Energy Economics and Technology *June 30, 2018; corrections Aug. 9, 2018*
AAPG Energy Minerals Division Committee
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The current era of the United States' energy abundance enabled by the family of "fracking" technologies (horizontal drilling and geosteering; hydraulic fracturing and high pressure pumping; and many additional innovations) has brought enormous benefits to energy consumers around the world, has had mixed impacts on the profitability of producers and oilfield service companies, and has enabled executives and policymakers – sheltered by the experience and prospect of low costs – to turn toward natural gas and renewable generation with little political backlash.

The Committee's annual reports have tracked these developments, underscoring (in last year's report) how astonishing it is for the nation to find itself so far removed from the era of profound scarcity that characterized the 1970s. At the doorstep of the shale revolution, natural gas prices (Henry Hub spot) exceeded $5.00 per million Btu from 2003 to 2008, averaging $7.09 per million Btu over these six years and exceeding $6.00 as recently as December, 2008. This period extended "demand destruction" by 2.4 billion cubic feet per day in fertilizer, petrochemical and other industries, a process that cumulatively shrank industrial demand by 5.1 billion cubic feet per day by 2007 and 2008, or 22 per cent below its high point in the late 1990s. High oil prices (and oil products, gasoline, jet fuel, etc.) in the neighborhood of $90 per barrel or higher, extended from November 2010 to October 2014[1] . Against this backdrop, the Committee delineated (two years ago) the financial savings experienced by consumers from heightened production of natural gas and oil in 2015. Oil had by far the greatest financial reach in volumes and geography, including driving down global liquefied natural gas (LNG) prices. This preceded any direct effects of US LNG exports which began in 2016.

Rather than belabor the extraordinary and, from a consumer's point of view, financially beneficial impacts of heightened production of oil (and natural gas), it now appears as of mid-2018 that US shale oil's impacts have largely become "built into" the psychology of oil pricing, whereas a year ago analysts and headlines still focused on the tsunami of US shale oil. While US oil production exceeds 10 million barrels per day and breaks historic records, the shock of US shale oil is becoming part of the fabric of price expectations, allowing a return to "normal" where other considerations, such as a geopolitical premium linked to Iran or Venezuela and global economic uncertainty linked to US trade moves, are reasserting their influence.

[1] This is the long plateau of high oil prices, as contrasted with the commodities supercycle or spike which crested in mid-2008 and collapsed with the Great Recession.

Admittedly, the trade moves are not "normal" and countermoves may have direct impacts on energy trade and investment, yet the point here is that the shale boom is no longer the principal story to which markets are adjusting.

Reviewing the past 18 months, this article **(1)** summarizes a few of the top developments in US oil and gas supplies, **(2)** examines the timing and extent of changes in the electric generation mix – where renewables through a combination of improving costs/performance and favorable subsidies are making substantial inroads – and **(3)** updates our monitoring of price uplift seen in the international coal trade. The changes taking place in the electric sector will draw attention, in particular, to developments in California and Texas. Their past, present, and future offer insight into the competitiveness of gas-fired generation where policies are permitting or encouraging wind farms, utility-scale solar, and batteries. Natural gas is also being seen within parts of the environmental community as a competitor to alternative technologies, raising the prospect that its trajectory may become a political football in addition to facing real competition of the type seen in California and Texas. Finally, giving texture to the non-shale or "normal" influences on oil prices, the article **(4)** presents a scenario of plausible developments in leading countries which underpin a $100 per barrel future. This is not to say $100 per barrel is around the corner or is supported in the futures markets, but the exercise helps us appreciate the normal turmoil influencing oil.

Top Developments in U.S. Oil and Natural Gas Supplies

The trend in US oil production since January 2017 is presented Figure 1. This is EIA's June 4, 2018 compendium of its own data streams and short-term forecast.

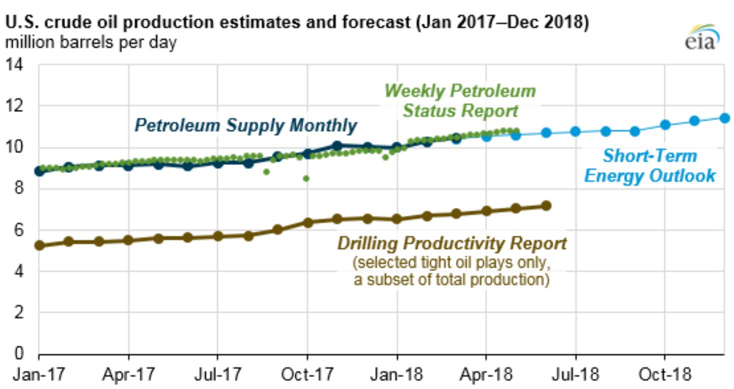

Figure 1. EIA's Estimates of US Crude Oil Production, 2017-2018.
Source: EIA "Today in Energy: EIA reports track U.S. crude oil production statistics and trends", Jun4 4, 2018. EIA data sources are *Petroleum Supply Monthly* with data for March 2018; *Weekly Petroleum Status Report*, with data for the week ending May 25, 2018; *Short-Term Energy Outlook*, May 2018; *Drilling Productivity Report*, May 2018.

Crude oil production grew from 8.77 million barrels per day (mmb/d) at the close of December 2016 to 10.81 mmb/d eighteen months later (EIA Sho*rt Term Energy Outlook* for June, 2018). That's a phenomenal 23% increase in eighteen months. Since November, monthly production levels have exceeded the historic peak of 9.94 mmb/d set in December 1970. Seventy-three per cent of the growth spurt over the eighteen months occurred after August 2017.

The lower curve in Figure 1 represents production from the major tight oil and shale plays, reported in EIA's Drilling Productivity Reports (DPRs. Those include some small amount of conventional oil production in these regions. Their production and growth are summarized in Table 1. Their share of US oil production was 59% in December 2016 and 66% in June 2018. They accounted for virtually all of US 2 mmb/d production growth. And of all the regions, it was the Permian that drove the lion's share of growth over this recent period (58%).

Table 1. EIA DPR Regions Oil and Natural Gas Production and Growth, Dec. 2016-June 2017

	Oil (1,000s b/d)				Natural Gas (Bcf/d)			
	Dec-16	Jun-18	Change		Dec-16	Jun-18	Change	
Anadarko	**399**	**524**	125	31%	**5.65**	**6.60**	0.95	17%
Appalachian	**81**	**114**	33	41%	**22.87**	**28.15**	5.27	23%
Bakken	**957**	**1,238**	282	29%	**1.56**	**2.28**	0.71	46%
Eagle Ford	**1,167**	**1,387**	221	19%	**5.96**	**6.87**	0.90	15%
Haynesville	**44**	**42**	(2)	-5%	**5.74**	**8.74**	2.99	52%
Niobrara	**410**	**596**	186	45%	**4.43**	**4.99**	0.57	13%
Permian	**2,114**	**3,277**	1,163	55%	**7.37**	**10.50**	3.13	43%
Total DPR Regions	**5,171**	**7,179**	2,008	39%	**53.58**	**68.12**	14.54	27%

Top Regions Share of Growth in Oil Production		Top Regions Share of Growth in Nat Gas Production	
Permian	58%	Appalachian	36%
Bakken	14%	Permian	22%
Eagle Ford	11%	Haynesville	21%
Niobrara	9%	Anadarko	7%

On the gas side, also shown for these regions, the Appalachian region (combines Marcellus and Utica), Permian and Haynesville are the top producers. The newly reported Anadarko region, combining the SCOOP/STACK plays of Oklahoma, the Woodford, Granite Wash and other formations, is in fourth place (announced August 15, 2017, Tod*ay in Energy*: "EIA's Drilling Productivity Report adds Anadarko region, aggregates Marcellus and Utica"). Associated gas out of the Permian now rivals the Haynesville, second only to the massive Appalachian plays.

EIA's DPR natural gas statistics offer a somewhat different picture from EIA's official shale gas statistics. The latter, provided by DrillingInfo, Inc., are not derived from EIA surveys and have somewhat different geographic coverage. Despite some uncertainty as to reporting dates, the growth since the end of December 2016 from Drillinginfo, Inc. is a similar story. Total shale gas grew a robust 9 Bcf/d or 21%, from 43 to 52 Bcf, as of the end of March or April 2018. Ninety-two percent of this growth was from the Marcellus and Utica, Haynesville and Permian shales. As a share of total dry marketed production of 85.5 Bcf/d for March, 2018, the shale gas total is 61% (Drillinginfo data) to 76% (DPR regions). Either way, the share is large and the growth out of the Permian represents a special kind of "threat" during times of a gas glut, as Permian gas is driven largely by oil-drilling economics and will follow the fortunes of oil market drivers and brakes.

Numerous economic analyses, executives and news reports point to the Permian Basin's multi-faceted problem of:

(1) Too much oil too soon, running up against oil pipeline "takeaway" capacity limits and leading to curtailments. The crunch will appear before the end of 2018, according to the CEO of one of the Permian Basin's top producers, Pioneer Natural Resources: "The Biggest U.S. Oil Patch Is Near Its Limits", Bloomberg, by Javier Blas, June 20, 2018. The company cited current production of 3.3 mmb/d, as also shown in Table 1's PDR for the Permian in June 2018, against a region pipeline capacity limit of 3.6 mmb/d. The consequence would be further tanking of the Midland to WTI (Cushing) price differential to as much as -$25 per barrel. Interestingly, Bloomberg reports that some companies have resorted to loading crude into trucks to get it to uncongested pipelines.

(2) Too much associated natural gas production. Aggravated by the region's price-indifferent associated gas is today's "lower for longer" view of natural gas prices (e.g. average NYMEX Henry Hub futures price of $2.79 for the months of 2019, reported in EIA June *Short Term Energy Outlook* or *STEO*; EIA *STEO* forecast of a nearly flat $3.08 for the same year, and EIA *Annual Energy Outlook 2018* average spot prices below $4.00/mmBtu through 2024 and below $4.50 through 2040). Gas pipeline "takeaway" capacity again presents a problem, with additions of about 7 bcf/d additional capacity across at least four pipelines not expected to come into service until late 2019-early 2020 (e.g., Gulf Coast Express, Permian-Katy, Pecos Trail and Permian Global Express, per EIA Natural Gas Weekly {NGW], March 28, 2018 and December 6, 2017). EIA points out that these are designed to serve new petrochemical facilities in Texas, LNG exports, and exports to Mexico, yet until they materialize, downward pressure like that seen for oil differentials will depress Waha-Henry Hub differentials. These reached -$1.03 per million Btu in June, 2018 (EIA NGW June 14, 2018).

    The problems don't stay in Texas. Our contributor and natural gas/energy analyst Stephen L. Thumb had tracked the Permian phenomenon and its implications from the beginning, coining the term "Battle of the Titans". He refers to Permian gas attempts to work its way north and east, anywhere but California (whose historic growth prospects have become limited by anti-gas pro-renewables policies), and Marcellus/Utica gas attempts to work its way south and west. A sign of this battle is the financial consequence for company valuations, e.g. "Side Effect of Rising Oil Drilling: Indigestion for Gas Frackers", *Wall Street Journal*, June 13, 2018, by Christopher M. Matthews. Through most of the first half of 2018, oil producers in the Permian have seen their valuation climb about 15% while gas producers in the Marcellus have been down about 15%, according to Matthews.

Summary of Oil and Natural Gas Production Trends from Major *Drilling Productivity Report* Regions

In charts, Figure 2.

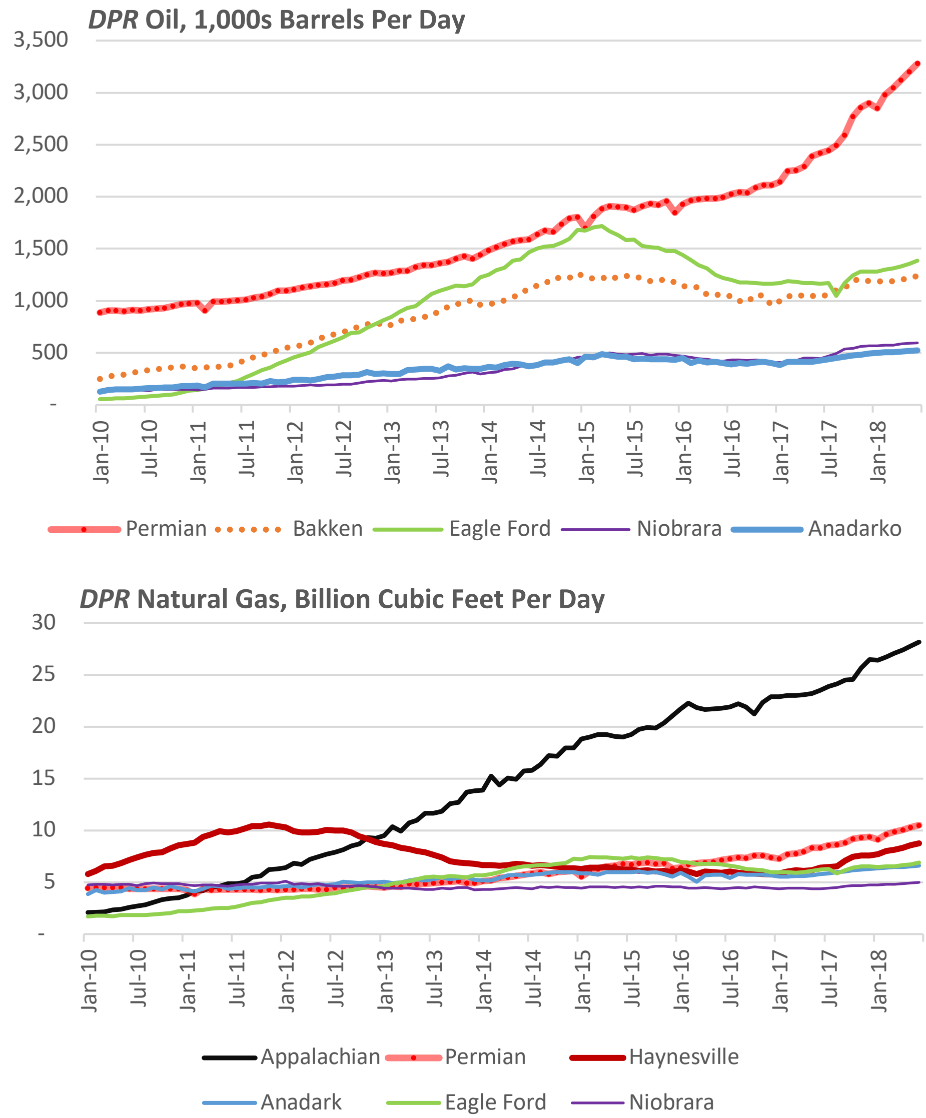

Figure 2. Production Growth, Principal Tight Oil and Shale Gas Regions, 2010 through June 2018

U.S. Electric Sector Generation Mix: Coal vs. Natural Gas vs. Renewables

The recent surges in renewables (especially wind generation over the past decade) and long climb of natural gas generation, largely at the expense of coal-fired generation, are shown in Figure 3. Covering the period 2001-2017, this EIA chart serves as a backdrop to more focused regional developments (EIA To*day in Energy*, "Electricity generation from fossil fuels declined as renewable generation rose", March 20, 2018, by Owen Comstock). Delivered costs of natural gas to the electric sector are added, highlighting the $4-6 per mcf band.[2]

[2] Reported costs except for 2018 which is based on EIA's *Short Term Energy Outlook* of June 23, 2018. Historic prices using EIA's US GDP Deflator.

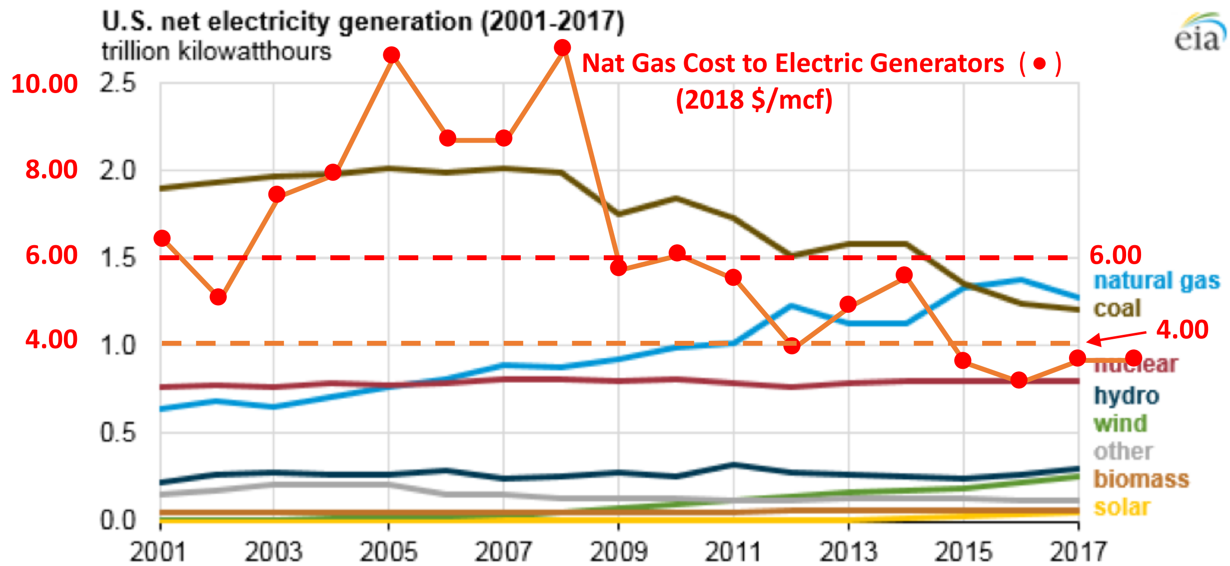

Figure 3. Electric Generation Mix Since 2001 with Electric Sector Delivered Natural Gas Costs

Coal generation's historic decline did not take off until the Great Recession. From 2008 to 2017, it dropped from 1.99 to 1.21 trillion kilowatt hours (TkWh, also "terawatt hours") or 39%. Not surprisingly, coal consumption for electric power generation fell 36% from 1.04 to 0.66 billion tons, setting the stage for ongoing acrimony in the U.S. over whether and how to preserve coal mining jobs, coal-fired power plants and nuclear generating stations. Local power plant measures, touched upon in the Committee's write-up in mid-2017, had been adopted in New York and Illinois and were pending in a handful of other states. Solutions are just as elusive by mid-2018, yet vastly more attention and analytical resources have been devoted to the matter over the past twelve months.

Significant developments have included: (1) The Department of Energy's "Grid Resiliency Pricing Rule", published in the Federal Register on October 10, 2017 as a Notice of Proposed Rulemaking, which argued that "grid resiliency" was the appropriate rationale to the tradition of market-based pricing in the electric sector.[3] It was rejected by FERC on January 8, 2018, finding the DOE could not demonstrate that rates and tariffs were "unjust or unreasonable" nor that retirements posed "a threat to grid resiliency".[4] (2) Subsequently, a National Security Council memorandum[5] leaked to the press argued that measures were needed to protect "fuel secure" plants on national security grounds[6], naturally raising questions of whether the pipeline network was particularly vulnerable to disruptions. This had been addressed almost a year earlier by the

[3] Federal Register: https://www.federalregister.gov/documents/2017/10/10/2017-21396/grid-resiliency-pricing-rule
[4] "FERC Rejects DOE's Proposed Grid Resiliency Rule", Power Magazine, by Sonal Patel. January 8, 2018. https://www.federalregister.gov/documents/2017/10/10/2017-21396/grid-resiliency-pricing-rule
[5] Leaked memorandum: https://www.documentcloud.org/documents/4491203-Grid-Memo.html T
[6] Bloomberg: "Trump Prepares Lifeline for Money-Losing Coal Plants", by Jennifer A. Dlouhy, May 31, 2018. https://www.bloomberg.com/news/articles/2018-06-01/trump-said-to-grant-lifeline-to-money-losing-coal-power-plants-jhv94ghl

Natural Gas Council.[7] (3) The ensuing firestorm included a response from the American Petroleum Institute, which absorbed the American Natural Gas Alliance on January 1, 2016, questioning the diagnosis and remedies.[8] (4) The Interstate Natural Gas Association of America declared natural gas was being "scapegoated".[9] (5) The Pennsylvania, New Jersey and Maryland Interconnection deemed market intervention in the name of reliability unwarranted.[10] Notably, all five members of the Federal Energy Regulatory Commission turned down this characterization of energy infrastructure risk before the Senate Committee on Energy and Natural Resources.[11] A recent summary of this activity was issued by RBN Energy on June 21, 2018.[12] The drama is not over and the direction of policy as of the end of June, 2018 remains undecided. A deeper dive into testimony and filings than possible at the time of writing may yield credible cost estimates of selective market intervention, whereas cost estimates on the order $15 billion per year appear to be motivated to make the strongest possible "case" against such measures.

Coal's trend after 2011 is almost a perfect mirror-image of gas-fired generation. April 2015 was the first month that gas-fired generation exceeded coal generation. Gas-fired generation since 2001 almost precisely doubled from 0.64 to 1.27 T kW, while consumption increased only 70% to 16 Bcf/d. The explanation is stunning efficiency gains -- heat rate improvements – across gas-fired units from above 10,000 Btus per kilowatt hour to nearly 8,000 Btus/kWh over this period.[13] Concerning renewables generation, particularly important now in Texas and California, their growth since 2008 has been quite rapid, reaching 0.25 T kWh in 2017.

It is the daily economics of production that drive coal-gas competition, as measured by output from different sources, namely the "generation mix". This is different from the competition between new capacity investments or retirements, i.e, megawatts rather than megawatt hours. Even with the scale and simplifications of Figure 3, weather episodes stand out. Weather exerts a strong influence on demand, gas prices and thus gas vs. coal-fired generation in certain years, especially 2012 and 2015, reflecting the mild winters of 2011-2012 and 2014-2015. The latter led to extraordinarily low natural gas prices from 2015 onwards (e.g., 2015 brought the lowest natural gas prices ever experienced since 1999). In the opposite direction, the "Polar Vortex" of Jan-Feb 2014 and extreme cold through March in the northeast, midwest and southeast flattened coal's decline and natural gas generation's climb in that year.

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[7] Natural Gas Council, *Natural Gas Systems: Reliable and Resilient*, July 2017. https://www.ngsa.org/download/analysis_studies/NGC-Reliable-Resilient-Nat-Gas-WHITE-PAPER-Final.pdf

[8] API Press Release: "Broad Energy Coalition Condemns Action to Subsidize Failing Coal, Nuclear Plants", June 1, 2018. http://www.api.org/news-policy-and-issues/news/2018/06/01/oil-wind-solar-condemn-action-to-subsidize-failing-coal-nuclear-plants

[9] INGAA Press Release: "INGA 'deeply troubled' by Trump administration plan to punish natural gas", June 7, 2018. http://www.ingaa.org/News/PressReleases/34641.aspx

[10] PJM Statement on Potential Department of Energy Market Intervention: http://www.pjm.com/-/media/about-pjm/newsroom/2018-releases/20180601-pjm-statement-on-potential-doe-market-intervention.ashx

[11] *Houston Chronicle*: "Senators, FERC commissioners question coal, nuclear bailout", by James Osborne. June 12, 2018.

[12] RBN Energy: "Why Can't We Be Friends? – Widely Varied Interests Coalesce Against Coal and Nuclear Bailouts", by Rick Smead. June 21, 2018.

[13] EIA *Today in Energy* "Electric power sector consumption of fossil fuels at lowest level since 1994", by Sara Hoff and Jason Winik. May 29, 2018.

High natural gas prices characterized most of this history. For several years after the 2009 price collapse and Great Recession, electric sector costs still averaged about $6.00/mcf, a major improvement (from a customer's point of view). The new "lower-for-longer" period did not start in earnest until 2015 – something we can only say with the wisdom of hindsight – seemingly nailed into place by shale's growth and, as we've discussed, the added weight on prices of associated gas production.

Texas and California – The Forefront of Renewables Generation

1. Past and Present

Texas and California are the first and fifth largest states in electricity generation. We review their past and present before turning to some indications of what further disruptions lie in store in the future. Of particular interest are the technological drivers of the renewables revolution, a counterpart to the shale revolution, and how this second kind of "Battle of the Titans" (shale technologies vs. renewable technologies) may play out. One view is that the benefits of gas-fired generation are just now being realized, another that the gas option may be snuffed out by a Green Wave hardly before it gets off the ground, and a third that natural gas is not a benefit but a threat to the nurturing of wind, solar and customer-side technologies and must be stamped out before it grows much more.

Disruptive effects from renewables generation have begun to appear over the last three to five years as renewables wind generation has taken off in Texas and solar, accompanied less so by wind, has grown sharply in California. Trends for these two states are illustrated in Figure 4. Note that these data principally reflect electric utility and independent power producers' generation. An exception is rooftop solar, which accounts for about 30% of solar output in California and is included in the solar total here. The figure emphasizes the most important market-responsive sources of power, thus excluding industrial gas generation or cogeneration, nascent solar in Texas, small levels of biomass and the like. Likewise, we omit power imports, conveying just the essential generation changes.

As we saw for the U.S., Texas natural gas and coal generation are mirror images, although their changes are much less steep. Numeric data for the last three years are summarized in Table 2. Texas wind reached half the output of coal in 2017 and has had a depressing effect on power prices in ERCOT (Electric Reliability Council of Texas). Negative prices have been reported, although it is doubtful that engineering costs associated with sharply turning down or ramping up coal and natural gas plants fully explain observed prices. These more typically reflect a calculation of the profits obtained by wind producers in West Texas based on a producer's Production Tax Credits and, in some cases, the terms of specific Power Purchase Agreements held by particular generators.[14]

[14] Subsidy-affiliated pricing in Texas has resulted in prices of (approximately) negative $37/MWh, rising to negative $23/MWh with falling subsidies. More generous PPAs, on the other hand, have supported oprices as low as negative $50/MWh or so. R. Deb and A. Aliyeva, LCG Consulting Inc., personal communication, May 2018.

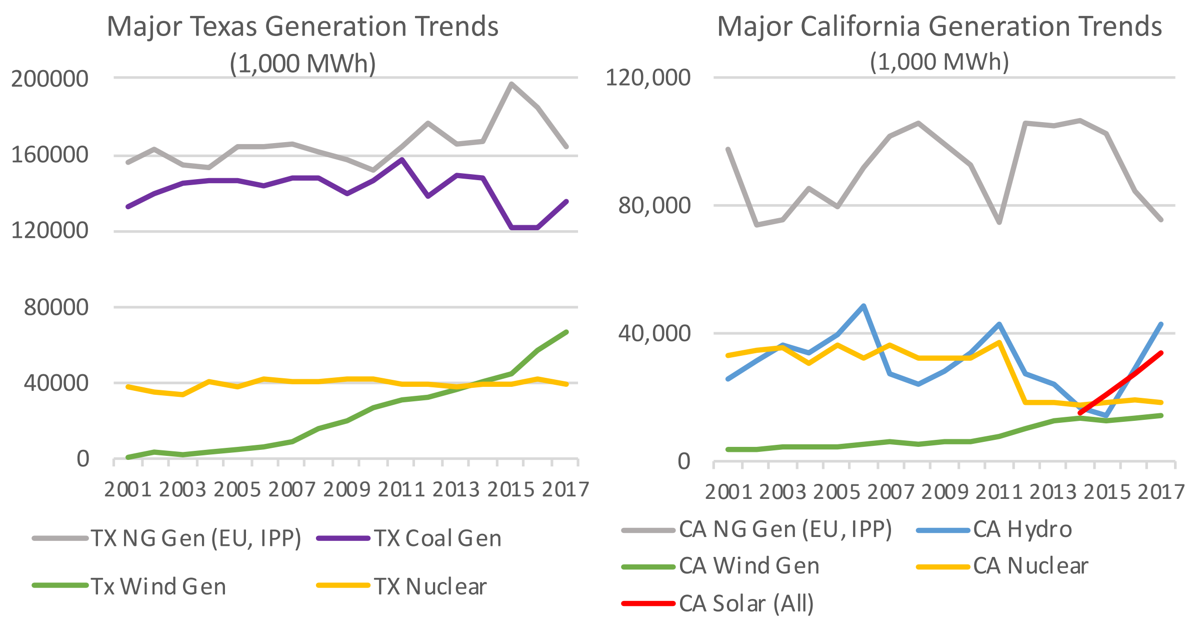

Figure 4. Generation Trends, Texas and California

Table 2. Major Generation Levels by Source in Texas and California, 2015-2017

	Texas (1,000 GWh)			California (1,000 GWh)		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**
Nat Gas	198	185	164	103	84	76
Coal	122	21	135			
Hydro				14	29	43
Wind	45	58	67			
Nuclear	39	42	39	19	19	18
Solar				21	27	34

Source: EIA Elecrtricity Data Browser, June 2018

The "mirror" to gas generation in California is not coal but hydroelectric generation. 2012 brought about dramatic changes with the shutting down of the San Onofre Nuclear Generating Station during a period with low hydro, requiring sharply higher gas-fired generation. The opposite occurred in 2016 and 2017, with sharp reductions in California's gas-fired generation due to improving hydro conditions after a severe two-year drought and, perhaps a sign of things to come, skyrocketing solar output.

These years in these states represent some of the more extreme regional changes in generation where renewable sources are making significant impacts. Looking to the future, it is helpful to extract some insights from a recent study conducted by LCG Consulting, authors of its UPLAN and related power generation-transmission-market simulation models and databases.

2. Future

While not knowing how fast wind and solar will grow, at the already significant levels of penetration experienced in Texas and California, they affect the profitability of all existing producers as well as the payoff of any new capacity, including the financial outlook for new wind and solar installations even with their subsidies. This occurs with a lowering of prices and a reshaping of historic "peak" and "off peak" prices over the day. Generators with high fixed costs, e.g. coal and nuclear plants, have relied on higher-priced periods and moments to cover these costs and pay themselves back for continuing to operate when they choose between "losing more" by shutting down and restarting and "losing less" by selling into these periods.

To explore the business impacts of higher levels of renewables, Lawrence Berkeley National Laboratory sponsored and co-authored a detailed analysis of what a full year, 2030, with high renewables would look like in four electricity markets: Texas (ERCOT, noted above), California (California Independent System Operator, CAISO), New York (New York Independent System Operator, NYISO) and the Southwest Power Pool (SPP) which principally encompasses the "wind belt" states of North and South Dakota, Nebraska, Kansas and Oklahoma.[15]

The study contrasts conditions with renewables frozen at 2016 levels to levels of 40% or more. Those could be achieved with a 20%-20% mix of wind and solar, a high wind mix of 30%-10% wind and solar, or a high solar mix of 10%-30% wind and solar. Importantly, these are levels of output to serve in-region demand, not levels of capacity, and thus are quite comparable to the historic generation mix trends we have presented. While purposely the totals are much higher than the present, the study points out that 2016 wind in SPP and ERCOT was 19% and 13% of the mix, respectively, with even higher wind in some individual SPP states, and solar and wind in CAISO was 14% and 7% respectively. The study kept the above-2016 figures.

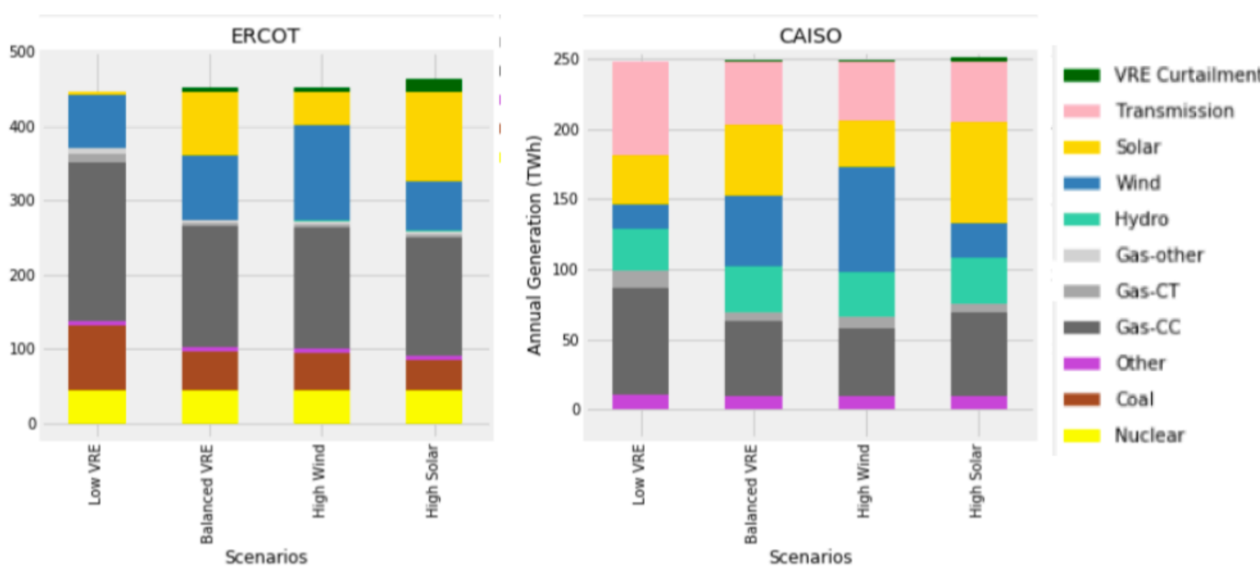

Figure 4. LBNL/LCG Generation Mix for ERCOT and CAISO (Terawatt Hours)
Source: LCG UPLAN-NPM simulation

[15] *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, by J. Seel, A. Mills and R. Wiser (LBNL) and S. Deb, A. Asokkumar, M. Hassanzadeh, and A. Aarabali (LCG Consulting). May 2018.

Notable from the point of views of natural gas and coal-fired generation is that:

(a) Compared to the Texas natural gas vs. coal battle in Figure 12, which magnified in 2012 but showed natural gas and coal generation holding their levels, 2030 “base case” gas generation (i.e. with frozen renewables) has grown well beyond historic highs to about 225-230 terawatt hours, while coal has shrunk about 25% to 90-95 TWh,

(b) With high levels of additional renewables generation of either type, coal generation is decimated. At 50 TWh, it shrinks to about one-third of its historic levels and 60% below its recent lowest levels. Gas-fired generation’s growth is eliminated entirely, with an output of about 170 TWh nearly matching its lowest levels over the 2001-2017 period, and

(c) A somewhat similar effect occurs in California, although there NGCC generation suffers the most and the impacts are not as severe at extremely high levels of solar.

As long as momentum behind renewables continues, one conclusion is clear. In-state power generation in either Texas or California cannot serve as a grand new opportunity for absorbing excess Permian associated gas and other natural gas production.

Electricity prices are the web that connects all the necessary generation investments, retirements and daily operations in simulations of the type conducted in this study. The near-zero energy costs of renewables lead to overall price declines in each of the four regions. One pricing phenomenon in particular has gained notoriety in California, and that is its “duck curve”. This refers to the pattern of prices throughout the day which have transformed understanding of what is “peak” vs “off peak” pricing. In the past, peak prices almost always occurred during highest load (demand) periods, such as the afternoon on hot days with maximum air-conditioning use. Now, however, it has been observed that solar power in particular is deeply shaving away the need for fossil generation during the middle of the day, so much so that peak prices may be shifted to morning and evening hours. Gas-fired units are making less money, so too are the very same solar units competing with each other, and everyone (coal, NGCC) seeks to way to maximize the flexibility of their operations to better follow profitability. (LBNL is even exploring such things as how to enhance nuclear plant operating flexibility.)

EIA offered a commentary on “duck curves” in *Today in Energy*, “California wholesale electricity prices are higher at the beginning and end of the day”, by Lisa Cabral, Bill Booth, Chris Peterson, July 24, 2017. They pointed out that CAISO anticipated these effects as early as 2013. The LBNL/LCG study examined what could happen to these patterns. Not surprisingly, ERCOT begins to resemble CAISO, CAISO’s dips become more accentuated, and higher levels of solar – 20% to 30% levels – forces the duck to practically drag its belly on the ground. While such scenarios might seem unsustainable – why would anyone invest in wind or solar or how could generators pay for gas unit maintenance? – there are other revenue streams which adjust and contribute to the whole, such as capacity payments (covering a piece of the fixed costs) and ancillary services (essential tasks that assure generation tracks the most minute changes).

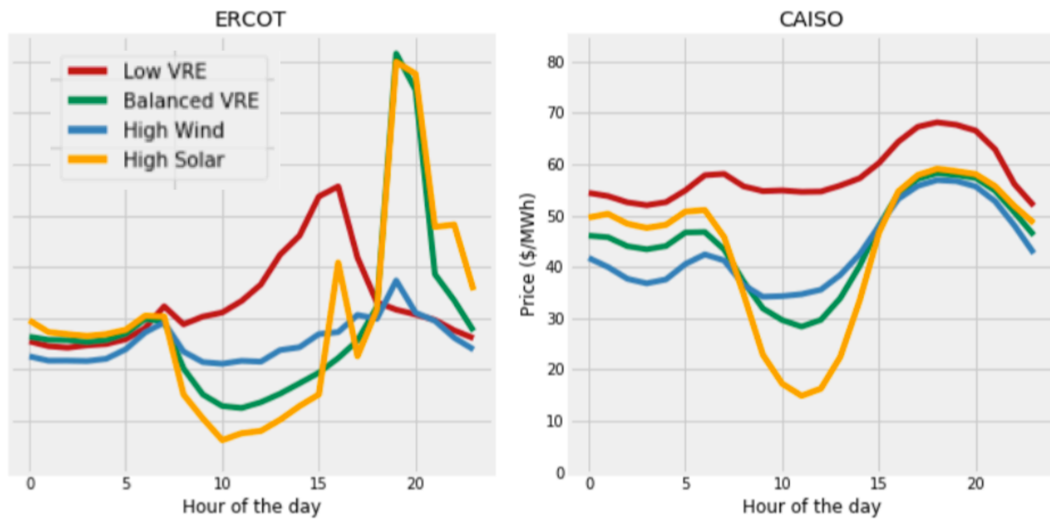

Figure 5. Weekday Average Energy Price Profiles for ERCOT and CAISO ($/MWh)
Source: LCG UPLAN-NPM simulation

The Renewables Tech Revolution/Evolution

The shale revolution has a counterpart in the technology advances taking place across wind, solar and batteries. Non-advocates have been waiting for these to become "ready for prime time", and perhaps that time is now. One of the more stunning announcements is that of an offer to sell power from a solar project to NV Energy for 2.3 cents per kilowatt hour ("NV Energy 2.3 cent solar contract could set new price record", UtilityDive, by Gavin Bade, June 13, 2018). This is apparently a 25-year deal with no escalation and no additional capacity charges, yet it may have a hitch by being contingent on a ballot measure, which is promoting electricity retail competition, being rejected. Despite that caution, it is definitely an eye-opener, so it is necessary to ask what is going on. Is renewables competition going to be just a California thing, or an SPP thing with its 19% wind penetration?

Bloomberg New Energy Finance (Bloomberg NEF) would definitely fall into the "advocacy" camp, having focused its business on the landscape of renewables growth in the US and internationally for many years. Their New Energy Outlook 2018 was issued on June 19, 2018. It included the projection that renewables will account for 55% of US generation by that time. This is predicated on a continuation of dropping cost trends across the renewables spectrum. The firmest data are their historical statistics, and several panels from this work are reproduced here. These are technology markers. The continuation of such trends, like the question of US LNG exports to China mentioned below, will certainly be vulnerable to what happens with the US-China trade war, but our purpose is not to speculate about projections.

The central ingredient of solar, crystalline silicon PV modules, fell in price from about $70/watt in 1976 to 30 cents estimated for 2018 (2018 constant dollars), portrayed in Figure 6. Just since 2010 prices fell 83% (Seb Henbest, "BNEF's New Energy Outlook 2018", Center for Strategic and International Studies, webcast June 20, 2018; https://www.csis.org/events).

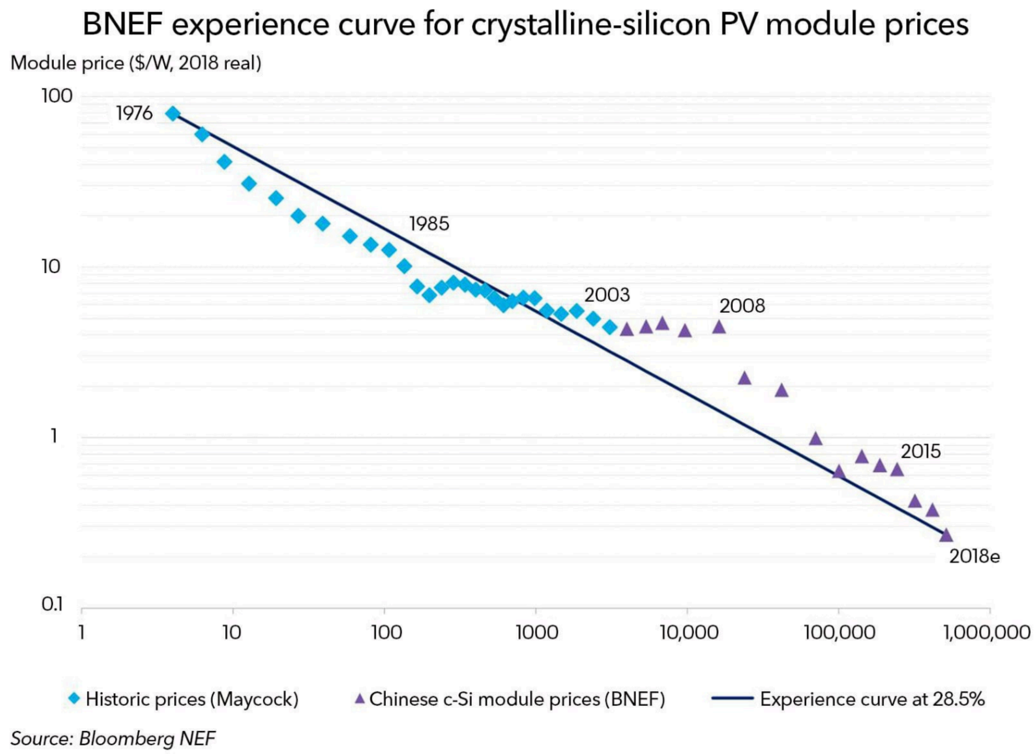

Figure 6. Bloomberg NEF Tracking of Solar Photovoltaic Module Prices
Source: Bloomberg NEF New Energy Outlook 2018; permission pending.

A similar decline of 80% took place in battery prices, from $1,000 to $200 per watt (2017 $) between 2010 and 2017, referring to Figure 7.

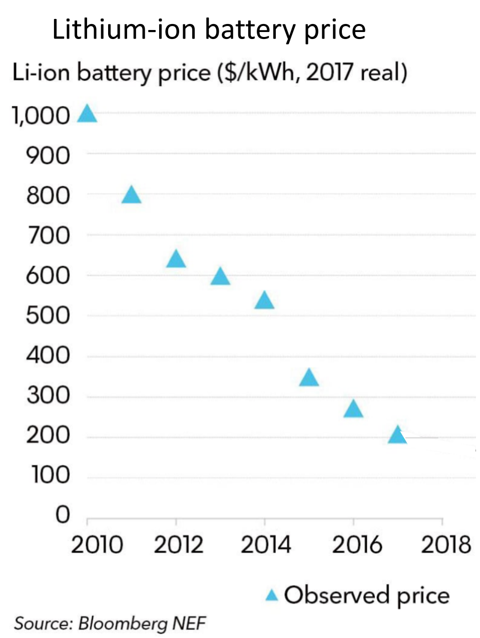

Figure 7. Bloomberg NEF Tracking of Battery Prices
Source: Bloomberg NEF New Energy Outlook 2018; permission pending.

Economies of scale have driven this decline and China's share of manufacturing capacity is anticipated to grow from 59% to 73% in 2021. Batteries at a commercial scale are a relatively new development. EIA reviewed installations in its May 2018 report *U.S. Battery Storage Market Trends*. A large wave of batteries, some 500 megawatts, was installed in just the three years 2015-2017, first principally in the Pennsylvania-New Jersey-Maryland Interconnection region, followed by California as it responded to the Aliso Canyon natural gas storage field leak, and Texas.

Regarding wind, a more mature technology, BNEF points out that prices per megawatt fell by 32% since 2010 even as installations have been producing more energy (higher capacity factors) with their installed capacity.

Competition with natural gas comes in large part from advances in costs and performance. It also comes from a highly favorable political environment in some states which tends to favor renewables (yet may overlook nuclear power's contributions to decarbonization). One of the outspoken voices promoting renewables and other alternatives, the Rocky Mountain Institute (RMI) sees natural gas-fired generation as a direct threat (RMI: *The Economics of Clean Energy Portfolios*, by Mark Dyson and Alex Engel, May 2018). The envisioned portfolios are aimed directly at natural gas, signified by UtilityDive's description upon release of RMI's report: "End of the gas rush? Renewables, storage reaching cost parity, report finds", by Hernmabn K. Trabisch, June 11, 2018. Rather than take sides, the important thing to note is that the portfolio of "clean energy" incorporates many things besides big windmills or utility-scale solar. Emphasis is also placed on efficiency gains, demand side management, and a dispersal of the family of renewable technologies to smaller installations. All of these developments will bear watching to determine how far natural gas will proceed in the power sector.

International Coal and China: A Complex Web, *by John Dean, JD Energy*

A common theme throughout energy publications over the past several years has been the inevitability of the decline of coal, yet ironically the global coal steam market is currently experiencing heightened price levels not seen since 2011. There are so many reasons behind this price spike that are sufficiently long-lived that most observers believe the existing tight market conditions may not really subside until the latter half of 2019.

In addition to exploring the drivers behind this totally-unexpected pricing, this portion of the article will provide additional focus on coal topics relating to coal trends in China (we note that trade disputes touch on LNG as well as coal and other commodities), coal company financial considerations, and various additional "wild cards" that complicate the international landscape.

A Multi-faceted Explosion in International Coal Markets

To set the stage, Figure 8 presents the roller coaster ride international (thermal) coal markets have seen since the peak of the global commodities "supercycle" in mid-2008 and the onset of the Global Recession later that year. Prices between 2004-2008 had skyrocketed on the back of a new era featuring expanding developing country demand, led largely by China and India. The global financial recession of late 2009 sent global coal prices into a free fall, but they bounced back quickly to almost equivalent levels by 2011 as suppliers retrenched and only a few kept expanding (e.g., Colombia), reaping huge price benefits in the process. Yet this price surge proved to be short-lived.

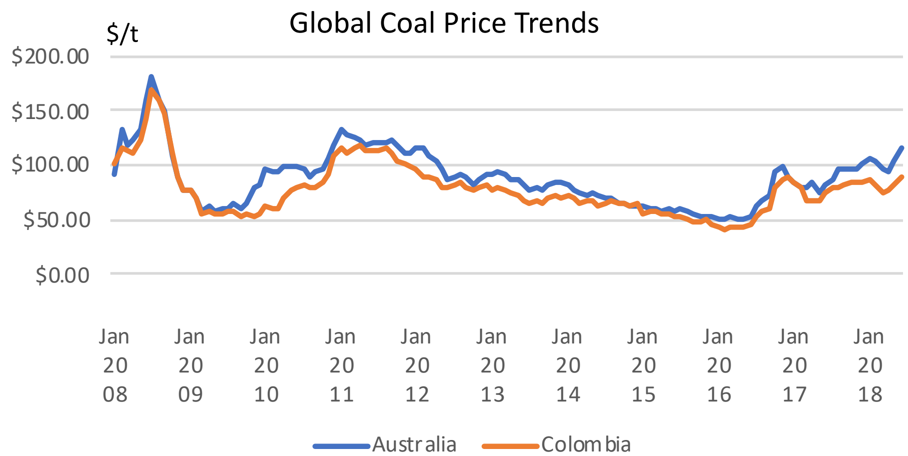

Figure 8. Australia and Colombia Thermal Coal Prices, 2008 to June 2018 (USD/metric ton)

A massive decline in international coal prices began in 2011 that set the stage for many observers to conclude that coal had begun a steady, irreversible downward trajectory. There were several major drivers behind this decline, but clearly the most prominent was significant oversupply in global steam coal mining capacity vis-à-vis the level of demand. Much of this supply had been built during the heydays of the 2004-2008 expansion in demand, but after the global recession, developing countries who provided so much of that demand struggled to regain their footing. A strengthening of the US dollar vs. Australian currency over the 2013-2016 period helped ease the pain of falling global coal prices for many foreign producers.

The downward ramp of coal prices after 2011 continued until the summer of 2016, when prices unexpectedly surged upward. The primary driver behind this development was the fact that the Chinese, in an effort to reduce conventional pollution problems associated with coal-burning without adequate control equipment, issued a directive to reduce both coal production and coal consumption in the country. This directive yielded a faster response on the production side than on consumption, as coal miner hours were sharply restricted but no meaningful adjustment was made to economic goals that required coal-supplied industry output. Coal production fell in China that year by 15%, raising domestic prices by about 40%. The result was a massive shift to steam coal imports, stretching global suppliers who never saw this coming. Moreover, world coal producers were slow to respond to this situation, both because they were still heavily involved in an on-going, lengthy process of rationalizing their operations to reduce excess international thermal coal supplies and because they were skeptical of how long this imbalance in China might actually last.

China had hoped to remedy the situation by mid-year 2017, but to this day (mid 2018) China continues to grapple with finding the necessary supply-demand balance. While China's problems gave loft to global steam coal prices throughout 2017, beginning that year even more issues arose to throw the global supply-demand balance further out of kilter. On the supply side, these additional problem areas included: (1) for Australia, weather (an early 2017 cyclone, Debbie, the worst since 2011), mining outages, infrastructure (the major railways Pacific Northern labor issues and Aurizon's ongoing dispute with government over its regulated rate of return); (2) for South Africa, weather and continuous labor issues resulting in stubbornly high coal prices; (3) for Indonesia, extensive rains as well as an official declaration (known as DMO: Domestic Market Obligation) requiring diversion of coal from the export market to serve expanding in-country coal use; and (4) for Colombia, enormously disruptive rains afflicting both 2017 and 2018.

While most of the market tightening has occurred due to supply shortfalls, there have been, and will be, growing concerns on the demand side as well. Extremely cold 2017-2018 winter weather in both Asian and European markets unexpectedly heightened coal demand. This has been followed by recent reports of extremely hot weather throughout North Asia, intensified by low hydro output in China. Japan and China are seen as key drivers of global coal demand in the second half of 2018 (per Citi analysis cited in Platt's *Coal Trader International*, June 25, 2018, p.6) and India will likely substantially increase its import take this year due to very low inventories, low hydro output, and logistical bottlenecks.

Given the magnitude and multitude of reasons behind the current global coal supply-demand imbalance, it appears probable that the market tightness will persist well into 2019. Yet one of the problems aggravating the situation – the reluctance of producers to significantly expand production in the face of a strong consensus of inevitable decline in coal markets – signifies the lurking and paramount role of long-term erosion in the outlook for coal. That reluctance to add new mining capacity will almost ensure the future occurrence of short-term supply disruptions (such as is being experienced now) as demand levels occasionally rise, but this only reflects the reality of an industry in slow but steady decline.

The China Situation

China has embarked on a policy of reducing both its coal production and consumption, in large part to ease the large problems of SO_2, NOx, and particulate emissions that have become a liability to the country as uncontrolled coal use has grown. As alluded to above, the higher rate at which production has fallen relative to consumption has caused a serious imbalance in global steam coal markets as the country has been forced to go outside its borders to obtain more coal.

China effectively accounts for roughly half the coal consumed in the world, so it is an understatement to emphasize that the energy policies it pursues are of utmost importance to global coal markets. Having once been a major exporter of steam coal, it is now a major importer of that type of coal. It imported in 105.3 million metric tons (tonnes) in 2017 (primarily from Australia, Indonesia, and Russia).

China is moving ahead with downgrading its coal production capabilities, both in terms of output and electricity generation. It reduced its coal capacity by about 250 million tonnes in 2016, 150 million tonnes in 2017, and in March 2018 at the National People's Congress, Premier Li Keqiang affirmed China's intentions of closing another 150 million tons this year. The previously imposed 276-day coal work restriction remains in place. Moreover, he indicated that all coal-fired power generating units under 300 MW without "desired controls" would be closed this year.

One of the problems facing China in the past few years has been its inability to readjust its economic goals as it ratchets both its coal consumption and production targets downward. China finally made such a modification early this year as it targeted its GDP growth target at 6.5%, down from the 6.9% growth achieved in 2017.

It is likely China will continue its policy to reduce the role of coal in its economy going forward. The primary economic planning agency in China, the NDRC (National Development and Reform Commission) announced last year that "coal is over…every year, it will be gradually reduced, city by city." Moreover, there are strong indications China views its rising role as a premier clean energy supplier offering higher economic rewards than continued investment in its coal sector. China currently owns seven out of ten of the world's largest solar PV companies, is the world's leading manufacturer of electric cars, is assuming a rapidly growing position in the energy battery storage industry, and is quickly rising among global wind suppliers through its Goldwind and Minyang firms.

Coal Companies' Financial Condition

The raft of coal company bankruptcies that roiled the industry have largely subsided. By the end of 2015, 44.3% of all coal produced in the United States came from companies that had been in bankruptcy. That percentage has gradually declined. The experience has left some lasting marks on the financial health and outlook of coal companies that are having, and will continue to have, profound impacts on the marketplace. Below are four major areas where changes have occurred.

First, companies that took advantage of exercising Chapter 11 bankruptcies are now in a substantially better position than those who managed through difficult times to stay solvent. This is a consequence both of the Chapter 11 firms' reduced debt as well as the significant restructuring that generally accompanied those bankruptcies.

Second, capital is becoming available to the industry once again, but in a very limited fashion. Coal company leaders report that investment is now much easier to obtain for operating established, competitive mining operations but much more difficult to acquire for new mines. Return on the specific investment in question (i.e. "project financing") is the primary consideration, rather than relying on general trends within the industry.

Third, metallurgical coal is now widely seen as a much worthier investment target than steam coal. This is due to the perception that the met coal outlook is better as global economic prospects improve, whereas continued pressure on steam coal from natural gas, renewables, and climate change considerations render the thermal coal option much less attractive. Some steam coal producers have reported that capital for new thermal coal mines is virtually impossible to obtain, although there have been some exceptions, such as Coalspur's Vista project in Alberta, Canada, designed to initially develop a 5-6 million tonne-per-year (tpy) surface mine for steam export coal that would eventually expand to 12 million tpy.

Finally, hedge funds are more likely to be providing capital to coal companies these days than banks who were burned so badly in the downturn, with some strong implications for future growth. Hedge funds are much more oriented toward shorter-term returns, so are much more likely to gravitate toward high price volatility and niche situations that provide a quick return. These conditions are not, however, favorable to the kind of long-term investments generally associated with new, large coal mine developments.

"Wild Cards" in the Coal Deck

While the general outlook presented in this section portrays coal markets as remaining quite tight in the next two years but declining over the long-term, experience has taught the benefits of being ready for surprises on the global coal scene. With that in mind, below are four areas where events could either upend or greatly alter the prevailing wisdom regarding the future of coal.

1. A Trade War?

The tariffs initiated by President Trump have caused global consternation, resulting in some retaliatory measures as well. The first concern is that an expanding trade war, which already encompasses Europe, North America and much of Asia, could lead to a major disruption to the global economy. Lower economic growth would undoubtedly harm coal along with other energy sources. A second repercussion for coal is based on the reality that the U.S. is a major exporter of coal (97 million short tons in 2017, 57% met coal) but imports very little (7.8 million short tons in the same period); as such, the U.S. coal market has more to lose in a trade war than gain. Already, two adverse situations have arisen that initially favored U.S. coal exporters but have now taken a bad turn. First, Turkey indicated it was increasing its allowable sulfur coal content to 3% (up from 0.7%), strongly suggesting U.S. Northern Appalachian and Illinois Basin coal would be able to supplant Colombia as the primary supplier to one of the few rapidly growing coal markets in this area of the world. Upset by the initiation of tariffs on steel and aluminum by the U.S., however, Turkish President Erdogan has now apparently decided on a 5% tariff on U.S. coals, possibly sufficient to undermine the U.S. advantage. Secondly, China had publicly suggested only a month ago that it would attempt to increase its purchases of U.S. coal (currently just over 3 million short tons-per-year, but growing) as a gesture toward improving its trade balance with the US. Following the announcement of President Trump's tariffs on that country, China has now overridden that policy and is now proposing to attach a 25% tariff on U.S. coal products. The implications for U.S. coal exports based on these two examples, as chances of a trade war appear to be increasing, are obviously quite onerous.

2. LNG Embroiled in U.S.-China Tensions

China-US trade tensions have potentially enormous impacts on the U.S. LNG exporting business. At the June 2018 World Gas Conference in Washington, DC, Bloomberg reported that Total SA's CEO Patrick Pouyannere spoke of these risks, writing that he "… warned that a trade war could 'be detrimental' to the U.S.'s nascent liquefied natural gas industry. LNG currently has no tariffs but the industry, which has potential for long-term growth, depends on good relations with China, the fastest-growing consumer of the fuel." ("Trump Trade Threats Turn Exxon, Chevron From Backers to Critics", by Kevin Crowley, Bloomberg, June 26, 2018, updated June 27, 2018). While still consuming less than half as much LNG as Japan, China has just edged over South Korea in the number two spot and has been far and away the leading source of growth in the LNG trade since 2015. Here price really matters. 2015 was the watershed year when oil-linked LNG prices followed oil's collapse into more competitive territory.[16] The top LNG supply and demand changes are concisely summarized by the Energy Information Administration in *Today in Energy*, "Global LNG trade continues to grow, especially from Australia and the United States", by Victoria Varetskaya, June 121, 2018.

3. Ocean Freight Changes Could Upend Market

The IMO (International Maritime Organization) has this year established a requirement that ships reduce sulfur levels from 3.5% to 0.5%, possibly beginning as early as 2020. Ship owners have maintained this could so substantially increase their operating costs that it would greatly curtail the long-distance thermal coal trade, suddenly favoring coal from closer locations to the user country. Given current trading patterns, this would greatly aid producing countries such as Indonesia and Russia, at the expense of nations such as the United States, Australia, and Colombia. In addition to the changes within coal markets, such a move will unquestionably raise the price of coal, placing coal at even more of a disadvantage to competing sources of energy.

4. Climate Change Developments

The elephant in the coal mine is clearly climate change, given its potential for massive disruption to coal markets. Objectively, there are strong arguments leading toward failure or success of international efforts to reduce CO_2 emissions. On the side favoring failure is the withdrawal of the U.S. from the 2015 Paris Agreement, resulting in the loss of both the leading political role played by President Obama as well as the large financial contribution the U.S. was likely to make to the effort. The European Union and China have endeavored to take over this role, but the EU is heavily embroiled in migration-related issues that threaten its very existence, while China has backed away recently from wanting to be out in front of this issue. Favoring the success side, no nation has followed the U.S. lead in withdrawing, and in June 2018, 23 countries signed an agreement supporting the UN's call for a summit to be held in September 2019 to step up goals beyond those already made in Paris. Although not a signatory to that document, in China a lead government organization has publicly floated the idea of that country moving up its pledge for 2030 (it already achieved in 2017 its 2020 goal for reducing carbon intensity). How these policy positions play out may not upend so much as slow or accelerate the forces we have discussed, yet in either case with large long-run implications for the international coal trade.

[16] LNG's price collapse in 2015 was one of many benefits to energy consumers from the U.S. fracking revolution. These were quantified in the Energy Economics and Technology Committee's 2016 report. See also: "Hitting the Jackpot During Oil-Gas Price Collapse: The Consumer", by Jeremy Platt. Search and Discovery Article #70251. http://www.searchanddiscovery.com/pdfz/documents/2017/70251platt/ndx_platt.pdf.html

$100 per Barrel Oil – A Thought Exercise*, by Stephen L. Thumb*

Following on the theme that oil's pricing, at least as far as the U.S. shale oil surge, has largely been "bake in" by now into the psychology of oil price expectations, our contributor Stephen L. Thumb developed a "scenario outline" on May 27, 2018 (i.e., well before Mexico's potentially historic election on June 30, 2018) emphasizing conditions and developments that could a return to significantly higher oil prices. This is presented below as a literal outline, highlighting factors which in combination could lead to this outcome. He gives it "at best, a 30 to 40% chance of occurring, which, while low, is better than several other potential scenarios."[17]

Our purpose is not to present some fringe thinking but rather to remind readers and analysts of the richness and scope of geopolitical and physical factors that, in "normal" times, have always tended to govern oil pricing. By constructing the discussion around measures of how big the different countries are in the oil world, an added motivation is to convey context that can be lost among the blast of headlines from around the world. Mr. Thumb's admonition is particularly apt, regardless of the probabilities and price levels: "The U.S. can't go it alone." We will not be surprised if we find ourselves giving more attention, then, to salient international oil market drivers (besides US import/export balances across crude oil and oil products) as well as to adoption of hydraulic fracturing in both oil and natural gas production outside the U.S.

Mr. Thumb does not put a timeline on the outline, but he is looking farther than just the next few years. For some comparisons, the EIA's *2018 Annual Energy Outlook* forecasts West Texas Intermediate will not reach $100 per barrel in constant 2017 dollars until 2039 (Brent $105), although it reaches a healthy $80/bbl by 2024 (Brent $84-85). EIA's June *STEO* sees WTI falling from its peak of $70 in May, 2018 to $62 by the last quarter of 2019 – whether this is high or low is in the eye of the beholder. Fundamentals (inventories, production capacity, etc.) may already be tightening, yet the role of OPEC or OPEC-plus (including Russia) may henceforth and principally be in the hands of just two countries, Saudi Arabia and Russia. These points are made in two articles by Reuters contributor Jack Kemp, addressing fundamentals and the capabilities of the two countries to prop up or undermine prices.[18] The manner in which US political pressure may influence decisions by these two countries one way or the other is a new and uncertain factor. Mr. Thumb's outline follows.

[17] Memorandum, S. Thumb to J. Platt, June 6, 2018.
[18] "Oil market's shock absorbers becoming dangerously depleted: Kemp", by John Kemp, Reuters, June 13, 2018. https://www.reuters.com/article/oil-prices-kemp/column-oil-markets-shock-absorbers-becoming-dangerously-depleted-kemp-idUSL8N1TF3SV and "After OPEC, oil market enters a new era: Kemp", by John Kemp, Reuters, June 28, 2018. https://www.reuters.com/article/oil-prices-kemp/column-after-opec-oil-market-enters-a-new-era-kemp-idUSL8N1TU3UZ

A Scenario of $100 per Barrel Crude and $4.00 per Gallon Gasoline   by Stephen L. Thumb

Demand: Not Slacking Yet

Despite forecasts for oil demand to peak over the next 10 years, *supply growth may not keep pace with demand growth.* Hence ==> Increase in oil prices.

* Impact of the electric cars is a long way away
* Demand growth for petrochemicals is very strong and will continue for the next couple of de

Supply Outside the Middle East

(See Table Footnote (^) for country notations **(#%, #%)** on production, reserves.)

The combination of geopolitical events **outside the Middle East** inhibits supply growth.

* The US can't go it alone. (US scenario elements at end of list.)

* **Venezuela (1.4%;17.6%)**[(1)]: It will take 20 years for Venezuela to recover from its current crisis.
  +++ World's largest bankruptcy likely
  > No more credit of any kind
  > Even China has given up

  +++ Law & order disappearing - gangs and roving militias
  +++ Economy in disarray & dramatic decline
  +++ Growth in Orinoco crude won't occur - no money & no credit
  +++ Light crude around Lake Maracaibo continues to decline - no labor & no maintenance of wells

* **Mexico (1.9%;0.4%)**: Outlook for oil supply growth turns on a dime.
  +++ 2018 elections result in a switch in parties and adoption of anti-business policies
  +++ Existing administration has approval rating below 20%; corruption a major problem
  +++ Obstacles arise for recent lease sales; contracts honored in concept, but rules change
  +++ Oil reserves are **not** nationalized, but protectionist policies are adopted

* **Brazil (3.2%;0.7%)**: Brazil's corruption & financial crisis significantly lowers outlook for any offshore production growth.

* **Canada (3.4%;1.0%)**: Country's environmental & anti-oil policies halt growth in tar sands

* **Libya (1.0%;2.8%):** Combination of political instability, lack of security, lack of capital & technical incompetence limit any further recovery.

* **Nigeria (2.0%;2.2%):** Combination of political instability, lack of security, lack of capital & technical incompetence limit any further recovery.
  +++ Rebel activity in Niger Delta continues almost indefinitely due to poverty & religious/political problems
  > Majors leave onshore; onshore production declines

  +++ Corruption & massive bureaucratic restrictions halt growth in offshore production
  > Ultradeep projects have become white elephants

* **Angola (1.5%;0.6%):** Combination of economic decline, lack of capital & technical incompetence limit any further recovery.
  +++ Corruption & massive bureaucratic restrictions halt growth in offshore production
  > Ultradeep projects likely the most costly in the world

* **China (3.7%;1.5%)**: Lack of good geology; production continues to decline.

* **North Sea (2.5%;0.6%):** With one exception North Sea production in decline due to mature geology & costs.

  +++ Exception is Norway's huge Johan Sverdrup discovery - first phase online 2020 ramping up to 660 thousand barrels per day or 25% of Norwegian production

* **Kazakhstan & Azerbaijan (2.5%;2.2%):** Production has peaked; countries will never reach their potential.

  +++ Significant political problems and high cost geology

* **Russia (11%; 6.4%)**: Despite sanctions, with winding down of OPEC production cutbacks, Russia likely to return to its historical pattern of adding 0.2 to 0.4 MMBD/year.

  +++ Nothing dramatic; steady small growth largely as a result of Russia tweaking its onerous mineral tax policies

  +++ Big gains from developing shale resources very unlikely due to sanctions, lack of infrastructure

  +++ Big gains from Arctic resources likely will not occur (i.e., enormous cost and no infrastructure)

* **US (10.3%;8.6%):** November elections likely to result in sharp change in direction.

  +++ Anti-fracking policies start to emerge in many regions, but not Texas

  +++ Permian is great but can't carry the entire nation

  > Infrastructure, labor, cost & water problems hold Permian growth in check

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Middle East

* **Iran & Iraq** never reach their potential

  Iran (4.0%;9.2%)

  +++ Sanctions inhibit oil development in Iraq

  +++ Plans to use foreign capital get delayed & delayed - terms & conditions major inhibitor

  +++ Moderates lose out to hardliners

  +++ Corruption takes its toll

  +++ Technical incompetence inside country

  Iraq (4.4%;9.0%)

  +++ Technical incompetence inside country

  +++ Terms & conditions continue to drive away foreign capital

  +++ Grand plans to achieve new production levels get delayed - low hanging fruit has been taken

* **Saudi Arabia (9.9%;15.6%)**: Country is a wild card, as it can increase production but only up to 12.5 million barrels per day.

* **Kuwait (2.7%;0.6%)**: Internal politics choke off any hope of increasing production.

(^) Notation: First figure is approximate percent of current global crude production, while second figure is the approximate percent of global proven reserves. In total the above encompasses approximately 75% of both production and reserves.

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