TESTIMONY OF KEVIN BOOK

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BEFORE THE
U.S. SENATE COMMITTEE
ON ENERGY AND NATURAL RESOURCES

OCTOBER 6, 2015

Chairman Murkowski, Ranking Member Cantwell and distinguished Members of this Committee, my name is Kevin Book, and I lead the research team at ClearView Energy Partners, LLC, an independent research firm that analyzes macro energy issues for institutional investors and corporate strategists. Thank you for the privilege of inviting me to contribute to your discussion regarding modernization of the Strategic Petroleum Reserve (SPR).

I am grateful for this Committee's initiative as it continuously reexamines U.S. policy to account for changing fundamentals. It is no small thing to adapt the laws and regulations of the world's largest economy to a transition from energy scarcity to adequacy and, increasingly, abundance. I appreciate the time and effort that this Committee and this Congress have devoted to revisiting the assumptions that informed earlier choices, such as the ban on crude oil exports and the 2007 expansion of the *Renewable Fuel Standard*. Resurgent production of domestic oil and gas resources may continue to provoke questions regarding some of the nation's legacy energy strategies.

That said, some decisions that date back to the *1975 Energy Policy and Conservation Act* and the legislative efforts that followed have withstood the test of time. In my view, one of those decisions is the creation of the SPR, which has durably insured our industrial economy against petroleum supply interruptions. Today, I would like to offer several observations regarding the size and composition of the Reserve.

U.S. Energy Security Has Improved

The International Energy Agency (IEA) treaty requires member countries to maintain strategic stocks equivalent to 90 days of net petroleum imports. According to Energy Information Administration (EIA) data, on a trailing, twelve-month (TTM) basis through June 2015, SPR inventories averaged 691.32 MM bbl and net petroleum imports averaged 4.81 MM bbl/d, implying approximately 143.7 days of net import "cover," or roughly 54 days in excess of treaty obligations.[1]

This fortunate circumstance is relatively recent. In June 2005, the SPR held slightly lower crude inventory levels (679.64 MM bbl on a TTM basis) and net petroleum imports were ~155% higher (12.793 MM bbl/d on a TTM basis), implying only ~54.4 days of net import cover.

Much of the difference can be linked to the well-documented growth of U.S. domestic crude production (9.23 MM bbl/d in June 2015 on a TTM basis vs. 5.43 MM bbl/d a decade earlier, a net gain of 3.8 MM bbl/d) that enabled U.S. crude to displace imported volumes. In addition, the combination of efficiency gains and structurally lower U.S. petroleum intensity of GDP appear to have reduced consumption by 1.48 MM bbl/d over the same interval (19.34 MM bbl/d on a TTM basis in June 2015 vs. 20.82 MM bbl/d a decade earlier).

Finally, a larger share of U.S. net petroleum imports now comes from a secure and reliable supplier with which our nation shares a common land border. In June 2015, according to EIA data, net imports of Canadian crude and petroleum averaged 3.15 MM bbl/d on a TTM basis, a substantial uptick from 1.99 MM bbl/d in June 2005.[2] Correspondingly, Canadian crude and petroleum made up approximately 41% of U.S. net imports on a TTM basis in June 2015, up from 16% in June 2005.

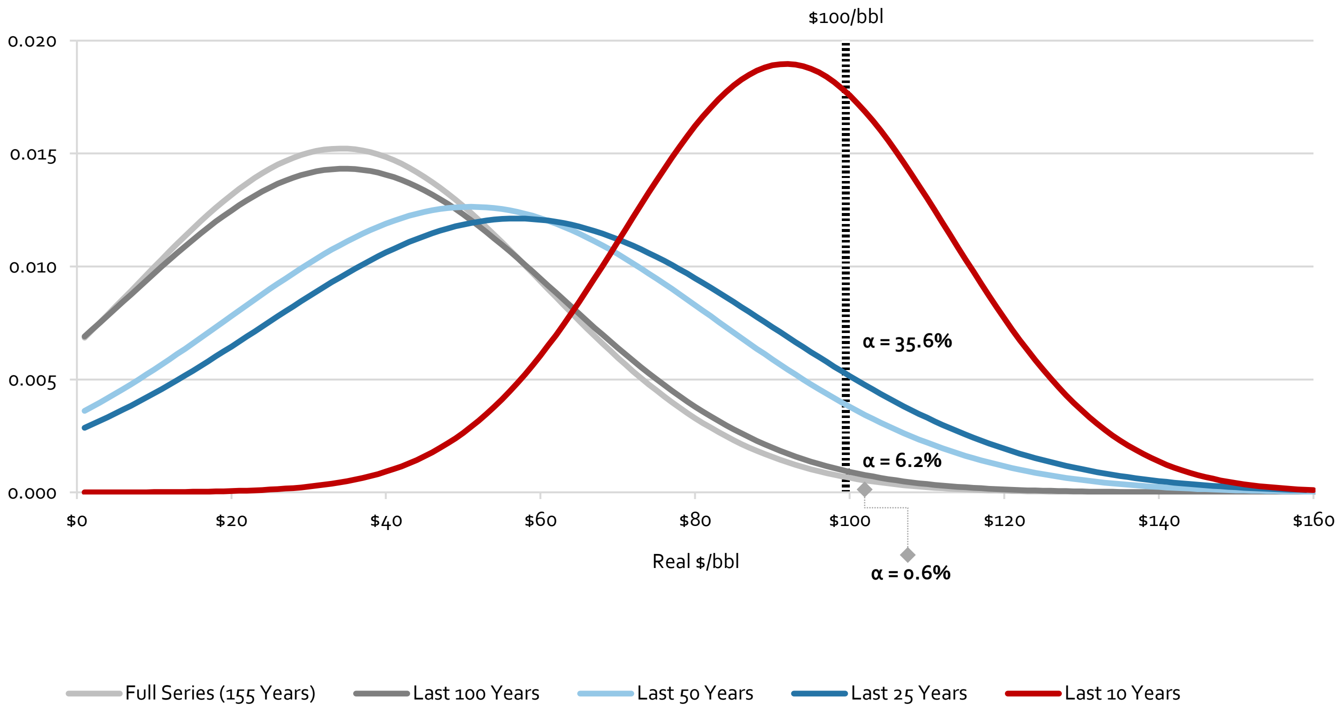
[1] For analytical purposes, our firm often uses TTM averages of macro energy data series to smooth out seasonality. For the month of June 2015, EIA data show SPR inventories of 693.89 MM bbl and 4.88 MM bbl/d of net petroleum imports, implying approximately 142 days of net import cover. Compared to a 90-day net import obligation, the difference between the raw data and the TTM average is not particularly significant.

[2] This total, which counts net petroleum exports to Canada, inadvertently diminishes the magnitude of two, remarkable dynamics in U.S.-Canada petroleum trade. On a TTM average basis, Canada exported 3.66 MM bbl/d of petroleum to the U.S. in June 2015, up from 2.14 MM bbl/d a decade earlier. U.S. petroleum exports to Canada posted an even more marked uptrend, reaching 0.51 MM bbl/d on a TTM basis in June 2015 vs. 0.15 MM bbl/d in June 2005.

Energy Security is a Long Game

From an energy security perspective, the foregoing data points offer incontrovertibly good news. At the same time, energy supply and demand tend to be "sticky," or slow to change. As a result, it may make sense to consider energy trends over longer time periods. As an example, Figure 1 presents normal distributions of real crude prices (2015 dollars) over several different intervals.

Figure 1 – Timeframe Selection Influences Analytical Perspectives Regarding "Average" Crude Oil Prices



Years in Series [1]	Mean Real Price ($/bbl) [2]	Standard Deviation ($/bbl)
155	$34.11	$26.20
100	$34.63	$27.84
50	$51.00	$31.55
25	$56.94	$32.91
20	$63.84	$33.38
15 [3]	$75.62	$30.00
10	$91.77	$21.03
5 [3]	$99.51	$25.19

Notes:

1. 2015 crude averages through August 2015 use data from EIA *Short Term Energy Outlook*; prior years from *BP Statistical Review of World Energy*.
2. Computed using *BP Statistical Review of World Energy*, which provides data through 2014 and inflating to 2015 dollars using CPI-U through August 2015.
3. Not pictured.

Source: ClearView Energy Partners, LLC using BP Statistical Review, EIA and St. Louis Fed data as of September 29, 2015

1H2014-vintage analyst expectations that oil prices might remain above $100/bbl for the intermediate future probably reflected some degree of statistical myopia. After all, over the (nearly) five-year series through August of 2015, real crude oil prices really *did* average almost $100/bbl. Likewise, the distribution I generated in Figure 1 from the mean and standard deviation of a ten-year real price series implies a better than one-in-three chance of a $100/bbl price. By contrast, the normal distribution I generated from the mean and standard deviation of the full, 155-year series implies less than a one percent probability of prices at or above $100/bbl, and the full series oil price averages about $34 per barrel in 2015 dollars.

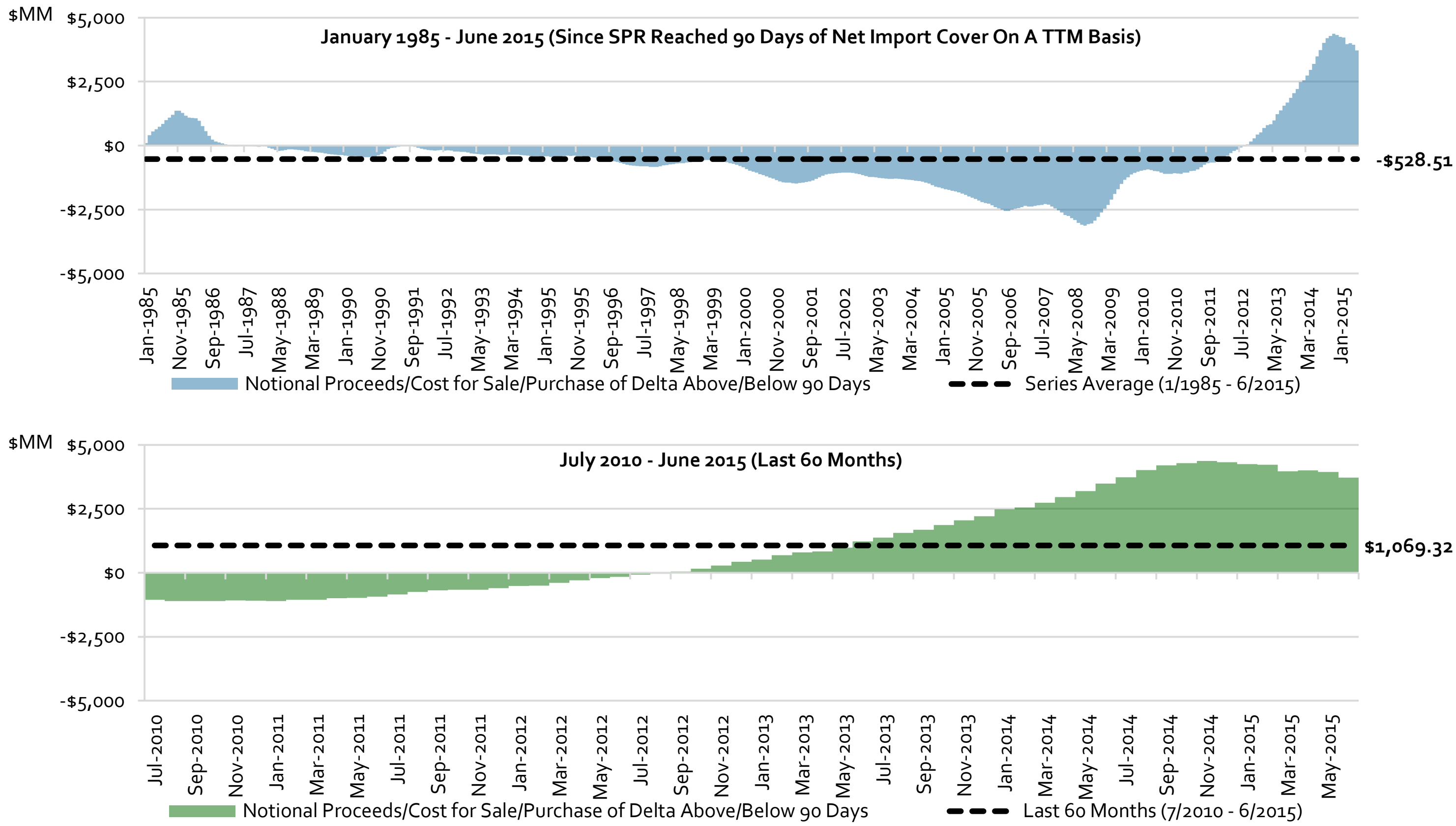
Which perspective is correct? Analysts tasked with looking ahead at commodity prices may be tempted to reason that the near future is more likely to look like the recent past than the whole of history. I would generally agree with that view, but recent oil market "lessons" reinforce the need for caution when making long-term decisions on the basis of short-term data. In that context, I think it may be worth examining long-term trends when considering an appropriate size for the SPR.

Legislative proposals to sell volumes out of the SPR to finance highway spending or pharmaceutical development appear to be predicated upon the view that the U.S. is carrying too much petroleum "insurance." Are we? I would not make too much of facile parallels between the SPR and the property and casualty insurance policies that individuals purchase, but the metaphor may apply in some respects. For example, it's generally cheaper to buy insurance at times when the market perceives lower degrees of risk. In that vein, a period of low crude prices may be a better time to expand – rather than reduce – the size of the SPR.

Likewise, it makes sense for individuals to periodically revisit their personal coverage when their life circumstances change. Should the nation downsize its SPR now that U.S. production circumstances have changed? My answer is: probably not.

Figure 2 presents the results of a simple thought experiment constructed using TTM averages of EIA monthly data series for SPR crude stockpiles, net petroleum imports and refiners' real, composite crude acquisition costs (in 2015 dollars) between January 1985 and June 2015.[3]

Figure 2 – Thought Experiment Using TTM Average SPR Stocks, Net Petroleum Imports and Composite Refiner Acquisition Costs



Source: ClearView Energy Partners, LLC using EIA and St. Louis Fed data as of September 29, 2015

The blue columns in the upper chart in Figure 2 represent the theoretical proceeds or costs associated with either (a) selling crude at refiners' real, composite acquisition costs in months when SPR stock levels exceeded 90 days of net import cover; or (b) buying crude in months when stocks fell below the 90-day level. The black dotted line represents the average result: a loss of ~$528 MM over the full series. The green columns and dotted black line in the lower chart replicate the same thought experiment for the five-year period through June 2015, with a different average result: a profit of ~$1 B.

In other words: timeframe matters. The short run can inspire spurious conclusions (i.e., real crude prices that remain above $100 forever) and unprofitable choices (i.e., selling a strategic resource only to buy it back later at a higher price). Over the long haul, the foregoing thought experiment suggests to me that tailoring the SPR down to a 90-day supply level could be a losing bet.

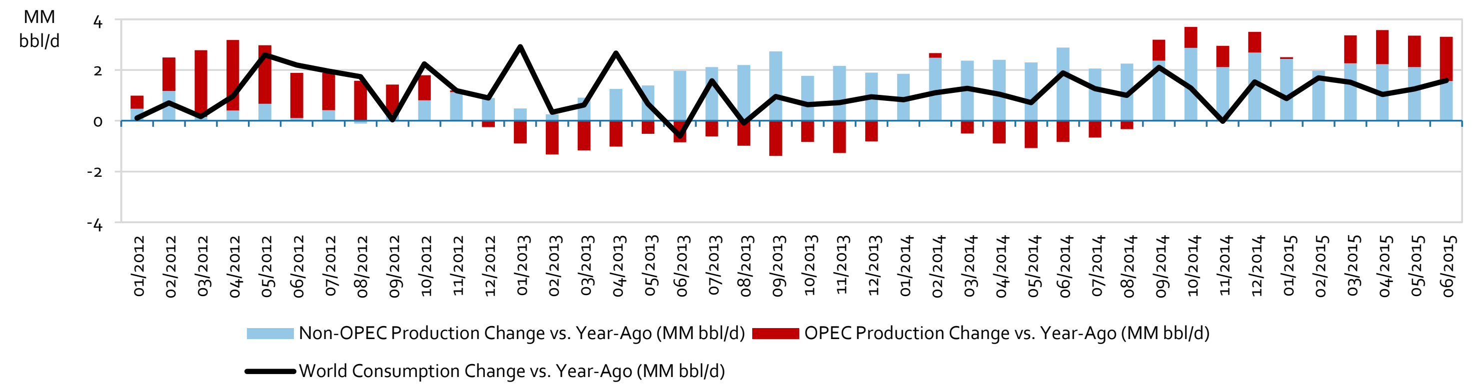
Spare Capacity and Shale

Today, instead of balancing non-OPEC production gains by cutting their volumes, OPEC producers appear to be running flat out in an effort to capture (and/or defend) their global crude market share.

Figure 3 charts monthly EIA OPEC and non-OPEC production vs. year-ago levels between January 2012 and June 2015 (note: these data are <u>not</u> averaged on a TTM basis).

[3] I chose January 1985 as the starting point for the series because it was the first month where the SPR net petroleum import cover was at or above 90 days on a TTM average basis.

Figure 3 – The Battle for Global Crude Market Share

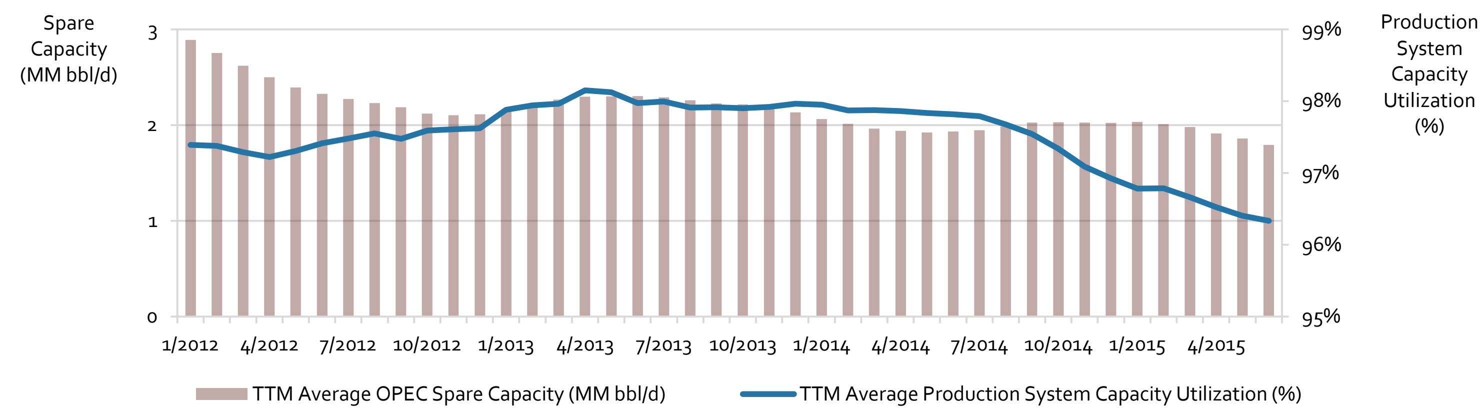


Source: ClearView Energy Partners, LLC using EIA data as of September 29, 2015

Since 4Q2014, year-on-year changes in OPEC and non-OPEC production (red and blue bars, respectively) have both trended above the x-axis, and – in the aggregate – well in excess of the year-on-year change in global consumption (black line). In addition to driving down crude prices, this notional battle for market share is probably also eroding the "spare" production capacity traditionally held in reserve by OPEC producers as a market balancing mechanism (by definition, running flat out is is the opposite of setting aside capacity), and this dynamic seems likely to continue.[4]

The pale red bars in Figure 4 trace the drop in spare capacity between January 2012 and June 2015 using EIA data on a TTM basis.

Figure 4 – OPEC Spare Capacity Is Likely To Continue Trending Down With Ongoing Contention For Market Share



Source: ClearView Energy Partners, LLC using EIA data as of September 29, 2015

Crude prices reflect consumption, production and inventory dynamics, but prices tend to be higher when the global production system is under more stress. As a result, OPEC spare capacity tends to correlate inversely with global crude prices. Accordingly, our computation of "production system capacity utilization," presented as the blue line in Figure 4, suggests that the global oil supply appears to be under less stress today than it was in previous years. In my view, this appears to result from production having risen faster than (a) spare capacity has fallen and (b) consumption has grown.[5]

Commercial crude inventories also tend to correlate inversely with crude prices. Figure 5 divides one EIA monthly data series by another: OECD commercial crude inventories divided by daily global consumption (the quotient is also known as "days of demand cover"). For perspective, I have also included EIA's forward-looking projections through December 2016 from the September 2015 *Short Term Energy Outlook* (STEO). EIA's outlook suggests a sustained inventory overhang.

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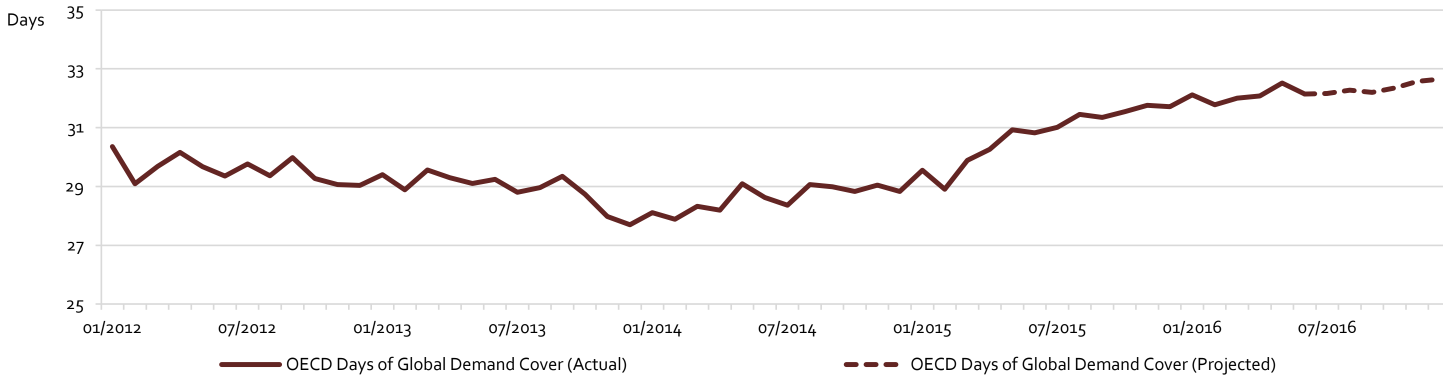
[4] The EIA defines spare capacity as "the volume of production that can be brought on within 30 days and sustained for at least 90 days."

[5] We define production system capacity utilization as

Consumption / (OPEC total liquids + Non-OPEC total liquids + OPEC spare capacity)

and our firm uses it as a simple "dashboard" of oil supply system stress. Statistically, production system capacity utilization exhibits a meaningful positive correlation with real crude prices (~0.59 on a TTM basis between January 1995 and June 2015), but values above 97% tend to be closely correlated with periods of high real crude prices.

Figure 5 – Commercial Inventories Represent a Significant Intermediate-Term Overhang for Crude Production



Source: ClearView Energy Partners, LLC using EIA data as of September 29, 2015

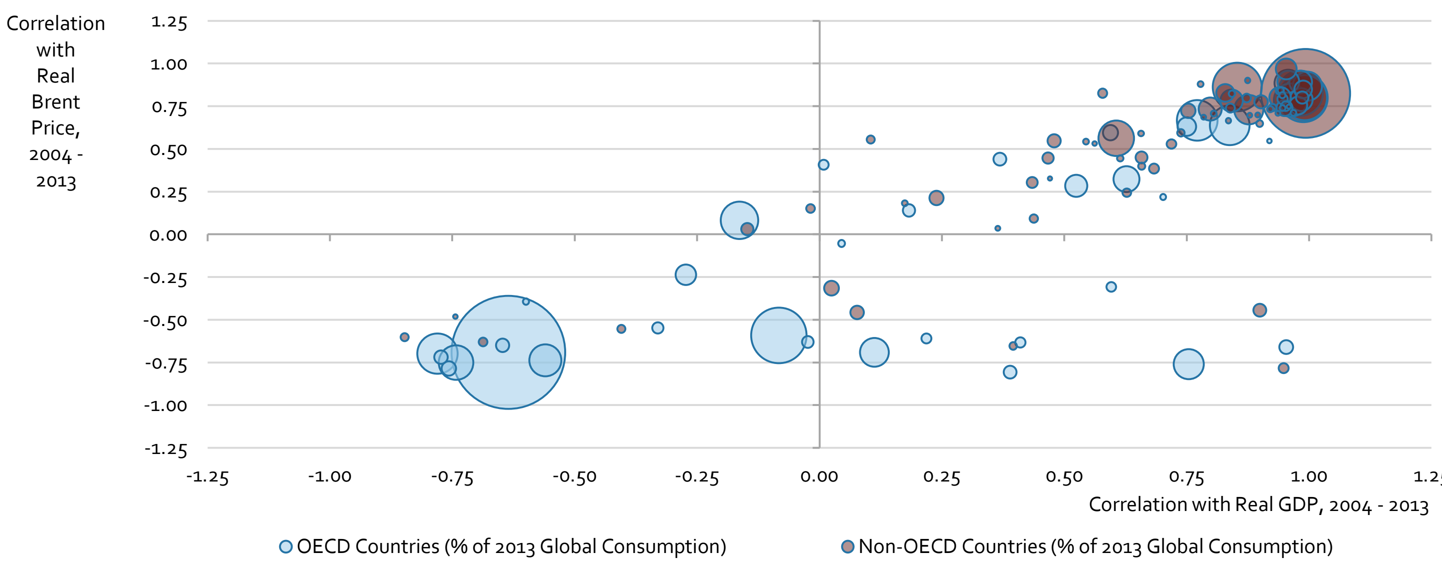
Long inventories and surging production may seem like more good energy security news, but I would be inclined to suggest otherwise. As the saying goes, "low prices are the solution to low prices." As swollen global stockpiles weigh on global markets, today's low prices have potential to stave off the resource investments the world will need tomorrow. At the same time, global supply from existing production continues to decline, and demand isn't likely to stay weak forever. By the time demand recovers, OPEC spare capacity may not be sufficient to buffer the global production system against unanticipated disruptions in a newly tight market.

This raises an important question: when is demand likely to recover? A robust answer lies outside the scope of this testimony, but my short answer is that different components of demand are likely to recover at different times. Industrialized (OECD) country consumption has been trending up this year, but this isn't likely to be the stuff of a demand recovery.[6]

Indeed, our analysis of EIA and World Bank data between 2004 and 2013 shows that non-OECD petroleum demand tends to be primarily correlated with country-level GDP, irrespective of price.[7] In other words, significant petroleum demand growth could return when the fortunes of countries like China, India and Brazil improve.

The quadrant diagram in Figure 6 contrasts the GDP-linked consumption exhibited by non-OECD countries (red bubbles, sized in proportion to 2013 global consumption) with the inverse relationship between price and consumption exhibited by OECD countries (blue bubbles).

Figure 6 – 2004-2013 Correlations between Country-Level Crude Consumption, Real Brent Price and GDP OECD and Non-OECD



Source: ClearView Energy Partners, LLC using BLS, EIA and World Bank data as of September 29, 2015

[6] Between 2004 and 2013, global petroleum consumption grew by a total of about 8.1 MM bbl/d, but this reflected a ~12.1 MM bbl/d *expansion* of non-OECD consumption and a ~4 MM bbl/d *contraction* of OECD petroleum consumption during the course of that decade.

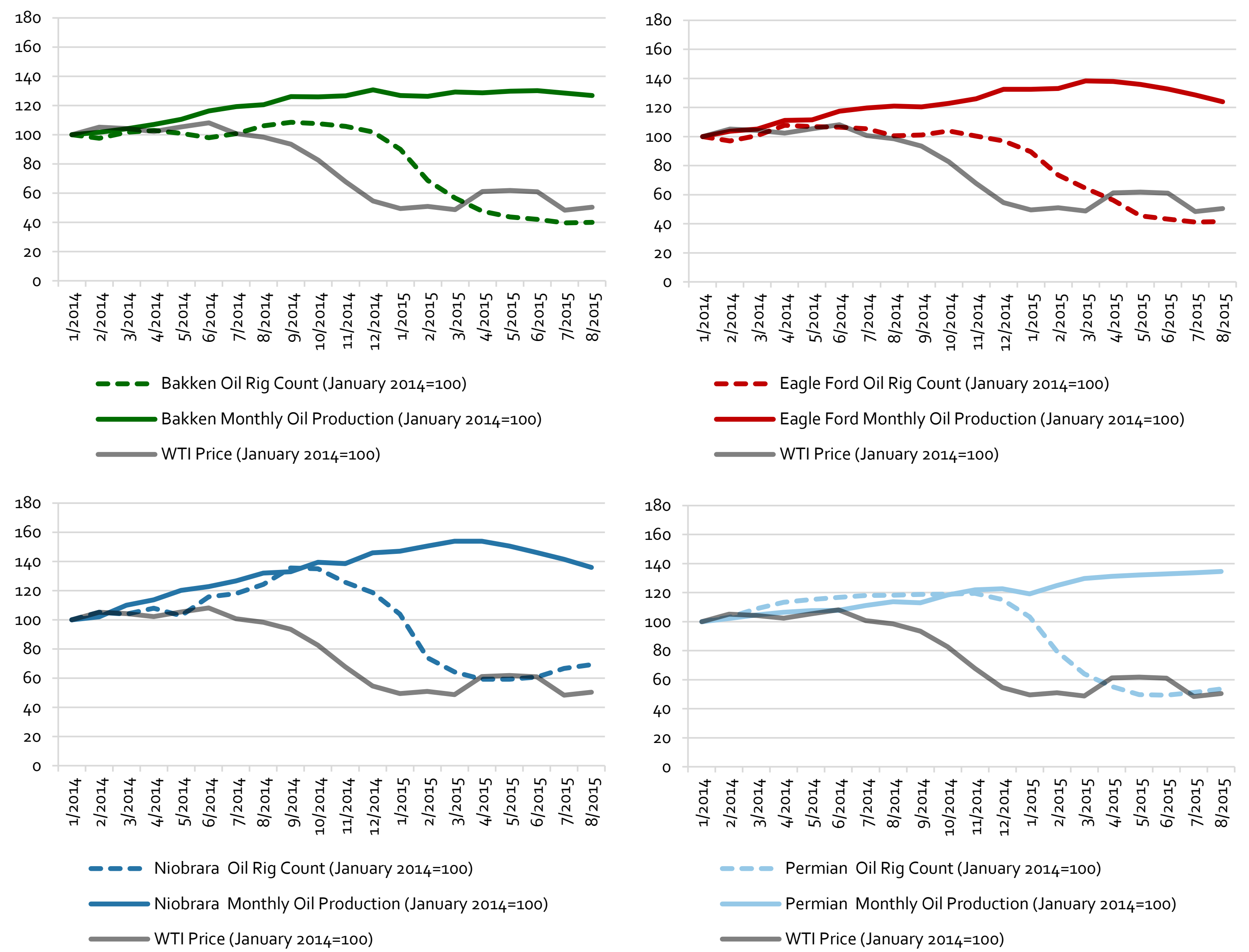
[7] Specifically, we found predominant GDP correlations (correlations that were stronger than correlations with price) in countries that comprised approximately 58% of 2013 consumption, and non-OECD countries made up ~43 percentage points of those 58%.

By the same token, the developed world in general – and the U.S. in particular – can still deliver dramatic, short-term demand spikes under the right circumstances. This year offers a good example. According to EIA data, June 2015 U.S. national gasoline prices averaged approximately 23.4% below year-ago levels. At the same time, total vehicle miles traveled (VMT) and gasoline consumption were both ~3.9% above year-ago levels, representing a gasoline consumption uptick of about 350 kbbl/d.

It is not yet clear to me whether price-responsive consumption was the primary driver of the increase or whether structural factors such as rising employment and disposable personal income levels were responsible for the result. For the purposes of this discussion, however, it may not matter. Low prices seem poised to have an enduring impact on consumption trends. According to St. Louis Fed data, during the 24 months through July 2014, new vehicle sales grew by an average of 6.5% vs. year-ago levels. Over that interval, the automobile share of light duty vehicle sales fell by 4.1%, from 49.2% to 45.1%. With Americans buying a growing number of bigger passenger vehicles, it may be too soon to conclude that U.S. petroleum consumption has peaked.

It may also be premature to conclude that U.S. shale oil production will serve as an adequate substitute for either spare capacity or strategic reserves in the event of a brisk, organic, global demand rebound. Although operators can bring some tight oil wells onstream in less than a month, U.S. shale production does not yet appear to have functioned like spare capacity in the wake of the recent price collapse. Instead, price and production data from the EIA and rig count data from Baker Hughes indicate that *drilling* responded to low prices much more promptly than *production* did, as presented in Figure 7.

Figure 7 – A Four-Basin View of Resilience in the Face of Low Prices: Bakken, Eagle Ford, Niobrara and Permian vs. January 2014



Source: ClearView Energy Partners, LLC using Baker Hughes, Bloomberg and EIA data as of September 15, 2015

Inasmuch as the timing and magnitude of the shale oil supply contraction in response to significantly lower prices was much slower than many analysts (myself included) expected, it seems reasonable to consider the possibility that a shale oil supply expansion in response to significantly higher prices might demonstrate similar latency. In particular, stark job cuts undertaken during a sustained price downturn could prevent some operators from quickly bringing substantial new capacity onstream, at least initially.

A Fair Premium

Is U.S. petroleum insurance too expensive? A robust answer to that question could require a number of heroic assumptions and complex calculations, but my back-of-the-envelope answer is "no." As a simple proxy for the notional "premium" the nation pays on the SPR, I might consider the *pro rata,* present value of SPR maintenance costs over a fixed period of time. *The FY2015 Consolidated and Further Continuing Appropriations Act* (H.R. 83) allocated $200 MM for "Strategic Petroleum Reserve facility development and operations and program management activities." Over a twenty-year period, this annual cost would total $4 B. At a 6% discount rate, the total would be worth ~$2.3 B in 2015 dollars. Holding SPR crude inventories constant at June 2015 levels of 693.89 MM bbl would therefore imply a premium of between ~$3.35/bbl (discounted) and ~$5.76/bbl (nominal) for a 20-year "policy."

What kind of coverage does this premium buy? A non-quantitative answer, given the prospect of recovering demand in a future without meaningful spare capacity, might be "the difference between having oil and not having oil," but that doesn't provide any way to assess whether $3.35 - $5.76/bbl is a good deal. Quantifying the SPR by multiplying total volumes by a given sale price doesn't really answer the question, either. For example, using $63.84/bbl – the twenty-year mean real crude price computed in Figure 1 – looks superficially like a good deal: premiums of $2.3 B provide $44.3 B of "coverage." What this calculation really says, however, is that the twenty-year *option* to sell crude currently valued at $44.3 B costs $2.3 B. Figuring out whether $2.3 B is a fair price for that option would entail making reasoned projections of future crude prices and price volatility that incorporate the odds, size and duration of potential supply disruptions. Any thorough answer should probably also consider "multiplier" effects of price mitigation across the whole of the U.S. economy. This, too, lies outside the scope of my testimony today.

For discussion purposes, I can offer a much more rudimentary, "ballpark" answer. According to EIA data, U.S. petroleum consumption through June 2015 averaged 19.34 MM bbl/d. Based on our short-run Brent model, adding 1 MM bbl/d of supply to the global oil market would correspond to an $11/bbl price decrease. Applying that ratio to TTM average consumption through June 2015 suggests that a 1 MM bbl/d SPR draw could save the nation as much as ~$212.7 MM per day in nominal petroleum costs. In reality, the ratio could be much lower, and it would vary with market conditions, the nature of the disruption in question and the size of any SPR draw(s). But even if I prorate these notional savings by 75% (to a nominal ~$53.2 MM per day), this simple calculation still values the full 693.89 MM bbl of SPR crude inventories at as much as ~$36.9 B.

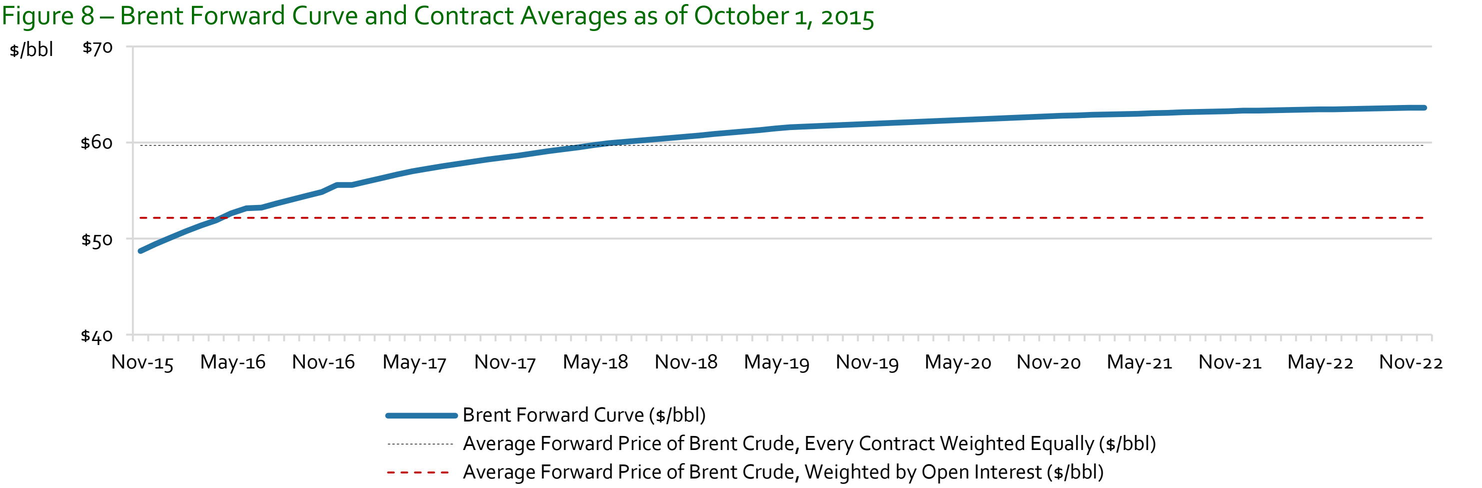
Paying premiums of $4B for twenty-year insurance coverage worth ~$36.9 B seems like a good deal, particularly as this figure does not count multiplier effects across the U.S. economy. A smaller SPR would means less coverage, however. Rationalizing SPR crude inventories at 90 days of net petroleum imports as of June 2015 (on a TTM basis) would require a sale of ~258.36 MM bbl. At $50/bbl, that sale would raise ~$12.9 B, but it would reduce the theoretical coverage value of the SPR by ~$13.7 B to ~$23.2 B. Giving up ~$13.7 B of coverage to raise ~$12.9 B may not necessarily be a good deal.

Buy Low, Sell High

Just as it may be analytically useful to think of the SPR as an insurance policy, proposals to reallocate proceeds from SPR sales to non-energy purposes indicate to me that some Members of Congress may think of the SPR as one of many assets in the portfolio the federal government manages on behalf of the American people. Extending this metaphor, financial managers usually try to match the maturities of the assets and liabilities on their balance sheets. It may not be optimal to liquidate long-term assets like SPR crude inventories for short-term financing purposes. In any case, buying high and selling low certainly seems like a bad strategy.

Figure 8 presents the Brent "forward" curve, which outlines prices for crude deliveries in accordance with the Intercontinental Exchange (ICE) Brent futures contract at monthly intervals between November 2015 and December 2022 as of October 1, 2015.

Figure 8 – Brent Forward Curve and Contract Averages as of October 1, 2015



Source: ClearView Energy Partners, LLC using ICE data as of October 1, 2015

At the time I prepared this testimony on October 1, the November 2015 contract was trading at $48.73/bbl and the December 2022 contract was trading at $63.64/bbl. An equal-weight average of every contract in the curve implied a forward price of $59.72/bbl over the next seven years. A weighted average in proportion to open interest (most of which is concentrated in the near months on the curve) implied a forward price of $52.18 over the same interval. The forward curve is far from an infallible predictor of future prices (it tends to vary with fundamentals as well as investor perceptions), but it does offer a snapshot of current market sentiment *vis-à-vis* crude prices.

Given that SPR crude inventories represent a "sunk cost," Congress may judge that selling them at any price – irrespective of their cost basis – is in the best interest of the American people. Even so, it may be worthwhile to evaluate that cost basis in both nominal and real-dollar terms. Figure 9 does so, taking into account federal appropriations for crude oil purchases and foregone revenues to the Interior Department associated with royalty-in-kind SPR fills.

Figure 9 – We Estimate Average Real Cost of SPR Crude At ~$74/bbl (vs. ~$32/bbl Average Nominal Cost)

Year[1]	Nominal Oil Account Appropriations ($MM)	Nominal Foregone DOI Revenue for Royalty-in-Kind Oil ($MM)[2]	Nominal Crude Acquisition Total ($MM)	Average CPI-U for Year[1]	Inflator (2015=1.00)	Real Crude Acquisition Total ($MM)
1976	$0		$0	56.9	4.14	$0
1977	$440		$440	60.6	3.89	$1,711
1978	$2,703		$2,703	65.2	3.61	$9,766
1979	$2,356		$2,356	72.6	3.25	$7,651
1980	($2,022)		($2,022)	82.4	2.86	($5,786)
1981	$3,205		$3,205	90.9	2.59	$8,308
1982	$3,680		$3,680	96.5	2.44	$8,986
1983	$2,074		$2,074	99.6	2.37	$4,909
1984	$650		$650	103.9	2.27	$1,474
1985	$2,050		$2,050	107.6	2.19	$4,491
1986	($13)		($13)	109.7	2.15	($28)
1987	$0		$0	113.6	2.07	$0
1988	$439		$439	118.3	1.99	$875
1989	$242		$242	123.9	1.90	$460
1990	$372		$372	130.7	1.80	$671
1991	$566		$566	136.2	1.73	$980
1992	$88		$88	140.3	1.68	$148
1993	($1)		($1)	144.5	1.63	($2)
1994	$0		$0	148.2	1.59	$0
1995	($108)		($108)	152.4	1.55	($167)
1996	($511)		($511)	156.9	1.50	($768)
1997	($220)		($220)	160.5	1.47	($323)
1998	$0		$0	163.0	1.45	$0
1999	$0		$0	166.6	1.42	$0
2000	$0	561	$561	172.2	1.37	$768
2001	$0	62	$62	177.0	1.33	$83
2002	$0	263	$263	179.9	1.31	$345
2003	$2	1,044	$1,046	184.0	1.28	$1,340
2004	$0	1,191	$1,191	188.9	1.25	$1,486
2005	$43	1,195	$1,238	195.3	1.21	$1,494
2006	($43)	0	($43)	201.6	1.17	($50)
2007	$0	306	$306	207.3	1.14	$348
2008	$0	1,600	$1,600	215.3	1.10	$1,752
2009	($22)	269	$247	214.6	1.10	$271
2010	$0	0	$0	218.1	1.08	$0
2011	$0	0	$0	224.9	1.05	$0
2012	$0	0	$0	229.6	1.03	$0
2013	$0	0	$0	233.0	1.01	$0
2014	$0	0	$0	236.7	1.00	$0
2015	$0	0	$0	235.7	1.00	$0
Total ($MM)	**$15,970**	**$6,491**	**$22,461**			**$51,195**
Average ($/bbl) [4]			**$32.37**			**$73.78**

Notes

1. Amounts appropriated reflect government fiscal years, which end September 30 (rather than December 31), so calculation represents a rough approximation.
2. Royalty-in-kind estimate based on volumes obtained by Interior Department at prevailing prices and royalty rates.
3. We estimate that Congressional reallocation of the $3.2B proceeds from the June 11 sale had the effect of raising the average acquisition cost of SPR crude by ~$4.50/bbl in nominal terms and ~$4.80/bbl in real terms.
4. Average based on June 2015 inventory levels of 693.89 MM bbl.

Source: ClearView Energy Partners, LLC using BEA, DOE, EIA and Interior Department data

The calculations in Figure 9 result in an estimated average acquisition cost of SPR crude of ~$32/bbl in nominal terms. Applying the CPI-U as an inflator implies a real average acquisition cost of ~$74/bbl, above the Brent forward curve through the end of 2022.

Diversification into Products

The current architecture of the SPR primarily relies on the nation's world-class refinery infrastructure to transform feedstock crude oil into higher value products for intermediate and end-use consumption. In my view, further diversification of the SPR into regional petroleum products reserves (RPPRs) could result in a combination of implementation challenges and unintended consequences.

Products selection presents an obvious implementation challenge. The 2013-2014 propane shortage during the "polar vortex" presented grave threats to the 37% of Midwestern households that rely on propane as their primary home heating fuel, and it was something of a surprise. EIA's 2013 Winter Fuels Outlook projected that propane inventories would "remain near the middle of their historical range during the upcoming winter." To my way of thinking, the propane shortage may call into question whether the Department of Energy (DOE) can have enough visibility into future, region-specific petroleum products needs to commit capital to operating segregated products storage and distribution infrastructure on a long-term basis.

Blissfully, the Midwest propane shortage also appears to have been a one-time event. In my view, this may be because market forces responded to prior-year price signals by mustering significant inventories ahead of the 2014-2015 heating season. This raises a second potential implementation challenge: can any drawdown of government-operated emergency stockpiles avoid muting the price signals that inform the behaviors of all market participants (suppliers and consumers alike)?

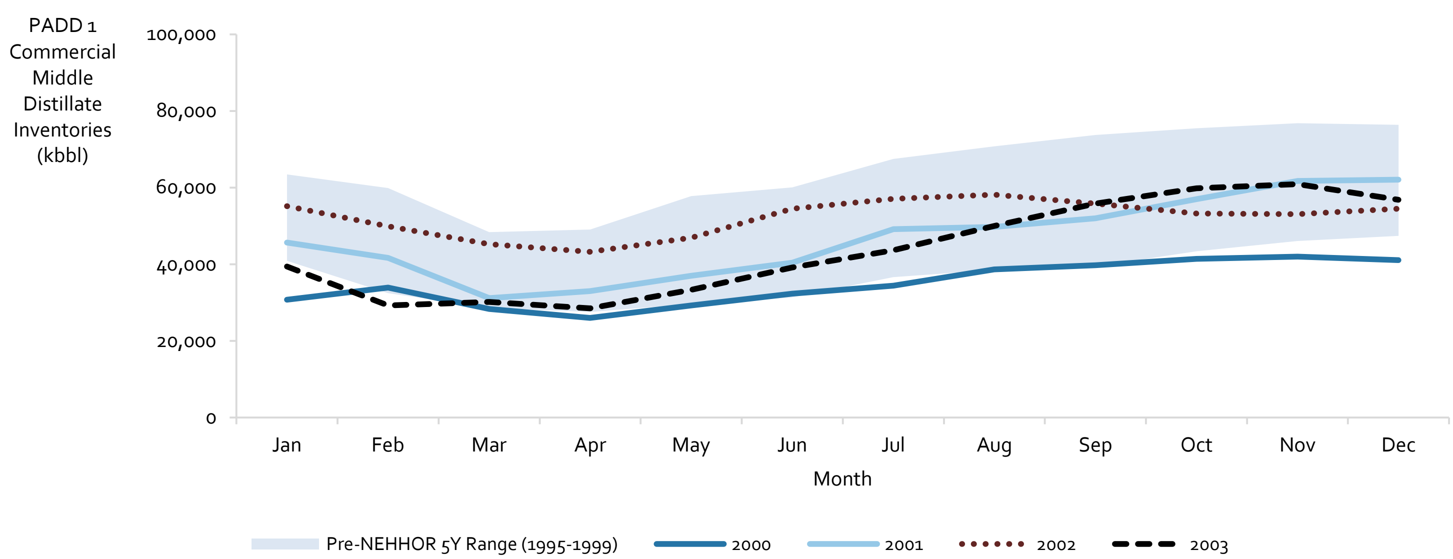
According to the DOE website, the Northeast Gasoline Supply Reserve (NGSR) that Energy Secretary Ernie Moniz created in 2014 as a response to Superstorm Sandy contains "700,000 barrels of gasoline located in the New York Harbor area, 200,000 barrels positioned in the Boston area, and 100,000 in South Portland, Maine." Based on Federal Highway Administration (FHWA) data through June 2015, I would estimate that inventories in the New York Harbor correspond to ~1.9 days of New York state gasoline demand and the combined New England stockpiles correspond to about one day of demand for Massachusetts, Maine, New Hampshire and Vermont.

It remains to be seen how – and whether – DOE might use the NGSR. The reserves are large enough relative to regional consumption that drawing them down could reduce gasoline prices during a major supply disruption, but their finite scale could also have the less desirable result of encouraging hoarding by drivers who fear that emergency fuel resources might be exhausted before commercial supplies are restored. At the same time, the NGSR is large enough to send one or several inbound products tankers to ports of call *without* RPPRs in pursuit of better spot prices, possibly delaying the replenishment of commercial stocks.

Over a longer time period, RPPRs could potentially shift investment from private operators to the federal government without meaningfully increasing energy security. The nation's first RPPR, the Northeast Home Heating Oil Reserve (NEHHOR), was created by President Clinton in July 2000 and filled in October of that year. The DOE SPR website emphasizes that NEHHOR's original, 2 MM bbl size was intended to be sufficiently large to buffer against supply shortfalls, but not so large as to undercut price signals or deter commercial operators from investing in inventories. A cursory look at historical data suggests a different outcome.

In 2000, commercial middle distillates inventories across the whole of PADD 1 fell below the pre-NEHHOR, 5Y range and remained so throughout the year before recovering to the middle of the pre-NEHHOR range in 2001, 2002 and 2003, as presented in Figure 10.[8]

Figure 10 – PADD 1 Commercial Middle Distillates Inventories, 5Y Pre-NEHHOR Range and 2000-2003

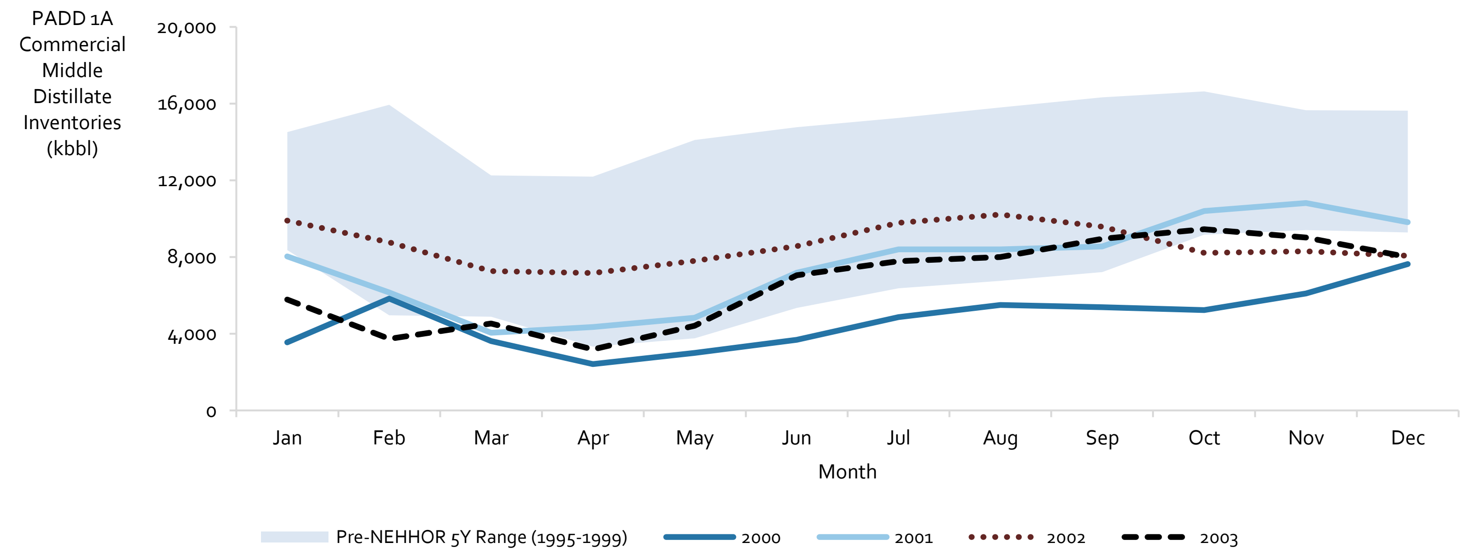


Source: ClearView Energy Partners, LLC using EIA data

[8] I confined my analysis to the immediate, post-NEHHOR years because commercial operators generally thinned inventories to manage working capital as Chinese demand growth drove oil prices beyond the $22-28/bbl OPEC "price band" in 2004 and thereafter.

In PADD 1A – the New England states where NEHHOR is located – commercial middle distillates inventories fell much further below the 1995-1999 range than they did in PADD 1 as a whole, as presented in Figure 11.

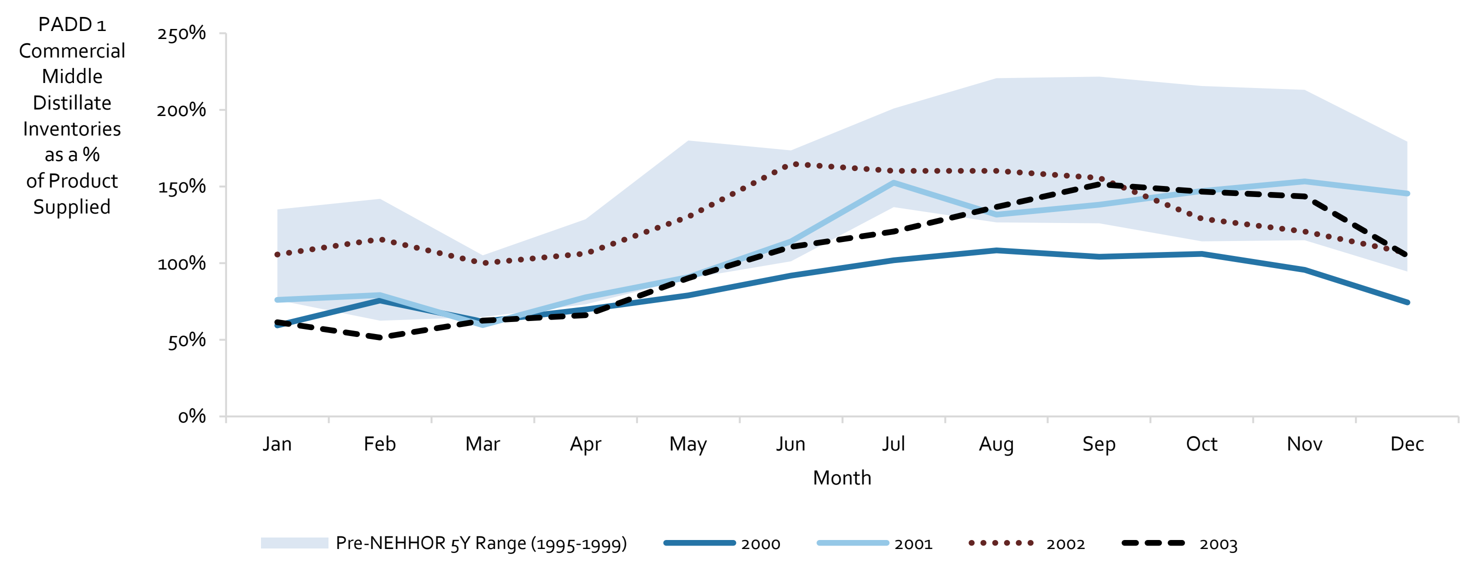
Figure 11 – PADD 1A Commercial Middle Distillates Inventories, 5Y Pre-NEHHOR Range and 2000-2003



Source: ClearView Energy Partners, LLC using EIA data

PADD 1A levels never recovered, and I would suggest that 9/11-related and recessionary pressures on middle distillates demand in general may have accounted for their modest uptick in 4Q2001. Markedly lower commercial middle distillates inventories as a percentage of monthly product supplied across the whole of PADD 1 in 2000, 2002 and 2003 would appear to reinforce this explanation, as presented in Figure 12.

Figure 12 – PADD 1 Commercial Middle Distillates Inventories as % of Product Supplied, 5Y Pre-NEHHOR Range and 2000-2003



Source: ClearView Energy Partners, LLC using EIA data

At first blush, this analysis would imply that government investment in products inventories may have deterred private investment, potentially countering some of energy security benefits of a heating oil reserve. If this conclusion is correct, I would not rule out a similar result for the NGSR in PADD 1A (although it is too soon for a comparable retrospective) and any other future RPPRs.

Madam Chairman, this concludes my prepared testimony. I will be happy to take any questions at the appropriate time.