TESTIMONY OF KEVIN BOOK
MANAGING DIRECTOR, RESEARCH, CLEARVIEW ENERGY PARTNERS, LLC
BEFORE THE
U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
JUNE 9, 2011

Chairman Bingaman, Ranking Member Murkowski and distinguished Members of this Committee, thank you for the privilege of contributing to your discussion today. My name is Kevin Book and I lead the research team at ClearView Energy Partners, LLC, an independent research and consulting firm here in Washington, D.C. that serves institutional and corporate energy investors.

Energy Security and Financial Prudence

Mr. Chairman, I am encouraged that this Committee continues to explore policies to promote efficiency gains and alternative fuels amid the dire fiscal circumstances that confront our nation. My clients – the investors who may capitalize some of the policies you are discussing today – frequently ask how tough decisions and stark reductions might shift energy policy priorities. Many of our clients share my view[i] that subsidizing or assuring loans can, in many cases, promote diffusion of innovative technologies at lower taxpayer cost than paying out cash grants or "tax equity".

Either way, I would suggest that energy subsidies that do not set a glide path towards unsubsidized profitability are unlikely to meet the explicit goal of reducing federal spending. In my experience, when governments give net financial rewards to the consumers or producers of otherwise non-economic energy resources, the payees take as much as they can[ii]. Academic research suggests this is less true of energy efficiency subsidies: "rebound demand" (using more because each unit is cheaper) tends to erode only a small portion of energy savings[iii]. In this context, "government-first" policies that target the considerable energy consumption by state and federal buildings and fleets offer two potential benefits: (1) reducing government spending, provided that fuels and technologies track towards unsubsidized profitability; and (2) creating a sales opportunity large enough to promote competition among producers so that they might achieve scale economies, potentially bringing down costs for industrial, business and residential customers.

Accelerating behavior change and infrastructure turnover to promote energy security has a financial cost, but energy security and fiscal prudence are different goals. Some policy choices may combine energy security with fiscal prudence better than others. For example, government loans that enable automakers to successfully retool for greater fuel economy could deliver financial returns if the loans are repaid, paying energy security dividends with every new vehicle mile driven between the showroom and the scrap heap. Alternatively, diversifying and increasing energy supplies by subsidizing production or consumption of alternative fuels may have strategic importance that overshadows the associated financial costs.

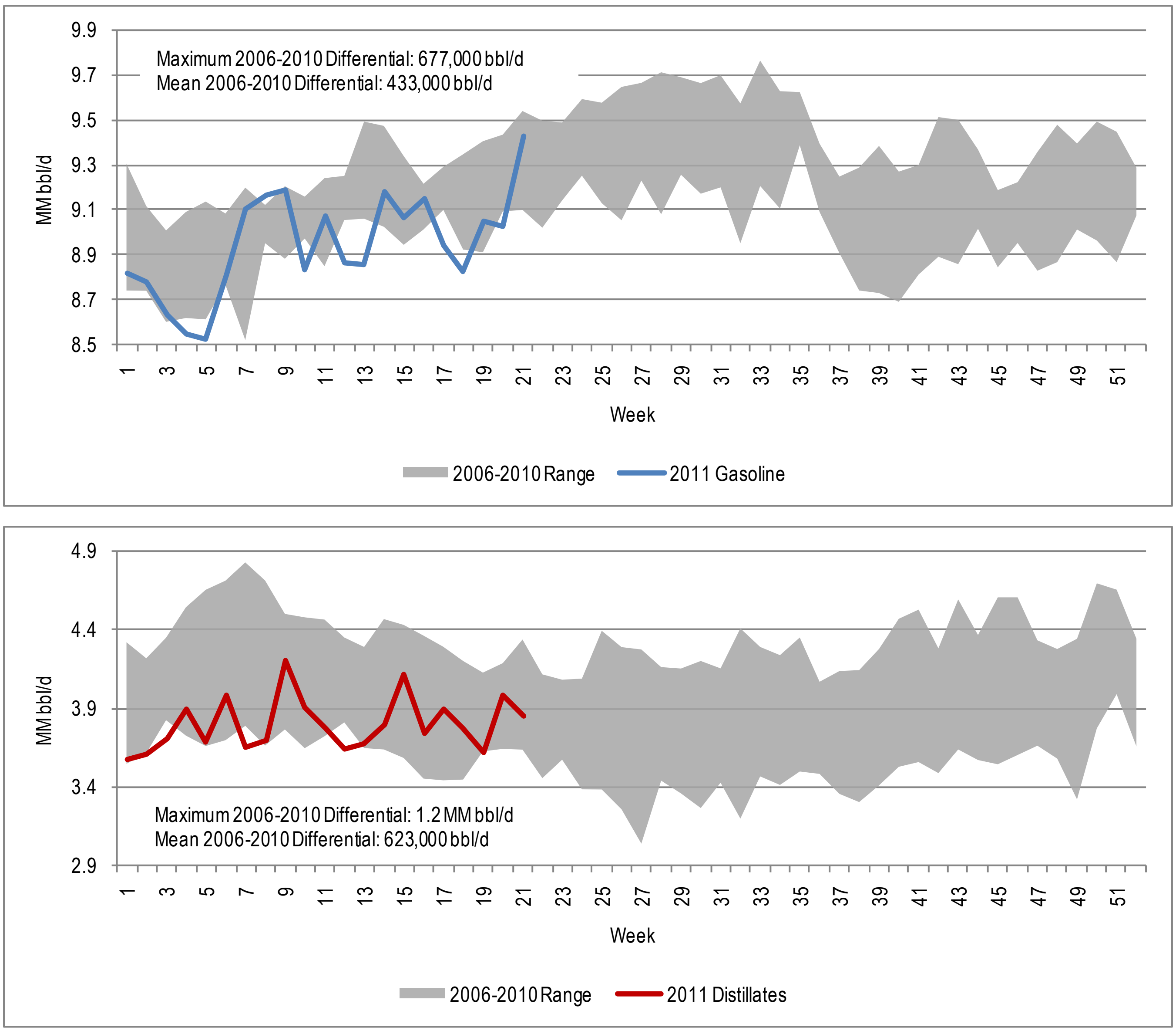
The open question appears to be how the relevant U.S. federal agencies should offset the costs of explicit subsidies and source the working capital with which to make or guarantee loans. Financing efficiency retrofits and alternative fuels with proceeds from new oil and gas production could be a fiscally prudent way to do it, provided that spending does not get ahead of the leasing and permitting activities that generate revenues. On the other hand, selling oil out of the Strategic Petroleum Reserve (SPR) to pay for efficiency gains and alternative fuels could seriously diminish U.S. energy security without necessarily delivering financial benefits. The remainder of my testimony today addresses this topic.

Demand Changes Could Change Producer Priorities

For the moment, the U.S. remains the world's top oil consumer and its primary destination market for exports. More importantly, changes in U.S. domestic consumption can still outstrip demand growth from fast-growing, non-OECD nations. Both of these things are likely to imminently change.

The shaded "ranges" in Figure 1 present maximum and minimum weekly U.S. gasoline and distillate fuels consumption between 2006 and 2010, as computed by the U.S. Energy Information Administration (EIA). The blue and red lines trace gasoline and distillate consumption, respectively, through the first 21 weeks of 2011. Taken together, the shaded regions represent the 1.9 MM bbl/d of peak-to-trough "swing" demand contraction that emerged as the Great Recession deepened. Averaging across all 52 weeks and five years implies about 1.05 MM bbl/d of U.S. end-user demand headroom.

Figure 1 – U.S. End-Users Still Matter When it Comes to Global Oil and Oil Products Supply/Demand Balances…For Now



Source: ClearView Energy Partners, LLC using EIA data

Changing demand dynamics. Figure 1 shows that U.S. consumption has been trending towards the low end of the five-year range for gasoline and distillates, despite a possible early indication that demand rose in response to falling gasoline prices. Leaving aside short-run demand volatility, much of which can be linked to data resolution[iv], Figure 1 depicts one side of a story that is now widely understood: global petroleum demand changed dramatically during the last decade. Consumption patterns flattened out within industrialized economies at the same time that oil products demand from non-OECD nations grew by an average of about 3.3% per year between 2001 and 2010, according to International Energy Agency (IEA) data. This represented an average annual increase of about 1.086 MM bbl/d – in other words, annual growth within emerging economies may be theoretically sufficient to offset a maximum "average" U.S. demand contraction. Moreover, the pace of this non-OECD growth has been accelerating at an average rate of about $8.3\%/Y^2$; had it not been for the global economic slowdown, the slope of the trend would probably have been much steeper.

Price implications. The implications of this change for oil prices are relatively easy to interpret, despite disheartening recent data that suggest slowing growth here at home. Nominal and currency-adjusted crude oil prices have risen because global demand growth has largely outpaced global supply growth. Supply is catching up, but production from new marginal and unconventional sources is more costly than the oil already in production.

Energy security implications. The implications for energy security may be less obvious, however. The U.S. is losing its importance as a source of marginal petroleum demand. The moment may soon arrive – possibly as soon as 2013 – when a U.S. demand decline could be wholly offset at the margin by growth from emerging economies, without any significant global price weakness.[v]

Why does this matter? Because the biggest customers usually get the best treatment in any business context. A large part of U.S. energy security comes from our strong commercial ties with our suppliers. Strategic alliances provide another tier of assurance. To extend the metaphor: if one cannot be the biggest customer, friendships and favors can go a long way towards securing favorable terms. And what if friendships break down? Getting fair treatment from a neutral or hostile supplier who sells to a highly competitive customer base would probably require something else: a big stick.

Thanks to the foresight and diligence of this and prior Congresses, we have one: the SPR.

First and foremost, the SPR is America's insurance policy against a serious petroleum supply interruption. As with individual policyholders, it seems appropriate for national purchasers of insurance to periodically re-examine their coverage options in light of any changes in their physical and financial circumstances. Accordingly, Section 202(a) of the Alternative Fuel Vehicles Competitiveness and Energy Security Act of 2011 (S. 1001) includes the following language:

> *(a)—Section 154(a) of the Energy Policy and Conservation Act (42 U.S.C. 6234(a)) is amended by striking ''1 billion barrels of petroleum products'' and inserting ''the quantity of crude oil and petroleum fuels imported into the United States each year from countries that are not signatories to North American Free Trade Agreement during an average 90-day period during the most recent calendar year for which data are available''.*

Figure 2 presents my interpretation of this provision using latest-available EIA data.

Figure 2 – Nominal and Real Net Proceeds from "Balancing" Strategic Petroleum Reserve Crude at Target Levels Implied by S.1001 Sec. 202

Year	Net Imports from Canada (000 bbl/d)	Net Imports from Mexico (000 bbl/d)	Net Imports, Total World (000 bbl/d)	90 Days of Non-NAFTA Net Imports (MM bbl)	Year-End SPR (MM bbl)	Nominal Annual Average Refiner Acquisition Cost ($/bbl)	Nominal Cost or (Benefit) of Balancing SPR Inventory ($ MM)	CPI-U Inflator (2010$=100)	Real Cost or (Benefit) of Balancing SPR Inventory ($ MM)
1976	571	53	7,090	582		$10.89	$6,337	3.897	$24,698
1977	446	155	8,565	717	7	$11.96	$8,486	3.704	$31,434
1978	359	291	8,002	662	69	$12.46	$7,391	3.467	$25,625
1979	438	418	7,985	642	92	$17.72	$9,744	3.173	$30,915
1980	347	506	6,365	496	108	$28.07	$10,899	2.785	$30,356
1981	358	497	5,401	409	230	$35.24	$6,302	2.491	$15,697
1982	397	632	4,298	294	294	$31.87	$13	2.298	$30
1983	471	802	4,312	274	379	$28.99	($3,061)	2.216	($6,782)
1984	547	714	4,715	311	451	$28.63	($3,998)	2.126	($8,501)
1985	696	755	4,286	255	493	$26.75	($6,371)	2.054	($13,084)
1986	721	642	5,439	367	512	$14.55	($2,106)	1.977	($4,164)
1987	765	585	5,914	411	541	$17.90	($2,324)	1.949	($4,529)
1988	916	677	6,587	449	560	$14.67	($1,614)	1.873	($3,023)
1989	839	678	7,202	512	580	$17.97	($1,226)	1.789	($2,195)
1990	843	666	7,161	509	586	$22.22	($1,711)	1.701	($2,911)
1991	963	707	6,626	446	569	$19.06	($2,334)	1.610	($3,758)
1992	1,005	706	6,938	470	575	$18.43	($1,922)	1.569	($3,015)
1993	1,109	809	7,618	513	587	$16.41	($1,216)	1.520	($1,848)
1994	1,194	860	8,054	540	592	$15.59	($806)	1.482	($1,195)
1995	1,260	943	7,886	511	592	$17.23	($1,381)	1.442	($1,990)
1996	1,330	1,101	8,498	546	566	$20.71	($409)	1.403	($575)
1997	1,444	1,178	9,158	588	563	$19.04	$473	1.362	$644
1998	1,451	1,116	9,764	648	561	$12.52	$1,085	1.341	$1,454
1999	1,421	1,063	9,912	669	567	$17.51	$1,778	1.319	$2,344
2000	1,697	1,015	10,419	694	541	$28.26	$4,322	1.284	$5,548
2001	1,717	1,166	10,900	722	550	$22.95	$3,932	1.238	$4,866
2002	1,864	1,292	10,546	665	599	$24.10	$1,591	1.224	$1,946
2003	1,932	1,395	11,238	712	638	$28.53	$2,100	1.193	$2,504
2004	1,980	1,456	12,097	779	676	$36.98	$3,842	1.170	$4,495
2005	2,001	1,394	12,549	824	685	$50.24	$7,001	1.136	$7,956
2006	2,194	1,450	12,390	787	689	$60.24	$5,936	1.093	$6,486
2007	2,266	1,254	12,036	766	697	$67.94	$4,725	1.071	$5,058
2008	2,229	969	11,114	712	702	$94.74	$1,008	1.027	$1,035
2009	2,241	912	9,700	589	727	$59.29	($8,145)	1.026	($8,359)
2010	2,320	833	9,440	566	727	$76.69	($12,329)	1.000	($12,329)
Cumulative Nominal Net Cost or (Benefit), 1991-2010							$9,249		
Cumulative Real Net Cost or (Benefit), 1991-2010									$11,268

Source: ClearView Energy Partners, LLC using data from EIA, DOE (SPR Annual Report) and BLS

Sales volume. By my estimate, fulfilling the directive within 202(a) would require a sale of approximately 161 MM bbl of crude oil from the SPR, reducing it from 726.6 MM bbl to 565.8 MM bbl. Using our internal CY2011 WTI price projection of $92/bbl, this sale would theoretically yield approximately $14.8 billion towards alternative fuels and vehicle efficiency spending! At prevailing WTI front-month futures prices of $100.85/bbl, the sale would theoretically generate approximately $16.2 billion! In practice, both projections are probably more than what an actual sale might bring in.

Price impacts. The mere act of declaring a sale this large is likely to be very disruptive to oil prices, at least the first time it happens. It's hard to know precisely how events might unfold, but the crude futures curve would probably steepen. Near-term contracts might sell at a deep discount as highly leveraged commercial buyers rushed to close their long positions and unravel their hedges at the same time that speculators established short positions in near months. Meanwhile, commercial and noncommercial players might also have reasons to stake out long positions in the out months on the expectation that OPEC would respond to the sale by cutting production.

Market dynamics. This calls into question the very premise for the sale in the first place – the notion that NAFTA production can be netted out of U.S. strategic assets because it faces differentially lower disruption risk. Although disruption risk is considerably lower in Canada and Mexico, Canadian and Mexican crude oil are sold at prices that reflect global supply-demand dynamics. Selling 161 MM bbl at today's market price leaves the U.S. vulnerable to having to buy them back at market price premiums in the event of a disruption tomorrow. More ironically, if the initial Section 202(a) sale were to send the crude strip into a steep contango (long-dated contract prices higher than near-term contract prices), selling today could actually *cause* a higher acquisition cost for U.S. refiners tomorrow.

Replacement costs. It is hard, if not impossible, to accurately quantify how future prices might rise or fall in response to geopolitical events, but it seems fair to assume that any major future disruption that impairs capacity of the global production system would probably raise prices and draw on inventories, increasing the vulnerability of U.S. refiners to further disruptions and raising odds for an SPR draw or exchange. On a nominal basis, purchasing oil to replace the oil drawn out of the SPR in this scenario would probably cost more tomorrow than the government might earn by selling it today. On the other hand, the real cost could be lower if the sale happens far enough in the future or, as in 2008, a recession creates a buying opportunity for governments looking to fill their strategic reserves.

Back-test. It is very easy, however, to look backward and ask whether excluding NAFTA from SPR assets in this fashion would have been cost-effective. My answer is no. Figure 2 also includes a simplified "gaming out" of the twenty-year interval from 1991-2010 if the U.S. government had sold the actual SPR whenever it exceeded the levels dictated by Section 202(a): on a nominal basis, the U.S. would have lost a theoretical $9.3 billion playing that game. Using the CPI-U with 2010 as a base year to capture inflation implies a theoretical loss of about $11.3 billion. This illustrates another point: when oil prices are rising faster than producer or consumer prices in general, it pays to hold onto the oil and sell high.

Figure 3 presents an estimate of the nominal and real costs of buying oil to fill the SPR.

Figure 3 – Approximate Gross Total and Per-Barrel Crude Cost of Strategic Petroleum Reserve (Nominal and Real, Using 2010$=100)

Year	Nominal Oil Account Appropriations ($ MM)	Nominal Foregone DOI Revenue for Royalty-in-Kind Oil ($ MM)	Real Oil Account Appropriations ($ MM)	Real Foregone DOI Revenue for Royalty-in-Kind Oil ($ MM)
1976	$0		$0	
1977	$440		$1,630	
1978	$2,703		$9,373	
1979	$2,356		$7,476	
1980	($2,022)		($5,632)	
1981	$3,205		$7,983	
1982	$3,680		$8,455	
1983	$2,074		$4,595	
1984	$650		$1,382	
1985	$2,050		$4,210	
1986	($13)		($26)	
1987	$0		$0	
1988	$439		$822	
1989	$242		$433	
1990	$372		$633	
1991	$566		$912	
1992	$88		$139	
1993	($1)		($1)	
1994	$0		$0	
1995	($108)		($155)	
1996	($511)		($717)	
1997	($220)		($300)	
1998	$0		$0	
1999	$0		$0	
2000	$0	$561	$0	$720
2001	$0	$62	$0	$76
2002	$0	$263	$0	$321
2003	$2	$1,044	$2	$1,245
2004	$0	$1,191	$0	$1,394
2005	$43	$1,195	$49	$1,357
2006	($43)	$0	($47)	$0
2007	$0	$306	$0	$328
2008	$0	$1,600	$0	$1,643
2009	($22)	$269	($22)	$276
2010	$0	$0	$0	$0
	$15,971	$6,490	$41,192	$7,360
Approximate Gross Total Cost ($ MM)	$22,461		$48,552	
Approximate Gross Average Cost ($/bbl)	$30.91		$66.82	

Source: ClearView Energy Partners, LLC using data from EIA, DOE (SPR Annual Report) and BLS

Better safe than sorry. The nominal total presented in Figure 3 of about $22.5 billion implies a gross average cost of oil to fill the SPR of about $31/bbl. Using the CPI-U as an inflator implies a total real cost of about $48.6 billion and a corresponding gross average cost of about $67/bbl. On the surface, selling 22% of the SPR for 33% of the real cost basis of the whole Reserve seems like a winning trade. So what's the problem? The nation is not yet technologically capable of transitioning 22% of its transportation energy demand to non-petroleum sources. In other words, although it doesn't make economic sense to buy insurance one no longer needs, it makes even less economic sense to give up insurance one still requires only to buy it back later at a higher price. And, as I noted in the first section of my testimony, supply risks may be increasing as the commercial importance of U.S. import demand decreases; it seems a more appropriate time to be expanding our insurance coverage – including new domestic production, greater fuel economy and broader fuels diversification – rather than reducing it.

As insurance goes, the SPR is pretty cheap. Figure 4 presents a simplified accounting of the subsidy costs associated with increasing annual U.S. ethanol consumption from 83 MM gal/Y in 1981 to 13.5 B gal/Y in 2010. Unlike many of the polemical efforts to "fully account" for ethanol subsidy costs, Figure 4 counts only the notional tax revenue lost due to the Volumetric Ethanol Excise Tax Credit (VEETC).

Figure 4 – Price and Payout of U.S. Ethanol Subsidies (VEETC Only)

Year	Ethanol Volume (MM gal/Y)	VEETC ($/gal)	Nominal Cost ($MM/Y)	Real Cost (MM 2010$/Y)
1981	83	$0.40	$33	$83
1982	225	$0.50	$113	$259
1983	415	$0.50	$208	$460
1984	510	$0.50	$255	$542
1985	617	$0.60	$370	$760
1986	712	$0.60	$427	$845
1987	819	$0.60	$491	$958
1988	831	$0.60	$499	$934
1989	843	$0.60	$506	$905
1990	748	$0.60	$449	$763
1991	866	$0.54	$468	$753
1992	985	$0.54	$532	$835
1993	1,151	$0.54	$622	$944
1994	1,289	$0.54	$696	$1,032
1995	1,383	$0.54	$747	$1,077
1996	992	$0.54	$536	$752
1997	1,256	$0.54	$678	$924
1998	1,388	$0.54	$750	$1,005
1999	1,443	$0.54	$779	$1,028
2000	1,653	$0.54	$893	$1,146
2001	1,741	$0.53	$923	$1,142
2002	2,073	$0.53	$1,099	$1,344
2003	2,826	$0.52	$1,470	$1,752
2004	3,552	$0.52	$1,847	$2,161
2005	4,059	$0.51	$2,070	$2,352
2006	5,481	$0.51	$2,795	$3,054
2007	6,886	$0.51	$3,512	$3,759
2008	9,683	$0.51	$4,938	$5,070
2009	10,847	$0.45	$4,881	$5,009
2010	13,508	$0.45	$6,079	$6,079
Total			$39,663	$47,725
Per-Barrel Cost ($/bbl/Y)			$123.32	$148.39

Source: ClearView Energy Partners, LLC using data from EIA, BLS and the Renewable Fuels Association

This cursory assessment implies that the last thirty years of ethanol subsidies added up to a nominal total cost of about $40 B and a real total cost of about $47.7 B – approximately the same on a real dollar basis as the cumulative acquisition cost of oil for the SPR. Counting ethanol gallon-for-gallon as a gasoline replacement (rather than prorating it for energy content, a frequent convention), this implies a nominal petroleum displacement cost of about $123/bbl and a real petroleum displacement cost of about $148/bbl – more than twice the displacement cost of the oil in the SPR[vi].

The proposal in Section 202(a) has historical precedent. In 1996, DOE also conducted three SPR sales for fundraising purposes. It seems unlikely that those sales, a total of 27.1 MM bbl, seriously impaired U.S. energy security. On the other hand, as I noted earlier, that was then. Not only do differentially tighter global market conditions and increasingly volatile geopolitical circumstances inject new risks, but the differentially greater size of today's SPR means that selling it without a strategic catalyst may leave a powerful implicit asset on the table: negotiating power.

Signposts to the SPR. Most histories of the petroleum industry highlight the concession granted to Standard Oil Company of California by Saudi Arabia to explore Hasa Province on May 29, 1933 as the beginning of U.S. reliance on foreign oil, even though exploration throughout the Persian Gulf and Arabian Peninsula began decades earlier. In a similar vein, most accounts of U.S. policy responses to oil shocks center around the October 17, 1973 Arab Oil Embargo, despite the many smaller policy actions taken in anticipation of, or response to, the complications U.S. producers encountered during the four prior decades of producer-led efforts to secure the market power OPEC enjoys today. Surprisingly, I have encountered very little (beyond the DOE website) written about another critical moment within the same narrative: November 18, 1985, the date of the SPR's 967,000 bbl "test" sale, a moment which may have been equal parts proof of concept and détente.

The defensive "oil weapon". Recent conversations with former senior U.S. and international energy security officials have reinforced my suspicion that the SPR may have served, on several occasions, as far more than an insurance policy against a supply interruption, but also as a negotiating tool to persuade producers to respond to market dislocations by ramping up production instead of banking scarcity premiums. Just as weapons tests during the Cold War gave credibility to nuclear détente, the 1985 test sale and 13 other catalyst-driven sales and exchanges since 1985 may have helped to reinforce petroleum détente. Based on my conversations with producers, the DOE projection that a maximum SPR draw could deliver 4.4 MM bbl/d into the market for 90 days is widely accepted as credible and realistic.

Payload. As defensive "weapons" go, 4.4 MM bbl/d is a non-trivial payload: that volume is approximately equal to estimated OPEC spare capacity during 1Q2009, when the price of oil plummeted below $40/bbl. Although OPEC producers could ultimately outlast price pressures during a full drawdown of the world's strategic reserves (the SPR plus the other IEA nations' combined crude and products reserves), doing so might prove to be a very costly choice. Not only might the ensuing price shock motivate unprecedented OECD investment flows into petroleum alternatives, but it's not clear how well OPEC itself would cohere during an all-out "oil war". Given the choice between selling incremental barrels into a tight market and facing off against IEA reserves, low-cost producers might prefer to share the gains associated with a coordinated increase in production rather than either (a) reducing revenues and potentially taking losses by undercutting SPR-mitigated market prices; or (b) ceding market share to competing, higher-cost producers who might choose to opportunistically defect from the cartel.

Conclusion

As I have testified in the past, petroleum fuels about 95% of global demand for transportation energy because of economic and physical realities, not ideological preferences[vii]. Oil is energy dense, broadly available, physically stable and readily shipped. During the 152 years since the Drake well in Titusville, Pennsylvania inaugurated commercial petroleum production, generations of scientists, engineers and political leaders have rigorously assayed a wide universe of alternatives. No fuel or technology has emerged as an economically viable, scalable or sustainable long-term substitute.

Although a "drop-in" or "plug-in" replacement for petroleum is unlikely to emerge anytime soon, we won't find one – or even a better way to improve supply diversity – if we don't look for it, and we won't look if we don't spend money on it.

I strongly support this Committee's continuing efforts to encourage greater vehicle efficiency and to explore fuel and vehicle technology alternatives, but not at the expense of this nation's well-conceived and highly effective energy security insurance policy.

This concludes my prepared testimony. I will look forward to any questions at the appropriate time.

---

[i] Testimony of Kevin Book before the U.S. Senate Committee on Energy and Natural Resources, February 12, 2009. http://www.cvenergy.com/public_testimony/2009-02-12-Kevin_Book-ENR_Testimony.pdf.

[ii] The repeated revisions and rescissions of European feed-in tariffs for alternative power technologies are well known, but examples abound here in the U.S., too. For example, see Maykuth, A., "Solar Energy Output is Outpacing Pennsylvania Mandate", *Philadelphia Inquirer*, June 5, 2011, http://articles.philly.com/2011-06-05/business/29623348_1_solar-advocates-solar-industry-solar-markets.

[iii] Schipper, L. and M. Grubb. "On the Rebound? Feedback between Energy Intensities and Energy Uses in IEA Countries". *Energy Policy:* Volume 28, Issues 6-7, June 2000, Pages 367-388.

[iv] Four week "moving averages" smooth out some of this jaggedness, but the jaggedness can be analytically interesting as an early indication of a changing trend, so I used weekly data for Figure 1. Both are available on the EIA website.

[v] A slow recovery from the Great Recession or a "double-dip" may obscure the extent of this change because emerging economies' energy demand is still strongly linked to the financial circumstances of their export markets.

[vi] This is not a perfect comparison because it does not capture the recurring nature of ethanol supplies (for an incremental cost, of course) relative to the finite nature of the SPR. Even so, the terminal value of ongoing ethanol supply would be far outweighed by a less-generous accounting of ethanol energy security per gallon, too. Most of the published efforts I have seen incorporate related and supporting subsidies for corn and ethanol infrastructure and the aforementioned energy-content-prorating.

[vii] Testimony of Kevin Book before the U.S. Senate Committee on Energy and Natural Resources, April 3, 2008. http://energy.senate.gov/public/_files/BookTestimony04308.pdf.