TESTIMONY OF
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BEFORE THE
U.S. HOUSE COMMITTEE ON WAYS AND MEANS
SUBCOMMITTEES ON SELECT REVENUE MEASURES AND OVERSIGHT

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Good morning, Chairman Tiberi, Chairman Boustany, Ranking Member Neal, Ranking Member Lewis and distinguished Committee Members. My name is Kevin Book and I head the research team at ClearView Energy Partners, LLC, an independent research and consulting firm headquartered here in Washington D.C. that provides macro-level analyses to financial investors and corporate strategic planners. Thank you for inviting me to contribute to your important discussion today regarding energy tax policy. Thank you also for your ongoing leadership during challenging economic circumstances.

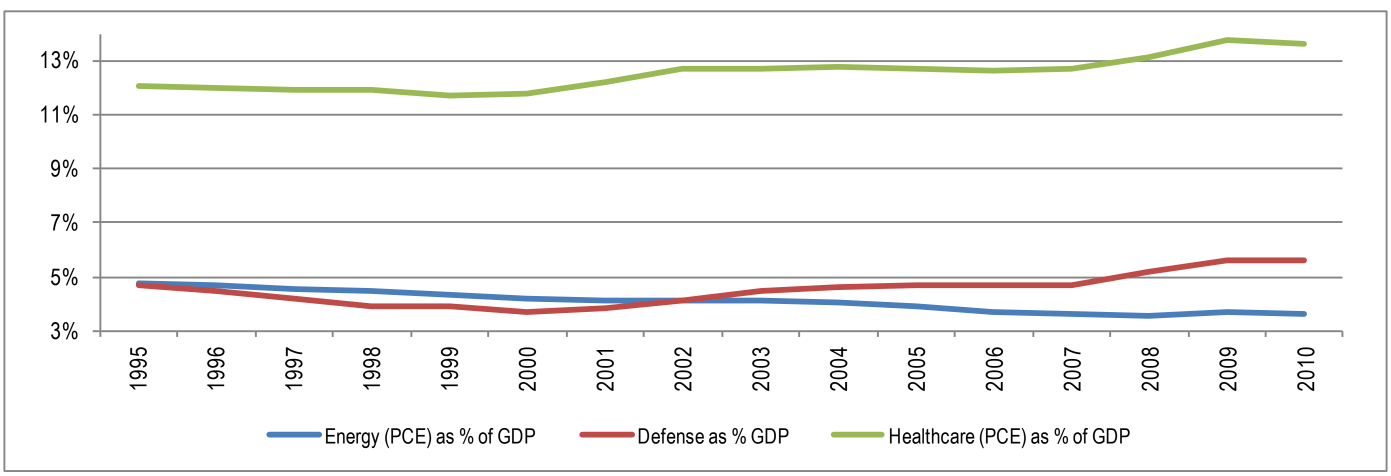
Recent developments frame the urgency of today's topic, especially volatile commodity prices, slow economic recovery and the deficit reduction deadline established by the Budget Control Act of 2011. My testimony considers the relationships between energy policy choices and economic outcomes. In short, my comments are intended to suggest that optimal energy policy should successfully balance potential opportunity with demonstrated efficacy and quantifiable benefit.

SUPPLY, DEMAND AND POLICY TOOLS

All over the world, governments largely own and control their natural resources. Most governments, to a varying degree, rely on taxes, industrial standards and social policies to influence energy demand, either directly or as a consequence of broader initiatives. Many nations also control the production and delivery of those resources, the supply side of their energy markets. The U.S. isn't typical. Our market democracy relies almost entirely upon private entities to deliver primary and secondary energy to the market.

Putting profit-maximizing, competing firms in charge of supply-side investment choices may have helped to keep domestic energy costs manageable for end-users. U.S. household energy spending as a portion of GDP has been falling at the same time that the GDP shares of other necessities, like healthcare and national defense, have been rising (see Figure 1, below).

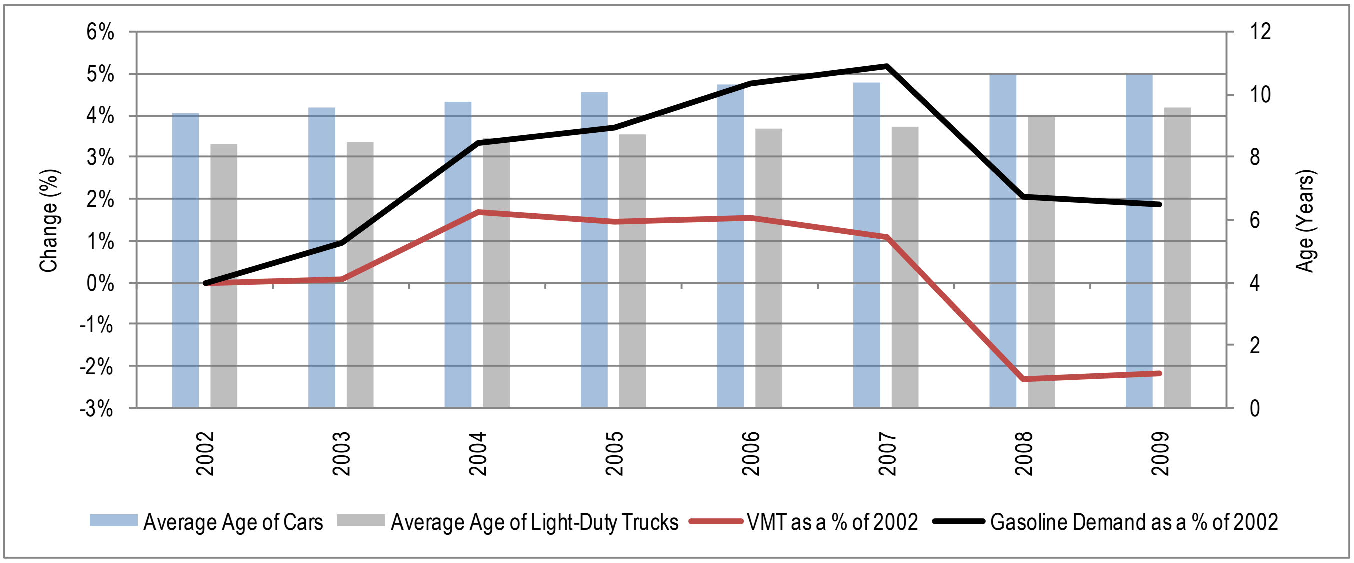
Figure 1 – Share of Household Energy and Healthcare Expenditures and National Defense as a Share of GDP, 1995-2010



Source: ClearView Energy Partners, LLC using BEA data

Because economically-independent end-users make their own demand-side allocation and consumption decisions, U.S. households and businesses can often respond quickly to broader economic circumstances, including price differentials between fuels and technologies. U.S. energy demand can indeed change swiftly, but the reasons are not always worthy of celebration. Figure 2 charts the change in U.S. average passenger vehicle miles traveled (VMT) and gasoline demand between 2002 and 2009 against the average age of U.S. cars and light trucks on the road.

Figure 2 – Vehicle Miles Traveled and U.S. Gasoline Consumption as a % of 2002 Levels vs. Car/Light Truck Age in Years, 2002-2009

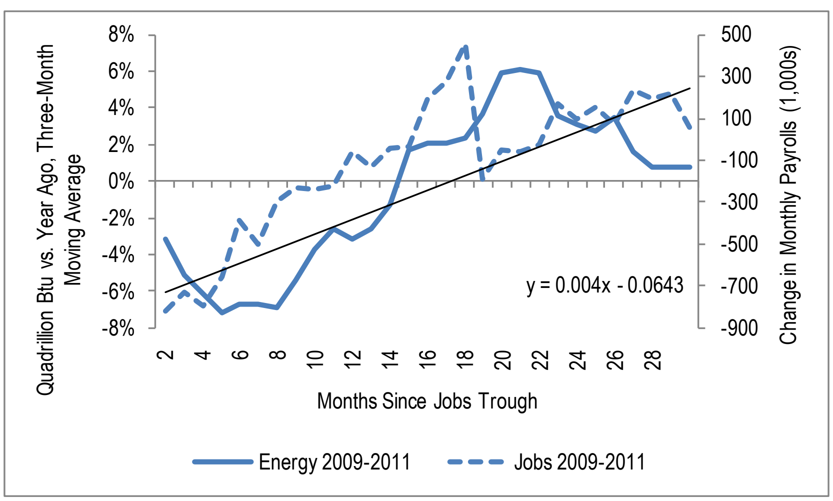


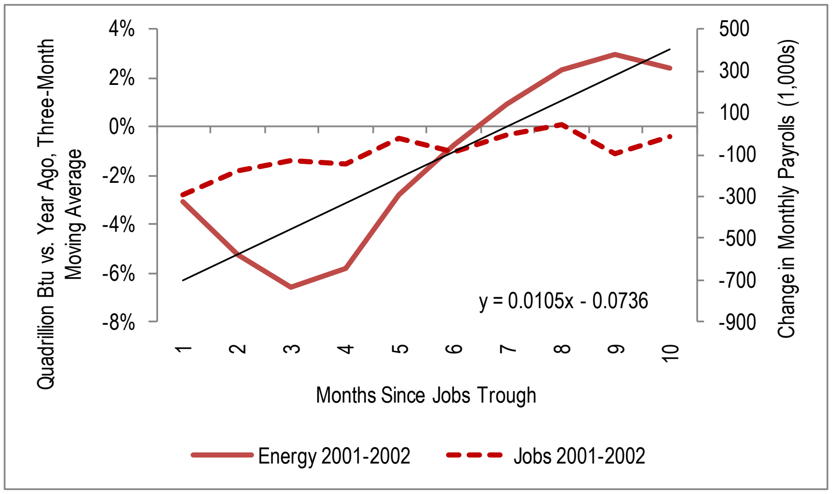
Source: ClearView Energy Partners, LLC using data from EIA, FHWA and R.L. Polk

VMT and gasoline consumption fell sharply in 2008 as vehicle age rose. This is a poignant portrait of a *behavioral* demand shift. For the most part, Americans were probably driving older cars (but driving them less) instead of purchasing new, higher-efficiency vehicles. Empirical and anecdotal data suggest that end-user sensitivity to energy costs is quite high and probably increasing.

Figure 3 examines the same circumstance from a different perspective by presenting nonfarm payroll growth and energy demand growth during two recoveries. Over the 29-month period since the Great Recession's employment trough, Americans are continuing to consume about one-third of the energy per job recovered that they did during the 2001-2002 recovery.

Figure 3 – Three-Month Moving Average Year-on-Year Change in Energy Consumption and Change in Nonfarm Payrolls, 2009-2011 and 2001-2002





Source: ClearView Energy Partners, LLC using BEA, BLS and EIA data

"Fixing" demand isn't always so easy. Demand-side financial incentives for end-user technologies can be undermined by the so-called "efficiency paradox", where the most price-sensitive end-users often lack the working capital to buy new equipment or retrofits. As a result, unrestricted, direct subsidies can have the unintended consequence of buying fuel for existing, inefficient infrastructure. Subsidizing specific energy technologies can prove equally vexing: outlays that fail to encourage adoption by price-sensitive recipients can end up merely giving discounts to price-insensitive purchasers of premium products.

Building energy infrastructure requires large amounts of time and money. Supply-side projects can take longer and cost more, however, due to uncertainties associated with securing rights to land (or other access), applying for and receiving permits and – in many cases – finding the energy resource in question and proving it exists in commercially viable quantities. Stable financial policies for energy projects may not encourage new supply-side investment when market conditions do not warrant it, but inconstant policies may actually discourage supply-side investment when it is needed.

In the face of fiscal austerity, it may also be tempting to suggest that government should not intervene in energy policy at all. But the U.S. is a net energy importer, leaving us captive to the actions of nations that do not always follow market principles and adhere to our democratic values. In this context, investments that provide for energy security may be worth more to our economy as a whole than they are to individual energy suppliers and consumers … at least in the short term. Congress has wisely recognized that government can play a useful energy policy role by encouraging technology innovation, supply diversification and end-user conservation.

Institutional investors and private firms generate value through returns on invested capital. Most money managers are judged against macro benchmarks like the S&P 500. Private firms typically gauge project performance against internally-established “hurdle rates”. Government investors in fuels and technologies could also set benchmarks for evaluating performance in a similar fashion. The figures that follow present several illustrative examples.

Using common metrics like “profit margin” (net income / sales) to assess financial performance allows investors to objectively compare diverse investments across disparate industry sectors, but profit margins don’t always tell the whole story. Financial ratios like “asset turnover” (sales / assets) describe the efficiency of invested capital. In that spirit, Figures 4 and 5 quantify the incentive costs of federal outlays directed at a diverse portfolio of power generation fuels and technologies in constant (2010) dollars per million British thermal units ($/MMBtu).

[One notable difference: asset turnover reflects yield per value (where higher means “more productive”), but mainstream convention for energy spending centers around cost per unit (where less expensive means “more efficient”). Sticklers will rightly note that $/MMBtu is technically the *reciprocal* of turnover, but I believe “less expensive” offers a more familiar basis for comparison.]

Figure 4 uses data from EIA’s April 2008 and July 2011 analyses of federal “interventions” into energy markets. Both studies break out total direct expenditures, tax expenditures, research and development spending, federal electricity support and loan guarantees for conventional and renewable power generation fuels. Figure 4 incorporates these figures, consolidates them by fuel and/or technology, adjusts them for inflation and divides them by the heat content of the corresponding power generated during the applicable periods.

Just as financial ratios should not be mistaken for forensic accounting, this rudimentary “incentive cost ratio” describes basic performance rather than a precise formula. In addition, both EIA reports include lengthy explanations of complex assumptions (including methodology changes) that deserve careful consideration.

Figure 4 – Incentive Cost Ratios - Power Generation Incentives, Estimated $2010 per MMBtu, 2007 and 2010 (EIA Methodology, Modifications Noted)

	2007 [1]			2010 [1]		
Power Generation Fuels	**T Btu**	**$MM [2]**	**$/MMBtu [3]**	**T Btu**	**$MM**	**$/MMBtu**
Coal [4]	6,885.4	$3,166	$0.46	6,314.8	$1,189	$0.19
Natural Gas and Petroleum Liquids	3,135.6	$239	$0.08	3,514.1	$654	$0.19
Nuclear	2,709.1	$1,332	$0.49	2,753.4	$2,499	$0.91
Biomass	136.5	$38	$0.28	129.6	$114	$0.88
Geothermal	51.2	$15	$0.29	53.5	$200	$3.74
Hydropower	880.3	$183	$0.21	863.1	$215	$0.25
Solar	3.4	$15	$4.32	4.4	$968	$218.37
Wind	105.8	$761	$7.20	322.9	$4,986	$15.44

Notes and Assumptions

[1] 2007 data from *Federal Financial Interventions and Subsidies in Energy Markets, 2007* (EIA, April 2008); 2010 data from *Direct Financial Interventions and Subsidies in Energy, Fiscal Year 2010* (EIA, July 2011); consolidates direct expenditures, tax expenditures, R&D spending, federal electricity support spending and loan guarantees.

[2] Inflation-adjusted to 2010 dollars using CPI-U

[3] Converted to MMBtu using 3,412 Btu/kWh; 2007 generation provided in 2008 report; 2010 generation taken from EIA *Monthly Energy Review*

[4] Combines coal and refined coal from 2008 EIA Study

Source: ClearView Energy Partners, LLC, using EIA, BLS data

The data in Figure 4 show that constant-dollar federal outlays increased between 2007 and 2010 for every fuel and technology except coal. Even in the case of nuclear power, where spending nearly doubled, incentive cost ratios for conventional sources remained within a narrow price band under $1/MMBtu, a reflection of conventional sources’ relatively lean federal incentives and large, mature generating bases. At the other end of the spectrum, some renewable sources’ incentive cost ratios grew by one to two orders of magnitude, reflecting stimulus-driven spending increases that outstripped corresponding power generation growth.

Figure 5 presents a broader, wider assessment of incentive cost ratios prepared by aggregating and standardizing expenditure and outlay data from multiple federal agencies and budget authorities (footnotes provide details regarding methodology and assumptions).

The broader incentive cost ratios in Figure 5 differ from the EIA-derived calculations in Figure 4 in several key respects:

- They are internally-consistent across a five-year interval but, due to data availability limitations, they exclude some of the line-items that EIA included;

- They combine sources within categories, due to a combination of simplifying assumptions and data granularity limitations; and

- They broadly attribute expenditures to oil and gas, including tax treatment that many studies exclude from their accounting because it doesn't fundamentally differ from "ordinary" tax treatment for business activities (a conclusion I share). These line-items are included in Figure 5 anyway for the purpose of defining an "upper-bound" investment cost ratio.

Figure 5 – Incentive Cost Ratios – All Categories: Estimated $/MMBtu, 2006-2010 ($2010, CVEP Methodology)

	Total ($2010, MM)					Total Energy (Trillion Btu)					$/MMBtu ($2010)				
Fuel/Technology	**2006**	**2007**	**2008**	**2009**	**2010**	**2006**	**2007**	**2008**	**2009**	**2010**	**2006**	**2007**	**2008**	**2009**	**2010**
Biofuels [1]	$2,834	$3,723	$5,510	$6,149	$6,260	486	614	840	950	1,090	$5.83	$6.06	$6.56	$6.47	$5.74
Coal [2]	$3,267	$3,239	$699	$254	$290	23,790	23,493	23,851	21,627	22,077	$0.14	$0.14	$0.03	$0.01	$0.01
Conv. Power [3]	$941	$799	$203	$346	$10,720	13,539	13,824	13,625	12,986	13,484	$0.07	$0.06	$0.01	$0.03	$0.80
Green Power [4]	$587	$550	$1,048	$2,532	$9,562	329	359	430	492	574	$1.78	$1.53	$2.44	$5.14	$16.67
Oil and Gas [5]	$7,903	$7,830	$9,493	$8,916	$9,663	32,179	32,954	33,631	35,017	36,466	$0.25	$0.24	$0.28	$0.25	$0.26

Notes and Assumptions

[1] Incorporates consumption impact (excise tax credit is paid for fuels sold or introduced into commerce in the United States) and therefore uses EIA consumption data in the denominator. Subsidies reflect estimates of actual tax expenditures for two-year-prior calendar year (e.g. 2010 data from FY2012 OMB budget request), including excise tax credits. Incorporates tax credits and DOE loan guarantees; excludes USDA loan guarantees and programmatic spending due to data granularity limitations.

[2] Incorporates production impact, relying on EIA production data in the denominator. Incorporates synfuels credits, where applicable; capital gains treatment of royalties on coal; credit for investment in clean coal facilities and partial expensing for mine safety equipment. Does not include programmatic spending at DOE (supply-side impact likely to lag outlays).

[3] Incorporates total generation of coal-, petroleum- and gas-fired power, nuclear energy and net conventional hydroelectric power in the denominator. Treats all transmission and distribution ("smart" or otherwise) as a subsidy for conventional power. Incorporates five-year carryback of net operating losses, interest exclusions for energy facility bonds and conservation subsidies, deferral of gain from dispositions of transmission property to implement FERC restructuring policy, amortization of air pollution controls, 10-year MACRS for distribution and 15-year MACRS for transmission.

[4] Incorporates total generation (all sectors) of wind, geothermal, solar, biomass (wood and waste) in the denominator. Incorporates PTCs, ITCs and DOE grants and loan guarantees, MACRS and renewable energy bonds. Data granularity limitations preclude breakout of subsidies by fuel or technology at this juncture.

[5] Incorporates total domestic production of oil, natural gas and natural gas liquids in the denominator, embedding the (liberal) assumption that refined product manufacturing and inventory incentives flow through to upstream. Incorporates IDC deductions, publicly-traded partnership treatment for MLPs, exception from passive loss limitation for working interests in oil and gas properties, temporary 50% expensing for equipment used in the refining of liquid fuels, natural gas distribution pipelines treated as 15-year property (liberal assumption that LDC demand stimulates upstream domestic production), two-year G&G amortization, EPA sulfur credits, EOR and CO_2 credits, oil, estimated gas and refined product share of Section 199 deduction, estimated oil and gas share of dual-capacity taxpayer status, estimated oil and gas share of LIFO revenue impact. Does not include royalty relief provisions (data granularity limitations preclude inclusion at this point).

Source: ClearView Energy Partners, LLC, using EIA, JCT, OMB and BLS data

The five-year time series in Figure 5 captures the spending impact of 2009-2010 stimulus programs as well as the demand contraction that preceded it. Averaging five data points is also more meaningful than averaging two of them. The resulting average incentive cost ratios fall into two relatively narrow price bands:

- $6.13/MMBtu for biofuels and $5.51/MMBtu for green power; and
- $0.07/MMBtu for coal production (excluding programmatic spending), $0.19/MMBtu for conventional power, and $0.26/MMBtu for fully-allocated oil and gas spending.

Other performance attributes of fuels and technologies lend themselves to similar analysis.

Figure 6 estimates the "abatement cost" of carbon dioxide emissions avoided by employing lower-emitting fuels and technologies in place of their conventional equivalents:

- Solar and wind power as replacements for the national average generating mix;
- New automobiles purchased under the Cash-for-Clunkers program as an alternative to older, lower-efficiency cars;
- Natural gas as a substitute for diesel fuel in heavy-hauler trucks, as devised by the NATGAS Act (H.R. 1380); and
- Corn ethanol as an alternative to conventional petroleum gasoline.

Traditional "marginal abatement cost curves" (MACC) define a supply curve of fuel and technology options for reducing greenhouse gases by computing fixed and variable costs. Most MACC curves are generated by determining the cost per metric ton of avoided carbon dioxide emissions ($MtCO_2e$) *implied* by project costs. The "implied abatement costs of outlays" presented in Figure 6 are similar, except that they are *in addition to* project spending by developers, financiers and/or end-users. Put differently, these abatement costs represent the price the federal government pays to eliminate one metric ton of carbon dioxide emissions, but they are not the whole price.

Figure 6 also presents lower-bound and upper-bound abatement costs for solar and wind generation. The lower-bound calculates abatement cost the way Figure 4 calculated incentive cost ratio: by applying FY2010 incentive levels to *total* CY2010 energy output. The upper-bound applies FY2010 incentive levels to 2009-2010 *growth* in power output.

Figure 6 – Implied Abatement Costs of Outlays: Carbon Price Implied by Estimated Current and Proposed Energy Spending, ($2010/MtCO2e)

Fuel/Technology	Amount Spent ($2010, MM)	Generation or Fuel (GWh, Tcf or Bgal)	Incremental Generation or Fuel (GWh, Tcf or Bgal) [1]	Emissions Avoided (MM $MtCO_2e$) [2]	Amortization Period or Asset Life (Years) [3]	Lower-Bound: Amortized Abatement Cost (Total), $/$MtCO_2e$ [4]	Upper-Bound: Amortized Abatement Cost (Incremental) $/$MtCO_2e$ [4]
Solar (EIA, 2010)	$968	1.30 GWh	0.24 GWh	0.78	20	$62.09	$197.71
Wind (EIA, 2010)	$4,986	94.65 GWh	12.46 GWh	56.79	20	$4.39	$20.01
Cash for Clunkers [5]	$2,925	NA		9.28 [5]	1.2 [5]	$262.68	
NATGAS Act [6]	$5,000 [6]	1.19 Tcf [6]		8.34	5 [6]	$119.85	
Ethanol (VEETC Only) [7]	$5,805	12.9 Bgal		18.13 [7]	20	$16.01	

Notes and Assumptions

[1] Using EIA generation data from the *Monthly Energy Review,* 2011 total generation vs. 2010 total generation.

[2] Using average carbon footprint of 0.595 $MtCO_2e$/MWh.

[3] For renewable assets, 20-year amortization period is applied as a simplifying assumption. For Cash-for-Clunkers, the 690,114 cars and light trucks averaged 9.2 mpg savings and the average age of the vehicle replaced left only 1.2 years of useful life. For the NATGAS Act, proposed program would put 140,000 heavy haulers on the road over five years and related fueling infrastructure.

[4] A range between amortized total and incremental cost may be most accurate. Not all of the tax expenditures for PTCs go to new infrastructure; not all ITCs paid out in a given year are for new projects. In both cases, there may be a time lag between disbursement and the onset of power generation (and emissions abatement).

[5] Assumes 12,500 mpy average VMT; uses 1.2 year incremental vehicle life and 9.2 mpg/vehicle average gasoline efficiency gains.

[6] Relies on preliminary information (five-year budget cost, 140,000-vehicle target); does not model in light-duty vehicles or associated incremental cost.

[7] VEETC only; uses 16% GHG differential (EPA, 30Y 2% discount rate for corn ethanol in a gas-fired dry mill).

Source: ClearView Energy Partners, LLC, using EIA, EPA, JCT, OMB and BLS data

Figure 7 quantifies petroleum security benefits by tabulating historical spending on the U.S. Strategic Petroleum Reserve (SPR) and the Volumetric Ethanol Excise Tax Credit (VEETC) and projecting potential outlays associated with the NATGAS Act. Instead of carbon costs, Figure 7 calculates the *implied* costs displacing imported petroleum on a volumetric and energy-equivalent basis.

Figure 7 – Implied Petroleum Displacement Costs of Past, Current and Proposed Federal Energy Outlays, ($2010)

Fuel Security Policy	Historical or Prospective Cost ($2010, MM)	Barrels Displaced	$2010 per Displaced Barrel	Trillion Btu Displaced	$2010 per Displaced MMBtu
NATGAS Act [1]	$5,000	212,416,667	$23.54	1,227	$4.08
U.S. SPR [2]	$48,552	726,500,000	$66.83	4,214	$11.52
Ethanol VEETC [3]	$47,725	321,428,571	$148.48	1,142	$41.77

Notes and Assumptions

[1] Observes simplifying convention of treating crude and products barrels interchangeably for volumetric purposes, but uses 137,500 Btu/gal HHV for diesel energy equivalency; evaluates at theoretical program end (e.g. when 140,000 trucks are already on the road and the $5 billion has already been spent) based on preliminary estimates. Assumes 65,000 mpy at 5.1 mpg for heavy-haulers. The cumulative impact of these assumptions may significantly undercount the displacement cost, particularly if vehicle mileage is lower. N.B.: alternative vehicles convey operational capacity rather than strategic capability – the gains are incorporated into the fuel mix as technology diffuses and are not available for a supply “surge” in the event of an emergency. Operational capacity will recur annually for the equipment life, making cumulative net displacement considerably greater than the five-year total projection indicated, but realizing actual strategic potential would require stockpiling of displaced volumes (or cash equivalents).

[2] Incorporates total acquisition cost for the Reserve, 1976-2010, including nominal appropriations and estimated royalty-in-kind revenues, adjusted for inflation using CPI-U. The SPR is a non-recurring surge capability, but it is separate from operating supply and therefore available for emergency deployment in the event of a supply interruption.

[3] Incorporates current U.S. production capability and historical VEETC outlays (excluding other subsidies). As with natural gas, cumulative displacement will grow as long as ethanol infrastructure continues operating, reducing the implied displacement cost, but capacity is not available to offset emergency supply losses without stockpiling of displaced volumes. Uses 76,600 Btu/gal energy content for corn ethanol.

Source: ClearView Energy Partners, LLC using EPA, DOE, EIA and BLS data

Incentive cost ratios, implied abatement costs and implied displacement costs offer three possible ways to measure the performance of federal financial incentives for energy production and consumption. Metrics of this sort could be used to prioritize spending – dynamically, perhaps through a reverse auction – or through legislated formulas that balance incentives for high-yield, low-cost sources with high-potential, emerging sources. Fuels or technologies that consistently fall short of established benchmarks may require a different type of government financial intervention (e.g. manufacturing assistance or pre-competitive R&D in place of production tax credits) or a different mode of financial support (e.g. loan guarantees instead of tax credits or deductions).

FINANCIAL RETURN AND FINANCING MODE

Most financial incentives to encourage energy production generally fall into two broad categories: *equity subsidies* that augment producers' cash positions and *debt subsidies* that lower producers' borrowing costs.

Figure 8 presents a simplified, *pro forma* model of a wind project operating at a 40% capacity factor over a 20-year operating life.

In the base case, the $2,000/kW capital costs for project hardware would be 20% equity-financed at a 15% cost of equity and 80% debt-financed at a 12% rate over a ten-year period. For simplicity, Figure 8 excludes startup time, rental fees and O&M spending. The resulting "levelized" fixed cost is about $0.045/kWh.

Figure 8 – Financing Mode, Quantified: Levelized Wind Energy Generation Cost, IRR and "Return on Tax"

Scenario	Base Case		PTC over ten years		30% ITC paid in Year 1		30% Grant in Year 0		Loan Guarantee 10% default rate	
			$417.25		$532.86		$600.00		N/A	
How Modeled			Deduct PV of Payment Stream from Capital Cost		Deduct PV of ITC from Capital Cost		Deduct PV of Grant from Capital Cost		Lower Interest Rate, 14% Credit Subsidy Costs, 10% EV of Default	
Effective Capital Cost	$2,000	per kW	$1,583	per kW	$1,467	per kW	$1,400	per kW	$2,000	per kW
Capacity Factor	40%		40%		40%		40%		40%	
Useful Life	20	years	20	years	20	years	20	years	20	years
Financing Life	10	years	10	years	10	years	10	years	10	years
Debt	80.00%	of project	80.00%	of project	80.00%	of project	80.00%	of project	80.00%	of project
Cost of Debt	12.00%	APR	12.00%	APR	12.00%	APR	12.00%	APR	8.00%	APR
Interest Costs	$1,127	nominal	$892	nominal	$827	nominal	$789	nominal	$714	nominal
Equity	20.00%	of project	20.00%	of project	20.00%	of project	20.00%	of project	20.00%	of project
Cost of Equity	15.00%	hurdle	15.00%	hurdle	15.00%	hurdle	15.00%	hurdle	15.00%	hurdle
Equity Costs	$60	levelized	$47	levelized	$44	levelized	$42	levelized	$60	levelized
Disc/WACC	12.60%		12.60%		12.60%		12.60%		9.40%	
Total Cost	$3,187	per kW	$2,522	per kW	$2,338	per kW	$2,231	per kW	$2,774	per kW
Total Hours	70,080	hours	70,080	hours	70,080	hours	70,080	hours	70,080	hours
Levelized Fixed Cost	$0.045	per kWh	$0.036	per kWh	$0.033	per kWh	$0.032	per kWh	$0.040	per kWh
Levelized Benefit			$0.009	per kWh	$0.012	per kWh	$0.014	per kWh	$0.006	per kWh
Cost to Taxpayer			$0.021	per kWh	$0.008	per kWh	$0.009	per kWh	$0.003	per kWh
IRR @ $0.15/kWh	-0.11%		3.57%		5.32%		6.46%		4.46%	
"Return on Tax"			45%		159%		159%		227%	

Source: ClearView Energy Partners, LLC

Figure 8 explores four financing options as alternatives to the base case.

- **Production tax credit.** Over the wind farm's 20-year project life, the present value of the ten-year, $0.021/kWh production tax credit (PTC) would average to about $0.0116/kWh, but only for taxpayers who could claim it. Developers without tax liabilities typically retain advisors to sell the "tax equity" of the payment stream to another, taxable party. Applying the resulting $344.23/kW (at the developer's discount rate) before fees and negotiated discounts to capital costs would translate to a $0.009/kWh cost reduction over twenty years. At a sale price of $0.15/kWh, this implies a 3.57% internal rate of return (IRR).

- **Investment tax credit.** A similar transaction to monetize a 30% investment tax credit (ITC) paid at the end of year one and apply the proceeds to capital costs would reduce levelized generation cost by about $0.012/kWh for a 5.32% IRR**.**

- **Grant (simplified).** Applying proceeds from a 30% government grant or rebate payable in year zero to capital costs would reduce levelized generation cost by a similar amount, approximately $0.014/kWh, yielding a 6.46% IRR.

- **Loan guarantee (subsidized).** A borrowing cost reduction of 400 basis points (4%) and government payment of the corresponding 14% credit subsidy costs would reduce levelized generation cost by about $0.006/kWh for a 4.46% IRR.

This highly-simplified, theoretical example omits several real-world elements. For example, a real project developer would also seek to monetize other value streams associated with the project, including the value of its depreciation under the Modified Accelerated Cost Recovery System (MACRS) and, when market conditions allow, a forward sale of Renewable Electricity Certificates (REC) under any applicable state Renewable Portfolio Standard (RPS).

Of course, in the real world, the transaction costs of monetizing tax equity and grants are not zero, and can be significant enough to affect project economics. In addition, third parties may apply higher discount rates to tax equity revenue streams, resulting in steep discounts for project sponsors. Policy uncertainty and commodity price fluctuations can also compress intangible project value.

From the developer's perspective, the best option in Figure 8 is probably the (transaction-cost-free) 30% government grant because it delivers the highest IRR. That stands to reason – cutting time and the "middleman" out of any transaction should leave more on the table for the developer. But Figure 8 also suggests a different way to judge subsidy performance – a "return on tax" metric that calculates how much theoretical project benefit a developer receives per government outlay dollar.

Accounting immediately for PTCs paid out over time clearly generates the lowest return on tax. Without transaction costs, return on tax would be essentially the same for 30% realized now or next year (especially at today's interest rates). In a world with transaction costs, time is money for developers, especially when dollars next year are paying transaction costs today. Developers might well question the value of complicating financial incentives with such a convoluted process. By the same token, a reasoned argument could be made that delay offers opportunity for greater due diligence and tax equity transaction costs may, practically speaking, buy that due diligence from private-sector professional services firms.

The fourth option in Figure 8 – a loan guarantee that lowers interest costs – offers the highest return on tax, assuming a 10% default risk, and a modest IRR, but debt subsidies may offer several other benefits, too. For example, it may be more appropriate to match the maturity of financing to the long useful life of the underlying asset. It may also be desirable from a policy perspective to align investor incentives with project viability. Collapsing equity payment streams into lump sums means that investors' first concerns are likely to be the spreads between their fully-loaded capital costs and the project's fully-subsidized investment yield. The clean energy or energy security produced by the underlying asset can become, ironically enough, little more than a positive externality of a financial transaction. Policy goals and investor allocations could diverge as credit costs increase or returns from other low-risk, fixed-income instruments improve.

Loan guarantees cannot minimize taxpayer cost per subsidy dollar without adequate due diligence. More importantly, taking a portfolio approach by financing a diverse range of fuels and technologies, including projects with less volatile risk/reward profiles, can enable necessary investments in "moon shot" innovation without compromising overall financial stability. It may be worth revisiting whether the Department of Energy's current appropriations-backed, solicitation-driven Title XVII debt financing program has the autonomy to structure an appropriately balanced portfolio. A public innovation financing program should supplement, not supplant private innovation funding, but it need not be condemned to holding a portfolio of slow antelopes. The best deals go quickly, and a freestanding "green bank" capable of swiftly closing promising transactions might avoid unintended negative performance bias associated with exclusively funding those deals the private sector has already rejected.

NON-FINANCIAL POLICY TOOLS

Several categories of non-financial policy tools can influence supply and demand outcomes, as well.

Non-market mechanisms provide energy producers with access to resources, intellectual property or commercial opportunities they might be unlikely to obtain without government intervention. Non-market incentives include pre-competitive research and development; government-funded demonstration or commercialization projects; government patents and technologies; and preferred access to government-controlled market segments.

Prescriptive standards that impose enforceable performance targets on energy producers by assessing penalties for noncompliance can effectuate rapid fuel, technology and emissions changes. On the other hand, the trade-offs for rapid results can include wealth destruction and higher energy prices for several reasons:

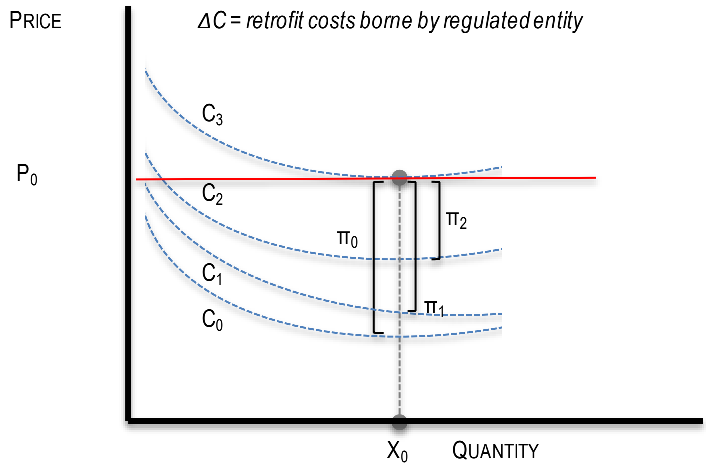
- Because producing assets have useful lives that can span many decades, standards that require operators to abandon infrastructure before it has been paid off tend to generate explicit losses. These losses can diminish capacity margins and increase import dependence when operators lack the capital or the economic incentive to replace shut-down assets.

- Standards that require operators to replace paid-for, legacy assets with new infrastructure can result in higher average production costs. Depending on industry structure and producers' market power, this can translate to higher end-user prices.

- Standards that require unscheduled (or "non-maintenance") capital investments in retrofit technologies can, in some cases, divert cash away from future investment, often to producers' financial detriment. Alternatively, when producers can pass retrofit costs through to end-users, customers may pay higher prices.

Figure 9 offers a conceptual representation of how prescriptive standards could impact supply.

Figure 9 – Prescriptive Standards: Compliance Implications for Price-Taking Commodity Producers



Source: ClearView Energy Partners, LLC

The theoretical producer in Figure 9 sells a commodity for a fixed price, P_0, and has optimized production, X_0, to take advantage of maximum efficient scale on production cost curve, C_0, generating economic profits of $\prod_0$. In plain English, X_0 is the firm-level output where producing more would cost more at the margin and producing less would leave money on the table.

Standards that require a one-time investment in plant retrofits would increase fixed costs, shifting the cost curve to C_1. In an undersupplied market, this producer might be able to spread this non-maintenance outlay across greater production volumes to arrive at a new, maximum efficient scale (a scenario that suggests higher end-user prices). In this example, demand is weak and this producer cannot sell more than X_0, causing his or her economic profits to contract from $\prod_0$ to $\prod_1$.

Standards that impose new fixed *and* variable costs would shift the production cost curve up to C_2. As above, a tight market might allow producers to pass costs through but, in this example, the impact would be a further reduction in economic profit, from $\prod_0$ to $\prod_2$.

Some standards could drive producers out of business. Cost curve C_3 implies new fixed and variable costs so high that they eliminate economic profits entirely at the externally-determined price, P_0, a circumstance likely to result in a plant shutdown. Even without plant shutdowns, operators adapting to leaner profits may be unlikely to hire new employees and may even make workforce cuts.

Due to the competitive, market-driven, privately-operated structure of the U.S. energy supply, prescriptive standards may be best suited to mitigating acute risks to national security or environmental quality. In many instances, clear regulations that set long lead times and fixed targets can minimize these financial and peripheral costs.

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