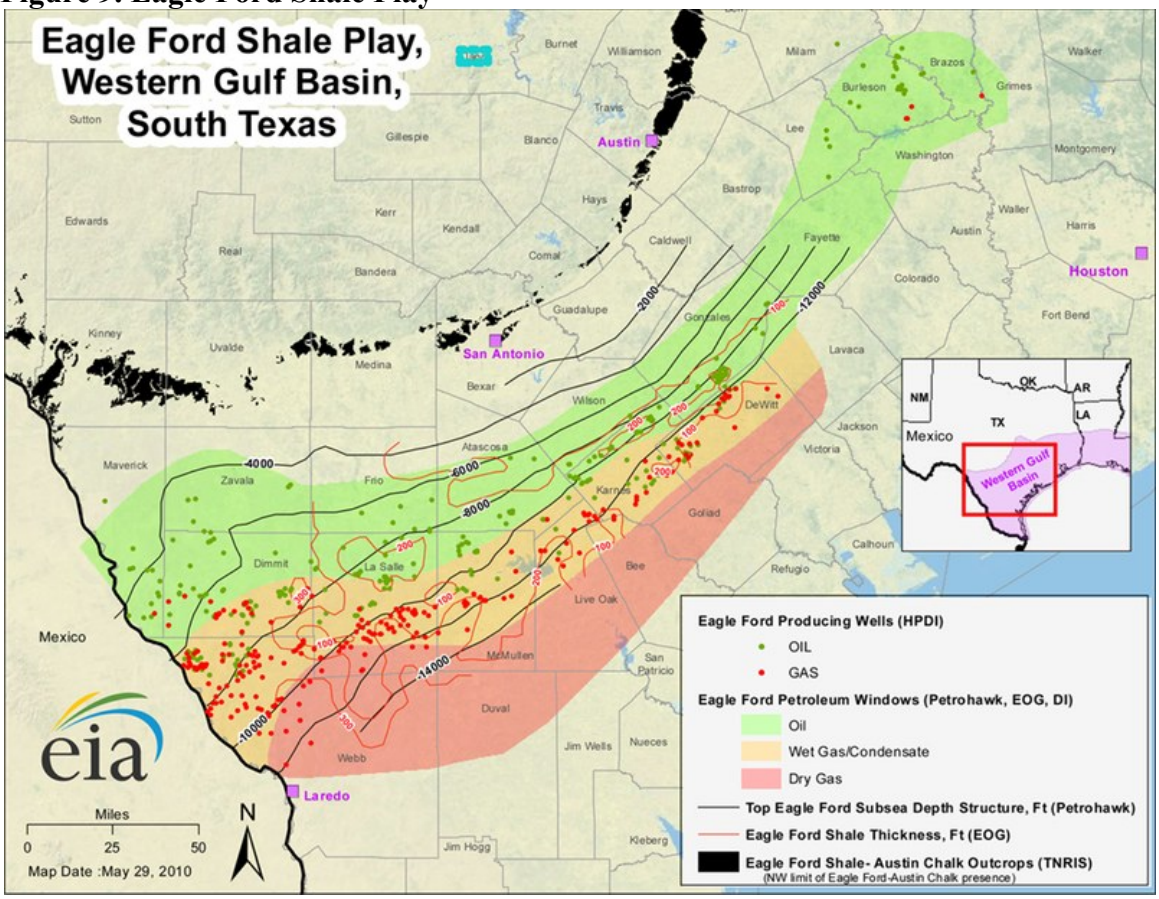
The spectacular rise of Eagle Ford exceeded even Bakken's giddying trajectory. In 2009, the entire basin produced less than 1 MBD. By 2011, Eagle Ford averaged 129.9 MBD and then

more than tripled to 401.6 MBD by 2013—excluding plant condensate produced in parallel. End-2013 volume topped 1 MM B/D, and Eagle Ford overtook Bakken output.

Explorers in 2010 shifted development focus from wet gas discoveries to oil-prone acreage. The result has been a sharp rise in Eagle Ford output. A mid-2014 forecast by the TRRC pegged Eagle Ford crude-only production at an average of 803 MBD; the EIA predicted that total liquids, crude and including condensate, but excluding other NGLs, should reach 1.45 MM B/D in August 2014. It should be noted that associated gas output, parallel to tight oil and yielding considerable condensate, will reach 6.51 BN CFD.

Top upstream companies have been reassessing their forecasts of recoverable reserves. ConocoPhillips is a typical example. In April, the company increased its assessment of in-place reserves to 2.5 BN BBLs, 59% crude, 20% NGLs, and 21% gas. Even though only a mid-sized player in this basin, ConocoPhillips expects to double output (on a barrels of oil equivalent basis) from early 2013's 126 MBOE to 250 MBOE by early 2017.

Figure 9. Eagle Ford Shale Play



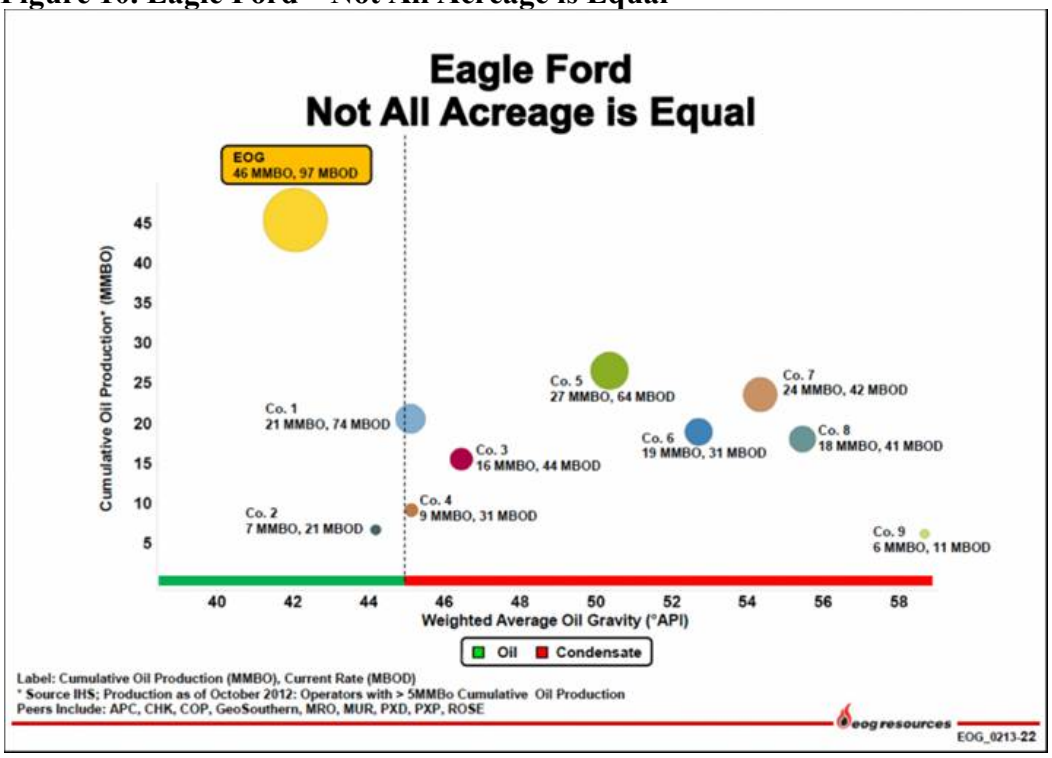
Other players expect even larger volume production. As a leading producer in Eagle Ford, EOG controls leases totaling 569,000 acres (roughly 2,300 sq. km). Other top producers include Chesapeake, ConocoPhillips, Marathon, and Murphy. As new output emerges, volume rankings have changed frequently. The impact of condensate is shaping Eagle Ford production. While Bakken contains relatively less condensate, Eagle Ford production still includes a large volume of condensate, despite the current emphasis on maximizing crude development. And though Bakken emerged as a tight oil zone first, Eagle Ford will likely impact international exports to a far greater extent.

A number of factors have shaped Eagle Ford as a very different type of development than Bakken. First, there is the matter of proximity, as this production area is very close to major crude buyers, and the Texas-Louisiana coast hosts the majority of US refining and base petrochemical capacity. Second, unlike North Dakota, Texas had extensive oil and gas

infrastructure already in place—for Eagle Ford output to rise, only brownfield expansions were needed, rather than greenfield construction of infrastructure. This allowed a rapid rise in tight oil output, while quickly harnessing associated gas production to yield both gas and NGL for sale. Third, Eagle Ford had a secure and nearby refining outlet at Corpus Christi that could immediately absorb far more incremental crude at a single location.

Yet, it is the variability in weight and quality of Eagle Ford tight oil that most distinguished it from Bakken. Output has varied enormously, even in side-by-side wells. It ranged from black oil as heavy as 36 API, to condensate averaging as high as 74 API. Figure 10 below details EOG's range of production. EOG is the largest-volume Eagle Ford producer.

Figure 10. Eagle Ford—Not All Acreage is Equal



Eagle Ford's proximity to USGC refining accelerated expansion of pipeline capacity to Corpus Christi, the nearest refining center, as well as Houston, the largest concentration of refining in the PADD-3 region. Producers were able to take advantage of existing transport infrastructure, fully harnessing the basin's NGL potential in relatively short order. Pipeline access to Corpus Christi, the nearest refinery outlet, and then Houston were quickly completed. Corpus Christi buyers

included Citgo (157 MBD; part of Venezuelan state PDVSA), Flint Hills (279 MBD; owned by independent Koch), and US refiner Valero (205 MBD). They quickly turned to this opportunity crude that emerged on their refinery doorstep. Flint Hills and Valero expanded capacity to run mainly light Eagle Ford. As takeaway capacity for Eagle Ford grew, the marketing reach of this output also extended as pipeline revamps, such as the reversal of the Ho-Ho line from Houston to Louisiana, were completed.

The net result has been the emergence of a new, major oil province that was a chief force in driving light, sweet crude imports out of PADD-3 refining slates. Expansion of existing pipelines has given Eagle Ford sales access to buyers east of the Houston Ship Canal, what we call the Greater Houston area. In addition, Corpus Christi soon will have piped supply of segregated condensate. In August 2013, Corpus Christi shipped 368 MBD of crude; by August 2014 this topped 500 MBD.

Table 9. Top Five Eagle Ford Producers (in MBD; Excl. Plant Condensate) (1)

Ranking	Company	Oil Output
1	EOG Resources	131.2
2	Chesapeake Energy	101.0
3	Burlington (ConocoPhilllips)	66.5
4	Marathon	56.0
5	Murphy	34.1

Note: (1) Based on the first half of 2013 only.
Source: San Antonio Business Journal, August 29, 2013.

c. How Much Condensate?

The question of how much of tight oil actually consists of field condensate becomes central if US export policy is shifting to allow sales abroad of lightly processed condensate. Eagle Ford and Permian output are particular points of focus, because they are not only relatively close to substantial US refining and petrochemical capacity on the USGC, but also to ports that would allow for condensate export.

Eagle Ford has been particularly difficult to forecast. In 2013, condensate at times made up as much as 44% of Eagle Ford tight oil production. APEC, among other analysts, believes that while explorers' shift to trying to maximize black oil over condensate would reduce the latter's

share of liquids output, the decline in condensate production in Eagle Ford has far outpaced earlier expectations.

If LNG exports increase rapidly from 2016 onward, that will likely underpin further pumping of associated gas in Eagle Ford and Permian formations and the stripping of gas for condensate.[6] According to BP's forecast of August 2014, US gas demand will grow by 12.5-19.5 BN CFD, a rise of 18-28%, by 2020 and could rise even further. The two underpinning supports will be LNG exports and the need to replace coal at many American power generation plants. As of 2014, roughly half of coal-based US power plants could not comply with recent regulations enacted by the Environmental Protection Agency (EPA).

Tracking condensate in crude production, particularly in tight oil, has become tricky. The EIA never paid much attention to the subject until relatively recently and attributed some of its statistical shortcomings to uneven and sometimes unreliable data provided by each state. There is some truth to this, as evidenced in the statistics shown in Table 10 following, but condensate was virtually ignored—until the possibility of export arose. A further caveat, APEC in examining TRRC statistics has noted a number of omissions and probable numerical errors in the data the state provided. While TRRC data on condensate is far more detailed than the EIA's numbers, it also has obvious statistical errors and so should be taken more as indicative of overall trends rather than actual.

[6] Bill Holland, "LNG exports to drive US gas demand: BP," *LNG Daily*, August 8, 2014.

Table 10. Texas Condensate Production (in MBD)

Month	Eagle Ford			Permian			Total Texas		
	Field	Plant	All	Field	Plant	All	Field	Plant	All
Jan	253.9	20.2	274.1	15.9	35.6	51.5	404.0	96.4	500.4
Feb	263.0	21.3	284.3	17.6	39.6	57.2	407.2	99.6	506.8
Mar	265.3	22.0	287.3	16.4	38.2	54.6	418.7	101.3	520.0
Apr	262.4	23.2	285.6	17.9	40.8	58.7	417.5	101.6	519.1
May	254.0	25.0	279.0	17.8	39.6	57.4	403.9	105.2	509.1
Jun	229.0	27.3	256.3	18.9	40.1	59.0	365.9	107.0	472.9
Jul	251.2	28.1	279.3	18.8	38.7	57.5	381.9	109.5	491.4
Aug	250.0	24.2	274.2	21.5	36.9	58.4	378.2	105.0	483.2
Sep	227.9	28.5	256.4	15.9	14.0	29.9	347.6	90.0	437.6
Oct	231.3	7.9	239.2	13.9	12.6	26.5	348.3	55.8	404.1
No	212.5	16.5	229.0	12.7	11.2	23.9	323.2	65.2	388.4
Dec	217.4	16.5	233.9	10.4	11.2	21.6	312.4	65.3	377.7
Average	243.2	21.7	264.9	16.5	29.9	46.4	375.7	91.8	467.6

Source: Texas Railroad Commission

Even with these caveats, it is clear that condensate plays an important part in tight oil production. Texas condensate output, according to TRRC numbers, in 2013 rose by almost 65% to 466.7 MBD, despite Eagle Ford producers maximizing oil output.

Table 11. Texas Condensate Production by Grade (1)

Condensate	2012	1-6/2013	7-12/2013	2013
Lease Condensate	**196.3**	**402.9**	**310.7**	**356.9**
Eagle Ford	150.1	306.5	222.8	264.7
Permian	12.7	20.8	8.5	14.7
Other Texas	33.5	75.6	79.4	77.5
Plant Condensate	**86.9**	**107.5**	**112.0**	**109.9**
Eagle Ford	35.5	41.7	24.0	32.9
Permian	32.9	47.0	32.3	39.7
Other Texas	18.5	18.8	55.7	37.3
Total	**283.2**	**510.4**	**422.7**	**466.8**

Note: (1) Lease condensate already accounted for in tight oil production; plant condensate is in addition to tight oil production by basin. We believe that Permian field condensate output is assessed incorrectly in TRRC statistics and have used APEC estimates for both 2012 and 2013 at 125 MBD and 140 MBD, respectively. According to the TRRC's numbers, plant condensate output in 2012 was about 2.5 times greater than field, and the same ratio was reported for first-half 2013. We believe this unlikely production pattern is a result of misreporting or mislabeling for the first half of 2013. Total condensate output for 2013 likely topped 700 MBD, rather than approaching 500 MBD, as TRRC numbers implied.
Source: Texas Railroad Commission; 2013 estimated by APEC in part to provide full 2013 year.

These TRRC statistics should be taken with more than a grain of salt, particularly for Permian output. Permian lease condensate, we believe, is woefully under-reported and in some months

TRRC numbers have been strikingly off their norm, which leads to concern about discrepancies in their statistical reporting.

Nonetheless, some things are clear. What has changed in APEC's outlook is that Eagle Ford operators, in shifting to emphasize black oil output, have reduced slightly the proportion of field condensate in tight oil outturn through increasing absolute volume condensate output. We had expected a minor drop in production volumes, while overall Eagle Ford production increased. This view was also held by many in the trade, as suggested by the following end-2013 table:

Table 12. US Tight Oil—Estimated 2013 Condensate Yield (in MBD)

Field	Condensate	Total Crude	%Tight Oil as Cond.
Eagle Ford	465	1,118	41.6%
Permian	228	1,330	17.1%
Bakken	135	1,000	13.5%

Source: Jay Harbison, "Evaluating Gulf Coast Condensate Markets in Relation to Blending," Eletricitie de France (EdF).

While the emphasis shifted to black oil, a sharp rise in associated gas production kept condensate relatively high as a proportion of total crude/condensate output. Though remaining significant—some 39-40% in 2014 (including plant condensate)—the percentage of crude in condensate in reality fell from 2013 levels. A Barclays Bank study in early 2014 concluded that if drilling patterns do not change and oil output remains the chief production driver, gas volumes still would rise—likely to add 1.4 BN CFD of output to total 6.8 BN CFD in 2014. Condensate volumes will also rise, but black oil output will rise faster.

This tremendous buildup in associated gas has also underpinned a sharp rise in LPG output and exports. If all planned USGC export terminals are completed, the US will be able to export more than 1.4 MM B/D of LPG abroad. Since US Mont Belvieu prices are some 30-40% lower than Japan's LPG landed cost, East Asia will attract sales. The Panama Canal revamp, allowing transit to wide-beamed tankers, will spur sales further.

Table 13. Eagle Ford Tight Oil Production Forecast—A Comparison (in MBD) (1)

Forecaster	2011		2012		2014		2016		2018		2020	
	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share
Wellhead Output (Crude & Field Condensate)												
BTU Analytics	397		698		1,466		2,389		2,770		2,988	
APEC	397		698		1,370		2,000		2,250		2,450	
Field Condensate Only												
BTU Analytics	147	37%	272	39%	601	41%	1,003	42%	1,163	42%	1,285	43%
APEC	143	36%	265	38%	534	39%	820	41%	968	43%	1,078	44%
Plant Condensate												
APEC	32	8%	35	5%	55	4%	80	4%	90	4%	123	5%
Total Condensate												
APEC	175		300		589		900		1,058		1,201	
Total Eagle Ford Oil/Condensate (Incl. Plant) Production												
APEC	429		733		1,425		2,080		2,340		2,573	
Total Condensate as % of Total Output												
APEC (2)	41%		41%		41%		43%		45%		47%	

Notes: (1) Rising condensate sales from field results in more gas; gas production also increases on sales to Mexico. (2) Some exporters will be recombining plant and field condensate; sag in condensate's share of output 2014-16 offset by drive for field condensate for export by 2017.

Still, it should be underlined that a good deal of tight oil output was and will remain condensate. And if the door has been opened to full condensate exports, then the US could potentially push out enormous volumes of this material.

d. Permian

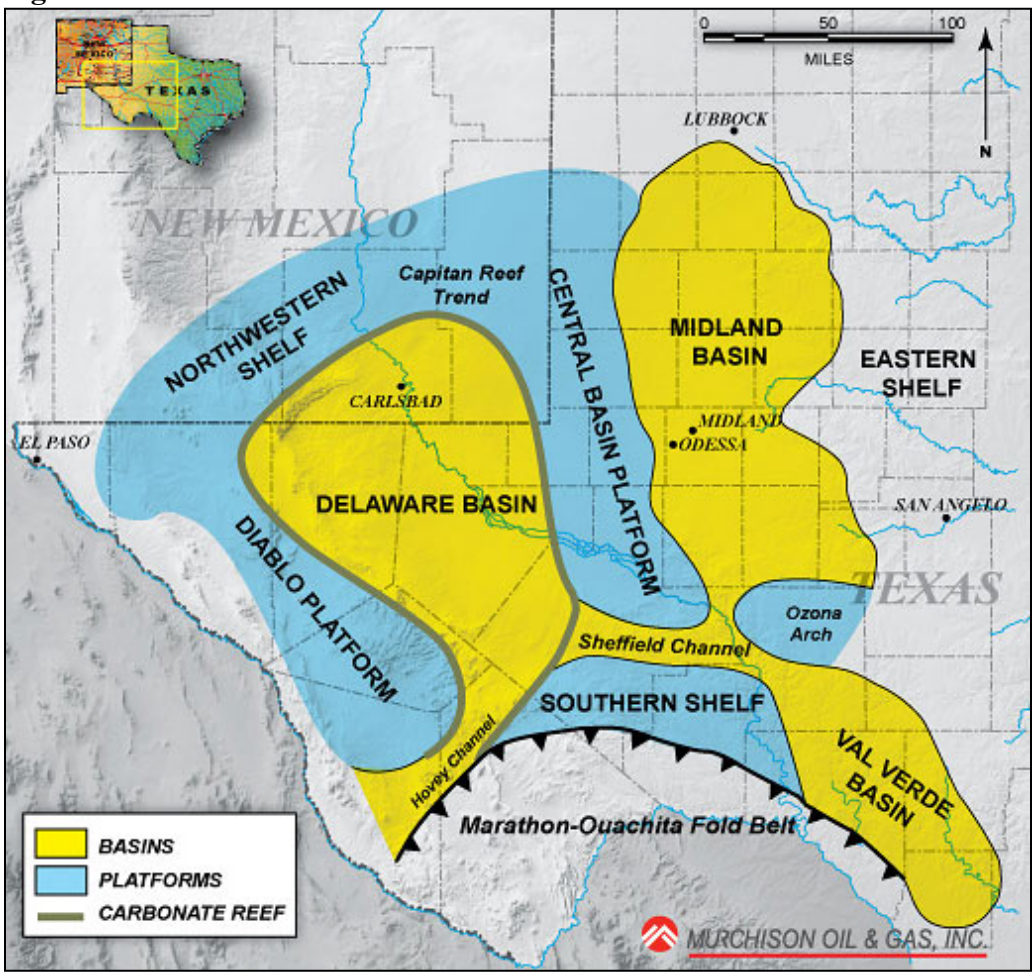
Permian is the only composite structure we will examine in this study, producing black oil from both conventional and unconventional development. As a conventional oil play, Permian has been pumping petroleum for nearly a century. Tight oil production is a relatively recent phenomenon. This enormous sedimentary, one of the largest in North America, measures roughly 420 km (250 miles) long and 500 km (300 miles) wide, stretching from Midland in western Texas well into the southeast corner of New Mexico—approximately 192,000 sq. km (37,066 sq. miles).

Within the butterfly-shaped Permian structure, there are two main sub-basins: Delaware to the west, extending into New Mexico, and Midland, Texas, to the east. Odessa and Midland, two small cities in west/central Texas, were the epicenters of conventional oil output, starting in the 1920s. Unconventional tight oil development at first focused on the Delaware sub-basin, where tight oil output by 2013 made up a sizable proportion of total crude production. Explorers have

been focusing in 2014 on surveying and wildcat (exploratory) drilling in the Midland sub-basin, and the number of horizontal wells as a proportion of total wells drilled has risen rapidly.

Sheer size is not what distinguishes the Permian Basin in the future production outlook, but the discovery of stacked stratum, similar to a cake with multiple levels of different icings. The Permian's mainly conventional oil and gas output topped 29 BN BBLs and 75 TCF of gas cumulatively through 2011. Explorers believe that fracking and horizontal drilling will make commercially exploitable at least an equal volume of still unexploited oil and gas output, with the greatest prospects in the Midland sub-basin.

Figure 11. The Permian Basin



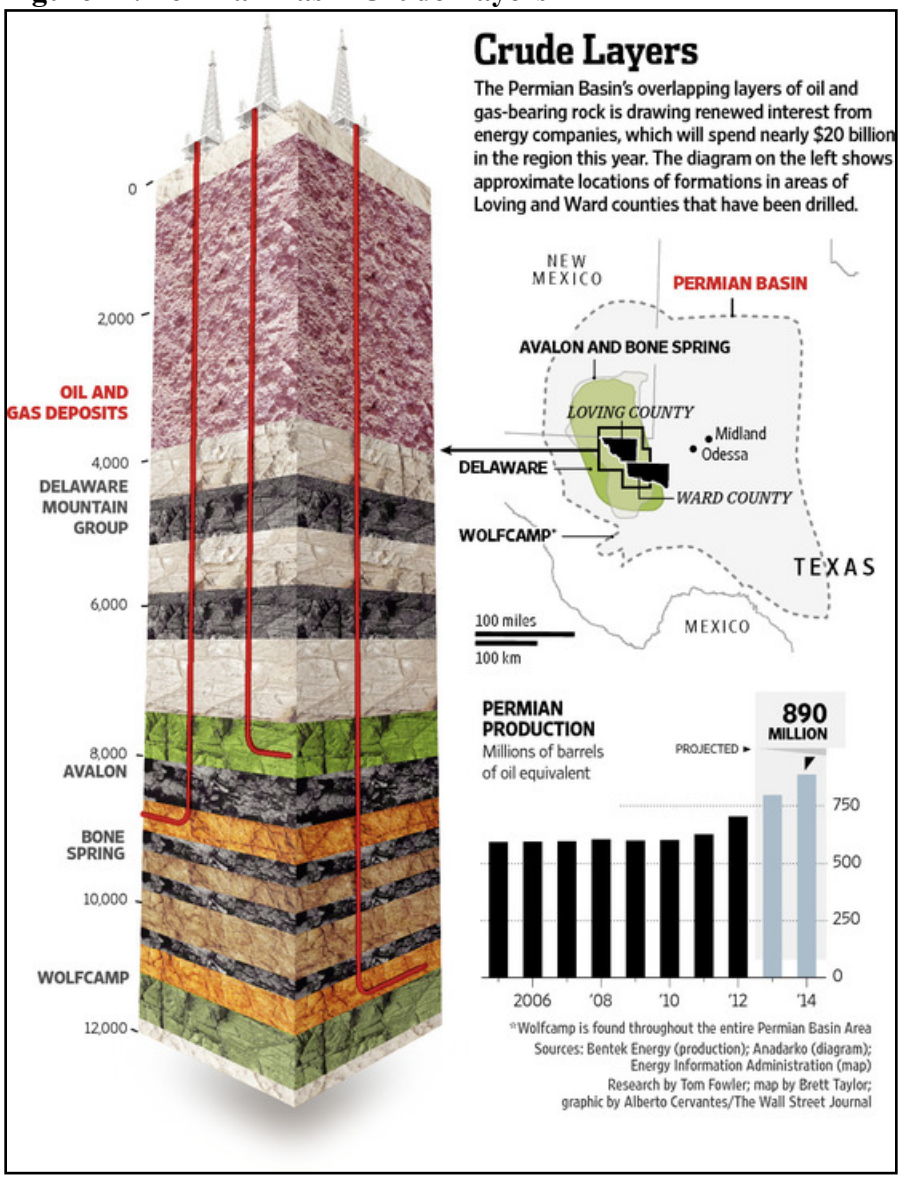
Explorers see 2014 as the year of decision. While recent increased use of enhanced oil recovery methods has boosted output in mature conventional wells, horizontal drilling has begun to make

its mark with unconventional oil output. Through 2014, most horizontal drilling was in the Delaware sub-basin and exploited the relatively shallow Avalon and Bone Springs strata, which were drilled at roughly 2,880 M and 3,250 M, respectively. These layers of hydrocarbon-bearing rock are considerably deeper than conventional oil output, which ceases production at roughly 1,800 M. The Wolfcamp formation, now being drilled with horizontal wells in the eastern *wing* of the Midland sub-basin, is at depths of slightly more than 4,000 M and can be as deep as 4,330 M. In both there are stacked strata consisting of Spraberry, Wolfberry, Cline, Wolfcamp, Bone Spring, and others—often having begun life as conventional producing fields.

Horizontal drilling is still risky. Pioneer Natural Resources, a leading producer, must begin to drill an enormous inventory of undrilled wells—some 10,000 at the beginning of 2014, many in the Midland basin. Oxy, though, will likely remain the largest volume producer as it holds the most acreage, although some of it is of lower prospectivity. In 2013, about 30% of Permian wells were horizontal wells. Explorers expect that unconventional wells will make up over 50% of Permian drilling soon.

Drilling deeper, and through more difficult source rock than the carbonate layers of Eagle Ford, means that Permian tight oil production has been slower to gain traction, but will become the main driver for future oil output. Wolfcamp and Cline formations are the focus of current unconventional drilling. Vertical wells have been long profitable, but now the focus is on horizontal drilling of multi-layered strata. RBC Capital forecast a 30% rise in Permian horizontal wells drilled, and at least some of these will explore the potential of oil zones that have been producing conventional output, such as Spraberry.

Figure 12. Permian Basin Crude Layers



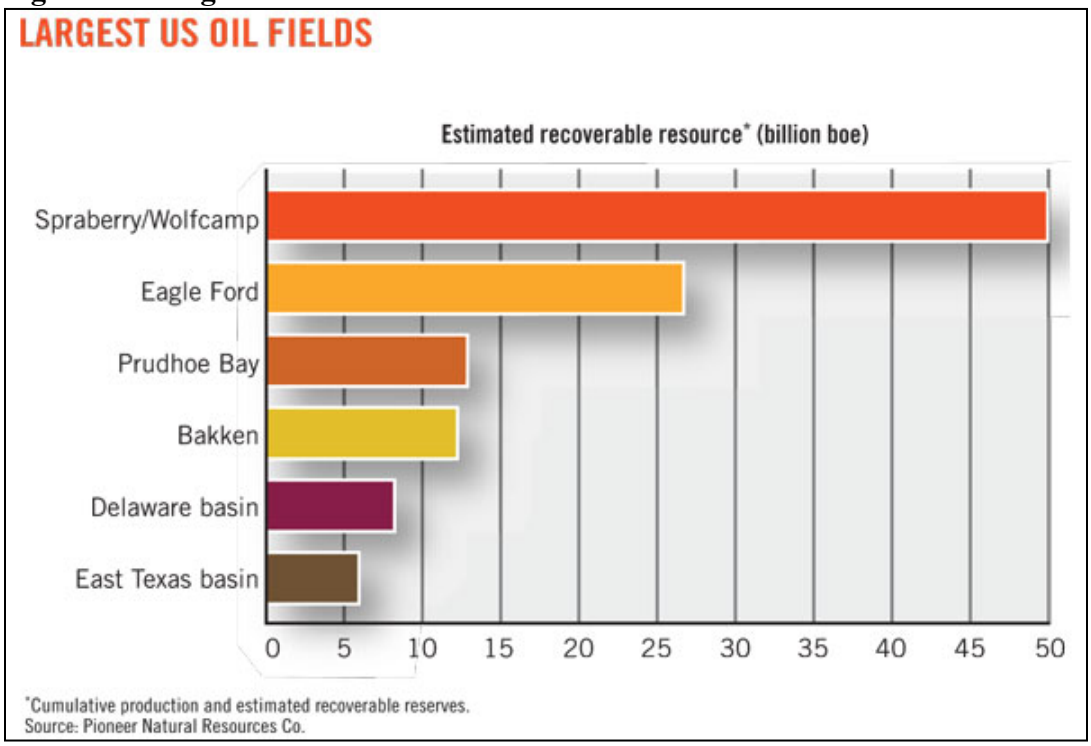
Source: Tom Fowler, "Second Life for an Old Oil Field," *The Wall Street Journal*, November 20, 2013.

The current impetus for horizontal drilling is to unravel the mysteries of the Permian Basin's stacked stratum. The Wolfcamp and Cline formations are important for another reason. In most shale developments operators targeted just one to two primary hydrocarbon-producing formations. For example, the hydrocarbon-producing zones for Bakken shale are drilled at 30-38 M and for Eagle Ford are drilled at a depth of 90-100M. Permian wells target multiple strata, unraveling the complexities of stacked oil plays, while well costs have been steadily declining. Originally Wolfcamp wells in 2012 cost roughly $9 million per well. By end-2013, this fell to $5.5 million and will fall to $4.8 million before end-2014. Developers also are aiming to raise

recovery rates—a slight rise in the recovery rate of 0.5% could mean hundreds of millions of barrels of more oil produced.

The Permian Basin features stacked columns with as many as nine target strata, with the combined thickness of the Wolfcamp and Cline shale, averaging 400-555 M. This may represent the oil equivalent reserves of six Eagle Fords—or possibly more—awaiting development, stacked atop each other. In early 2014, Pioneer estimated that recoverable reserves in BOE terms were in the range of 75 BN BBLs—and later suggested that this represented "the low end" of reserves, because it only detailed six of 13 oil-bearing structures in the basin. In late 2013, the company claimed 50 BN BBLs BOE.

Figure 13. Largest US Oil Fields



In recent months, Permian drilling has focused ever more on the Texas Cline Shale Play, parallel to Wolfberry/Spraberry and Wolfcamp drilling. Total Permian mid-year output was roughly 5.62 BN CFD of gas and 1.52 MM B/D of crude and condensate. In the first half of 2014, gas outpaced oil, but explorers believe the situation will reverse once Wolfcamp development gets fully underway. According to Wood McKenzie, a consultancy known for their

upstream forecasting, the Wolfcamp shale development will overtake Bakken by as early as 2017. Operators will spend some $12 billion in 2014, ranking it third in upstream spending this year behind Bakken and Eagle Ford.

This play alone—and there are multiple development plays in the Permian—will average 200 MBD of crude and condensate output in 2014, rising to as much as 700 MBD by 2020, according to WoodMac. Crude in 2014 should rise by about 34% over 2013 levels and the Wolfcamp play is only in a preliminary development stage. WoodMac argued that the Midland Basin will outpace the emerging Delaware Basin because of higher oil cuts, lower well costs, and better supporting infrastructure. WoodMac concluded that the Permian Basin will drive tight oil production for the next two decades with more than 40,000 remaining locations to be drilled.

At end-2013, the number of horizontal rigs drilling in the Permian exceeded vertical wells for the first time. The cost is considerably higher, with a horizontal well costing some $7-12 million, while vertical wells can be as cheap as $2-3 million. Horizontal wells are the chief reason why estimates of the Permian peak liquids output increased from 1.5 MM B/D to 1.9 MM B/D to 2.4-2.5 MM B/D since early 2012. Reducing exploration and development costs remains an underlining concern, though.

A broader question emerges from the changing focus of Permian tight oil development—what will be the physical nature of production? The eastern half of the Permian Basin supplies much of the crude output that made up WTI and WTS, which in 2013 were produced roughly on a 70:30 volume basis. Conventional output accounted for the vast majority of these two crude grades in 2013, and the naphtha yields from these grades tended to be Naphthenes and Aromatics (N+A)-oriented. Yet as tight oil production from Avalon and Bone Springs strata increased in the western Delaware sub-basin, it has become increasingly paraffinic (P)-oriented. Will Midland tight oil production follow?

As has been the case in other tight oil developments, new and better operating techniques and the use of specialized fracking chemical blends are driving costs down. An Apache presentation of late 2013 showed the company had over the course of that year reduced its average well drilling

and completion costs by at least $1 million a well in targeting Wolfcamp and Cline shale. The number of drilling days has been reduced by pad drilling, improved drilling mud programs, and optimizing bit selection. Fracking costs have been cut by better well programming and coordination of pad drilling.[7]

Another difference of Permian output (since the basin has been a major oil province for many decades, initial incremental tight oil production had no trouble finding an outlet) is that local refineries were in fact saved by the advent of large volumes of relatively inexpensive, light, sweet crude, available right on their doorstep. By 2013, a half dozen West Texas refineries as well as a New Mexico plant were running solely on Permian output, shifting to full runs of mainly tight oil slates, including El Paso, Texas (Western, 128 MBD), Artesia, New Mexico (Holly-Frontier, 100 MBD), Big Springs, Texas (Alon, 70 MBD), and Borger, Texas (Phillips, 146 MBD). While this is a sizable aggregate capacity, totaling nearly 450 MBD, it also is widely spread out over two large states. Eventually, though, incremental output overmatched local refineries to absorb it. This began the great divergence of WTI prices, used as the basis of US paper trade, and Brent, the most widely used international trade marker. The race was between rapidly rising Permian output and the startup of *takeaway* capacity, bringing it to USGC refineries.

It is only in 2014 that explorers are systematically drilling the Midland sub-basin with horizontal wells. Beyond Wolfcamp and Cline, drillers are investigating the Central Basin, Northwest Shelf, Spraberry, Wolfberry, and Yadda Yadda strata. Questions remain: How much will horizontal oil wells yield and what will be the nature of production?

These efforts to push quickly into unconventional horizontal well drilling have begun to yield results. Pioneer Resources, for example, planned to nearly double the number of horizontal wells drilled in the Spraberry/Wolfcamp formation in the second half of 2014. By mid-2014, half of the company's 183 BOE/D output came from unconventional developments in these strata, with about 80% of that crude or condensate. The company expects to raise production by a further

[7] "Driving Down Costs in Resource Plays," *Barclays Bus Tour Presentation*, Apache Corporation, October 4, 2013, http://files.shareholder.com/downloads/APA/0x0x698561/9900df20-c64b-42ac-8b38-1e8030deb751/Apache_Barclays_20131004.pdf.

25% by end-2014.[8] Similarly, Marathon has been moving up in the Permian output race, and a good deal of the 102 B/D of oil equivalent produced by half year from Spraberry/Wolfcamp is condensate. The company has been exploring new marketing outlets for its production—most of its liquids outturn consists of crude and heavy condensates, at times averaging less than 50 API or heavier. Like Pioneer, the company is already exploring ways to export condensate; a formal application was made to the DOC in mid-2014.

The volume of condensate that potentially would be available for export will rise rapidly by end-year, both from the Permian and Eagle Ford developments.

Table 14. Permian Basin Production (1)

Year	Total Production	Tight Oil Production		Rate Increase Total Output
		MBD	%Share	
2012	1,169	456	39.0%	
2013	1,366	574	42.0%	16.9%
2014	1,529	673	44.0%	11.9%
2015	1,660	797	48.0%	8.6%
2016	2,069	1,055	51.0%	24.6%
2017	2,120	1,124	53.0%	2.5%
2018	2,310	1,271	55.0%	9.0%
2019	2,410	1,374	57.0%	4.3%
2020	2,491	1,470	59.0%	3.4%

Note: (1) Includes plant condensate.

Table 15. Permian Production Forecast—A Comparison (in MBD) (1)

Forecaster	2011		2012		2014		2016		2018		2020	
	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share
Wellhead Output (Crude & Field Condensate)												
BTU Analytics	1,004		1,135		1,503		2,049		2,339		2,532	
APEC	1,004		1,135		1,470		1,970		2,200		2,350	
Field Condensate Only												
BTU Analytics	60	6%	79	7%	120	8%	205	10%	281	12%	329	13%
APEC	90	9%	125	11%	176	12%	256	13%	330	15%	400	17%
Plant Condensate												
APEC (1)	20	2%	34	3%	59	4%	99	5%	110	5%	141	6%
Total Condensate												
APEC	110		159		235		355		440		541	
Total Permian Oil/Condensate (Incl. Plant) Production												
APEC	1,024		1,169		1,529		2,069		2,310		2,491	
Total Condensate as % of Total Output												
APEC (2)	11%		14%		15%		17%		19%		22%	

Note: (1) Plant condensate estimates not available from BTU Analytics. APEC assumes rising condensate sale from field

[8] "Condensate takeaway needed for exports," *Platts Oilgram*, p. 6, August 6, 2014.

results in more gas; field condensate and wet gas rise with further horizontal drilling; gas production also increases on sales to Mexico and increased local sales.

(2) Some exporters will be recombining plant and field condensate and following the lead of Eagle Ford exporters. Horizontal drilling will replace conventional wells as chief support for oil output and result in more wet gas and condensate.

Table 16. Top Five Permian Producers (in MBD; Excl. Plant Condensate) (1)

Ranking	Company	Oil Output
1	Occidental Petroleum	110
2	Pioneer Natural Resources	66
3	Apache	54
4	Kinder Morgan	51
5	XTO Energy	35

Note: (1) First-half of 2013 data.
Source: Texas Railroad Commission

e. Transport and Takeaway

Two transportation issues are shaping Permian production: total takeaway capacity—mainly for piped crude, but supplemented by rail and occasionally by trucking—and the issue of carrying crude, crude/condensate, or condensate only.

The race between building production and takeaway capacity has been the key factor in dictating price differentials between Midland, in the heart of Permian production; Cushing, the basis point for WTI; and Houston, the focal point of USGC coastal refining. When takeaway capacity lags production increases for the Permian, an overhang of crude in the interior depresses the price of WTI in relation to Brent. The table below compares pipeline takeaway capacity at the beginning of each year versus APEC's forecast of Permian production. It is clear that for the most part added Permian production will be matched by increased pipeline carrying capacity. It is when takeaway capacity lags incremental crude output that pricing incongruities afflict Cushing and Midland.

Table 17. Permian Takeaway Capacity (in MBD)

Year	Pipeline Capacity	Permian Output Forecast Same Year
1/2014 (1)	2,000	1,529
1/2015	2,375	1,660
1/2016	2,880	2,069
1/2017	2,910	2,120
1/2018	2,950	2,310
1/2019	3,000	2,410
1/2020	3,020	2,491

Note: (1) New pipeline capacity includes BridgeTex (300 MBD), Permian Express (200 MBD), and Cactus (200 MBD); all other additional capacity is from rail expansion.

While Permian takeaway capacity has grown rapidly, it has had difficulty keeping up with incremental production. Magellan will increase pumping capacity for its pipeline and raise carrying capacity from 225 MBD to 300 MBD by end-year. Together with limited rail transport, the takeaway capacity will handle additional crude output at least in the short-to-medium term, while other pipeline completions, such as Keystone Southern, Seaway Twin, and the Flanagan South lines will add to crude avails from distant Canada.

This has led to the nearly total back-out of USGC light crude imports by end-2013; USAC refiners will likely follow by mid-2015; West Texas Intermediate (WTI) is re-establishing pricing relations with other crude grades on quality and transport costs, and a substantial narrowing of Brent's premium over WTI over the course of 2013-14. WTI together with Louisiana Light Sweet (LLS) have re-established a steadier and less volatile pricing relationship with Brent in 2014, and the USGC's buildup of light product exports is strengthening the linkage.

As of mid-2014, just one dedicated condensate-only pipeline was operating from the Eagle Ford basin to the port of Corpus Christi, a joint venture between the two midstream companies Enterprise and Plans All-American. This 350 MBD pipeline allows the transport of pure condensate—if condensate is moved through a crude pipeline, through the process of batching, it inevitably picks up traces of oil remaining within the pipeline.

Pioneer has suggested that a new condensate pipeline is needed to transport growing Permian condensate output, particularly from the Delaware sub-basin, in the western portion of the basin. As condensate production grows, particularly in the Delaware sub-basin in the western Permian, industry will need to figure out how to keep it separate from other crude oils, either by batching it or moving it on a separate condensate line.

This—as well as many other investment decisions—remains pending until the US DOC defines clearly its criteria of minimal processing of a base material into product and whether this is applicable solely to field condensate or to crude as well. DOC's stance that this form of distillation is applicable only to condensate makes little logical sense. If, in what is rumored to be the case with the Enterprise June sale, some 15% of the field condensate was distilled and removed from the condensate blend, the need for condensate-only piped transport will become pressing.

f. Bakken

A third of the tight oil big three producers, Bakken, differs from Eagle Ford and Permian Basin production in a number of ways. Bakken was the first of the major tight oil basins and unlike its sister Texan projects was a relatively minor oil producer before shale discoveries. Bakken was distant from most US refining capacity, unlike Eagle Ford and Permian, and relied heavily on rail transport to get crude production to end-users. Yet, Bakken producers had one advantage that its southern competitors could not match—it borders Canada, which remains the only foreign market where crude sales are allowed without special permit. Much of the crude export surge in the first half of 2014 consisted of Bakken sales to Canadian refiners searching for light, sweet crude.

Today, Bakken production has been overtaken by Eagle Ford output and will soon be surpassed by tight oil production (solely) in the Permian Basin. Yet, as can be seen in the BTU Analytics forecast below, the frontier zone can still increase considerably its output of black oil. In 2Q, 2014, oil production in North Dakota, home to the majority of Bakken output, hit the 1 MM B/D mark for the first time and, according to the state's Department of Mineral Resources, should reach 1.5 MM B/D by 2017. Upstream analysts see a faster rate of buildup, with 1.6 MM B/D

likely by 2015, 1.8 MM B/D by 2018, and 2.0 MM B/D plus by 2020—and these are among the more conservative outlooks. In 2000, North Dakota produced from conventional developments 100 MBD of petroleum; in 2Q, 2014, Bakken produced its billionth barrel of black oil.

Future prospects have brightened, but there remain hurdles to jump. First, there is a growing need for pipeline transport of Bakken output. In 2013, the majority of Bakken output moved to end-users by rail, some 700 MBD of 811 MBD. If production rises to a level of over 1.6 MM by 2016, much of it will have to be piped. The pressure to move away from reliance on more costly rail transport will slow the Bakken buildup, even though the state's investigation into Bakken's physical characteristics showed it was no more dangerous than any other light crude. The requirement for new and more expensive rail cars coupled with a big jump in Bakken volumes to move are powerful incentives to build a pipeline. Finally, the surge of exports into Canada may prove to be the trump card. In June 2014, the US averaged 389 MBD in exports, almost all of that to Canada and much of it Bakken output. American crude exports, even without loosening legal restrictions, have for the first time exceeded that of an OPEC member, Ecuador. Koch Pipeline Company's proposal to increase piped oil takeaway capacity failed in early 2014, but we believe some other project will gain traction soon.

A more difficult problem is curbing gas flaring and increasing NGL recovery. North Dakota tightened oil production and development regulations in June and July, requiring operators to submit a plan to capture associated gas output, rather than flare it, for any oil development. Slightly over a third of associated Bakken gas was flared in 2Q, 2014, as the state produced 1.1 BN CFD; state officials took action because gas production is expected to almost double to about 2 BN CFD by 2020. Bakken associated gas has been wet, with wetness ratios of up to 12 gallons/MM CFD of wellhead output. Gas processing capacity will rise to almost 2 BN CFD by January 2016, a 25% rise over current capacity.

The new measures have some of the features of a good news/bad news joke. The bad news was that reducing gas flaring might delay production buildup while increasing costs. Some operators have balked at the investment needed to build infrastructure for gas/NGL capture, processing,

and transport infrastructure. They claim that this will stretch out the buildup of Bakken output, now likely to reach 2 MM B/D by 2020.

The good news is that not only valuable gas will be saved and sold, adding revenue, but also substantial NGL output will result. Continental, one of the largest volume producers in Bakken, warned of the strain on limited construction capacity and possible field development delays, but nonetheless supported the measures. A series of gas pipeline and NGL stripping/processing projects are underway. They will have to be expanded further if North Dakota will meet its goal of utilizing at least 90% of gas produced by 2020. Condensate impact could be substantial, as Bakken gas is wet and certainly would add to the operator's overall revenue—perhaps yielding an additional 50-100 MBD of condensate, field, and plant by end-decade. A number of forecasts predict that total western Canadian condensate output will nearly double in the period between 2014 and 2020.

The industry is counting on increasing drilling and completion efficiency to sustain rising production. Continental targeted up to 32% increase in its output this year and is banking heavily on enhanced well completion techniques, including increased use of propane to hold open hydraulic fractures. Increased well costs of $1.5-2.0 million per well have been more than offset by increased output—something in the range of 30% per well.

Table 18. Forecast NGL Production, North Dakota (Primarily Williston Basin/Bakken)

	2014	2016	2018	2020	2014-2020 Gain	
					MBD	% Increase
NGL	135	170	210	240	105	78%
Plant Condensate	8	12	20	35	27	338%
Total	**143**	**182**	**230**	**275**	**132**	**92%**

Source: Don Bari, "Adding Value to the Bakken NGLs" (PowerPoint presented at The Williston Basin Petroleum Conference, Bismarck, North Dakota, May 21, 2014).

Top Bakken producers have been mainly independents, though Norwegian state company Statoil was able to break into the ranks. Whiting's buyout of some smaller Bakken producers makes the company the likely production leader for 2014.

Table 19. Top Five Bakken Producers (in MBD)

Ranking	Company	Oil Output
1	Continental Resources, Inc.	72.2
2	Whiting Oil & Gas Corp.	66.8
3	Hess Corporation	66.3
4	EOG Resources, Inc.	46.2
5	Statoil Oil & Gas LP	42.9

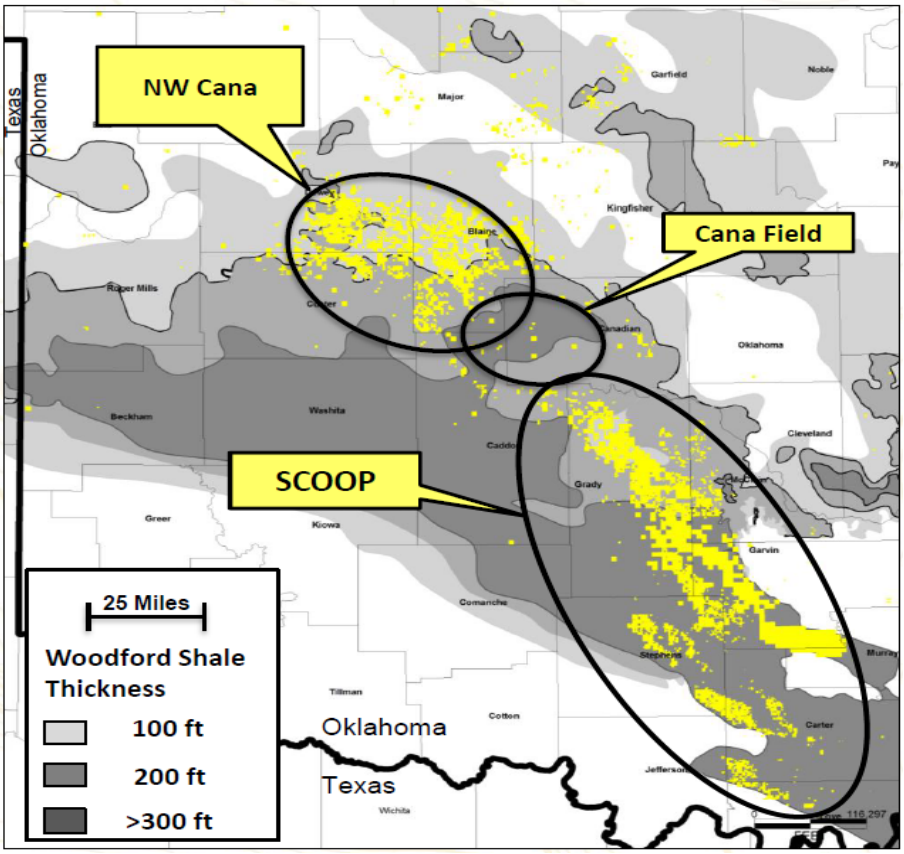
2. Up and Coming–SCOOP/Cana-Woodford, Niobrara, and Uinta

The next wave of tight oil development will feature, at minimum, three frontier zones: the South Central Oklahoma Oil Province (SCOOP)/Cana-Woodford, Niobrara, and Uinta. Current forecasts see SCOOP and Niobrara as just breaking the 500 MBD output barrier by end-decade, with Uinta producing substantially less tight oil. But as has been seen in Bakken, Eagle Ford, and Permian basin development, reality has had a curious way of outstripping predictions within a short period of time once intensive fracking and horizontal drilling have begun in earnest.

a. SCOOP/Cana-Woodford Basin

SCOOP has many features in common with the Permian basin to the south. As part of the Cana-Woodford basin, it has long pumped oil in conventional wells, has substantial oil and gas transport and processing infrastructure, and like Permian production, has had the commercial advantage of relatively easy access to the oil gathering point of Cushing, Oklahoma, home of the WTI marker. The Woodford formation contains three highly prospective shale plays: Ardmore, Arkoma, and Cana basins, and drilling has steadily increased in 2013-14.

Figure 14. SCOOP/Cana Woodford Basin



Source: Anadarko

Cana-Woodford is a medium-sized basin, extending from Oklahoma north into Kansas, and SCOOP only accounts for the southern third of this frontier exploration zone. That amounts to about 3,300 sq. miles (8,550 sq. km). It was only in 2013 that tight oil exploration and development began to get into gear. Oklahoma oil output, which averaged only 160 MBD in January 2010, topped 300 MBD four years later and will likely average over 400 MBD in 2014. It should be noted that like the Permian Basin, the sharp rise in tight oil output masked the decline in conventional oil output. Overall production has not only risen, but tight oil output has more than compensated for the fall in conventional production. The question remains open, though, as to plateau production levels. In 2013, some analysts were forecasting only 100 MBD at peak for Scoop and double that for Cana-Woodford. Others forecast that SCOOP alone would yield more than 500 MBD in tight oil output. We have sided with the more upbeat output predictions.

Continental, a leading explorer in this basin, estimated that SCOOP contained as much as 70 BN BBLs of oil in place with oil stratum as thick as 400 ft. (123 M). The company already leased more than 277,000 acres and is busy delineating fairways in the play. This play has substantial takeaway capacity, gas processing, and easy access to the USGC.

SCOOP has many promising geologic indicators and, as survey and exploration drilling accelerated in 2013-14, the signs of probable higher output levels seem to emerge. Total organic carbon (TOC), by weight, averaged 6-15%, compared to Bakken at 5-20% and Eagle Ford's 3-7%. Geologic formations have not been highly fractured, a problem in many shale basins. Porosity and oil in-place estimates have been comparable to Bakken and Eagle Ford, but targeted strata are fairly deep and will require costly wells.

Big players in SCOOP include Continental, Marathon, Newfield, and Eagle Rock Energy Partners. Continental, which originated the catchy play name SCOOP, emphasized reducing costs through careful well placement to extract tight oil from both the upper and lower Woodford strata. Continued improvement in drilling and development operations will be necessary to fully exploit this area's full tight oil potential. The basic *takeaway* capacity in piping crude out of Oklahoma already exists; unlike Bakken, there is no need to depend on rail shipments to get production to buyers.

Table 20. SCOOP/Cana-Woodford Basin Production Forecast (in MBD)

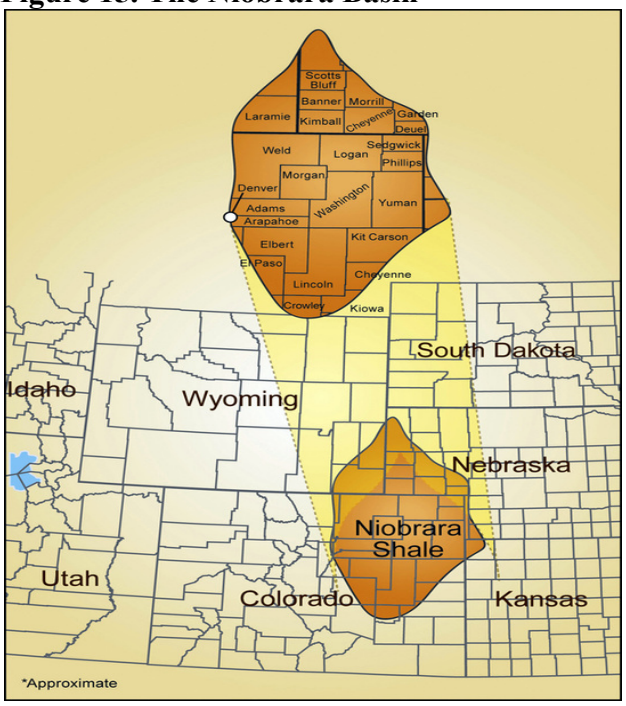
Forecaster	2011	2012	2014	2016	2018	2020
BTU Analytics	289.0	341.1	434.0	490.2	507.9	522.5
APEC	289.0	341.1	434.0	285.0	460.0	510.0

b. Niobrara

Niobrara is typical of the smaller shale basins in the US that are under development.

Many analysts looking at tight oil production tend to lump together Niobrara output—on the edge of the central Great Plains, but primarily in Colorado—and Uinta, Piceance, on the western slope of the Rocky Mountains and mainly in eastern Utah.

Figure 15. The Niobrara Basin



Source: Condor Energy Website

RBN, in an interesting mid-2014 analysis identified Niobrara, together with Uinta, as a regional classification of *Rocky Mountain* output and predicted this area will produce the next surge of tight oil without a nearby refinery home. The Rocky Mountain region (in RBN classification PADD-4 plus North Dakota) is home to only 17 refineries, totaling 742 MBD. Refineries are small and average only 42 MBD. The company's conclusion was that even if Rocky Mountain tight oil production rose to a moderate output, it would have to go, for the main part, to refiners outside the region. RBN sees aggregate (Niobrara and Uinta/Piceance) rising from 520 MBD this year to 790 MBD by 2020. This may be so, but only if the two basins are considered a unitary whole.

Niobrara (including the Rockies' Powder River basin) has shown continuing growth since unconventional tight oil development began. We expect 2014 output to rise to about 250 MBD, a sizable increase over 2011's less-than-100 MBD. This could very well double by end-decade, but much depends on expanding takeaway capacity, particularly oil pipelines, as at present much crude gets to refiners by rail car or truck delivery.

Crude quality ranges significantly. The Denver-Julesburg basin produces a range of light crude and condensate with APIs ranging from the low 40s to mid-50s. Output from the Powder River Basin to the Northwest has been much heavier at 35-40 API, rather like Permian production. Development costs are significantly lower than Bakken, simply because the most productive strata have been found at about 2,245 M (7,300 ft.), compared to much deeper deposits in Bakken and Permian production. Top producers are all independents, including Anadarko, Noble, Chesapeake, EOG, and WPX Energy.

A great surge in Niobrara production that began in 2013 and has been building output volume has revived plans to build a Colorado-to-Texas pipeline planned by midstream company NuStar Energy. A mid-2012 proposal by this midstream independent proposed reversing its products pipeline that carried material from McKee, Texas, to Denver, Colorado, allowing the movement of up to 130 MBD of Niobrara product southward to USGC refiners. At that time, there was little interest among buyers, but now with the possibility of lightly processed condensate allowed to be sold abroad, export options may make a pipeline more attractive. A final investment decision is expected by end-2014.

Table 21. Niobrara Basin Production Forecast (in MBD)

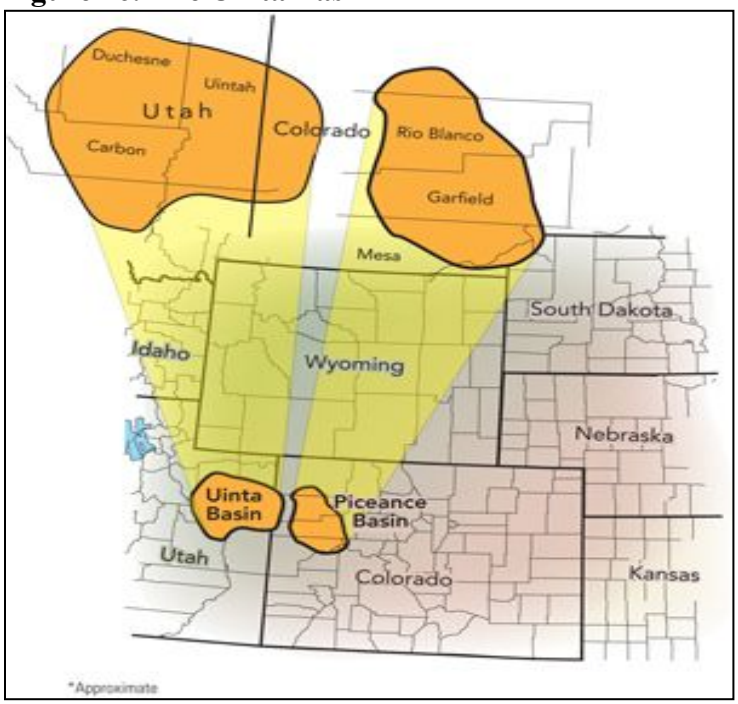
Forecaster	2011	2012	2014	2016	2018	2020
BTU Analytics	98.3	107.9	279.0	421.1	497.8	554.3
APEC (1)	98.3	101.0	270.0	390.0	480.0	520.0

Note: (1) Includes Powder River.

c. Uinta

While still proving up reserves, we expect that Uinta may become a major tight oil zone, despite minimal local refining, dependence on rail transport, and the waxy nature of the crude produced.

Figure 16. The Uinta Basin



Source: Oil and Gas Journal; Unconventional Oil & Gas Magazine

Uinta crude generally had been mid-weight to light, but unusually for US production, highly paraffinic, meaning that the crude contains substantial wax in its residual, which must be processed further to gain a maximum yield of mid-weight and light products. Further, waxy crude presents additional logistics problems—it must be heated because of its high pour point and low viscosity, in order to remain a liquid, otherwise it solidifies. Waxy crudes are heavily discounted against WTI, as most US refiners are unfamiliar with this oil, though it makes excellent cracking feedstock.

Most of Asia Pacific's crude output consists of this oil quality group, and refiners that have traditionally run Asian crude in their plants, such as Chevron, not only know how to handle these grades, but have also learned to maximize middle distillate yields by carefully cracking the fuel oil from waxy crude, creating low sulfur waxy residual (LSWR). Similarly, majors, such as ExxonMobil, with considerable equity production of waxy crude in Asia Pacific and West Africa had little problem in utilizing this type of crude.

Uinta crude was traditionally processed in local refineries. However, it is now being shipped by rail as far as the USWC and locally by heated road tankers. Independent Newfield has been the largest volume producer in Uinta Basin, and the company believes—conservatively—that output should almost double by end-2015.

Table 22. Top Five Uinta Producers (in MBD; Utah Only)

Company	Volume
Newfield	20.7
Resolute Energy	9.4
Bill Barrett	6.5
Berry Petroleum	4.7
Wolverine Gas & Oil	4.4

Local producers have been trying to achieve better sales prices for their crude production by a multifaceted campaign: to improve transport logistics to carry Uinta out of the local region to USWC buyers; to build production to sufficiently large volumes to consider pipeline sales to the USGC; and, most of all, to familiarize refiners with the nuances of waxy crudes. Refiners have been attempting to utilize Uinta crude to maximize gasoline outturn. Yet as a waxy, paraffinic grade, it is best for maximizing middle distillate production. We expect Uinta to become a "major minor" tight oil producer by 2020.

Table 23. Uinta Basin Production Forecast (in MBD)

Company	Volume
Newfield	20.7
Resolute Energy	9.4
Bill Barrett	6.5
Berry Petroleum	4.7
Wolverine Gas & Oil	4.4

Source: Petroleum News Bakken, March 2013

Table 24. Bakken Production Forecast—A Comparison (in MBD)

Forecaster	2011		2012		2014		2016		2018		2020	
	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share	MBD	%Share
Wellhead Output (Crude & Field Condensate)												
BTU Analytics	404		610		976		1,660		2,013		2,283	
APEC	404		610		960		1,580		1,860		1,930	
Field Condensate Only												
BTU Analytics	12	3%	110	18%	29	3%	66	4%	81	4%	114	5%
APEC	44	11%	67	11%	106	11%	174	11%	223	12%	232	12%
Plant Condensate												
APEC (1)	12	3%	24	4%	38	4%	63	4%	93	5%	97	5%
Total Condensate												
APEC	57		92		144		237		316		328	
Total Bakken Oil/Condensate (Incl. Plant) Production												
APEC	416		634		998		1,643		1,953		2,027	
Total Condensate as % of Total Output												
APEC (2)	14%		14%		14%		14%		16%		16%	

Note: (1) All Williston Basin.
(2) The rise in both field and plant condensate production will come from the harnessing, rather than flaring, of associated gas with Bakken production.

3. Verdict Pending—Utica/Marcellus, Monterey, and Tuscaloosa

This set of tight oil developments remains the most uncertain, but does very well illustrate the dangers of forecasting upstream developments. First Monterey, and then Utica were touted as major additions to future tight oil production, potentially backing up and then overtaking the big three tight oil producers by the coming decade. Instead, Monterey has been downgraded to minimal output by the IEA; Utica appears to be considered more of a dry gas rather than tight oil discovery, and skeptics are already downgrading Tuscaloosa's chances of success before major survey and drilling campaigns are completed.[9]

We begin with Utica/Marcellus, as the two—when considered together as a tight oil/condensate production region—will still record major production gains by end-decade, while Monterey appears to have little chance of bouncing back from reserve downgrades. And while preliminary drilling indicated possibly commercial oil finds within Tuscaloosa, opinion is deeply divided over its future potential as a tight oil producer.

a. Utica/Marcellus

Upstream opinion has swung from considering Utica the next Eagle Ford to redefinition as an ancillary dry gas hotspot next to Marcellus. We are not convinced that Utica can be fully written

[9] "Monterey, Utica Temper US Shale Euphoria," *Petroleum Intelligence Weekly*, July 28, 2014.

off, though continued drilling has given the impression that at best we have a "major minor" tight oil production area emerging.

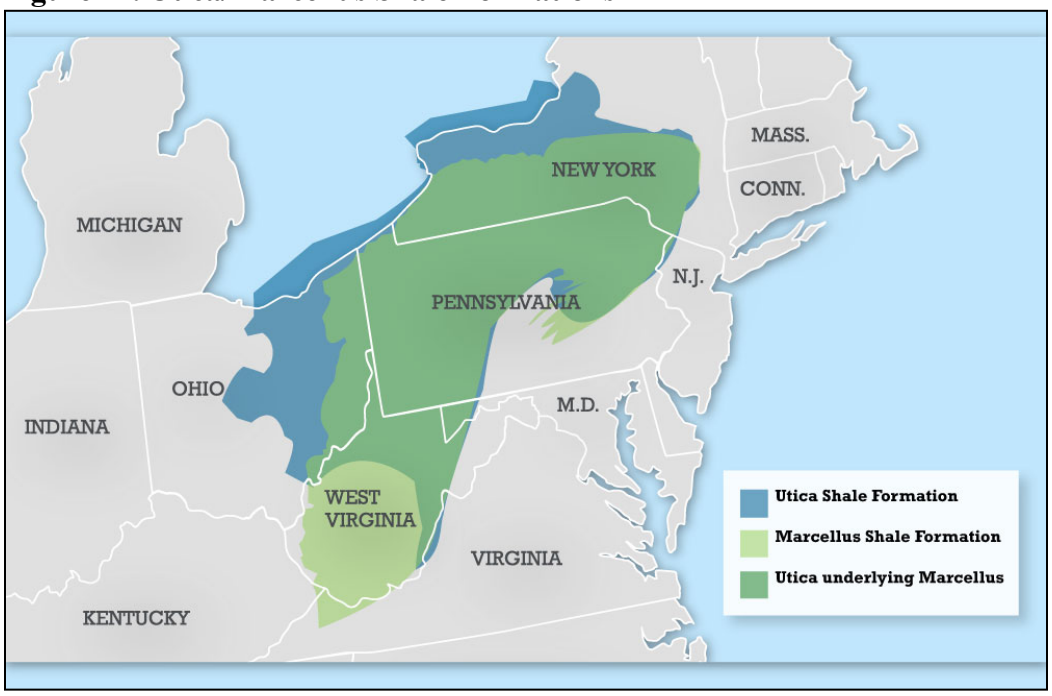
Certainly Marathon—which is investing in building splitters at its Catlettsburg, Kentucky, and Canton, Ohio, refineries—believed strongly enough in Utica's future potential to move ahead with its downstream investments. But the PIW analysis underlined a solid point—that public hype often runs far ahead of exploration results' reality, and Utica, as late as early 2014, was still being promoted as a major tight oil basin of the future.[10]

We believe, however, that if accounted together with Marcellus, Utica will make a substantial contribution to tight oil and condensate output in the Northeast US, particularly as Marcellus gas production continues to build up.

Marcellus covers a huge area of the Northeast US, and the Utica formation can be found beneath much of the Marcellus shale gas basin. We would temper the assessment of Utica as solely dry gas because a) relatively little survey and drilling has yet been completed and b) technological advances in fracking and horizontal drilling continue to accumulate at a dizzying rate, increasing the chances of finding wet spots. This PIW analysis acknowledged, "ExxonMobil chief executive Rex Tillerson has often emphasized that key resources being developed today were economically unthinkable just a few years ago, but technological advances have made development viable."[11] Utica/Marcellus and Monterey are certainly future developments, and it is unclear how much they will supplement the big three.

[10] Ibid.

Figure 17. Utica/Marcellus Shale Formations



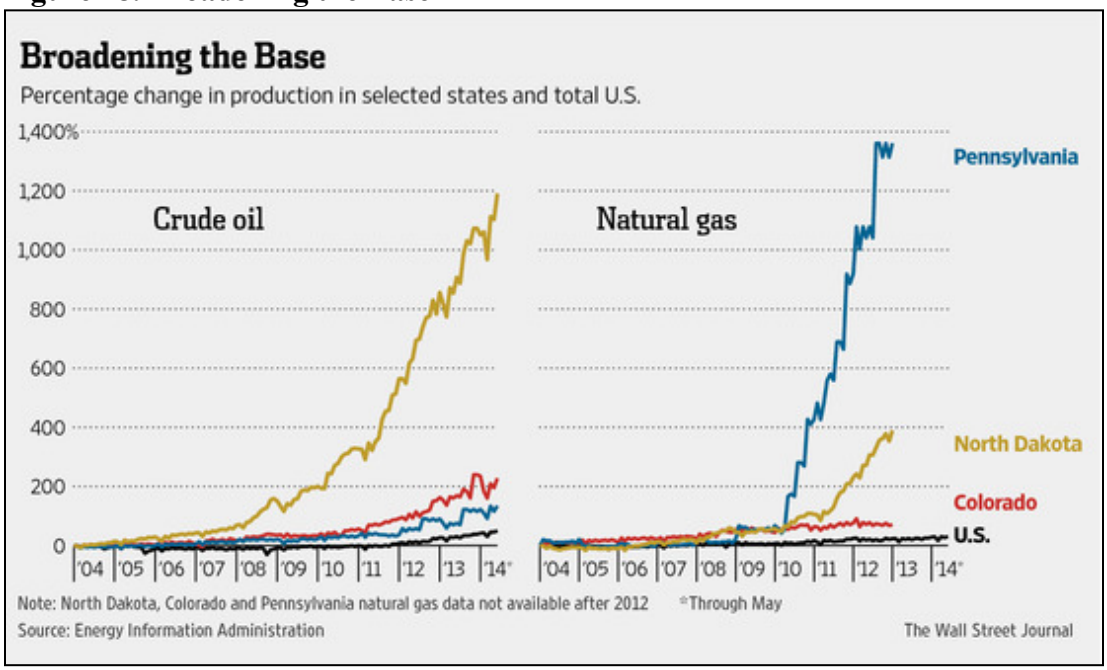
Source: "Marcellus and Utica Shale Formation Map," Marcellus Shale Coalition, http://marcelluscoalition.org/pa-map/.

We suspect that the write-off of Utica as a liquids producer may be premature, as the region may witness a substantial rise in condensate output. A number of analysts have judged that at least modest volumes of tight oil will emerge from Marcellus and Utica, supplemented by substantial condensate. RBN, for example, forecast that plant condensate would more than triple in the medium term from 2013's level, while crude would nearly double—for Utica alone. RBN emphasized that substantial fractionation capacity is under construction. Fractionation separates the NGL stream stripped from gas production into distinct products (i.e., ethane, propane, butane, and condensate). Further pipeline takeaway capacity is also under construction to allow export of condensate to Canada, using the Cochin Southern Lights route. All are signs that the condensate buildup will be larger than many forecast. Bentek supported this view, seeing a sharp rise in condensate and crude through 2019 to well over 100 MBD.

We believe that the key here will not be tight oil per se—though skeptics under-weigh Utica/Marcellus potential for this as well—but condensate from gas stripping. And that is very much dependent on gas takeaway capacity and downstream capacity to absorb NGLs, in particular the ability of the petrochemical sector to catch up with Marcellus' future ethane

output. The first problem is being overcome rapidly. According to BTU Analytics, some 9 BN CFD of new pipeline projects have been proposed to take away Marcellus Utica gas production, and this atop the 16 BN CFD of gas already in production by mid-2014. The consulting firm forecast that the region would be able to produce 25 BN CFD for a sustained period, supported by the enormous backlog of wells that have built up in Marcellus drilling.[11] Marcellus' ballooning output will continue as tracked by Pennsylvania data below, while oil/condensate will rise at a more modest rate.

Figure 18. Broadening the Base



Source: Amy Harder, "Democrats Increasingly Backing Oil and Gas Industry," *The Wall Street Journal*, August 11, 2014.

The reason why so many wells have been drilled and capped after discovering commercial gas is ethane rejection (i.e., the sale of ethane simply on its BTU or caloric value, rather than its far higher potential value as feedstock). RBN in 2Q, 2014 expected some 330 MM CFD of ethane will be rejected this year, roughly 20% of what otherwise could be produced. Lack of petrochemical buyers and limited export options forced many operators to delay producing NGL-rich Marcellus gas. As new olefin plants start up in the Northeast and ethylene crackers expanded

[11] Kathryn Miller, "The Pipes May Be Coming, But How Long Will the Gas Flow?" BTU Analytics, July 30, 2014, http://btuanalytics.com/the-pipes-may-be-coming-but-how-long-will-the-gas-flow/.

on the USGC (supplied by the ATEC ethane/propane pipeline), far greater use of this NGL in petrochemicals can be expected. The net result is far higher gas production in Marcellus/Utica, and a modest proportion of that gas—some 10-15% at minimum—consisting of condensate. Consequently, we believe that BTU Analytics' outlook under-weighs the condensate impact at the end of the forecast period.

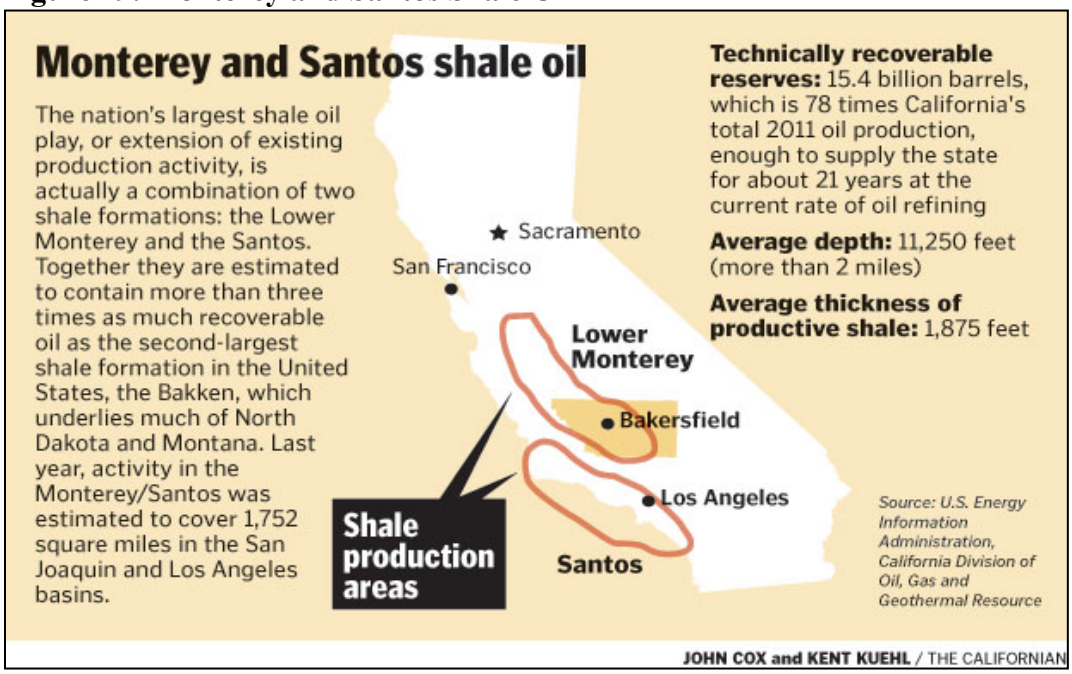
Table 25. Utica/Marcellus Production Forecast (in MBD)

Forecaster	2011	2012	2014	2016	2018	2020
BTU Analytics	20	23	48	126	216	214
APEC	20	23	52	138	236	244

b. Monterey Downgrade

We offer no projection of increased output for Monterey tight oil, which we see as a perfect example of mass delusion, or public opinion getting the cart in front of the horse. Even the fairly conservative EIA in its forecasts had tagged Monterey as a major oil-producing province, and it was expected that this shale basin would vastly increase California's oil output. Typical of the outlook was this graphic from mid-2012.

Figure 19. Monterey and Santos Shale Oil



Source: John Cox, "Monterey Shale brightens Kern's oil prospects," *The Bakersfield Californian*, June 9, 2012.

While some established Californian oil producers like Chevron were cautious from the start—with concern over the region's complex geology—others, including Occidental and Shell, moved full steam ahead to upgrade reserve estimates and projections of future output. Oxy in 2010 suggested that "California shale had the potential to become one of its largest businesses within the space of a decade,"[12] while the EIA estimated technically recoverable tight oil reserves at as much as 13.7 BN BBLs.

Oxy has rather abruptly reversed course, spinning off its California assets from tight oil development in the Permian Basin, while the EIA in 2014 reduced its technically recoverable reserve estimates for Monterey by over 90% to *only* 600 MM BBLs.

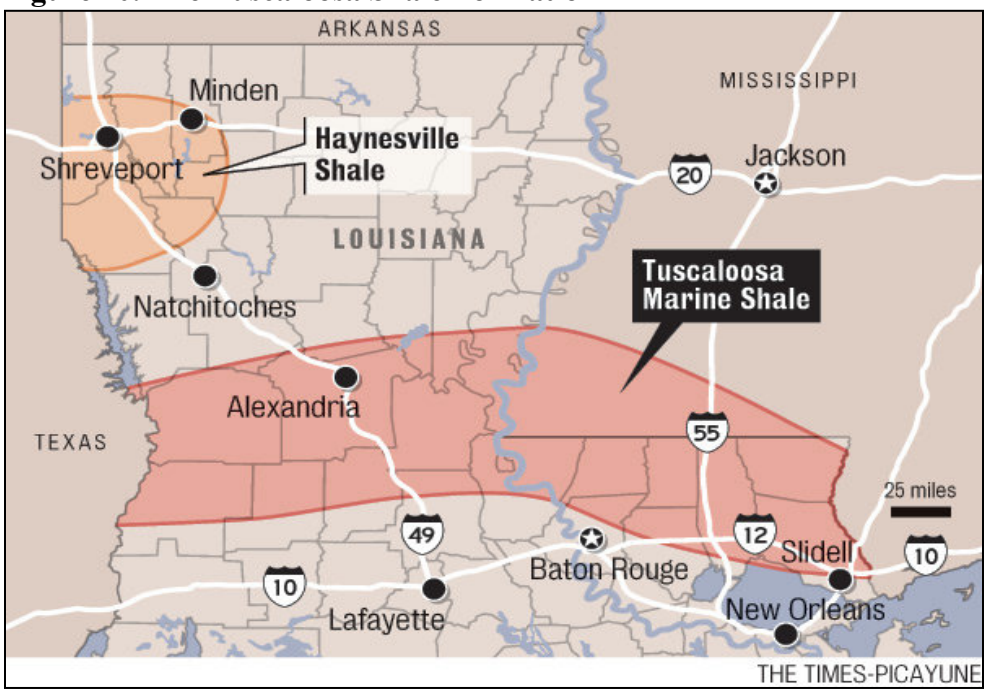
Monterey shale basin geology, unlike Bakken and Eagle Ford, consists of strata that are fractured and twisted. The large volumes of oil detected cannot be easily released by current fracking techniques. Monterey shale consists of two large formations; one in central California centered on the San Joaquin Basin, and the other in the south centered on the Ventura and Los Angeles basins. These basins are much younger than Bakken or Eagle Ford shales. The oil so far produced appears to have *migrated* from other source rock. Output remains tiny, about 12 MBD at end-2013, and we expect flat output through 2020.

c. Tuscaloosa

Even more tentative are Tuscaloosa Basin prospects, stretching across central Louisiana and into neighboring Mississippi. Some consultants believe that future output will be minimal, less than 30 MBD by the end of the decade, according to a BTU Analytics outlook. Others remain upbeat. And there are considerable obstacles to development here as well, including the depth of shale stratum, ranging from 3,400–4,620 M (11,000–15,000 ft.), and low porosity of the reservoir rock in many places, decreasing oil flow. Further, costs of services and drilling support have been high, though should decline as upstream activity increases.

[12] "Monterey, Utica Temper US Shale Euphoria," *Petroleum Intelligence Weekly*.

Figure 20. The Tuscaloosa Shale Formation



Source: *Louisiana Weekly*, December 9, 2013.

Yet EnCana, Goodrich Petroleum, Sanchez Energy, and EOG, all leading companies in 2014 drilling, emphasize the upside. Goodrich and Sanchez confirmed their claims by sharply increasing acreage leased in the first half of 2014.

This is overwhelmingly a tight oil play, with target stratum containing at least 90% liquids, possibly higher. The oil layers are substantial, up to 250 M in thickness, and Louisiana, a generally poor state, has encouraged oil and gas exploration, making permitting relatively easy. Unlike many shale basins, plentiful water supply allows for the drilling of horizontal wells in great quantity, if necessary.

As an advantage, Tuscaloosa is close to USGC refining and already possesses limited oil and gas infrastructures. Any limited production could easily be transport by pipeline or barge to the St. James oil hub, center of LLS trade. The only definitive estimate of in-place reserves, made by geologists from Louisiana State University (LSU), is a very wide 2.7–7.0 BN BBLs. This certainly is a prospect worth investigating.

Goodrich estimated that the tight oil play stretched over 2.5 million acres of Louisiana, producing oil of API 38–45, with some high calorific value, clean, associated gas. In drilling its dozen or so wells completed so far, the company encountered pay stratum of 61.5 M (200 ft.) to 77 M (250 ft.).

Reducing costs is the key beyond finding the tight oil *sweet spot*. Goodrich hopes it can cut the costs of wildcat wells from $13 million to levels seen now in Permian exploration, roughly $6.5 million. Permian drilling costs were sharply reduced by unit-pad drilling and increased service company competition—and Goodrich believes that the same would occur in Tuscaloosa exploration.[13] We have only modest expectations for Tuscaloosa, though unlike BTU Analytics, we see a buildup in tight oil output. A clearer picture of Tuscaloosa's future potential, however, will only emerge later in the decade.

Table 26. Tuscaloosa Production Forecast (in MBD)

Forecaster	2011	2012	2014	2016	2018	2020
BTU Analytics	10.8	10.1	10.7	13.2	14.6	15.7
APEC	10.8	10.1	10.7	15.0	20.0	28.0

Chapter III. Setting the Stage—Downstream

The basic trends of the downstream oil sector have been remarkably consistent over the period from 2013 to 2014—domestic production has continued to rise, mainly on tight oil output; foreign crude imports have continued to decline, with the USGC having essentially completed its back-out of light crude imports by mid-year; and US oil demand growth has been minimal, with little prospect of any large medium-term rise.

The EIA said that July 2014 saw US crude output average 8.5 MM B/D, the highest in 27 years, and predicted oil production will average 8.5 MM B/D for the entire year. This was an increase in EIA's forecast for 2014 of 80 MBD; the agency expects 2015 production to rise further to 9.3 MM B/D, which would be the highest US oil production since 1972.

[13] "Tuscaloosa Marine Shale E&P Summit," Goodrich Petroleum Corporation (PowerPoint presentation, June 18, 2014).

Increased crude output, coupled with the historic levels of refinery runs, have reduced petroleum imports, both crude and products. The EIA predicted that imports, as a share of US consumption, would decline to 22%, compared to 2013's level of 33%. In 2015, the EIA expects imported oil and oil products will fall to its lowest share of US demand since 1970. We will detail this further in our US refining section. The future demand outlook remains tepid. The EIA's July forecast predicted no more than a 70 MBD rise in US oil product use, or less than 1% demand growth this year. If anything, the agency has been trimming rather than increasing demand projections.

Table 27. US Demand Growth Cut by EIA

Product	Forecast Demand Change	
	2013/2014	2014/2015
Gasoline	30	(10)
Jet	10	(20)
Distillate	120	60
Residue	(60)	(30)
Other (w/NGLs)	(110)	70
Total Products Demand Cut	**(10)**	**70**
Total Forecast Demand	**18,880**	**18,950**

Source: US Energy Information Agency

The EIA's August US outlook was unchanged, but global oil demand was revised downward to 91.56 MM B/D, a drop of 60 MBD, with consumption rising 1.1 MM B/D this year and a further 1.4 MM B/D in 2015. China was expected to see demand rise 370 MBD in 2014 and 430 MBD in 2015, roughly half of what its average gains have been in recent years, while Japan and Europe will lead OECD markets in declining oil demand.

The Paris-based IEA, as well as OPEC, have much the same cautious world outlook as seen in the July forecasts below.

Table 28. World Demand Outlook (in MM B/D)

	IEA		OPEC	
	2014	2015	2014	2015
Demand	92.66	94.06	91.13	92.35
Demand Growth	1.23	1.4	1.12	1.22
Non-OPEC Supply	56.3	57.5	55.65	56.96

Source: US Energy Information Agency

In the IEA's July report, global demand was forecast to rise by 1.4 MM B/D to reach 94.1 MM B/D, with the vast majority of demand growth in the developing world in 2015 some 1.4 MM B/D.[14] Since then, the IEA in its September outlook revised 2014 growth down to 900 MBD and cut 2015 demand growth to 1.2 MM B/D, with European demand growth expectations falling.[15]

Since non-OPEC oil production will rise by 1.2 MM B/D, mainly from the US and Canada, the call on OPEC production will likely fall. Market observers have focused at mid-year on whether emerging geopolitical crises in the Ukraine, Syria, Iraq, and Libya will cut demand in the near term.

A portent for future world crude prices can be detected in mid-year Brent pricing, as growing US crude output has begun to reshape world oil markets, indirectly and even before any substantive export of US oil. Brent crude futures are trading at a discount through January 2014, as of early August, and this price contango is a longer-term indication of abundant crude supply, even with geopolitical flashpoints across the globe. Given the above, we now turn to investigate the impact in the US downstream.

A. *Tight Oil Impacts, US Refining*

Tight oil has had multiple effects on the US downstream sector, and in particular the USGC, which is home to the bulk of US refining and base petrochemical capacity.

Among the more important impacts are:

- A consistent backing out of light crude imports, substituted by growing use of less expensive crude from Eagle Ford, Permian, and to a lesser extent Bakken crude. On the USGC, this had been substantially completed by mid-2014, with only holders of equity barrels, such as Motiva (Shell/Aramco), running imports. We expect the USAC to

[14] "IEA forecasts 2015 global oil demand at 94.1 MM B/D," *Platts*, July 17, 2014.

[15] "Oil demand growth slowing at 'remarkable' pace – West energy agency," *Reuters*, September 11, 2014.

complete its back-out by end-2015, using mainly Bakken for import barrels. Then we should begin to see some back-out of medium sour barrels, at least in modest quantity.

- Rising product exports should continue, but how much increase there will be 2014-16 depends on, first, the ability of the Atlantic basin to absorb additional products barrels, with demand recovery in Europe weak and South America uncertain; and, second, on clarification of the current condensate export regulations. Little does Washington realize the extent that the uncertainty has handicapped refinery investment plans

- As noted in the above upstream section, the price differentials between US Texas grades—WTI, WTS, Eagle Ford, and Permian output, as well as output from offshore sours (such as Poseidon) and LLS—is very much influenced by the ability of pipeline and storage capacity to keep up with rising tight oil output. While generally this takeaway capacity has caught up and kept pace with rising tight oil production, hiccups still occur as Permian began to overmatch takeaway capacity.

- A major consequence, though, of transportation infrastructure buildup has been to narrow the premium that Brent enjoyed over WTI for much of 2011-13. We do not expect imports, however, to make any significant rebound.

- It should be noted—as many refiners already have—that increased product outturn from plants has to compete, at least indirectly, with large-scale and growing NGL production from Eagle Ford and increasingly Permian projects. As of mid-2014, Enterprise owns all or part of eight fractionation trains on the USGC, totaling 570 MBD capacity, Targa 538 MBD, ONEOK 203 MBD, and Lone Star NGL a further 200 MBD. This enormous NGL fractionation capacity is still expanding—and bringing ethane, LPG, and condensate to the USGC to compete with refinery outturn. RBN Energy judged that this is sufficient for now, but what happens if rising Permian tight oil production is paralleled by increased NGL output? Already midstream companies such as Plains All American have been considering building condensate-only pipelines from the Permian Delaware sub-basin to the coast.[16]

[16] "Talking About My Fractionation," *RBN*, July 7, 2014.

- Yet from 2012 through the present, USGC refiners have reacted quite cautiously to the surge in tight oil production. In its May 29, 2014, report on US crude quality, the EIA forecast that more than 60% of incremental US crude output will be 40 API or lighter, and a good deal of that new crude production will consist of condensate. Since permitting of refinery projects normally takes two years and construction even of relatively simple units—such as distillation towers or condensate splitting complexes—takes two to three years, it can be seen (as detailed in Table 29 below) that relatively little new capacity has been added by conventional refiners. For the most part, their reaction was to readjust cut points and modify existing distillation towers to run a lighter slate, and in some cases to add topping capacity, allowing the same objective. It is notable that the only major to commit to a splitter project has been BP, a leader in world condensate trade, and the company's role is to supply feedstock and then sell splitter outturn. Partner Kinder Morgan has assumed the capital costs of building the complex and will operate it, not BP.

Table 29. PADD-3 Tight Oil Dependent Refining Capacity—January 2014 (in MBD)

Site	Company	Completion	CDU	VDU	Coking	HDC	R/FCC	THC/VSB	Cat. Reform
ALABAMA			**80**	**28**	**-**	**-**	**-**	**-**	**18**
Saraland	Shell		80	28	-	-	-	-	18
LOUISIANA			**3,116**	**1,552**	**1,528**	**363**	**1,056**	**22**	**519**
Baton Rouge	ExxonMobil		502	236	1,117	24	232	-	74
Belle Chasse	ConocoPhillips		247	95	23	-	96	-	40
Chalmette	Chalmette Refining		193	109	28	-	72	-	23
Convent	Motiva Enterprises		235	110	-	42	76	12	40
Garyville	Marathon Petroleum Co.		522	265	86	91	131	-	121
Lake Charles	Calcasieu Refining Co.		78	28	-	-	-	-	-
Lake Charles	Pelican Refining		-	11	-	-	-	-	-
Lake Charles	Citgo Pertroleum Corp.		428	223	122	42	147	-	99
Meraux	Valero Energy Corp.		125	54	-	30	24	-	22
Norco, St. Charles	Motiva Enterprises (1)		238	90	25	42	111	-	38
Norco, St. Charles	Valero Energy Corp.		205	156	78	92	98	-	23
Port Allen	Placid Refining Co.		59	26	-	-	25	-	10
St. Rose	Shell		45	24	-	-	-	-	-
Westlake	ConocoPhillips		239	125	49	-	44	10	29
MISSISSIPPI			**330**	**288**	**98**	**68**	**86**	**-**	**86**
Pascagoula	Chevron		330	288	98	68	86	-	86
TEXAS			**5,370**	**2,434**	**843**	**629**	**1,831**	**-**	**1,059**
Baytown	ExxonMobil		560	277	90	26	213	-	120
Beaumont	ExxonMobil		344	140	45	65	113	-	142
Big Spring	Alon USA		67	24	-	-	23	-	21
Borger (2)	WRB Refining		146	76	26	-	55	-	31
Corpus Christi	Citgo Pertroleum Corp.		163	84	41	-	78	-	47
Corpus Christi	Flint Hills Resources		293	82	13	14	165	-	59
Corpus Christi	Trigent Ltd.		-	27	-	-	-	-	-
Corpus Christi (3)	Valero Energy Corp.		325	95	16	48	89	-	48
Deer Park	Shell		327	173	83	56	72	-	65
El Paso	Western Refining		122	45	-	-	31	-	27
Houston	LyondellBasell Industries (Houston Ref)		264	178	83	-	97	-	-
Houston (3)	Valero Energy Corp.		160	37	-	64	64	-	-
Nixon	Lazarus Energy		11	-	-	-	-	-	-
Pasadena	Astra Oil/Petrobras		100	36	-	-	38	-	17
Port Arthur	Motiva Enterprises (1)		600	316	145	77	88	-	121
Port Arthur	Total		226	96	55	-	75	-	36
Port Arthur	Valero Energy Corp.		330	175	88	96	70	-	39
San Antonio	Calumet Lubrications Co.		16	-	-	-	-	-	5
Sunray	Valero Energy Corp.		156	49	-	26	52	-	46
Sweeny	ConocoPhillips		247	125	70	-	109	-	34
Texas City (4)	Marathon Petroleum Co.		451	225	30	129	220	-	124
Texas City	Marathon Petroleum Co.		84	-	-	-	55	-	10
Texas City	Valero Energy Corp.		225	129	51	-	82	-	17
Three Rivers	Valero Energy Corp.		93	31	-	28	23	-	33
Tyler	Delek Refining		60	14	7	-	19	-	17
Texas Condensate Splitters			**75**	**-**	**-**	**-**	**-**	**-**	**-**
Port Arthur Cond.	BASF/Total		75	-	-	-	-	-	-
Total PADD-3 Tight Oil Dependent Refining Capacity			**8,971**	**4,302**	**2,469**	**1,060**	**2,973**	**22**	**1,682**

Notes:

(1) Motiva is a Shell-Saudi Aramco JV.

(2) WRB Refining LLC is a JV of ConocoPhillips and a subsidiary of EnCana, with ConocoPhillips being the managing member. WRB Refining has operating assets at both Borger, Texas, and at Wood River, Illinois, and the JV plans to expand heavy oil processing capacity at these facilities from 60 MBD to approximately 550 MBD by 2015.

(3) Valero plans to invest $730 million to expand light crude processing capacities at its Corpus Christi and Houston refineries by end-2015; upgrades will not add to refineries' output capacities.

(4) Marathon Petroleum purchased this refinery from BP in September 2012.

Source: US Energy Information Agency, Industry

Table 30. PADD-3 Planned Tight Oil Dependent Refinery Capacity Changes by January 2015 (in MBD)

Site	Company	Completion	CDU	VDU	Coking	HDC	R/FCC	THC/VSB	Cat. Reform
LOUISIANA			**25**	**-**	**-**	**-**	**6**	**-**	**8**
Chalmette	Chalmette Refining	3Q-2014	-	-	-	-	-	-	2
Port Allen	Placid Refining Co.	2Q-2014	25	-	-	-	6	-	6
MISSISSIPPI			**90**	**-**	**-**	**-**	**-**	**-**	**2**
Pascagoula	Chevron	4Q-2014	90	-	-	-	-	-	2
TEXAS			**252**	**-**	**46**	**54**	**14**	**-**	**-**
Baytown	ExxonMobil	4Q-2014	24	-	-	-	-	-	-
Corpus Christi	Magellan/Flint Hillls (Koch)	1Q-2014	-	-	2	-	-	-	-
El Paso	Western Refining	1Q-2014	25	-	-	-	-	-	-
Port Arthur	Motiva	4Q-2014	88		-	44	-	-	-
Port Arthur	Valero Energy Corp.	4Q-2014	90	-	44	-	-	-	-
Sunray	Valero Energy Corp.	4Q-2014	25	-	-	-	-	-	-
Texas City	Marathon Petroleum Co.	4Q-2014	-	-	-	10	14	-	-
Texas Condensate Splitters			**50**	**-**	**-**	**-**	**-**	**-**	**-**
Galena Park Cond.	Morgan Kinder	4Q-2014	50	-	-	-	-	-	-
Total PADD-3 Tight Oil Dependent Capacity Changes			**417**	**-**	**46**	**54**	**20**	**-**	**10**

Source: Industry

Table 31. PADD-3 Planned Tight Oil Dependent Refinery Capacity Changes by January 2016 (in MBD)

Site	Company	Completion	CDU	VDU	Coking	HDC	R/FCC	THC/VSB	Cat. Reform
TEXAS			**212**	**-**	**-**	**-**	**-**	**-**	**-**
Corpus Christi	Magellan/Flint Hillls (Koch)	1Q-2015	40	-	-	-	-	-	-
Corpus Christi	Valero Energy Corp.	4Q-2015	69	-	-	-	-	-	-
Houston	Valero Energy Corp.	4Q-2015	88	-	-	-	-	-	-
Tyler	Delek Refining	4Q-2015	15	-	-	-	-	-	-
Texas Condensate Splitters			**50**	**-**	**-**	**-**	**-**	**-**	**-**
Corpus Christi	Trafigura	4Q-2015	50	-	-	-	-	-	-
Galena Park	Kinder Morgan	4Q-2015	50	-	-	-	-	-	-
Total PADD-3 Tight Oil Dependent Capacity Changes			**262**	**-**	**-**	**-**	**-**	**-**	**-**

Source: Industry

Table 32. PADD-3 Planned Tight Oil Dependent Refinery Capacity Changes by January 2018 (in MBD)

Site	Company	Completion	CDU	VDU	Coking	HDC	R/FCC	THC/VSB	Cat. Reform
Texas Condensate Splitters			**185**	**-**	**-**	**-**	**-**	**-**	**-**
Channelview (Houston Ship Channel)	Targa/Noble	4Q-2016	35	-	-	-	-	-	-
Corpus Christi	Castleton	4Q-2017	100	-	-	-	-	-	-
Sweeney	Chevron	4Q-2017	50	-	-	-	-	-	-
Total PADD-3 Tight Oil Dependent Capacity Changes			**185**	**-**	**-**	**-**	**-**	**-**	**-**

Source: Industry

Table 33. PADD-3 Tight Oil Dependent Refining Capacity—January 2018 (in MBD)

Site	Company	Completion	CDU	VDU	Coking	HDC	R/FCC	THC/VSB	Cat. Reform
ALABAMA			**80**	**28**	**-**	**-**	**-**	**-**	**18**
Saraland	Shell		80	28	-	-	-	-	18
LOUISIANA			**3,141**	**1,552**	**1,528**	**363**	**1,062**	**22**	**527**
Baton Rouge	ExxonMobil		502	236	1,117	24	232	-	74
Belle Chasse	ConocoPhillips		247	95	23	-	96	-	40
Chalmette	Chalmette Refining		193	109	28	-	72	-	25
Convent	Motiva Enterprises		235	110	-	42	76	12	40
Garyville	Marathon Petroleum Co.		522	265	86	91	131	-	121
Lake Charles	Calcasieu Refining Co.		78	28	-	-	-	-	-
Lake Charles	Pelican Refining		-	11	-	-	-	-	-
Lake Charles	Citgo Pertroleum Corp.		428	223	122	42	147	-	99
Meraux	Valero Energy Corp.		125	54	-	30	24	-	22
Norco, St. Charles	Motiva Enterprises		238	90	25	42	111	-	38
Norco, St. Charles	Valero Energy Corp.		205	156	78	92	98	-	23
Port Allen	Placid Refining Co.		84	26	-	-	31	-	16
St. Rose	Shell		45	24	-	-	-	-	-
Westlake	ConocoPhillips		239	125	49	-	44	10	29
MISSISSIPPI			**420**	**288**	**98**	**68**	**86**	**-**	**88**
Pascagoula	Chevron		420	288	98	68	86	-	88
TEXAS			**5,834**	**2,434**	**889**	**683**	**1,845**	**-**	**1,059**
Baytown	ExxonMobil		584	277	90	26	213	-	120
Beaumont	ExxonMobil		344	140	45	65	113	-	142
Big Spring	Alon USA		67	24	-	-	23	-	21
Borger	WRB Refining		146	76	26	-	55	-	31
Corpus Christi	Citgo Pertroleum Corp.		163	84	41	-	78	-	47
Corpus Christi	Magellan/Flints Hills (Koch)		333	82	15	14	165	-	59
Corpus Christi	Trigent Ltd.		-	27	-	-	-	-	-
Corpus Christi	Valero Energy Corp.		394	95	16	48	89	-	48
Deer Park	Shell		327	173	83	56	72	-	65
El Paso	Western Refining		147	45	-	-	31	-	27
Houston	LyondellBasell Industries (Houston Ref)		264	178	83	-	97	-	-
Houston	Valero Energy Corp.		248	37	-	64	64	-	-
Nixon	Lazarus Energy		11	-	-	-	-	-	-
Pasadena	Astra Oil/Petrobras		100	36	-	-	38	-	17
Port Arthur	Motiva Enterprises		688	316	145	121	88	-	121
Port Arthur	Total		226	96	55	-	75	-	36
Port Arthur	Valero Energy Corp.		420	175	132	96	70	-	39
San Antonio	Calumet Lubrications Co.		16	-	-	-	-	-	5
Sunray	Valero Energy Corp.		181	49	-	26	52	-	46
Sweeny	ConocoPhillips		247	125	70	-	109	-	34
Texas City	Marathon Petroleum Co.		451	225	30	139	234	-	124
Texas City	Marathon Petroleum Co.		84	-	-	-	55	-	10
Texas City	Valero Energy Corp.		225	129	51	-	82	-	17
Three Rivers	Valero Energy Corp.		93	31	-	28	23	-	33
Tyler	Delek Refining		75	14	7	-	19	-	17
Texas Condensate Splitters			**360**	**-**	**-**	**-**	**-**	**-**	**-**
Channelview	Targa/Noble		35	-	-	-	-	-	-
Corpus Christi	Trafigura		50	-	-	-	-	-	-
Corpus Christi	Castleton		100	-	-	-	-	-	-
Galena Park	Kinder Morgan		100	-	-	-	-	-	-
Port Arthur	BASF/Total		75	-	-	-	-	-	-
Sweeney	Chevron		50	-	-	-	-	-	-
Total PADD-3 Tight Oil Dependent Capacity			**9,835**	**4,302**	**2,515**	**1,114**	**2,993**	**22**	**1,692**

Source: Industry

B. *The Muted Response of the Refinery Sector*

All of this leads to the question then: Why has the US refinery sector's investment response been so far muted? And further, how would modification of US export regulations shape that in the future?

The drive to construct condensate splitters was originally conceived by midstream companies as a way of making an "end run" around the crude export ban. It evolved then to becoming a markets tool, as independents with substantial skills in paper trade saw that owning physical barrels could be the instrument to leverage enormous volumes of trade using paper. Companies such as Trafigura and Castleton backed condensate splitter projects. Now with Washington's approval of the Enterprise and Pioneer June sales, other midstream and many upstream firms have talked of adding condensate processing (though it is unclear what processing stage is necessary beyond stabilization), but the majors, with the possible exception of Chevron, have remained on the sidelines.

While it is clear that less expensive crude and cheap gas for refinery process fuel will allow USGC refineries to run at fairly high utilization rates for some time, ultimately it comes down to a question of market (i.e., end-user) absorption of incremental product. No matter how cheap the crude is, a refiner must recover the cost of base material, manufacture, transport, distribution, and retail sales. And refiners have worried about building assets that may become stranded, if sustained product demand growth does not recover, particularly in the Western world.

The outlook through the medium term of three to five years supports caution. In the US, oil demand growth will unlikely accelerate in this timeframe, most analysts agree. There are signs within the Atlantic basin of supply saturation, as demand growth will remain—at least in the short term—minimal in Europe and Latin America. Further, refiners worry that the structural shift in oil demand to East of Suez markets and in particular to developing economies will only accelerate in the medium term.

These signs of saturation are most pronounced in light-end product markets. The US has become the world's largest products exporter overall, and this has not only come from increased products exports from refineries, but from field LPG. As splitters begin operations—the Kinder Morgan complex is due by end-2014—the overhang of light products will grow. Refiners have adopted, for the most part, a wait-and-see stance until they can weigh the impact of these splitters.

Which leaves the "go East" solution to increased product supply (i.e., moving cargoes to Asia Pacific, where demand growth has slowed, but the expectation remains that this region will lead world oil demand growth at least through end-decade). We expect that expansion of the Panama Canal—which will allow liquid tanker cargoes of up to 160,000 DWT, as well as passage to all LPG and most LNG tankers—will not be completed until 2016-17. For the immediate future, USGC product sales to Asia will have to go the long way around past the Cape of Good Hope, resulting in larger cargo sales that are harder for buyers to utilize quickly—or lumpy product supply.

And finally, refiners fear the possible imposition of restrictions on product exports, particularly if gasoline prices do rise after US crude export restrictions are eased. While little has been heard in recent years of the suggestion by the House Minority Leader, Representative Nancy Pelosi, of a ban on product exports, there still is a lack of understanding among many that exports stabilize prices ultimately, though not necessarily increase them. No country can have a complete energy autarky—it is as fruitless as King Canute commanding the tide to turn back.

C. *Historic Mismatch of Incremental Crude and Refining Capacity*

By 2Q, 2014, the steady growth of tight oil output finally began to note a looming problem—a fundamental mismatch between the kind of crude that was being produced in increasing volume in the US and the crude needs of American refiners. US refineries, particularly on the USGC, have been designed to run on a mid-weight to heavy slate of crude grades and are equipped to process crude high in sulfur, or *sour* grades. As PIW noted, energy secretary Ernest Moniz and White House advisor John Podesta had "said crude exports are being considered, in light of the mismatch between rising light, sweet crude production and domestic refining capacity…"[17]

By midyear, the EIA was preparing at the request of legislators a "series of studies" on hypothetical crude exports. Earlier suggestions by the EIA to ease rules for crude export, such as an exchange of US Eagle Ford light crude for Mexican heavy grade Mayan, had gained little traction, foundering on administrative details in federal regulations.

[17] "Market barriers raise issues for US crude exports," *Petroleum Intelligence Weekly*, May 19, 2014, 2.

The completion of USGC light crude back-out by 2014 gave further urgency to a decision, yet it has been recent geopolitical flashpoints threatening energy supplies that pushed a re-examination of crude export restrictions. Disruptions to Libyan crude exports, Russian threat to limit oil and gas exports to the European Union (EU) over the conflict with the Ukraine, the continuing civil war in Syria, and the sudden emergence of ISIS (Islamic State of Iraq and Syria) threatening Iraqi oil production all were cited by advocates as good causes to easing oil export restrictions.

D. *Splitter Projects in the Twilight Zone*

Figure 3 on page 8 above illustrates splitter proposals on the USGC that APEC judged to be likely to move ahead before the June decisions by the DOC. The BIS decision that month to allow Enterprise and Pioneer to export "lightly processed" condensate abroad threw the entire petroleum sector into confusion. However, no company has yet abandoned a project, and several—including Kinder Morgan, Martin Midstream, Targa, and Magellan—have stated publicly that they will press ahead—for now. (We will detail the commercial and technical issues concerning the definition of "processing" in the following chapter.)

Just how much confusion has been introduced into the sector can be gauged from some of the following comments:

"I think as far as future splitters are concerned, it's going to make the potential people who utilize those splitters probably think carefully about whether they want to proceed," said Kinder Morgan CEO Richard Kinder.

"We believe that our industry has the ability to handle much more of the light shale crude oil and condensate than is processed today," said Marathon Petroleum CEO Gary Heminger.

Marathon plans to build two condensate splitters in the Ohio Valley to process Utica and Marcellus output. "But the investments to do so will not likely be made in the environment of uncertainty that has been created."[18]

[18] Brian Scheid, "Uncertainty fails to slow US condensate splitter plans," *Platts*, August 11, 2014.

Much hinges on what constitutes "processing," but we believe that those splitter projects that are oriented to trading companies, rather than midstream operators, have the best chance of completion, such as the Kinder Morgan/BP, Trafigura, Noble, and Castleton proposals. Marathon's splitters will push ahead as well, if only to use opportunity feedstock. Projects promoted for other reasons have lower probability of success.

In Table 34 below, Barclays gives a somewhat different outlook for splitter completion than APEC. Both forecasts show no petrochemical company willing to follow Total's lead in building a condensate splitter—and this unit has been operating for more than a decade. There simply will be plentiful other alternative feedstocks available.

Table 34. US Condensate Splitter Capacity (in MBD)

Company	Location	2013	2014	2015	2016
Total SA	Port Arthur, TX	75	75	75	75
Kinder Morgan	Galena Park, TX	-	50	100	100
Marathon	Canton, OH	-	25	25	25
Marathon	Catlettsburg, KY	-	-	35	35
Castleton	Corpus Christi, TX	-	-	100	100
Martin Midstream	Corpus Christi, TX	-	-	-	100
Magellan/Trafigura	Corpus Christi, TX	-	-	-	50
Targa/Noble	Houston, TX	-	-	-	35
Total		**75**	**150**	**335**	**520**

Source: Barclays as stated in Scheid, "Uncertainty fails to slow US condensate splitter plans."

But much hinges on the definition of "processing." Why is this important? Because while analysts differ as to the actual volumes, it is clear that field condensate or "lease" condensate makes up a significant proportion of tight oil output, particularly within Eagle Ford among the big three producers. If field condensate will be exported with minimal processing, it will change the entire panorama of US oil.

Table 35. Forecast US Lease Condensate Production

Forecaster	2014	2016	2018
RBN	1,200	1,440	1,600
APEC 'Big Three'	816	1,250	1,521
Eagle Ford	*534*	*820*	*968*
Permian	*176*	*256*	*330*
Bakken	*106*	*174*	*223*

Chapter IV. The US Policy

A. *US Oil Definitions: "Curiouser and Curiouser"*

In struggling to comprehend the twists and turns in US condensate regulation, we think it appropriate to lean heavily on the noted author, Oxford mathematics lecturer, and master of logical paradox, Charles Dodgson, better known as Lewis Carroll.

It is important not to underestimate the role that mistakes, muddle, or simply poor timing can play in making policy. "It ain't necessarily so," as the Gershwin lyrics ran in "Porgy and Bess," and cautious skepticism should be the analyst's guiding principle.

The stakes are high, even if there is a modest easing of export regulation, rather than completely abolishing what Daniel Yergin, a noted energy commentator, had labeled accurately a "remnant of another time."[19] Yergin, the vice chairman of consultants IHS/CERA, has not been alone in claiming a broad range of benefits to lifting the US crude ban—the IEA had publically called for its modification, if not abolition, far earlier. An IHS forecast claimed that if the government reversed the oil ban, it would add $1 trillion to federal revenue through 2030, trim fuel prices, and add an average of 300,000 jobs a year to the US economy. Gasoline prices would fall an average $0.08/gal. or $3.36/BBL or $29.23/MT. Over the forecast period, this would be savings of about $265 billion. A later analysis by the Brookings Institution supported IHS/CERA's

[19] "Lifting Export Restrictions on U.S. Crude Oil Would Lower Gasoline Prices and Reduce U.S. Petroleum Imports While Supporting Up to 964,000 Additional Jobs, IHS Study Finds," *Reuters*, May 29, 2014, http://www.reuters.com/article/2014/05/29/dc-ihs-idUSnBw286314a+100+BSW20140529.

conclusions, but estimated that dropping the crude ban would cause American gasoline prices to fall some $0.09-0.12/gal., while increasing US crude production by 1.5-2 MM B/D.[20]

Other benefits would accrue. US government revenue would increase $1.3 trillion from 2016-30 from energy related taxes and royalties, and job addition both in oil production and employment in the oil field service sector would rise at an average of 340,000/year, peaking in 2018 at an additional 964,000 new posts. Further, the US would save an average of $74 billion on oil imports alone. This policy change would boost US oil output by an average of about 1.2 MM B/D and attract some $746 billion in additional investment 2016-30, according to IHS.

The approval of condensate exports this June, by the "most transparent administration in history," has left the energy sector baffled as to what has changed—or as the administration insisted—what has not.[21] We will attempt to unravel the current mysteries by reviewing US export policy, after laying out the indisputable facts of condensate export, and then speculate as to what changes may be underway in US federal policy.

B. *Long-standing US Export Policies; What Happened in June 2014*

"Begin at the beginning," the king said, very gravely, "and go on till you come to the end: then stop."[22]

For nearly 40 years, US crude exports have been prohibited, with only one major modification of these regulations allowing oil sales to Canada. The original authority to restrict crude exports came from the 1975 Energy Policy and Conservation Act and expanded under a further law, the 1979 Export Administration Act. Enforcement of export restrictions was the responsibility of the BIS, within the DOC. While there has been a subsequent easing of the initial absolute crude export ban, notably allowing limited export of Alaskan and Californian oil production under

[20] Brian Scheid, "US Congress to delay oil export decision until 2015," *Platts*, September 11, 2014.
[21] Jonathan Easley, "Obama says his is 'most transparent administration' ever," *Briefing Room, The Hill*, February 14, 2014, http://thehill.com/blogs/blog-briefing-room/news/283335-obama-this-is-the-most-transparent-administration-in-history.
[22] Lewis Carroll, *Alice's Adventures in Wonderland* (New York: The MacMillan Company, 1920).

strictly circumscribed conditions, only Canada has represented a major importer of US oil since the 1970s.

The key provision in the Export Administration Regulations has long been Chapter 15,part 754, the BIS definition of crude[23]: "Crude oil is defined as a mixture of hydrocarbons that exists in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and which has not been processed through a crude distillation tower."[24]

In the 1970s, both oil products and crude were banned from export. By 1981, amended by law in 1985, oil products sales abroad were allowed. The current regulations have a second, end-use rule that is used to enforce export regulations. The second part of the definition that separated crude oil from oil products and NGLs was processing of a base material, oil. "Refined petroleum products would be defined as those products that have been processed from crude oil through a 'distillation process' in the United States. This 'distillation process' must yield at least two distinct refined petroleum products. Petroleum that has not been distilled in the United States in this manner would be treated as crude oil."[25]

This would appear simple and straightforward. But then the analyst looks closer and finds some interesting complications.

NGLs (ethane, propane, butane, iso-butane, condensates) have been defined as hydrocarbon products and are free of any government export controls. Condensate, however, should be defined, like crude, by its origin, as hydrocarbon liquids "suspended in gas reservoirs at sub-surface temperature and pressure." All condensate exists as particles of liquid hydrocarbon suspended in gas at underground reservoir pressure and temperature. If plant condensate is exported, wellhead condensate—which comes from the same source and is not "in a liquid phase" underground—cannot be defined as crude. Yet, BIS regulations defined field condensate

[23] John Kemp, "Pass the dictionary: US gets in muddle over oil exports," *Reuters*, July 30, 2013.
[24] 15 CFR 752 (a).
[25] "License to Trade: Commerce Department Authority to Allow Condensate Exports," Congressional staff for Senator Lisa Murkowski, Committee on Energy and Natural Resources, April 2, 2014.

as crude and plant condensate as product, but by the method that it has been separated from gas. In BIS' progression of logic, since field or wellhead condensate—labeled lease condensate in the US—falls naturally out of the gas stream, it is defined as crude oil and therefore banned from export. However, condensate that is mechanically stripped from the gas stream—plant condensate, or as it is known in the US market natural gasoline—is a product and can be exported.

The apparent contradiction between the two approaches—the origin point of condensate and whether it is "processed" from a base material into oil products—has long been obvious and was underlined once again by congressional research before the June decisions. "While 'lease condensate' is included in the BIS crude oil definition, there is a potential contradiction within the definition. BIS defines crude oil as hydrocarbons that existed in liquid phase underground. However, condensate is generally in a gas phase underground and condenses to a liquid at atmospheric conditions. This apparent contradiction, along with other considerations, raises questions about the applicability of export restrictions to condensate."[26]

We will delve further into this regulatory Neverland later, but it is first important to establish what actually occurred from June through August of 2014. Considerable misinformation was reported by the press, even energy specialists, because BIS—and the DOC as a whole—refused to clarify in any detailed fashion the basis of its rulings, while the companies involved were reluctant to share their privileged commercial information.

What is clearly known, from public or private sources of information, includes:

- BIS in the first half of 2014 received applications for "private letter rulings" from Enterprise Product Partners and Pioneer Natural Resources, asking how the Department of Commerce would classify condensate that had undergone some "basic processing." Initial discussions started as early as February and other, still unnamed companies, made similar requests.

[26] Phillip Brown, Robert Pirog, Adam Vann, Ian F. Fergusson, Michael Ratner, and Jonathan L. Ramseur, "U.S. Crude Oil Export Policy: Background and Considerations," Congressional Research Service, March 26, 2014, 12.

- Private letter rulings, as the advisory opinions are known, do not create government policy or change the law. Instead they interpret how existing law applies to the specific set of facts outlined in the original request letters.

- BIS ruled that both companies could export to foreign markets "lightly processed" [field] condensate, as this would convert a base material, condensate—classified as crude oil—into a finished or semi-finished oil product.[27]

BIS' confirmation that stabilized and minimally distilled condensate was no longer considered crude for export purposes and cleared for export sale certainly had more logic to it than earlier explanations that Enterprise "said the equipment that its customers use to treat oil for shipment on its pipelines chemically alters the condensate in a way that makes it an exportable fuel."[28]

Industry traders and supply executives reported that in early 2013 requests by a producer as well as an independent oil trader for private letter rulings, with the material run solely through a stabilization unit, were rejected by BIS.

APEC, like so many other analysts in the past, had asked in their discussions with BIS as to what constitutes processing, and it was then defined as running a base material through a "distillation tower," as stated in BIS regulations. Clarifications by the agency, which was then somewhat more willing to answer queries before the current controversy, stated: 1) removing gas and NGLs alone does not constitute the transformation of a base material into oil products. For that reason, stabilization, which uses mild heating to drive off gases from liquid hydrocarbons did not constitute processing. 2) The outturn of processing should consist of separate and distinct group of products, finished and semi-finished, with at least two groups distinguishable, and 3) such product groups had to be fungible on commercial markets as product. It is clear that Enterprise, as well as Pioneer, have had to add another step beyond simple stabilization, but well short of simple refining through full distillation. As another condensate seller familiar with their processes characterized it: "If this is refining, the cuts have been made with a machete."

[27] Christian Berthelsen and Lynn Cook, "U.S. Oil Exports Ready to Sail," *The Wall Street Journal*, July 30, 2014.
[28] Ibid.

The ruling—claimed by BIS to represent no change in government policy or in law—opened the way for massive exports of US field condensate. APEC estimates that field condensate from US tight oil production should exceed 1 MM B/D—output solely from Eagle Ford and Permian fields, both with easy access to USGC ports, in 2014 together should top 700 MBD.

Yet, the two companies publicly named have differing interpretations of the rulings. Pioneer executives said its ruling was company and project specific, narrowly drawn to fit its own operations. Enterprise has claimed its ruling is not specific to its own operations or processing equipment and that any company that processes condensate according to BIS rules can sell it to Enterprise for export. Enterprise, of course, will only reveal these details if a company is working with them; BIS refused throughout the summer of 2014 to clarify its often confused statements. Assessments by industry experts such as by Daniel Yergin, claiming that this is " the wedge that's pushing the door open" for more ultralight oil exports, are not fully correct—at least not yet.

Secrecy, legitimate or not, has been the guiding principle in Department of Commerce decision. Company applications were approved in February and March, first to Enterprise in March, then to Pioneer. News broke of this potentially fundamental shift in interpreting export regulations only in June, and as of September 2014, BIS has yet to explain its reasoning, claiming it had no obligation to disclose commercial and possibly privileged confidential information. Various "clarifications" of dubious logic and truthfulness have been offered since by the DOC, but the reality has been that the oil and gas sector has been left in the dark by Washington, and the regulatory authority has left a very uneven playing field for companies in the energy sector (we will detail this further below).

Nearly two dozen companies have since applied for their own rulings on oil exports, according to industry executives. All these applications remain pending, as their requests have been "held without action"—a bureaucratic procedure that allows an indefinite pause in the review process, reportedly to allow officials to seek additional information to aid decision making. In effect, it

puts any attempt by any other company to export crude on indefinite hold, effectively stalling an industry push to export.[29] No deadline was announced for completion of the DOC review.

And then there is the troubling idea of a bureaucracy taking little responsibility for its decisions. BIS may well need more time to formulate comprehensive public guidelines as to what kind of oil can be exported and meet its institutional obligation to clearly define government regulations and implement them. Those familiar with the workings of the Department of Commerce have suggested that BIS' claim that they have only shifted their technical interpretation of regulation, not changed the law itself, at best can be seen as rationalization, at worst as sophistry bordering on intellectual fraud. The Department of Commerce has refused to comment on requests for clarification from the press. It appears that officials in BIS were surprised by the uproar created by their decisions and have now retreated in order to consider whether they had initially understood the entire picture. The sticking point is whether BIS provided consistent and coherent commercial advice, as required by their mandate, which is a basic function of the "good government" so often promised in recent years.

The Washington merry-go-round does not stop there. Senators have written commerce secretary Penny Pritzker, but Commerce and the White House denied any interference in BIS decision-making, claiming there was no effort to modify federal policy. "Those were decisions made at the Commerce Department, and were not coordinated with the White House, to my knowledge," said John Podesta, presidential counselor overseeing energy policy. "The Commerce licenses were in the regular order of applying their current standards to two license applications."[30]

At least five cargoes have been committed as of mid-September 2014. The Singapore flagged BW Zambesi, which set sail end-July, was the first condensate export cargo, sold by Enterprise, reportedly through Japanese trading house Mitsui, to end-user GS Caltex, a South Korean affiliate of Chevron. Later sales in September went to Koch Supply and Trading and will likely move to Rotterdam, where the company operates a condensate splitter, while the fifth cargo was

[29] Valerie Volcovici and Timothy Gardner, "U.S. condensate oil export requests put on hold for now," *Reuters*, July 29, 2014.
[30] "Condensate oil export decisions 'not coordinated' with W.House-aide," *Reuters*, July 29, 2014.

sold to SK energy, bound for South Korea, though it has remained uncertain as to whether the cargo will be processed in SK's splitter or in the conventional refinery.

All cargoes so far have ranged from 300,000–400,000 BBLs, some 35,000–50,000 deadweight tons (DWT). This cargo size is roughly the limit that cargoes can be shipped from USGC ports in Texas, at least for now. Enterprise so far has been the sole export seller and awarded six cargoes through end-2014 to two Japanese trading houses, Mitsui and Mitsubishi.

Initial cargoes were sold to South Korea (GS Caltex), Netherlands (ExxonMobil), and Japan (Cosmo); the second cargo was diverted—due to a lack of a suitable tanker to transverse the Panama Canal (35,000 DWT)—from Cosmo to ExxonMobil, with Cosmo, a Japanese refiner, taking the third lot. It has been clear that Asia Pacific has been the primary marketing target. All three initial cargoes were sold to refiners without any specialized condensate processing units, while later sales were made to buyers with condensate splitters.

Enterprise has acted as agent for Pioneer and BHPBilliton, major tight oil producers in Eagle Ford. Enterprise transports output, aggregates store, sells, and finally ships condensate cargoes. Its status as the sole exporter of US field condensate will likely be short-lived, as Pioneer is adding export infrastructure to market on its own and other companies will surely follow.

Condensate sales will become more regular over the second half of 2014, though oddly enough, still in relatively limited volume. Enterprise's term sales tender was awarded to Mitsui for 3Q, 2014, and a further three to Mitsubishi affiliate Petrodiamond through end-2014. Other terms sales agreements are likely by end-2014. While attention has been focused on Enterprise and Pioneer, other companies have been involved already in the export push. We understand that at least one other company, and possibly more than one, has had similar private letter rulings from BIS, allowing them the export of condensate. Of course, BIS has made no reference to this or any other pertinent information to the public, as it is reviewing its regulatory logic.

Some analysts forecast very optimistic figures on the future of US field condensate exports. Citibank project exports of 300 MBD by December 2014, which would work out to roughly a

36,000 DWT cargo a day departing from the US. Barclays' outlook is even rosier, predicting exports of 800 MBD in the medium term. We suggest these outlooks do not fully take into account infrastructure constraints in condensate exports. A more realistic forecast was that Cosmo Oil suggested that US exports to Japan could by end-year reach about 15 MBD.

Price has been the main attraction for Korean buyers. GS Caltex loaded its end-July cargo at a discount to WTI (itself still at a $5–6/BBL discount to Brent); freight to South Korea was about $5/BBL. It should be noted that any such sale benefits from preferential tariff and tax considerations given that South Korea is a Free Trade Agreement (FTA) partner with the US.

Traders reported that the first cargo sold to South Korea had rather odd characteristics for condensate. APEC has learned that roughly 15% of the base material processed by Enterprise was removed from the material sold as condensate to GS Caltex, and the yield pattern seen in the first cargo sale seems to confirm that. Naphtha outturn was very low and just above or below 20%—normally whole condensate (field and plant combined) averages 50% or greater naphtha yield. Fuel oil outturn in whole, blended condensate (field together with plant) rarely averages above 8%, often at 4% or less, other than some special grades, such as Kazakh Karachaganak, which averaged about 17% residual yield. This first cargo, according to Asian traders, was believed to have yielded about 17% fuel oil, leaving unprovable speculation that light crude was blended with field condensate.

Additional technical information from Enterprise's sales tender provided some further details on the physical nature of this "condensate." But since a full assay has yet to be released by the seller, the results have to be taken with caution as this analysis is based on fragmentary information. The tender technical data showed a whole material API of 53.4—but LPG was not included in at least part of the analysis given and had to be estimated. The whole condensate is low in sulfur (0.025%S), with a low pour point—all typical of condensate. The naphtha yield is highly paraffinic, and this too made sense as Eagle Ford condensate has become strongly and increasingly paraffinic in recent years. This means the material would be better for ethylene cracking feedstock than gasoline manufacture or aromatic petrochemicals.

Yet, other results were odd—our estimated naphtha yield was just under 42%, rather low for a field condensate, though within the realm of possibility, while the residual yield was high at more than 10%. As noted above in our analysis of trader information, it is rare to have any condensate with more than 7–8% residual outturn and often far lower.

If these reports of lower-than-expected naphtha and higher-than-normal residual outturn were accurate, then the material sold as *condensate* could not be processed in a standard condensate splitter. This may well explain why all three named end-users in the initial single cargo sales—GS Caltex, ExxonMobil, and Cosmo were refiners, without any specialized units, such as splitters, to process standard-quality condensate. They were likely only interested in blending the lots into their crude pool and then running it through standard refinery. Whether later sales differed in condensate quality form the initial trio of cargoes has yet to be determined.

Further, it was claimed that Enterprise added value through aggregating condensate from different buyers. Based at least on the first cargo, we see little evidence to support this claim. It would appear that Enterprise had dominated initial sales because of its strong position as a major midstream company in pipeline capacity and storage as well as its half ownership of the sole condensate-only pipeline, carrying output from Eagle Ford to Corpus Christi. It remains unclear as to why Enterprise—and not Plains All-American, another midstream company owning the other half of the condensate-only pipeline—has been able to establish a commercial lead over its rival.

Though Enterprise's tender revealed some further details on condensate exports, we thought its information too limited for an accurate yield estimate. Since Enterprise has not released a crude assay, or a distillation curve, APEC has estimated yield patterns from information from Asian traders. This should be considered only as indicative.

Table 36. Characteristics of First Condensate Cargo Exported (in %Vol)

Product	Composition	Cut (Deg. C)	Yield
LPG	C3/C4		4.36%
Light Virgin Naphtha	C5/C6	C5-70	18.70%
Heavy Virgin Naphtha	C7/C10	70-90	44.29%
Kerosine	C11/C12	190-230	8.50%
Gas Oil	C13/C17	230-350	14.50%
Fuel Oil	C18+	350+	9.54%

Final boiling point (FBP) was given as 360 degrees C (680 degrees F) and was a positive clue, as it indicates the absence of vacuum bottoms, often the indicator of a light crude rather than a heavy condensate. This material resembles a condensate more, but an FBP this high is still atypical for condensate.

C. *Defining Oil, Condensate, Products—Bureaucratic Routine and Industry Rumination*

"I can't go back to yesterday, because I was a different person then."[31]

We now will review BIS procedure in an attempt to better understand decision-making in the Department of Commerce and follow this with a survey of what informed speculation within the industry on the future path of condensate exports.

The key uncertainty is what constitutes "an instrument of transformation" that "processes" a base material into products. The great fear within the oil and gas sector is that BIS has so little familiarity with the topic of condensate that its fact-finding pause—reportedly to gather further information—may become an extended period of official information blackout. An amusing, though unverified anecdote told of the meetings held by Pioneer, Enterprise, and the Department of Commerce was that a BIS official reportedly asked "How do you spell 'condensate'?" There is concern that BIS has made its rulings with little true understanding of the broader implications of its decisions.

An analysis by RBN in early August has been cited by those familiar with the workings of government bureaucracy as representing a fairly full and generally accurate summary of the

[31] Carroll, *Alice's Adventures in Wonderland.*

decision-making process at BIS. While this may well be so, and APEC has accepted conditionally that the RBN account is accurate, we believe that some of the conclusions are at best speculative and could be challenged.[32]

Some of the major points made by RBN—and areas where APEC takes some issue with RBN—include:

1. RBN contends that the hold placed on new applications was simply "an administrative process" that allows the applicant to "provide additional supporting information that the BIS requires." What RBN does not note fully is that BIS has been unable to explain what information it exactly requires. Independent analysts outside of RBN have claimed that BIS has taken a strictly engineering approach in evaluating company applications. APEC has been informed by company applicants that they were asked strictly commercial questions as well—such as whether the resulting outturn could be sold as product. This is hardly a "straightforward process," as characterized by RBN.

2. RBN accurately detailed at length the bureaucratic process of working with BIS. The commercial quest for the Holy Grail is to have BIS grant a proposed export, an approval designated EAR99, which assigns a Common Classification Automated Tracking System (CCATS) number to the material. While crude exports require an export license—and all lease condensate was defined as crude until 2014—"lightly processed condensate" is only assigned a product classification number. As earlier noted, for condensate or crude to be exported under the decades-old regulations, it had to have been "processed through a crude oil distillation tower." RBN's summary of the administrative process, we believe, has been the most accurate public account so far.

3. We believe that RBN rightfully pinpointed that generally the press and industry erroneously concluded that stabilization was a form of processing, satisfying BIS requirements. It has

[32] Sandy Fielden, "CCATS Scratch Fever – Navigating Condensate Exports at the Dept. of Commerce," *RBN Energy*, August 7, 2014.

become clear that there must be a transformation of the base material processed far beyond the removal of gases and NGLs, the primary function of stabilization.

4. RBN commented that the raison d'être of BIS is to classify everything that is permissible for export. APEC has observed that the BIS has often been opaque in its decision-making process, and at times may have overstepped its mandate of simply enforcing export restrictions. BIS tracks thousands of exportable items in its Commerce Control List (CCL), which contains Export Control Classification Numbers (ECCNs), which are applied to all products requiring an export license. But some products, generally items freely exportable, are assigned a general classification of EAR99, rather than an item specific ECCN. An EAR99, RBN explained, is what current company applications are seeking, as it allows a company to "export as much as you want." On the other hand, if seeking an ECCN approval for crude exports, a license from BIS is mandatory and your sole export outlet is Canada. RBN's conclusion is that "to export condensate you don't need a license from BIS," but rather you need to have it classified as an EAR99 item and need a BIS ruling that its CCATS determination is absolutely correct. Yet, this too has further implications, APEC believes, which RBN has left unsaid.

5. Enterprise and Pioneer received product classifications and not licenses. This is important because once a product classification is granted, that material can be exported in whatever volume the seller desires and with no time limit. There is no need to re-apply for permission on each and every cargo sale. Further, the EAR99 determination "'runs with the product' and need not be obtained or held by the exporter."[33] In contrast, a license is restricted solely to the company exporting a crude grade.

6. The devil, then, is in the detail. No one knows how BIS determined how the Enterprise and Pioneer applications passed the test or what constitutes "processing." RBN's explanation that "… main business of this federal agency is making sure the US doesn't export critical technologies to the wrong countries" falls flat in the case of crude export restrictions. BIS justifications of its refusal then fell back on the need to protect privileged commercial information, but the bureau has not made any open, public statement as to its exact guidelines in

[33] Ibid.

considering applications. RBN's explanation that national security "accounts for the secrecy surrounding these applications" falls short on fact as well as logic. National security may have been the original intent of the regulations. Their current application certainly is not justified on national security grounds.

7. If one extends BIS logic to its ultimate conclusion, one finds further paradoxes abound. RBN justifiably flagged the concept of "processing" as key in BIS determinations. Yet BIS insists that this applies solely to its ruling on field condensate. Under the traditional interpretation of export regulations, if a base material, whether crude or condensate, is distilled into a set of products, finished or semi-finished, it no longer is a base material but an oil product and is therefore exportable. Why, then, the further distinction still? A final point, while the issuance of an EAR99 determination is supposed to go with the product, Pioneer was very clear that its ruling was project specific and Enterprise said its ruling was applicable to other cases. Which is correct? We do not know because BIS is unwilling to explain its rulings.

D. *"In the Long Run …"*

John Maynard Keynes famously remarked of his fellow economists' use of the phrase "in the long run" that "in the long run we will all be dead." So is it true for the great export classification fiasco; the "clarifications" issued so far have only further muddled an already confused situation. As ever more companies submit their applications, a little further knowledge about requirements will become public through this dribble method. If the Commerce Department hopes to inform the commercial sector that it oversees, this is a dubious means of making regulations understood.

As of mid-2014, more than 300 MBD of condensate stabilization capacity was operating. How much of it can take the additional transformation step in distillation remains unknown simply because of the inability of government to act swiftly to clarify a long-running set of regulatory ambiguities. Even if none of these units currently operating beyond Enterprise and Pioneer would meet the mysterious standards set by BIS conversion of stabilization to stabilization plus, they would not be terribly expensive and certainly would cost less than building a grassroots condensate splitter, let alone a new-build conventional refinery. We are unable to forecast how

much capacity would allow for condensate exports until the Department of Commerce sets public standards—certainly a goal of an "open government."

Still, the Commerce Department should not be judged too harshly, as at least one high-ranking official did make an attempt in August 2014 to explain how BIS came to its earlier decisions. Eric Hirschhorn, Under Secretary of the Department of Commerce and the top official for the BIS, asserted that his department's decisions were based on the premise "that once crude oil was processed, it is no longer technically crude," and therefore the BIS decisions were consistent with earlier policy.[34]

There was nothing new in this "clarification." Hirschhorn, an attorney by training, neglected to define what constituted "processing." As quoted in the trade newsletter Washington Trade & Tariff, Hirschhorn said: "Lease condensate means condensate as it comes out of the ground. Processed condensate, if it's been processed through a crude oil distillation tower, is not crude oil. That's the regulation."[35] Yes, quite true, but if crude was processed in a distillation tower, it too could be exported—as products.

Hirschhorn then continued with a puzzling statement: "What's new is the composition of what's coming out of the ground, which may be different." [36] Or may not, we should add. The key assumption of the entire oil and gas industry for many years has been the need to use an "instrument of transformation" to convert a base material into exportable product(s). The under secretary appeared to imply that the base material itself was different—i.e., field condensate (lease condensate) produced by Enterprise and Pioneer was different from all earlier such production. This is difficult to accept as true.

But if this were the case, then it would contradict Hirshhorn's flat statement that "policy on crude exports has not changed since 1986."[37] Enterprise has stated quite clearly and publicly that it takes a further step to process its condensate after it is stabilized; Pioneer has confirmed the

[34] "U.S. Commerce official seeks to clarify condensate export rules," *Reuters*, August 5, 2014.
[35] Ibid.
[36] Ibid.
[37] Ibid.

same in private. They made no reference to "the composition of what is coming out of the ground," but emphasized the processing of material.

Such clarifications have done little to enlighten and the industry remained in September 2014 as puzzled as it was before Hirschhorn cleared things up. The under secretary was absolutely correct in one statement, however, that the boom in U.S. shale oil production is generating a surge in condensate output and so increased interest in regulatory details. Unfortunately, so far the Commerce Department's response has been underwhelming.

a. A More Commercial Explanation

"Contrariwise," continued Tweedledee, "if it was so, it might be; and if it were so, it would be; but as it isn't, it ain't. That's logic."[38]

In the EIA's annual Washington, D.C., summit in July 2014, Jacob Dweck, the lawyer who represented Enterprise in its dealings with the Department of Commerce, provided some further detail as to what is required by BIS in considering an application. Dweck, a partner with the Sutherland, Asbill & Brennan law firm, underlined three main points in his presentation—a substantial distillation process, different product streams, and a different and marketable product from the condensate feedstock—as necessary to meet Commerce's export approval.

Others are less sanguine over the clarity of BIS guidelines. APEC has learned in discussions with another company granted permission to export, but not yet publicly named, that further complications lie ahead.[39]

BIS has yet to publicly state these necessary points for export approval; all information available can only be garnered second hand. According to BIS' guidelines, a lease condensate is processed if it has been through distillation in which the distillation process results in two significant output fractions—in other words, the input stream is split into two or more output streams; there is a substantial difference between the input product and the output products; and the finished

[38] Lewis Carroll, *Through the Looking-Glass*.
[39] Companies familiar with the export challenge.

product is suitable for nonrefinery use.[40] Again this raises further questions as to "how much is enough" in terms of transformation.

The first cargoes of condensate sold by Enterprise took production from both Pioneer and BHPBilliton/Black Hawk; some was reportedly stabilized earlier in order to transport it. At least some of this output did not meet BIS export requirements and had to be processed a second time by Enterprise.

Enterprise then debutanized the material by refining at a very low temperature—likely flashing off LPG and lighter gases at 122 degrees Fahrenheit (about 50 degrees Celsius). Much of the outturn could only be characterized as "semi-finished," if produced in a refinery or condensate splitter. What emerged from the bottom of the tower was a mass of undifferentiated liquid hydrocarbons—certainly not commercial product, finished or semi-finished, and would need further processing.

Roughly 15% was drawn off the top in this distillation process. It consisted of LPG and naphtha mainly, and was made up a broad, semi-finished product group; this, too, has to be processed further. This apparently is taken by Enterprise as part of its processing arrangement.

The two public condensate export approvals given so far have pivoted on the specific framing of their petitions. All the permissions so far granted came about because petitioning companies asked the right questions in the right way.

Enterprise's role has been buying wellhead material that is stabilized by the producer and aggregating and transporting it to seaport, in the Houston metro area and Corpus Christi, to store for sale.

What does Enterprise do to add value in its blend? It doesn't seem like terribly much, as suspicions that condensate and crude were mixed have mounted. Pioneer signed a term supply

[40] Brian Scheid, "Did the US Commerce condensate export rulings mean nothing?" *Platt's Website Blog*, July 18, 2014.

contract some time back—roughly 3-4 years ago—and has been beginning to regret its terms. The company supplied condensate to both of the first two Enterprise sales and it is believed that BHP/Blackhawk provided material as well for the first cargo.

Since the earlier rejected requests by companies were made under private letter rulings, it is unlikely to be revealed, at least in the near future, why the applications were rejected.

E. *Washington Whispers*

"No, no! The adventures first, explanations take such a dreadful time."[41]

Other Washington observers have alternative views. One analyst, well-acquainted with decision-making in the Commerce Department, speculated that the BIS decision was made "strictly on an engineer's" view of processing, and that the use of heat in stabilization could be broadly interpreted from that viewpoint as processing. This interpretation ignores the commercial and operational parameters of the oil industry's downstream sector, as well as the industry's understanding of regulations, that fungible product must result in processing outturn. (We shall further detail the difference between refining and stabilization below.)

Another Washington insider interpretation was that there was no change in law, but a substantial change in the way that the law has been interpreted, whether purposefully or by accident. As noted earlier, many in the oil sector suspect that a decision was made by a middle-level BIS official who neither understood the differences between refining and stabilization nor fully grasped the implications of such a ruling and accidently opened up the potential floodgates to massive export of US condensate and eventually crude. Pioneer Natural Resources CEO Scott Sheffield predicted that the US will fully drop restrictions on crude exports by 2017, and he is not alone in this view. A cynic would suggest that the long delay in an official government response was necessary to jetty-build a logical framework to backdate and justify a fundamentally erroneous decision.

[41] Lewis Carrol, *Alice in Wonderland.*

F. *Summing Up: Stabilizers, Distillation Towers, and Splitters*

Most crude oil production and almost all field condensate output were processed through stabilizers in 2013. Both oil and condensate need stabilization to remove excess gas, a proportion of the lighter (ethane, propane, butane) NGLs contained within output. This reduces vapor pressure and results in a safer and more stable liquid to transport, whether through pipeline, by rail car, or highway tanker truck.

A stabilizer first separates gas and liquids into separate streams at atmospheric pressure. A stabilizer then treats the gas stream, using very limited heat to separate out the lighter, more volatile NGLs from heavier liquids. It should be noted that much of the lighter NGLs are removed from the gas stream at this stage, while heavier NGLs, most notably field condensate, remain within the liquid stream. Heat flashes lighter ends into a vapor that is collected from top of the stabilizer. Wet gas is further processed to clean the gas and separate the remaining NGLs, including some of the lighter condensate, from the essentially dry clean gas. Condensate stripped from the gas stream in the processing complex is generally lighter than field condensate and kept segregated from other NGLs.

Some have argued that multiphase stabilizers operate more like a splitter than a traditional stabilizer. Yet even more sophisticated types of stabilizers do not separate liquids into distinct fractions of product, whether finished or semi-finished. [42]

Since all field condensate is stabilized, as well as most crude, if stabilization alone is considered processing, then most if not all US crude and condensate could be exported. Previously BIS insisted that there had to be substantial change in base material through commercial distillation, and the separation outturn into at least two separate and distinct product groups. Now the BIS standard is completely confused, at least to those outside the tight circle of government regulators and the lawyers dealing with them.

[42] Sandy Fielden, "With or Without Splitting? Changing Lease Condensate Export Definitions," *RBN*, June 25, 2014.

We believe the rumors that stabilization alone acts as an instrument of transformation are false; further, that an artificial breakpoint of API 45 or even API 50 would see production above these specific points be considered condensate. The first assertion is simply ridiculous. If the logic is pushed to its limits and minimal distillation (i.e., solely separating gas and lighter NGLs from liquid hydrocarbons) is accounted commercial distillation, then the ultimate logic is that all crude that has been stabilized is accounted "distilled" and therefore can be exported. Still, the industry has no idea what exactly are BIS standards for "processing" anymore. If "Pioneer and Enterprise operate advanced, large-scale stabilization units that look a lot like small oil refineries," [43] the industry remains ignorant of what step beyond simply removing gas and lighter NGLs makes these "instruments of transformation." Another hint of a bureaucratic error came from Pioneer's explanation of the BIS decision.

Enterprise spokesman Rick Rainey said, "Nothing has changed. There's quite a bit of confusion over what this all means. It's not policy change or a loosening of any regulations." [44]

Pioneer said its "crude stabilization process" "includes central gathering facilities with a distillation unit." The company said "that the distillation process by which our EF Shale condensate is stabilized is sufficient to qualify the resulting hydrocarbon stream as a processed petroleum product, eligible for export without a license."[45] Note singular, not plural. Pioneer refers solely to an undifferentiated mass of liquid hydrocarbons, not to two or more product groups. Something changed, and Pioneer's detailing of the outturn from its unit differs significantly from Enterprise's details. "The stabilization process at Pioneer's Eagle Ford Shale central gathering facilities involves a distillation unit that lowers vapor pressure and removes volatile lighter hydrocarbons."[46] So do all stabilizers, whether for crude or condensate, whether sophisticated or simple. Something is missing.

We must conclude, as did analyst John Kemp, that "if BIS admitted that any separation through vaporizing and condensing qualifies as distillation and readies raw oil for export, it was not clear

[43] John Kemp, "Pass the dictionary: US gets in muddle over oil exports," *Reuters*, July 30, 2014.
[44] Brian Scheid, "Questions remain on US condensate ruling," *Platts*, June 26, 2014.
[45] Ibid.
[46] Ibid.

where the bureau could draw the line."[47] Surely if the Department of Commerce's claims about not changing the policy was true—and many have doubts—then no official would like to take such a far-reaching step to change policy. Rather than clarify, the process has become even more clouded and uncertain.

The EIA will release a report in fall 2014 that will attempt to clarify the situation. "The new study will define splitters, stabilizers and other refining projects, and offer details on what is meant by processing." [48]However, the EIA's findings are not binding on Commerce Department policy as "the Commerce and EIA are separate agencies with different regulations." [49] What exactly needs to occur for condensate to be deemed processed is the Commerce Department's call and for now, its position remains opaque.

G. *Exceptions Allowed; Export Debates and Downstream Investment*

Exceptions Pursued

"When I use a word," Humpty Dumpty said in rather a scornful tone, "it means just what I choose it to mean—neither more nor less."

"The question is," said Alice, "whether you can make words mean so many different things."

"The question is," said Humpty Dumpty, "which is to be master—that's all." [50]

One could possibly argue that the Commerce Department was simply trying to interpret the existing law as it best understood the regulations. But the agency has been strangely reluctant to act on earlier suggestions from the EIA to allow for crude exchanges, a suggestion made in part to address both the need of USGC refiners for a base load of heavy, sour crude while reducing the overhang of light, sweet tight oil—in particular from Eagle Ford.

[46] "US EIA to release report on crude processing next month: Sieminski," Platts August 19, 2014.
[48] Ibid.
[49] Ibid.
[50] Lewis Carroll, *Through the Looking Glass*.

Current law allows for crude oil swaps, but imports must be of the same quantity and quality as exports. And the current crude legislation does not define quality. Generally light sweet oil grades are considered high quality compared to heavy sour oil types, but would Mexican Mayan oil be low quality because it is heavy or would it be high quality because it is well-suited to USGC refineries?

Current law says US oil can be exchanged in similar quantity "with persons or the government of an adjacent foreign state" or temporarily exported across parts of an adjacent country and then re-entered into the US. This is how Canadian crude can be exported from USGC ports. According to the BIS, this includes not only Canada and Mexico but also Panama, likely a historic remnant of the US Panama Canal Zone.

To complicate matters further, there are many who believe that under the NAFTA agreement, Mexico should have the right to free trade in all products, including crude oil, or at very minimum be given preferential status in a crude oil swap. A number of proposals to the Commerce Department to allow swaps not solely on exact volume and value, but on an exchange with settlement of the different values in cash, have come to naught. Many suspect that the BIS has not given serious consideration to varied suggestions, though a Mexican crude swap would enhance energy security for both countries.

This becomes relevant—though parallel—to the overall condensate controversy because at least one swap application, from Continental Resources, has been made and others are likely to follow. The Commerce Department's silence on potential crude swaps has been deafening.

Parallel Debates; Downstream Investment Decisions

"Would you tell me, please, which way I ought to go from here?"
"That depends a good deal on where you want to get to," said the Cat.
"I don't much care where," said Alice.
"Then it doesn't matter which way you go," said the Cat.
"—so long as I get SOMEWHERE," Alice added as an explanation.

"Oh, you're sure to do that," said the Cat, "if you only walk long enough."[51]

What this regulation saga appears to confirm is the absolute inability of current US energy regulations, let alone government policy, to deal with the fast-changing reality of the shale revolution. Hirshhorn's surmise that growing condensate output was the driver in increased interest in regulatory details was correct; what he neglected to address was this interest has been prompted also by confusing and contradictory regulatory policy. Apparently neither the energy regulatory agencies nor the political, policymaking side of government wants to deal with the most obvious impact of the shale revolution.

The question impacts not only crude oil, but also oil products, natural gas, and NGLs. There has been very little guidance from those who are supposed to lead in how the energy sector should cope with a rising supply overhang for all hydrocarbons across the board. And there has been little sense of urgency, at least from what APEC can discern in resolving these matters, nor any understanding of how such a delay may well eventually slow, or actually scupper, rising production from the shale revolution.

Both upstream and midstream companies are pausing on investment plans until they can work out how BIS intends to apply regulation. But that is nothing compared to the uncertainty induced in the US downstream, both in condensate splitter projects and in revamping and expanding currently operating conventional refineries. And the capital costs are far higher than modifying a stabilizer or building a condensate-only pipeline.

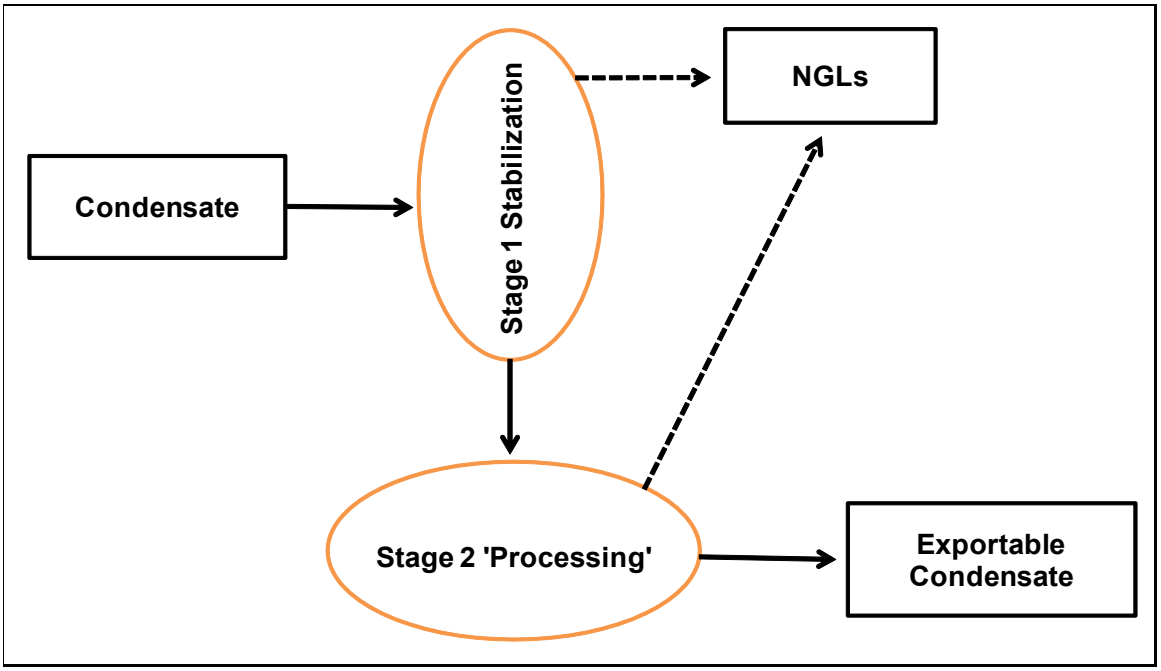
Roughly 20 companies have looked at the idea of building a condensate splitter, i.e., a special-built distillation tower capable of running a condensate-only slate, and converting a base material into a full range of products from LPG to residual. We have detailed the companies that we believe have made substantial progress in their projects; some others, unlisted earlier, remain serious but would likely only commission a complex at end-decade. But what of the less serious proposals, in particular those designed mainly to do an end-run around the traditional parameters of the export ban? Since the costs of building a new stabilizer meeting BIS stabilizer plus

[51] Lewis Carroll, *Alice's Adventures in Wonderland.*

requirements would still be far less than $300 million and the cost of modifying an existing unit even less, there will definitely be some fallout among splitter proposals.

The contrast can be seen in Figure 21 below:

Figure 21. BIS Approved—Exportable Condensate Plant



A different approach has been suggested for Bakken by Quantum Energy, which proposed building up to six "micro-refineries," each of which would work together with a 100 MBD stabilizer unit but process only 20 MBD of finished product. Whether this is a stabilizer plus or a small scale distillation tower in addition to a stabilizer remains unclear, but may well represent a further approach to creating exportable condensate.[52]

No additions to conventional refineries have been canceled, but certainly the Commerce Department snafu has many investing companies pausing to consider their projects. Ultimately the problem for both splitters and conventional refineries is that they can invest in new

[52] Timothy Gardner and Kristen Hays, "Loophole for condensate exports may apply to other U.S. crudes," *Reuters,* June 27, 2014.

equipment to process condensate and ultralight oil—but then, with a low-growth home market, where do the light products go?

But the final word, for now, is from another master of paradox:

"Everyone strives after the law," says the man, "so how is that in these many years no one except me has requested entry?" The gatekeeper sees that the man is already dying and, in order to reach his diminishing sense of hearing, he shouts at him, "Here no one else can gain entry, since this entrance was assigned only to you. I'm going now to close it."[53]

Chapter V. Winds of Change

Trying to quantify the volume of condensate that would meet current BIS standards for export, whatever they are, is problematic at best. If we take figures for Texas alone, the volumes could be substantial, though nowhere in the 500-800 MBD levels estimated by bank analysts.

Since there is no public definition of what constitutes processing, we will assume that only stabilizers that are large and generally more sophisticated—what is known as "multi-phase" stabilizers—could be converted at relatively low cost, probably at less than $10 million, to meet BIS standards. The US Gulf region has between 250-350 MBD of such larger stabilizer capacity as of early 2014. If we take a mid-point of 300 MBD and assume that modifications could be completed in a year or less, that gives us a 300 MBD conversion capacity for condensate exports.

Then there is the condensate itself. Eagle Ford by far produces the largest volume of field condensate in Texas, slightly less than 500 MBD in 2014 is expected, and the volumes of lease condensate from the Permian development were comparatively small, but quickly growing. If we assume that US national stabilization capacity of 300-350 MBD could be converted at least partially to meet BIS processing requirements for export, we believe at minimum that would allow for, let us say, 150-200 MBD of exportable condensate. This could be happening in as short a period as 12-18 months.

[53] Franz Kafka, *Before the Law*.

Even if only this minimal volume figure were achieved, it certainly would accentuate some current marketing trends that have resulted from increased US product exports. We examine these trends, detailing the potential impact of new condensate avails.

A. *Macroeconomic Impacts Already Evident*

1. An Era of Relaxed International Oil Prices

It has been noticeable that in all of the varied geopolitical hiccups of the past two years (2012-14)—whether disruptions of OPEC production (Libya, Iraq), simmering civil wars (Sudan), hot wars (Syria), or the threat of natural disasters interrupting production—oil prices have reacted relatively mildly to bad news events. US tight oil appears to serve as a shock absorber to world oil markets, even before the first barrel of American output was exported. In the first half of 2014, disruptions of up to 1.8 MM B/D in OPEC output had no impact on crude prices. What, then, will be the impact of small export volumes of US condensate that grow steadily through mid-decade? It will likely put a damper both on paper market price panics as well as speculative bull attempts to push prices up.

Further, the rising tide of US oil output has begun to close the gap between WTI price levels and Brent while at the same time bringing the price of Brent, on average, lower the first half of 2014 compared to 2012-13. This has had the next impact of lowering world oil prices.

While there still are disconnects between various crude markets in the US, growing pipeline capacity, storage, and port infrastructure have reshaped pricing and markets and re-established crude marker pricing relationships in the US market, reconnecting it to the world oil market. Hiccups still have occurred and bottlenecks in pipeline transport kept Midland WTI prices well below that of Cushing WTI for much of the summer of 2014, but it appeared that we will be swinging back toward more stable crude pricing relationships.

B. *Imports Backed Out USGC; USAC by 2015*

We have already noted the impact of backing out light crude imports on the USGC, which was essentially completed by mid-2014. We expect USAC imports of light crude to be finished by no later than end-2014. As recent reports have highlighted, the backout has not stopped with light

crude, but moved to medium/sour grades, an area dominated by Saudi sales. Total US imports of this crude grouping were well over 3 MM B/D in 2008 and by June 2014 had fallen to a level slightly above 2 MM B/D, of which some 45% was Saudi crude,[54] which as equity production going to Motiva, tends to be exempt from any substitution. The consistent rise in tight oil output is beginning to put great pressure on medium-weight grades in US slates as well.

C. *Light/Heavy, Sweet/Sour Deltas in Flux; Push of Light Sweets East*

The backout of light crudes by US refiners has had immediate impact on Atlantic Basin exporters that previously depended on this market. Nigerian sales have shifted eastward to Asia, with India replacing the US as the largest volume customer of NNPC. At mid-2014, India purchased roughly 750 MBD, while the US purchased only about 250 MBD. Nigerian exports to China and Malaysia also exceeded US purchases—and few people realize that buyers, particularly in India, prize the middle distillate yield on Nigerian crude as much as its light ends.

Canada has been taking increasing volumes of mainly Bakken crude as well as field and plant condensate for diluent use. Sales of Algerian crude to North America have dwindled solely to small volumes sold to eastern Canada, and how long this will continue will be a function of Bakken market penetration.

The net result is that light crudes traditionally absorbed by the US have been moving to Asia-Pacific in ever-increasing volumes, while the premium of light, sweet grades has eroded substantially since 2012. The arrival of large volumes of condensate will weaken this premium further. And as the Eagle Ford sale to Rotterdam showed, not all condensate will move to Asia.

D. *Little Noticed Canadian Heavy Output Pushing Similar Latin America Crude East*

Despite the continuing delays on approval of the Keystone XL pipeline to the USGC, US imports of Canadian heavy crudes too are beginning to impact balances. In 2012-14, sales by rail have increased exponentially, approaching 200 MBD by mid-2014. This is costly transport, in mid-

[54] Sandy Fielden, "Here Comes the Reckoning Day–When US Refiners Can't Process all the Domestic Crude," RBN, August 24, 2014.

2014 averaging $15/BBL to USGC, but operational improvements are lowering the rail movement costs.

A little noticed parallel phenomenon has been the rising export of Canadian crude to non-US markets. Better access to markets internationally will make Canadian heavy more competitive and improve transport. TransCanada expects to complete its Alberta-to-Atlantic pipeline by end-2016, while Enbridge's 525 MBD pipeline west to the Pacific is slated for 2018 completion. We have some serious doubts about forecasts that predict a relentless rise in Canada's oil output—in particular forecasts of bituminous crude output doubling to 3.6 MM B/D by 2020, but it is clear that the buildup in crude exports is too impacting the Atlantic Basin even before export pipelines are completed.

E. *European Refinery Closures; US Product Export Drive*

The buildup of condensate exports by end-2014 will also impact oil products. The period of 2012-14 was shaped by two complementary but opposite trends: the continued closure of European refining capacity and US back-out of African lights pushing barrels east. In the past two years, over 500 MBD of European refining capacity has closed, most of it permanently, while US product exports have grown steadily, with net exports at mid-year roughly 2.3 MM B/D. American exports have pushed European sales out of Latin America and Western Africa, both traditional European outlets, and exports to Europe have expanded steadily through the first half of 2014. Many analysts have begun to fear that the Atlantic Basin is near saturation with American export products, particularly light end products. Condensate sales, rather than the products derived from condensate, may ease this downward pressure, particularly if condensate moves increasingly to Asia.

F. *IEA Warning: Allow Exports or Sabotage the Shale Revolution (mid-2013)*

If the Commerce Department backs off of its June export approvals, we will see the supply overhang of tight oil and condensate back up through the US downstream, particularly USGC refineries, and this will eventually hamper expansion of shale development for all hydrocarbons. The day is near when US refineries will be unable to process all incremental tight oil output, let alone segregated field condensate. New production will outrun downstream capacity and back up

through the entire system. This is what the IEA has long warned of; it does little to improve US energy security if the shale revolution is derailed by outdated regulations.

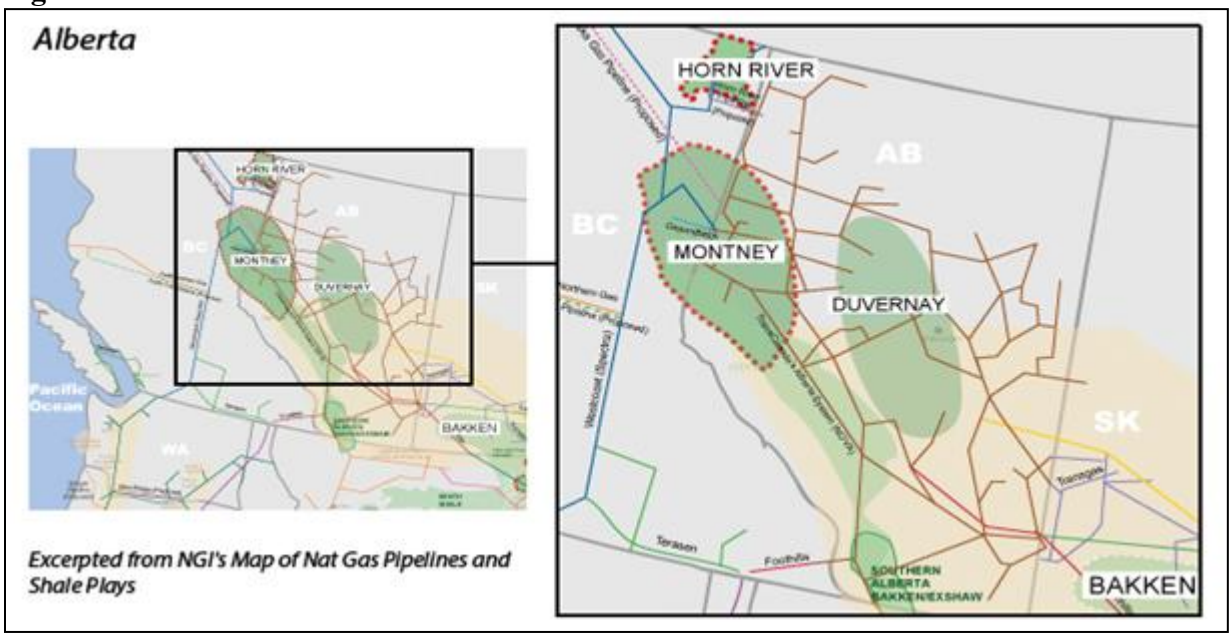
G. *Canada and Mexico Have Begun to Follow the US Shale Revolution*

The neighbors, too, will impact the US shale revolution and the export option. Canada already has begun to produce tight oil in Western Alberta. Drilling the Dunleavy Basin, followed by the development of Montney Basin for longer-term Canadian LNG exports, will increase Canadian light oil and condensate output to commercial volume levels before 2016 and to substantial output by 2020. Mexico is a bit further behind, but some 33% of the Eagle Ford basin, including its wet window, lies within Mexican territory, just as roughly one-fifth of Bakken extends into Canada. With Mexico's dire need for light crude, as well as wet gas, it will likely be an onshore development priority.

H. *Canada: A Development Trio*

Let's look at this in three parts: Duvernay, Montney (Alberta–map below), and the LNG projects. The difficult thing in each of these areas is quantifying progress.

Figure 22. Canada Shale Reserves



Source: Natural Gas Intelligence, website, Canadian Shale Basins by Province

As late as 2013, the Canadian Association of Petroleum Producers (CAPP) expected a decline in condensate output. But now expectations have fully reversed—the National Energy Board (NEB) expected Canadian condensate output to rise 13% to total 172 MBD this year, with the Kaybob zone, within the Duverney Basin, the top performer.

According to Alberta's Energy Resources Conservation Board (ERCB) medium-case in-place reserve estimate, the formation is roughly twice the size of Eagle Ford and can yield 445 TCF of gas, 11.3 BN BBLs of NGLs and 61.7 BN BBLs of oil and field condensate. These numbers are always exaggerated, but even if "2-P" reserves were a third of these levels, it would be enormous. The focal point of development, Kaybob, is about 255 km from Edmonton, the central condensate gathering point for Alberta crude.

As of mid-2014, total NGL output was in the range of 100 MBD, of which about 20 MBD was plant condensate. A good proportion of the 45 MBD in tight oil, however, is condensate—perhaps almost half of that or about 20 MBD. Wood McKenzie, a consultancy well-respected for upstream analysis, forecast that Duvernay production would average 1 million barrels of oil equivalent (MM BOE/D) in 2024, with a mix of 47% gas, 33% oil and condensate, and 20% NGLs.

If we take the 2024 outlook for oil of 330 MBD, and assume 20% is field condensate (conservative when one considers the US average currently is about 25%), that would total about 65 MBD. If we use a 1.2: 1 conversion for BOE for the NGL segment, then 200 MBD is about 165 MBD. If we take 20% of that as plant condensate (and current averages are higher), then we have a conservative further 35 MBD. That would total 100 MBD of condensate from this field alone, as well as over 260 MBD of light tight oil output—and this was a very conservative outlook. Duvernay alone could add up to 100 MBD of condensate; the question is how quickly this development will take place. If US condensate exports remain a regular feature of the North American crude/condensate balance, then US producers will still need Canada to absorb excess condensate output. What if this assumption proves false, if Duverney condensate production outpaces this forecast? In its high-case scenario, Wood McKenzie also forecast that Western Canada could produce 375 MBD of condensate by 2025, with 200 MBD from Duvernay alone.

The flip side would be if delays in commissioning new bituminous crude output slow the buildup in Canadian diluent. We remain skeptical of diluent forecasts, but Wood McKenzie expects demand to surge to 900 MBD by 2025. What if it is less? US condensate sellers will have to find other markets and for Bakken production, this will be difficult.

Montney is longer term. At end-2013, the NEB, together with the British Columbia provincial government, estimated "2-P" commercial reserves for the Montney Basin as totaling 449 TCF of gas, 14.5 BN of NGLs, and 1.125 BN BBLs of black oil. This is roughly one-third of the size of North Field gas, and roughly equal to Qatar's condensate reserves, assuming a quarter of NGLs are condensate, and "black oil" includes a substantial share of field condensate. Add to this Western Canada Sedimentary Basin's remaining gas recoverable of 189 TCF, and multiple LNG projects are understandable.

The basin only produced about 35 MBD in 2013 or only 1% of Canadian liquids output. The report said the Lower Triassic Montney formation covers about 130,000 square km, ranging in thickness from 100 to 300 meters, and is at its deepest on the western side. Montney is even larger than Duvernay and may contain four times Eagle Ford's reserves.

The question remains how much, how soon? We tend to think that Montney will only begin to have commercial impact after Duvernay, probably beginning to kick in appreciable output by 2018-19. Much depends on permitting and project progress overall.

LNG projects are an important driver. All eyes are on Petronas, which is the only project promoter that has committed with an FID decision this year, though at least three other projects were active. The Malaysian state company claimed in May 2014 to have proven up half of the 15 TCF of usable reserves needed for its $33 billion 12 MM MTA project.

We have assumed that two LNG projects will be at least test-running by 2019-20. At first phase plateau, these two projects would need roughly 3.5 BN CFD of wellhead gas to provide supply for LNG export at minimum, and using only moderately wet gas ratios we expect this to add at

least 50 MBD of condensate output by 2020. If wetness is greater than now forecast, this could easily double.

The implications are clear: by as early as 2016, Canadian condensate output would begin to rapidly rise and that by 2018-20, depending on the buildup of bituminous crude output, Canada may begin to limit the volume of American condensate imports it takes.

I. *Mexico—Need for Gas Drives Shale*

Mexican shale development is an even longer-term prospect than Canadian efforts, but the move to break state Pemex's 75-year sector monopoly, the passage of laws allowing direct foreign investment through profit sharing contracts (PSCs) or licenses, and a new interest in shale development—sparked by the success of Texas in Eagle Ford and made more acute by ballooning Mexican gas needs—will likely provide long-term support for shale development. The Mexican government predicted no new development through 2018 and the goal of boosting output to 3 MM B/D has been delayed until 2020, but this market directionally is on the right track.

As of May 2014, only 25 shale wells drilled in Mexico—compared to 60,000 in the US. While Pemex's estimates of hydrocarbon reserves in shale basins are greater than its conventional reserves of 55 BN BOE, this is likely optimistic, but potential is there. The slow passage of enabling legislation for Pemex, the ownership of mineral rights by the state (as in Europe outside of the UK) rather than land owners, drug violence, a lack of water, and—most tellingly—the lack of gas and NGL infrastructure are all impediments that make incremental output likely only an end–decade possibility.

Yet Eagle Ford beckons and Pemex already is investing in large-scale gas trunk lines to bring US gas, including output from Eagle Ford, to Mexican end-users. Stalemated crude exchange proposals with the US will give further impetus to Mexican shale development. Still, it is a 2020 timeframe before commercial production is achieved.

Chapter VI. Looking Ahead, or Problems in Predicting the Future without a Past

"There are known knowns. These are things we know that we know. There are known unknowns. That is to say, there are things that we know we don't know. But there are also unknown unknowns. There are things we don't know we don't know."[55] Donald Rumsfeld

The former secretary was as glib a devil as ever graced the halls of the Pentagon, but he could have expressed his idea simply by saying "We know what we don't." In his tongued-tied response, however, Rumsfeld stumbled upon an important truth central to the calibration of our outlook on US export impacts and to the attempt to identify variables that cannot be gauged exactly and to quantify how much these issues can change our outlook. We will focus on some key issues, upstream and downstream**.**

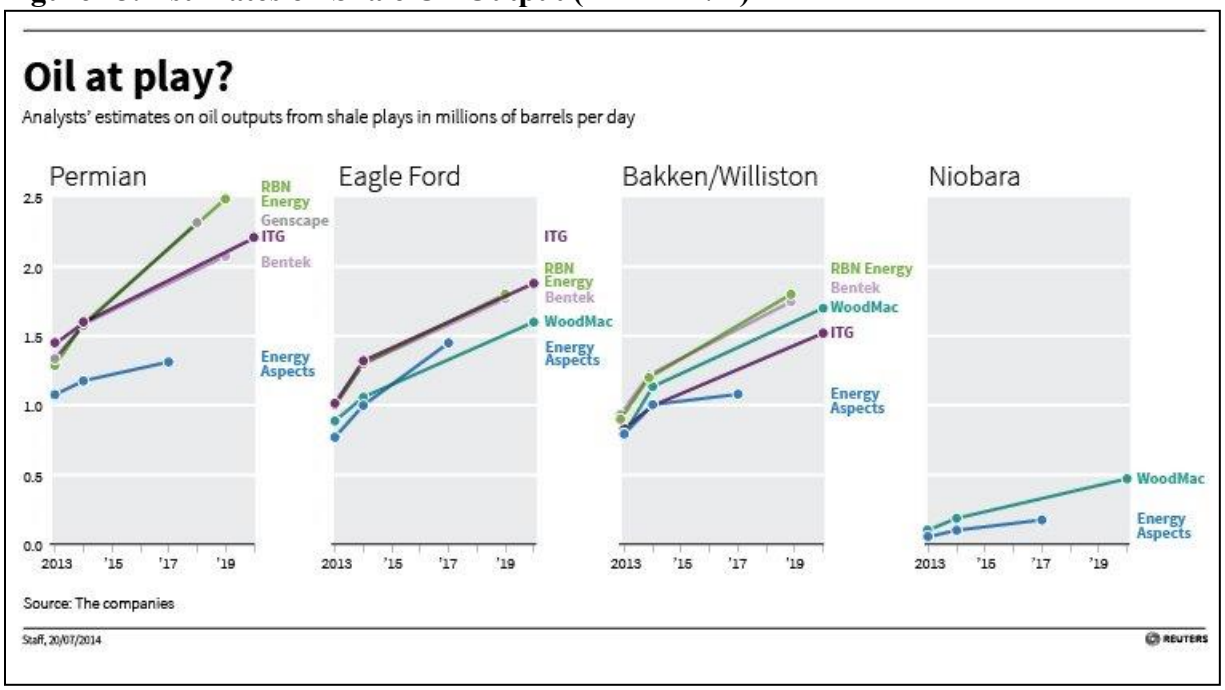
A. *Upstream*

1. Forecasting Shale Gas/Tight Oil: The EIA/IEA Track Record

We have noted how consistently behind the forecasting curve the EIA has been in predicting tight oil outlook and the IEA even more so. But this crystal ball gazing is not as easy as it looks and their outlooks have ranged no more than many respected commercial analysts. A thoughtful analysis by *Reuters* at mid-year illustrated well the range of opinion that some well-respected forecasters have given on some key tight oil basins (see Figure 23). (Please note that the Bakken/Williston shale play represents Bakken output).

[55] US Secretary of Defense Donald Rumsfeld, Department of Defense news briefing, Washington D.C., February 2002.

Figure 23. Estimates on Shale Oil Output (in MM B/D)



Source: *Reuters*, July 9, 2014

By 2017, Permian forecasts range roughly from 1.3-2.5 MM B/D (a later RBN/Bentek outlook modified its forecast to over 2.3 MM B/D by 2020). In the same time frame, Eagle Ford predictions ranged from about 1.37 MM B/D (RBN) to 1.34 MM B/D (Wood McKenzie), though a later forecast by RBN/Bentek put Eagle Ford output at about 1.850 MM B/D for 2017, and Bakken output for 2017 spanned outlooks of 1.2 MM B/D (Energy Aspects) to 1.7 MM (RBN/Bentek), a predicted level of production essentially unchanged in later RBN/Bentek predictions.

Two things become clear. First, there is a lot of room for honest disagreement on future production, in part, simply because we have never had a phenomenon such as tight oil development in the past, and we need a past in order to accurately predict the future. Second, the production forecasts can change with astonishing rapidity. If one placed in serial order all the forecasts for any one basin of RBN, or Wood McKenzie, side by side, we would expect that both would change quite rapidly. At end-August 2014, the EIA predicted a 38 MBD rise in Permian oil production for September; prorated, that is more than 450 MBD. At the beginning of 2014,

the EIA forecast that Permian output would only rise marginally, with incremental production form horizontal drilling only replacing decline in conventional production.

2. The Impact of Technology on Upstream Efficiency

Whether producers can continue to add incremental oil output is a function of the price they receive in selling their oil output. Estimates on Permian drilling by RBN showed very positive rates of return on capital employed (RORCE) of 63% on even moderate length-lateral wells in the Wolfcamp shale strata, of the Midland Sub-Basin, based on current prices and a return in the range of 30% even if oil prices fell to $60/BBL. This is the main driver for Permian production gains this year of more than 300 MBD through 8/ 2014.[56]

Much of the production gains made in tight oil output have come from more efficient drilling not more productive wells. Much of the improvement in operating efficiency has come from shorter drilling time; costs also have fallen sharply 2010, due to pad drilling.

Currently the Permian basin is the proving ground. Accelerated drilling in 2014 of Wolfcamp will prove or disprove whether this will become the biggest tight oil production area—even excluding its conventional oil output. In 2014, almost 5,000 wells were planned, with upstream spending to reach $25 billion. And experience counts. Compared to results from Eagle Ford, Bakken, Niobrara, and Permian/Delaware developments, only Permian/Midland recorded greater increase in tight oil output, and this is a reflection of better well placement by operators.

The EIA at mid-year predicted tight oil output will rise 37% from about 3.5 MM B/D in 2013 to 4.79 MM B/D by 2020. "There are other forecasts that are much more optimistic than this one," said EIA chief Adam Sieminski, [but] "we're still a little concerned about what the geology looks like for crude oil production. As technology moves, these numbers could grow."[57] The open question remains: how much will technology grow?

[56] Sandy Fielden, "Here Comes the Reckoning Day–When US Refiners Can't Process all the Domestic Crude," *RBN,* August 24, 2014.

[57] "Drilling Trends/Bakken + Eagle Ford," *US Shale Newsletter*, Rystad Energy, Vol. 1, No. 3.

3. Reduced Upstream Costs Underpinning Shale "Factories"

Another school of thinking considers oil price nearly irrelevant, as positive cash flow for tight oil projects, which started in 2014, and growing exploration and production (E&P) efficiencies will make developments immune to soft oil prices.

A study by investment bank Raymond James concluded at mid-year that "With rising US production and falling costs per unit of production, US E&P companies are now poised to actually grow cash flows even in a flat or modestly lower energy price environment."[58]

The bank concluded that after a decade of costs outweighing revenue by about 40%, explorers have driven per barrel exploration, development, and production costs to a point where companies react to flat or soft oil prices by expanding output. The bank detailed that "The reason for the improved capital efficiency is oil and gas volumes have been increasing at a rapid clip. Initial oil and gas production from three key horizontal plays (Bakken, Eagle Ford, and Marcellus) has increased an incredible 10-fold since 2007." [59]

"We now think E&Ps [exploration and production companies] are capable of growing cash flows solely through volume growth and cost efficiencies and in spite of a backwardated oil curve.[60] This is a massive paradigm shift in the energy sector," Raymond James concluded.[61]

In other words, upstream oil and gas companies have economics similar to a manufacturing firm, rather than a sector that has lived or died by the price of its specific commodity. This has remained an interesting, but unproven idea. If confirmed by production in 2014-17 (the medium term) the flow of tight oil rising will not shut down even if world oil prices crash.

This also means that the popular assumption that US crude production will rise because domestic prices would increase to higher world levels may be false. If US producers keep on pumping out

[58] Bill Holland,"Shale drillers becoming immune to prices: Raymond James," *Platts*, July 14, 2014.
[59] Ibid.
[60] Backwardation is when prompt prices for a commodity are below the expected future price for that commodity.
[61] Bill Holland,"Shale drillers becoming immune to prices: Raymond James," *Platts*, July 14, 2014.

increased tight oil output regardless of price, there will not be much of a delta between the two sets of crude prices and that will also impact current backwardation in futures prices.

4. The Rules of the Game: Export Rules and Future Output

Yet the greatest "known unknown" remains the US government's policy. The industry spent a long hot summer awaiting word from Washington as to how interpret the BIS' definition of exportable condensate; this would allow the firms to plan accordingly on how they should invest upstream, as well as downstream. Given our discussion above, we think it is utterly nonsensical to claim that "nothing has changed"—for investment, everything has changed.

A good example has been Plains All American. The mid-stream company, half owner of the sole condensate-only pipeline in Texas, in July 2014 announced it was considering building a new pipeline from the Delaware Sub-Basin of the Permian to bring rising condensate output to the coast. Such a decision would hinge upon changing regulations for condensate export, as Plains would move ahead with the project only if customers wanted to move large volumes of condensate to the coast for possible export. Further, the company has mulled expansion of its large-scale Gardendale stabilization center for condensate, but needs to know exactly what meets the BIS definition of exportable condensate before moving ahead. Delay and uncertainty, of course, cost money.

5. Following the US—Is the Shale Revolution Replicable and at What Cost: Argentina

APEC has long been confident that Canada and then Mexico will follow the US in developing shale resources, though the latter may encounter some delay. Less certain—and definitely a known unknown in the shale revolution—are shale discoveries such as in Argentina, a looming prospect that potentially could have a big impact on Atlantic Basin export economics. As is the case with China in Asia Pacific, the geologic base for Argentina is vast, the reserves are known—at least in part—to be quite wet, and the country's top prospect Vaca Muerta (Dead Cow), despite its off-putting name, may well emerge as a major rival to US condensate exports by end-decade.

Chevron has been a leading company in surveying this prospect. "Vaca Muerta is like one big cake, 1000 feet (305 M) thick in places, which means one well could be much more productive," according to one company executive.[62]

Chevron has claimed that this formation is unusual in thickness; Chevron claims multiple plays within Vaca Muerta, rather similar to the stacked strata of the Permian Basin. Vaca Muerta was the reserve rock source for oil and gas in conventional production in central Argentina. The shale basin has many of the characteristics of Bakken, Eagle Ford, and Permian: "organic-rich shales with low clay content in areas that had already produced oil and gas and that had an established infrastructure."[63]

Chevron has been relentlessly upbeat on its acreage and has been seeking further funding from independent investors, but the production results so far have been modest, despite a record high 107 rigs drilling in the basin in June 2014. In 2Q, 2014, the company produced 13.6 MBD of oil, 5 MM CFD of gas and 4.9 MBD NGLs. Still the gas has been very wet; the NGL-to-gas ratio is very wet at 0.980 BBLs per MM CFD, and the tight oil to NGL proportion has been 4:1. All promising numbers, but these are early days.

Vaca Muerta and the Los Molles shale formations contain almost all of this country's shale reserves. The EIA estimated in 2013 that Argentina held just under 10% of world shale reserves technically recoverable. Other major upstream players in Argentine shale include state YPF, Apache, EOG, ExxonMobil, Total, and a few smaller independents.

Big problems remain, such as Argentina and its debt default. Though the Argentine government might swerve and duck, it must face up to the fact that even if Vaca Muerta proves up to expectations, it will take enormous investment to develop this giant resource. YPF claims it will go it alone in developing Vaca Muerta, but this will be impossible without access to international funding, technology, and operating experience. While the Vaca Muerta basin is located in the Neuquén region, with extensive oil and gas infrastructure, enormous sums must be invested to

[62] John Kemp, "Flirting with default, Argentina enjoys oil drilling boom," *Reuters*, July 22, 2014.
[63] Ibid.

build further gas, NGL and oil processing, storage, and transport capacity. Vaca Muerta's brownfield development is far more similar to Eagle Ford than Bakken, but it will cost plenty. Funding is vital and Argentina is broke.

6. Shifting Focus: Where Will Upstream Investment Go?

Follow the money and you have a good idea of where upstream interest has shifted. The stakes could not be bigger, with multibillion-dollar investments needed to explore and develop oil and gas reserves. This spans markets as diverse as Saudi Arabia, Iraq, Russia, Venezuela, and China. All are being impacted by the investment shift to shale gas and tight oil, and will have to compete for upstream funds over the next decade.

Take Saudi Arabia, which appears to be of two minds when it comes to the shale revolution. On one hand it has welcomed its relatively high cost, relative to the low-cost pool oil developments that are the norm in Saudi Arabia, that keep non-OPEC oil development of costly offshore and Arctic projects to a minimum, while reducing competition from OPEC's higher-cost producers. On the other hand they cannot decide whether to pursue tight oil development in the home market. Many Saudis argue that rather than beginning with an expensive and unfamiliar technology, the kingdom should focus efforts on conventional oil development, where it still holds sizable low-cost reserves. Incremental oil projects in Saudi Arabia still average an investment cost of about $4.50/BBL, far less than tight oil.

Money that would have flowed to upstream development in the Mideast Gulf, as well as deep offshore West Africa, in Venezuela's Orinoco Belt syncrude projects and into massive and expensive Russian Arctic developments, has been moving back to North America. This is beginning to squeeze upstream capital availability worldwide. And the great uncertainty is where investment money will flow for the rest of this decade.

B. *Downstream*

The uncertainties are considerable downstream as well, particularly in view of lack of clarity of what constitutes sufficient transformation to qualify condensate as exportable. Nor is it clear whether the BIS policy extends to crude. APEC agrees with most analysts that some

modification of regulations—or at least in the way they are interpreted—is imminent and will be codified, but this may await the end-2014 mid-term elections.

In what follows, we first we look at stabilizers versus refinery investment—the structural unknowns. Then we will focus on refiners' investment outlook for conventional plants, the potential impact of government policy on transport fuels use, the impact of an expanded Panama Canal, and whether the US will shift its export focus. We conclude with some observations on the possible evolution of unconventional oil and gas development and its global impact.

1. Modified Stabilizers

It is certain that if only minor modification is necessary to convert at least the larger, more sophisticated stabilizers to processing complexes that would yield BIS-compliant condensate ready for export that a substantial percentage of multi-phase stabilizers will be converted to condensate export plants.[64] This may well give refiners—as well as condensate splitter promoters—pause in adding new capacity. This is a known unknown that is difficult to quantify as well.

Pioneer, Anadarko, and ConocoPhillips have been three companies with major production in the condensate window of Eagle Ford and are major operators of stabilization capacity. These are not midstream companies with stabilizers such as Plains All American (Gardendale, TX), but actual producers that have a vested interest in finding an export route out for condensate production.

Pioneer has a dozen central gathering plants, each of which is equipped with a condensate stabilizer. Capacity in aggregate totaled at least 50 MBD as of mid-2014, perhaps as much as 80 MBD. Pioneer has been determined to reduce its dependence on Enterprise for condensate sales and will be modifying its stabilization units to produce exportable condensate while searching to replace its dependence on Enterprise transport. Pioneer signed a term condensate sales contract

[64] Sandy Fielden, "You're A Stabilizer Baby—Eagle Ford Condensate Infrastructure: Pioneer, Anadarko and ConocoPhillips," *RBN*, July 20, 2014.

with Enterprise first in 2010. Like Enterprise, the company is determined to maintain its lead in export capabilities against newcomers and will see its condensate output rise sharply by 2016.

Anadarko is seeing its condensate output rise rapidly and though still awaiting BIS permissions, has far more stabilization capacity, some 75 MBD at Corrizo Spring, TX, and 15 MBD at Brasada, TX. The company had access to Corpus Christi through the Gardendale condensate-only pipeline and will add Houston access to that at Corpus by 2015. If minor modifications could make Anadarko condensate exportable, certainly the company will move in that direction.

ConocoPhillips, the upstream half of the disintegrated major of the same name, potentially could be the biggest player in modifying stabilizers for condensate export. The company produced 71 MBD of oil and field condensate in 2013 and recently moved up estimates of more than doubling that output, perhaps as early as by end-2015. The company operated stabilizers in Eagle Ford at Helena (60 MBD), Bordovsky (15 MBD), and Pawnee (15 MBD) and now is considering modifying these units. ConocoPhillips has pipeline access for stabilized condensate to move to Corpus Christi.

The bottom line is that at least three major Eagle Ford producers could be adding substantial volumes of condensate exports independent of Enterprise within 12 to 18 months. The uncertainty is how quickly and thoroughly they will move to revamp their stabilization complexes to meet BIS' (still unknown) standards. Infrastructure outlays may balloon if the uncertainty is resolved.

2. Refinery Investment in an Uncertain US Market

The flip side, as detailed earlier in the condensate splitter section, is that while splitter promoters and refiners will invest at least somewhat in the near- to-medium term, how much they expand capacity to handle light tight oil and condensate remains a moot point and the stabilizer issue remains floating. Since refineries remain geared mainly to heavy crude, there is some question as to whether further investment in handling lighter slates would be commercial. A further uncertainty, and deep-seated anxiety, is whether domestic US demand will recover to allow for steady growth in gasoline and diesel consumption. That, too, is a known unknown.

Regional differences also make up a part of the known unknown downstream quandary. The backout of imported light crude has long been underway on the USGC and USAC. The volume of tight oil going to the US West Coast, PADD-5, has remained small in part because there remains no crude pipeline transport from Bakken, Permian, or Eagle Ford (let alone a number of smaller tight oil producing areas closer) to bring crude to refiners. Everything has moved by rail and requests to expand rail infrastructure have met with delay. An attempt to build a pipeline to ship Permian output to the USWC failed in 2013, but will a future pipeline take Permian or Bakken output to US refiners on the Pacific Coast? Earlier in 2014, Questar, a small midstream firm, revived Kinder Morgan's *Freedom* pipeline concept and proposed a Permian Basin to southern California crude pipeline—if there was interest enough from refiners. This is a known unknown, and whether refiners will invest in a plant to handle such crude is a parallel uncertainty.

3. <u>How Government Tax/Tariff Policies Shape Demand Growth, Particularly Transport</u>

A major fear holding refiners back from major plant investment is future demand growth in gasoline use and overall for transport fuels. Higher minimum car and truck mileage standards have been responsible, at least in part, for minimal incremental demand for gasoline. The lackluster rate of recovery in the recent recession has also kept the rise in gasoline use minimal. Yet what if the federal government takes other measures to encourage alternative highway fuels? There have been plans to convert vehicles to LPG, to compressed natural gas (CNG), and even to LNG. Certainly these proposals, based on an inexpensive and growing supply of NGLs and gas from the shale revolution, have as much chance in succeeding as electric vehicles.

Generally unrealized is that government plays a decisive role in setting transport fuel policy. The US oil sector became structurally distorted over much of the 20th century, as clean gasoline was favored over dirty diesel, unlike many European markets. Now that diesel engines are at least as clean—if not cleaner—than gasoline engines, will the US government stop penalizing diesel use by evening the tax/tariffs for these fuels? It would be too much to ask of Washington quick or decisive action, but it should be evident to all that many fuels could displace future gasoline use over the next decade—and long before electric or eventually hydrogen-powered vehicles become the norm. And refiners would rather wait and see before investing millions more in plants.

4. Waiting on Panama; the Atlantic Basin Absorbing US Exports

As noted earlier, the ability of the Atlantic Basin to absorb further large volumes of US products, particularly light products, is beginning to come into doubt. US refineries have been running newly flat out, particularly on the USGC. "The question longer term is where US refiners … send their products? There is still scope to reduce US product imports, but over time domestic refiners need to find bigger overseas markets for their output."[65]

Further, there is great uncertainty as to whether Europe is moving into a third round of recession, a triple dip that will reduce any ability of the other major half of the Atlantic Basin supermarket to absorb US output. American exporters cannot rely upon European refinery closures to continue to create a supply hole that US exports will fill.

From the viewpoint of mid-2014, we have seen US diesel/gas oil net exports rise three-fold and gasoline exports rise by more than 500%. Light end exports from US refiners have grown even faster, in part because of the contribution of shale development to rising field NGL production.

Uncertainty surrounds the new deadline for the completion of the Panama Canal expansion, and many analysts believe that delays beyond the official startup of end-2015 are probable. Some US refiners think 2017, not 2016, is a more likely date for the startup of the renovated waterway. Until then pressure will build on US product exports.

5. Switching from Products to Crude or Condensate Exports

At what point does it pay to sell lemons rather than lemonade? When does the whole exceed the sum of its parts? Another uncertainty will be the relative value of selling a base material—albeit a light base material such as condensate—versus the products that could be derived from a barrel of condensate. Putting aside for the moment whether the current shift in Commerce Department application of export rules covers both condensate and crude, we will assume that only field condensate is in play.

[65] "Made in America," *PIW*, July 21, 2014.

"To sustain growth in domestic oil and natural gas liquids production as well as higher refinery utilization rates, higher product exports will be necessary," argue refining consultancy Turner Mason. "Net exports will have to climb from about 1.4 million b/d in 2013 to 4 million b/d by 2023."[66] This will be a very difficult path to follow.

There are times that the whole crude or condensate would be worth more than its constituent parts. A recent analysis focused on the impact of increased use of tight oil and flat domestic gasoline use surmised "the US will soon be facing a European-style gasoline surplus and will need to seriously expand exports." [67] We suggest, however, that the new markets for gasoline—as well as naphtha and LPG—will only be of adequate size to absorb US exports in Asia, and that the economics of exporting to Asia will improve enormously, when the Panama Canal revamp is completed. For the medium term, though, this light end overhang will begin to depress light product prices.

BIS-standard modified condensate may well further depress light crude premiums in the Atlantic Basin, but even without the Panama Canal, such cargoes are eagerly sought by Asian buyers. It is interesting to note that among the buyer groups with the highest interest in US condensate supply have been aromatic petrochemical producers—this despite indications that the Eagle Ford cargoes are highly paraffinic. What they have, and that buyers want, is much lower prices than traditional condensate imports from the Mideast. The relative economics of selling products versus selling modified condensate will also temper US export behavior, within newly modified rules.

6. Further Speculation on Known Unknowns

We believe that increasing US production of tight oil, condensate, and natural gas is providing US refiners with three fundamental advantages as exporters: less expensive feedstock; the ability to maximize light end product output; and inexpensive gas for process fuel. These three supports will solidify the US as important product exporter—perhaps the most important product exporter

[66] "Made in America,"*PIW*, July 21, 2014.
[67] "US Needs New Markets for Gasoline Surplus," *PIW*, August 25, 2014.

worldwide. The question remains whether modified condensate exports, and eventually crude sales, will follow the same pattern.

Improving shale technologies will eventually see other producers. We have detailed Argentina, but longer term there is the question of China. If Asia's largest market—and by the next decade likely the world's largest oil market—can supply a significant portion of its needs from shale development, this will prompt US exporters to rethink their long-term export strategy.

The common industry belief is that increasing US oil, gas, and NGL production will feed on its own success. Will world markets need or want a USGC-based marker? After decades of seeing WTI become ever more parochial in interest, it would be richly ironical if a future tight oil-based marker, such as Permian Shale Light would replace Brent as the general arbiter of global oil prices. Yet it is quite uncertain whether the world needs, wants, or requires such a price marker.

Just as hazy in a longer term is the question of whether strengthening fundamentals will convert the US into the price-setter for supply by refining the marginal barrel of light, sweet crude.

Chapter VII. Scenarios for the Medium Term

One of the basic assumptions of economics is that man is a rational animal and, when presented with full information and clear gain or loss from his choices, will always make the rational choice that will benefit his future prospects.

As questionable as that assumption can appear at times, even if accepted, it should be noted that modifying or abolishing the crude export ban is as much a political decision as one involving economics. While economics will play a major role in shaping future policy change, politics will be in the driver's seat for the immediate future.

If the German Chancellor Otto von Bismarck was correct in defining politics as "the art of the possible," we judge at this point it would be far too complex, depending on multiple political compromises, for this oft-judged archaic crude ban to be fully lifted. Even in a political climate

more attuned to compromise, this would be difficult. In the current climate of Washington gridlock we judge this highly improbable.

Further, anything that will be perceived as increasing gasoline prices would be the "third rail" for any politician foolish enough to touch it. Over the long months of research for this, we gradually came to the realization that our order of possible scenario for change should be reversed. While it is the least likely, because of political implications, we see a total abolition of the crude ban as the most logical. We detail this, therefore, first:

A. *Total Revocation of Export Restrictions Least Likely, but Most Logical*

Though we see total abolishment of crude export restrictions as unlikely in the medium term, the idea has both logic and economics as solid supports.

- The original petroleum export law, passed after the first oil shock of 1973-74 and strengthened after the second oil shock of 1979-80, reflects a reality that no longer exists. Rather than feeling a pinch of shortness in oil supply, we are drowning in a supply overhang.

- That original set of legislation was followed by a further law, which allowed oil product exports without limitations. Somehow exporting crude oil (including field condensate) was a national security risk, while selling oil product abroad was a commercial transaction. As Sam Goldwyn aptly phrased the oxymoron, "same difference."

- As the IEA has pointed out a number of times, the continuing US crude ban deforms international oil balances and mocks the common convention, held by both Democrats and Republicans, in a belief in the efficiency of free markets. While the simple existence of a looming crude overhang has calmed geopolitical jitters driving up the price of oil, often on very short-term and ultimately inconsequential geopolitical hiccups, the actual appearance of US condensate and crude barrels on international markets would create an enormous buffer of oil price stability—figuratively pouring oil on troubled waters. If the US could export base material as well as oil product, this would take the speculative edge

off much oil market price maneuvering. Reconnecting American oil with world oil supply/demand balances would likely have a stabilizing effect on world oil prices. Many do not realize that the vast majority of international oil prices are set using Brent as a price marker—a marker (though it now includes many other North Sea grades) that depends on a small volume (well less than 1 MM B/D) and on production that is rapidly declining.

- For those who rail against "speculators" (not realizing that they play an important and often positive role in commodities markets), there is the likelihood that unrestricted US oil exports would reduce backwardation of crude oil futures. Backwardation is when prompt prices for a commodity are below the expected future price for that commodity. Contango is when the future, or forward, price is higher than the prompt spot price of oil. Backwardation is favorable for investors holding long positions, hoping futures prices will rise.

- While we are not as bullish as many analysts in predicting a sustained rise in American crude prices, if exports were allowed without restriction, it is certain that crude prices would rise to world levels—but inversely world prices would also soften, as large volumes of additional supply became freely available. This would have a number of positive domestic impacts. First and foremost, the pace of expansion for US tight oil output should accelerate (putting aside the shale development as a manufacturing activity idea) and support the economics of developing what would appear to be only marginally economical fields. It certainly would improve the economics of robust and expanding production at tight oil developments such as Eagle Ford or Permian, likely raising our forecast levels at least moderately. Yet we emphasize that oil prices will find a new equilibrium, perhaps higher for crude that is now restricted in the US, but inversely reducing the international average price of crude by sharply expanding available supply in international trade.

- Among the sillier arguments that have been made in retaining export bans—or even extending them—were those by the petrochemical sector. Dow Chemical, a leading

petrochemical firm, argued that the export of NGLs from the US would make feedstock costs higher and cut into the profitability grassroots olefin plants, based on very inexpensive ethane, causing the possible cancellation of a number of projects. No company can be compelled—at least outside of command economies—to spend its money on profitless commercial activities. Dow could not recognize that this applies to upstream corporations as much as to petrochemical. This argument to restrict NGL exports runs counter to longer-term commercial logic: surely a petrochemical company investing a minimum of $8 billion in an integrated olefin complex would prefer having decades of somewhat discounted ethane—at least feedstock far less expensive than non-US competitors—rather than accessing only for a limited time heavily discounted feedstock that would cease within the medium term. We doubt if Dow, or any other company, would opt for a huge loss on a stranded asset. It is notable that only Valero among large US refiners has objected to a lifting of the crude ban—and perhaps it is because the company is strictly a US refiner, solely operating in the downstream. (For further details on this controversy, please see the Baker Institute's "NGLs in the Shale Revolution," April 2013).

- The oil sector could make better use of its current transport and storage infrastructure and there would be a boom in building new infrastructure to accommodate sustained crude and condensate exports. There is a strong suspicion among many downstream analysts that the pipeline and storage systems of PADD-3 refiners, particularly along the Texas and Louisiana coast, have been clogged up by refiners attempting to balance their slates by blending heavy (often imported) grades and light tight oil barrels. The huge amount of capital used for this could be put to better use.

- The US products export boom cannot be counted on forever. It was created in part due to the artificial constraint of being unable to export the base material of most oil products (LPG can come from gas field production as well as refining) and, as detailed earlier, there are signs of saturation in the Atlantic Basin for US products. Yet if crude and condensate could be exported, there is a likelihood that US refiners would concentrate solely on the products that recorded the best profit margins possible, rather than

converted crude wholesale into exportable product. APEC believes that US refiners—among the most operationally efficient in the world, running some of the most sophisticated refineries on Earth, relying at least in part on locally produced tight oil and using inexpensive natural gas for process fuel—would capitalize on their technical advantage and still dominate international markets, at least in the Atlantic Basin. Total volumes of product export may well fall slightly, but refiners will focus on what is most profitable, in the home market and in sales abroad.

- Without the need to accommodate ever growing volumes of discounted, but at times unsuitable, crude US refiners could pick and choose as to what medium-weight and heavy grades they would like to import, at the best price possible. Tight oil is mismatched with the current USGC refinery system—designed to run heavy and sour grades—and could easily attract premiums from countries looking to push out their own heavy crude production and import light and sweet grades, currently in the Atlantic Basin Mexico and Brazil. And since diesel/gas oil will be the arbiter of the demand barrel, at least through the medium term, fully utilizing the severe secondary units of USGC refineries residual and fluid catalytic crackers (R/FCC), cokers, and most of all hydrocrackers (HDC) to maximize middle distillate outturn makes economic sense.

- The macro-economic impacts would be tremendous, including increased employment in oil producing areas, as well as in the refining and infrastructure sectors; a sharp improvement in the US balance of payments, as imported crude has been a major item in federal trade deficits; increased US and state revenue from royalties and other forms of taxation, direct and indirect, and most of all a major and sustained boost to the current, though rather anemic, recovery that now spans five years.

- The key issue remains the price of gasoline. Will completely freed crude exports increase product prices or lower them? The average American believes cheap gasoline should be guaranteed as a constitutional right, plentiful, always available, and inexpensive. Two opposing viewpoints can be summarized in brief:

- The price bulls believe that a complete end to the crude ban will result in refiners paying much higher prices for their domestic feedstock; and refiners, attempting to defend their refining margin, will raise prices particularly for the transport fuels gasoline, diesel, and jet/kerosene (aviation fuel). If gasoline prices rise—at least for any sustained period—heads will roll in the political arena.

- The bears believe that recent market behavior has demonstrated the softening impact of increased US supply to world markets. Even indirectly, the growing overhang of US tight oil and condensate output already has moderated light crudes premiums in the Atlantic Basin. While domestic crude prices would rise, the flip side would be an increased impact on the level of international crude prices, particularly for light grades; witness the slow deflation of Brent prices over the course of 2014, despite continued geopolitical hiccups. The combination of free crude/condensate exports joining massive gasoline and diesel sales abroad would reduce international prices for transport fuels and keep any rise in US prices minimal. There would not be much incentive to refine gasoline to export, unless the difference in prices between the US market and foreign markets was great. They argue the famed third rail is not electrified; politicians can trip over it, but not be electrocuted. APEC believes that the bears' argument wins out: markets will rebalance and, if the evidence of the past 18 months shows anything, rather quickly.

- In any shift of regulatory policy there are winners and losers. We believe that US refiners—blessed with relatively inexpensive feedstock (even if it began to rise toward world price levels), long-term discounted process fuel, sophisticated plants, excellent support infrastructure, and capable management—will still be profitable, even with free export of US crude. Producers certainly would benefit, though the higher prices might not be quite as high as many now think. And if the change in regulation only allows an export of "modified" condensate, a scenario we detail below, it would remove a problem for the refiners, while give field producers an incentive to maximize the value of this output.

B. *Status Quo Ante?*

"So they go on in strange paradox, decided only to be undecided, resolved to be irresolute, adamant for drift, solid for fluidity, all-powerful to be impotent." Winston Churchill

We judge it unlikely that the *status quo ante* will remain, despite political gridlock in Washington.

Once the cat is out of the bag it is hard to get the animal back under full control. Whether this was a calculated move by the Commerce Department, in recognition of the growing overhang of tight oil clogging the US energy sector, or simply a decision by some middle level bureaucrat with little familiarity with a rather complex issue, mistakenly opening the gates to crude exports, is hard to determine. As pointed out earlier, history is made sometimes by mistakes, misunderstanding, and mistiming—and we tend to believe that a verdict of misadventure is most likely. Claims by government insiders that the law had not changed, but the implementation of the law could have changed, appear to back this surmise.

Many oil analysts believe that the Commerce Department now must retroactively build a scaffolding of logic to justify a decision made in error. Or as one independent phrased it: "It is rather like a pregnancy, where the woman claims to have remained virginal, but also pregnant—a sort of immaculate conception of decision-making."[68]

And there have been press reports that the Office of the US Trade Representative and the National Security Council have both held internal talks about potential free trade challenges to the crude ban from NATO allies and other friendly governments, such as South Korea and Mexico. The EU's Commissioner for Trade said in early September 2014 that oil and gas exports need to be freed up as a condition for confirming an FTA between the US and the EU.[69]

Since a re-interpretation of existing law is far easier, rather than abolishing the current law, we expect that the bureaucratic wiggle room inherent in enforcing legislation will give sufficient

[68] APEC private conversation with industry executive, August 2014.
[69] Timothy Gardner and Valerie Volcovici, "US considering options if oil export ban challenged," *Reuters*, September 17, 2014.

political cover to allow limited changes in how export regulations are applied. We do not believe that the Obama administration can put the genie back in the bottle simply by repeating, "There's been no change." The industry smells blood in the air and the time appears ripe for change.

C. *Limited Modification of Export Ban*

1. Redefining Condensate to Encourage Segregation and Export

If there actually was an active and coherent program to modify US crude export regulations, the question arises why BIS did not simply redefine field condensate or lease condensate as condensate. It would have been far simpler taking the route of implementing export regulations in a new and still not fully clear fashion.

This is made far easier by the government's definition of the origin and nature of condensate, which APEC fully agrees with: liquid hydrocarbons, suspended in gas reservoirs, at sub-surface temperature and pressure. The logical incongruity in the government application of regulations was to then define field (lease) condensate, where the NGL precipitates naturally out of the gas stream or condenses, versus condensate actively stripped out of the gas, plant condensate, or natural gasoline. But rather than take this easy, administrative approach that would have generated less controversy, BIS chose to add some new mysterious element to its definitions of what constituted processing.

2. Allowing Swaps

Also puzzling has been the lack of interest, let alone progress, within the Commerce Department to multiple suggestions on improving flexibility for potential crude swaps, particularly with NAFTA neighbor Mexico. This is what mathematicians would call an elegant solution, allowing both the US and Mexico to meet national security needs by swapping light for heavy oil, with some mechanism of compensation in cash or kind.

3. Extending Limited Crude Sales to All Free Trade Treaty Partners

Another measure that could have eased the currently building tight oil overhang would be extending limited crude sales to free trade agreement (FTA) partners by executive order, citing the expressed presidential authority to allow this as a matter of "national security." Despite

congressional calls to explore this approach, prompted by the recent crisis in the Ukraine, it appears little groundwork has been done. This initiative would have the added benefit of making a broad-based US/EU FTA quite attractive to the European side concerned about potential curbing of oil supply from North Africa, or more recently, Russia.

In the end we believe that the Commerce Department will move to simply justify its previous decisions. Therefore, let us detail the impacts of a modified condensate only easing of export regulation. A change to allow lease condensate exports benefit both Gulf Coast producers and refiners. Initially we thought this would only occur after the November 2014 mid-term elections, even though pressure has been building rapidly for the government to act to define what constitutes processing.

D. *Impacts of Increased US Modified Condensate Exports*

1. How Much? How Soon?

As detailed earlier, we have had to make some basic assumptions in trying to gauge the probable range of potential condensate exports under the current policy of allowing modified field condensate.

Our basic assumptions in our outlook for exportable processed condensate are:
Initial exports have begun from US PADD-3. All have been from Eagle Ford and will be supplemented by Permian field production and possibly output from other developments. We have assumed, though, for now only Eagle Ford and possibly Permian field condensate as the base for potential export. Eagle Ford output alone could provide roughly 534 MBD in 2014, about 800 MBD in 2016, and up to 968 MBD in 2018. The two could provide base supply of about 1,050 MBD by 2016.

- Yet that is only the first step. The next stage in quantifying export volumes is identifying larger, more sophisticated stabilizer complexes that could be converted with relative ease to add the BIS-required extra step of "processing," though we still have no official definition of what that consists of. Pioneer, Anadarko, and ConocoPhillips alone in Eagle Ford operate at least 220 MBD of stabilization capacity and we have total Texas

stabilization capacity of up to 350 MBD. Let us assume that about half or slightly more of that 350 MBD in stabilization capacity can be converted to BIS-compliant standard within 18 months, i.e., as of January 2016. That would allow for maximum export avails of 175-200 MBD by January 2016.

- The next step would be logistics and support infrastructure. Dredging has not been completed yet as planned for the Corpus Christi harbor and while enormous volumes of new storage are under construction, condensate must compete with tight oil and refined product shipments form USGC ports in Texas. If we assume that cargoes will move in lots of 35,000 DWT (290 MB) to 50,000 DWT (415 MBD), this would require about 225 separate shipments to cover 175 MBD at the smaller cargo size and 154 shipments at the larger, 50,000 DWT lot size. That is a lot of traffic for a relatively small port to handle.

- We think that sellers could meet this goal of 175 MBD in exports with the completion of new infrastructure, allowing for more efficient shipping and bigger average sales cargoes. So we have assumed that there will be a relatively small volume of modified condensate this year—in 2014, roughly eight cargoes at an average size of 500 MB, or a total volume of only 11 MBD, building to perhaps 100 MBD in 2015, and reaching 175 MBD by 2016. While there will be more than enough condensate avails to increase exports to over 175 MBD post-2016, we cannot predict with any exactitude what condensate export volumes will be. This will be dependent on the call on Texas condensate by local splitters, which will draw a substantial volume of field condensate output into their processing, as well as relative prices; US field condensate versus international average; and the netback value of a barrel of Eagle Ford condensate fully distilled in a splitter versus its export value as a base material. We have assumed an export volume range for modified condensate of 250-375 MBD by 2018 and 450-600 MBD by 2020. So if we take the midpoint values for 2018 and 2020, we get the following modified export volumes:

Table 37. Modified US Condensate Export Volume (In MBD)

Case	2014	2016	2018	2020
Low	9	100	250	450
Base	11	175	300	500
High	15	225	375	600

2. Impacts

The impact on limited-volume processed condensate exports will include:

a. A New Ying/Yang?

We have detailed how US condensate would naturally be drawn to Asia Pacific, particularly once the Panama Canal revamp is completed, pushed by the American structural overhang of supply and pulled by Asian needs for petrochemical feedstock and condensate as a proxy for light crude. We characterize this process as an emerging yin/yang of opposite and complementary trends. A second pull center for light feedstock is emerging in Latin America, as at least three crude producing countries—Mexico, Venezuela, and Argentina—have said they are considering importing light cheap crudes in an effort to cap rising products imports. What is astonishing is that Mexico and Venezuela, long standard-bearers of crude self-sufficiency, see little other choice in avoiding soaring product imports.

b. If Only Condensate Exportable

If the Commerce Department insisted that processed condensate is exportable—though black oil, run through the same *l*ight processing remained banned from sales abroad—this would shift some development to wet gas in the condensate window in some basins, notably Eagle Ford. How much impact it would have remains uncertain, but in tight oil developments, where increasing field condensate output is a parallel option, at least some upstream operators will shift their chips from black oil to condensate. This may cap, or even possibly reverse, the shift from targeting oil-rich rather than gas formations. Baker Hughes' statistics showed that oil-targeted rigs as of January 2009 totaled fewer than 400, but by August 2014 nearly quadrupled to more than 1,500; in the same time frame, gas-oriented drilling saw the number of rigs fall from 1,300 to 300 units.[70]

[70] "Oil Market Feels Full Force of US Boom," *PIW,* September 1, 2014.

3. Among the Benefits

a. Macroeconomic Bonus

Even a limited-volume export of processed condensate— say 175 MBD by 2016—will vastly increase federal and state government revenue, raise employment, and reduce the federal budget deficit and the national trade deficit. Further, it will attract substantial sums in the short- to medium-term in investment in additional midstream pipelines, storage, and port infrastructure and a mini-boom in revamping stabilization units into condensate processors.

b. Easing the Pressure

Price pressure is building on the entire light-end spectrum of oil products and will likely create a downward pressure on this part of the products market. Sales of condensate will ease the impact of a further surge of light products expected from up to a half-dozen Texas-based condensate splitters. Further, these barrels will replace, in part, reduced crude exports from the Mideast. The IEA in mid-2014 forecast that crude exports from that region to OECD countries, mainly Europe (though significant volumes to Japan), will decline by 1.4 MM B/D, 2013-19. And since global trade in products is growing, while sales of crude and condensate is falling, exporters may find selling a base material more profitable than a finished oil product. The IEA in this same report predicts that trade in crude/condensate will fall 1.1 MM B/D from 2013 through 2019, despite increased global oil demand.[71]

c. Reduce European Dependence

While the European recovery will take some further time and it is likely that further refineries will close, the EU will still need refinery and petrochemical feedstock. Europeans have been concerned about sanctions disrupting Russian crude supply and would like to lessen, if not overturn, its dependence on increasingly unstable Mideast oil supply—particularly from the Maghreb (Libya, Egypt, and possibly Algeria). APEC has assisted European petrochemical companies in securing US NGL feedstocks and we believe that there would be far more interest in the EU in US condensate exports than many analysts gauge. Supply, even of limited volumes of processed condensate, would be an additional incentive for the EU to sign a free trade agreement with the US as well.

[71] "Products Make Gains in Global Oil Trade," *PIW* July 21, 2014.

c. Strengthen Asian Business Ties

While the pace of demand growth will slow, it is likely that Asia Pacific will continue to lead world markets in incremental oil demand. Condensate fits into Asian feedstock needs exceptionally well. Condensate sales could reduce the US trade deficit, while ever more closely binding the two regions' economic interests together. This is particularly true for the Sino-American economic relationship.

d. Impact on US Refiners Mixed

While Valero has been vociferous in its protests on allowing exports, other refiners, particularly integrated majors, have had a more balanced position. Condensate sales will reduce the average API of tight oil. This would increase the medium-weight black oil available to domestic refineries at a modest discount to international price levels. Further, the more sophisticated refiners, who market abroad as much as in the US, believe that discounted crude alone is not their main advantage in product sales; operational efficiency and alert marketing, domestic and international, also play a role. Majors have a role in marketing condensate, even if they are not among the top producers of tight oil. It is notable that Chevron had a hand in finalizing the first condensate sale abroad to its Korean associate, GS Caltex.

e. National Security

We believe that condensate exports will open the door to crude/condensate exchanges, first with Mexico, and possibly later with all FTA country/markets. Even limited condensate sales offer some alternative supply to US allies and partners, as illustrated most recently by the looming threat of a Russian energy embargo of oil and gas supplies to the EU. More broadly, the ability of the US to supply, on relatively short call, large volumes of condensate (and eventually crude) exports reduces the threat implicit in Russian talk of energy embargoes. Further, since US exports of gas, NGLs and refined products have helped to stabilize the international price of oil, we would expect that adding processed condensate further would increase world supply and price stability. Shell CEO Ben van Beurden underlined the point in September 2014, stating that a gradual lifting of the crude ban would make the global energy system and prices more stable.

f. Deflating Oil Exporters Influence

Even limited condensate exports have begun to impact the stranglehold that the Mideast Gulf has long held over East Asia. If expanded, or extended, to crude the net result will be a reduction of OPEC influence and the organization's ability to set oil prices. Furthermore, for a potential re-emerging strategic foe—such as Putin's Russia—stable, possibly softening international oil prices, prompted by US exports, will both reduce that country's main exports earner, while weakening the value of the ruble.

4. Structural Shift in World Oil, Gas and NGLs

Even for OPEC, the news is not totally negative. The grouping's top oil exporter, Saudi Arabia, has concluded that the US shale revolution, including increased US exports, will have positive impacts, even as exports expand to condensate and possible future oil sales. Ibrahim al-Muhanna, a senior advisor to the Saudi Ministry of Petroleum, detailed the impacts as including:

- Diversification of world oil supply keeps oil markets calmer when there are bouts of geopolitical instability. The US will provide more depth and range to world markets and overall act as a "stabilizing" influence.

- Stabilizing prices also increases consumers' sense of security, particularly as the major developments in the shale revolution, most of all in the US, are far outside the direct impact of Mideast political instability.

- Tight oil has established a global floor price of $60 to $80/BBL. This floor can neither be easily disrupted by geopolitics nor by high-cost oil producers, OPEC, or non-OPEC.

- Longer term, tight oil drives out marginal, high-cost oil producers, particularly non-OPEC developments and oil projects in high-cost, high-risk zones such as deep offshore and in Arctic weather conditions.

- The creation of a steady, long-term floor price allows for investment planning long term for oil, gas, and NGLs.

- For Saudi Arabia, which claims tremendous shale gas and tight oil prospects, the US experience shows the way toward future development and the long-term maintenance of the kingdom's role as a major oil producer.

- Most important, the emergence of tight oil has finally crippled, if not killed off, the peak oil theory. Peak oil advocates had long underestimated the impact of technology and upstream improvements in operational efficiency. Tight oil's success has shown how this misjudgment has come back to wound, perhaps fatally, the peak oil theory.[72]

Conclusions

- The shale revolution rumbles on, with the continuing rise of tight oil production, the latest facet of the phenomena to reshape world oil markets. What has become increasingly evident in the rising flood of light, sweet crude is that the long-standing, near-total US ban on crude and condensate exports has become a political, economic, and commercial anachronism.

- The decision in June 2014 by the regulatory bureau BIS of the US Department of Commerce to allow for the export of "lightly processed" condensate has let the cat out of the bag. While the Commerce Department has been slow in attempting to explain the seeming contradictions between current policy, such as it is, and past, it has become increasingly evident that condensate exports will emerge as the fourth wheel to exports of natural gas, NGLs, and refined product, with global impacts.

- Whether the change on interpreting export regulations was purposeful or accidental remains unknown. Nor has the extent of the new ruling been yet revealed to the public. The Commerce Department insisted it applied solely to condensate, not black oil, but

[72] Ibrahim al-Muhanna, senior advisor to the Saudi Ministry of Petroleum, "Why Saudis like Shale Boom," as printed in *MEES,* March 7, 2014.

even if only "slightly processed" condensate is regularly exported, it will begin to reshape world oil markets.

- Within the US upstream we expect an enormous and continuing boost for tight oil basin development—with a parallel emphasis on separating, segregating, and exporting field condensate—once processed in a manner to make it BIS-compliant. The impact will be felt most immediately and strongly in Texas, where Eagle Ford tight oil output already had contained a high proportion of field condensate, roughly in the range of 40% in 2013-14, yet other basins, notably the Permian, will also benefit from the proximity to USGC ports. The export of a base material for refining, rather than refined products themselves, will allow US crude prices to rise to world levels, though in the longer-range outlook, would also mean the softening of global crude prices, particularly for light sweet crude and condensate.

- While some US refiners have complained that any easing of the export ban would make their feedstock costs become too expensive, many have realized there is opportunity as well as challenge in this shift. With a portion, perhaps a significant portion, of Eagle Ford condensate separated from the crude pool, the average weight of Eagle Ford black oil will increase, making it more a mid-weight grade rather than a light to ultralight grade. This will provide a feedstock to USGC refiners—which make up the largest portion of the US refining industry—more suitable than the light and ultralight tight oil previously purchased. The mismatch between rising tight oil output and what refiners need to use their plants to full capacity, has been a continuing downstream worry in recent years.

- Less clear is the future of the many USGC condensate splitter proposals. Since the public still remained (as of August 2014) in the dark as to what "slightly processed" condensate meant, investors have been trying to decide whether to go ahead with original plans, or see whether less expensive processing plants could be built to meet the new export standards. Of the roughly dozen or so more serious projects, we expect five, possibly six, splitters to be completed regardless, by end-decade. The first of this new wave of

downstream processing, the Kinder Morgan/BP project near Houston, will start up by end-2014.

- The macroeconomic benefits of a continued—and amplified—shale oil and gas boom cannot be underestimated. Oil product exports and reduced crude imports have already made a substantial dent in the US balance of payments deficit. Shale development has increased employment in many states, while the infrastructure, services, construction, and manufacturing sectors all will be boosted by the sector surge. Federal and state tax revenues have increased and will grow faster as production and exports continue to rise, and the sector's growth will help reverse the slowing national economic growth rate.

- Condensate by definition is light and low in sulfur. Even before the June 2014 rulings, tight oil was impacting international crude oil flows and pricing. The US has had a substantial impact already with the backout of over 2 MM B/D of crude imports. This backout pushed exports from Libya, Nigeria, and Algeria into a search for new markets. It has weakened the global crude benchmark Dated Brent into a deep contango, discounting prompt barrel sales in relationship to future, while the gap between Brent and US marker WTI has narrowed significantly.

- US crude backout has begun to pressure Mideast crude exporters, as light barrels from the Atlantic Basin have moved increasingly to Asia Pacific. The sale of condensate—note that the first cargo went to a South Korean buyer—poses a more direct marketing threat to Mideastern sales. Further, condensate, together with the backout of crude, are remaking light/heavy, sweet vs. sour price deltas.

- Condensate exports have another, more subtle benefit of diversifying sales abroad away from mainly refined products. The Atlantic Basin appears to be near saturation for US light products and, until steady recovery gets underway in Europe and Latin America, it will have only a limited ability to absorb incremental volumes. Condensate as a base material produces the full range of refined products from LPG to fuel oil and is the only NGL to do this. US product exports as of mid-2014 rose to 3.7 MM B/D, up from 2.9

MM B/D. Selling a refining feedstock rather than a refined product may prove, at least in the medium term, more profitable.

- The revamping of the Panama Canal—officially set for end-2015, but more probable by 2016-17—will be the game-changer on US condensate's market impact. We noted in the April 2013 Baker Institute study "NGLs in the Shale Revolution" that the structural overhang of NGLs in the US, together with Asia Pacific's need for light feedstocks and desire to lessen dependency on Mideast supply, were forming a complementary yin/yang with the push from the US market—now greatly enhanced by the ability to export field condensate—mirrored by Asia's pull of this material into the great growth engine for oil demand. While the rate of demand growth in Asia Pacific will likely slow through end-decade, it is just as likely to remain the global demand growth leader. And the US has entered the race exporting LNG, refined products, other NGLs—and now condensate.

- Seismic geopolitical shifts will emerge from the changes in US export policy. If exports stabilize—and that eventually will soften global world prices—the geopolitical weight of possibly destabilizing exporters, such as Russia, will be reduced. Even OPEC, while vital to world oil supply, will see its geopolitical heft somewhat diminished. Oil prices will likely stabilize and consumers will be greatly assured by the emergence of alternative supply to exporters whose political stability has become increasingly questionable.

- The longer term big picture is that the US, followed by North American neighbors Canada and eventually Mexico, will challenge the Mideast exporters to capture the future energy needs of the still-growing Asia Pacific. Only North America has the size, the geologic reserve potential, the political stability, the capital, and the technology to challenge the Mideast for Asian market supremacy. And lower, more stable energy costs may be the spur needed to kick the global economy into a faster pace of economic expansion. This ultimately may well be the story of the 21st century.