2013 Connecticut Comprehensive Energy Strategy
Appendix A: Efficiency & Industry Sectors Strategy Analysis

INTRODUCTION

The efficiency and industry sector analysis estimates several energy consumption scenarios and their costs and benefits to evaluate energy efficiency and fuel switching potential for the three major fuels (electricity, natural gas, and oil) used in Connecticut between 2012 and 2050.

This Appendix describes the approach to calculating sector energy consumption scenarios, the approach to identifying their costs and benefits, the main assumptions underpinning the analysis, and the key outputs of the analysis.

PROJECTING BUILDINGS AND INDUSTRY ENERGY CONSUMPTION

The analysis projects efficiency and industry sector energy consumption from 2012 to 2050 for electricity, natural gas, and oil in the following four scenarios:

- No efficiency programs — no efficiency program funding or associated energy savings;
- Base efficiency — current levels of efficiency funding and energy savings;
- Expanded efficiency — increased efficiency funding to capture all cost-effective energy savings; and
- Fuel switching — expanded efficiency plus converting all oil use to natural gas and electric heat pumps.

"NO EFFICIENCY PROGRAMS" AND "BASE EFFICIENCY" ENERGY FORECAST

Electricity

To define electricity consumption in "no efficiency programs" and "base efficiency" scenarios, the analysis took two steps (Figure A-1): (1) Define the total electricity consumption from 2012–2050 and (2) Split the total electricity consumption by sector.

(1) Define the total electricity consumption from 2012–2050: The Connecticut 2012 Integrated Resource Plan (IRP) provides projections for No efficiency programs and Base efficiency electricity consumption for Connecticut through 2022.[1] Brattle Group, the author of the IRP, projected this consumption past the 2022 IRP time horizon to 2050 for the purpose of the Strategy.

(2) Split the total electricity consumption by sector: The combined electricity projections for both No efficiency programs and Base efficiency scenarios are broken down into projections for the energy efficiency sector (residential and commercial buildings) and the industrial sector using data from the U.S. Energy Information Administration (U.S. EIA) State Energy Data System (SEDS) for Connecticut and

[1] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

data from 2012 U.S. EIA Annual Energy Outlook (AEO) forecasts for New England.[2] The SEDS data provides the electricity consumption for each sector (residential, commercial and industrial) in the year 2009. The share of electricity sales per sector from SEDS applied to the total electricity consumption data from the IRP determines the 2009 electricity consumption per sector in the No efficiency programs and Base efficiency scenarios. Since the relative share of electricity consumption between efficiency and industrial sectors is expected to change over time, sector growth rates are needed to create a more accurate split of electricity consumption between sectors for 2012–2050.

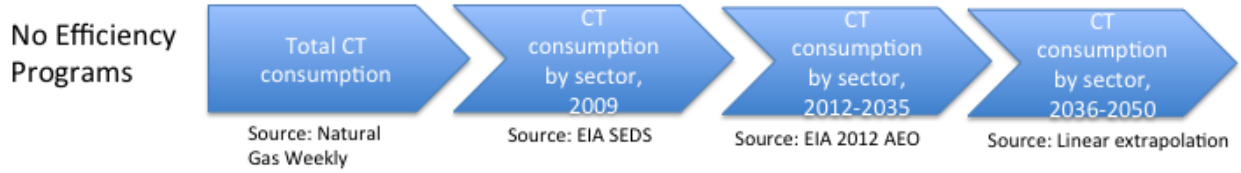
The sector growth rates used were from the U.S. EIA 2012 AEO forecast for the New England Region, which runs from 2009–2035.[3] The annual growth rate in each sector's electricity consumption from 2009 to 2035 is applied to Connecticut's 2009 electricity consumption to develop sector-level electricity consumption from 2012–2035. Sector electricity consumption from 2036–2050 is linearly extrapolated from the 2012–2035 sector compound annual growth rates.

FIGURE A-1: Electric "No efficiency programs" and "Base efficiency" energy consumption forecast methodology

Natural Gas

Since there is not a Connecticut projection for natural gas use like there is for electricity, projections for both No efficiency programs and Base efficiency scenarios had to be developed. To develop the No efficiency programs scenario, the 2009 Connecticut consumption from U.S. EIA Natural Gas Weekly is used and split into sectors using 2009 U.S. EIA SEDS sector consumption.[4] It is projected to 2050 using the same process detailed in the electricity section above (Figure A-2).

FIGURE A-2: Natural gas "No efficiency programs" energy consumption forecast methodology



To develop the Base efficiency scenario, the efficiency potential of current efficiency programs, as identified in the Connecticut natural gas potential study, is subtracted from the No efficiency programs

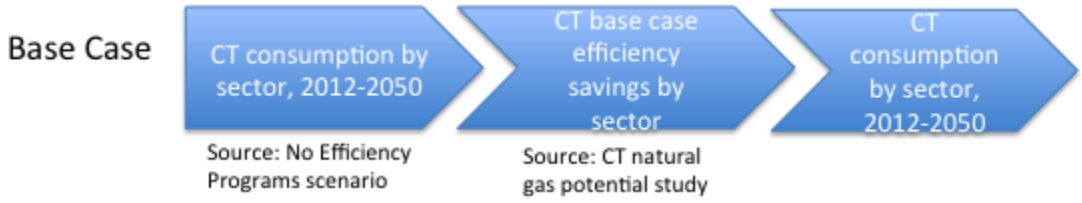
[2] U.S. Energy Information Administration State Energy Data System, "Annual Energy Outlook 2012." Available at http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

[3] *Ibid*.

[4] U.S. Energy Information Administration, "Natural Gas Weekly Update." Available at http://www.eia.gov/naturalgas/weekly/.

scenario energy consumption forecast.[5] The current efficiency programs potential savings is 0.29% of the No efficiency programs scenario annual natural gas consumption for the commercial and industrial sectors.[6] This percentage is applied to all years of the forecast, assuming that savings beyond the ten-year forecast provided in the potential study will be achieved at the same rate. The natural gas potential study does not cover the residential sector. The model therefore assumes that the residential efficiency potential of current efficiency programs, as a percentage of sales, is identical to the commercial and industrial sectors.

FIGURE A-3: Natural gas "Base efficiency" energy consumption forecast methodology



Oil

Just like natural gas, Connecticut does not have a long-term projection for oil consumption in the industrial, residential, and commercial sectors. The same approach that is discussed above for natural gas is used to create the oil projection. The main difference being that consumption of motor gasoline and industrial feed stocks is excluded from the U.S. EIA SEDS data since the buildings and industrial model analyzed efficiency and fuel switching opportunities for buildings and processes but not transportation. All residential sector oil consumption is assumed to be for heating and is included in the model inputs.

There is currently no consistent oil efficiency program funding in Connecticut. Therefore, the Base efficiency scenario oil forecast is the same as the No efficiency programs scenario.

"EXPANDED EFFICIENCY" ENERGY FORECAST

The Expanded efficiency scenario models the capture of all cost-effective efficiency potential for each fuel. The Connecticut electricity and natural gas potential studies are used to define the cost-effective potential. However, the natural gas potential study did not define the potential in residential buildings and there is no state-level oil potential study. To accommodate these data gaps the Connecticut studies were supplemented with a recent Massachusetts residential natural gas potential study and a Vermont oil potential study.[7],[8]

[5] KEMA, "Connecticut Natural Gas Commercial and Industrial Energy-Efficiency Potential Study." Available at http://energizect.com/sites/default/files/CTNGPotential090508FINAL.pdf.

[6] KEMA, "Connecticut Natural Gas Commercial and Industrial Energy-Efficiency Potential Study," p. 1-6. Available at http://energizect.com/sites/default/files/CTNGPotential090508FINAL.pdf.

[7] GDS Associates, "Natural Gas Energy Efficiency Potential in Massachusetts." Available at http://www.ma-eeac.org/docs/PAcites/GDS_Report.pdf.

The sections below provide additional detail on the cost-effective efficiency potential for each fuel.

Electricity

The Connecticut electricity potential study calculates each sector's ten-year cumulative "program achievable potential" efficiency savings, which defines all cost-effective energy efficiency for the Expanded efficiency scenario.[9] The ten-year cumulative efficiency potential (6,616 GWh for all sectors) is divided equally into each year to determine an annual average efficiency potential for each sector (residential, commercial, industrial). For each year beyond the ten-year efficiency potential study forecast, the efficiency potential is held constant as a percent of the No efficiency programs scenario electricity consumption. This assumes that technology development will replenish the energy savings potential at the same pace it is captured.

For example, the Connecticut electricity potential study determined that the ten-year cumulative efficiency potential for industry is 910 GWh. That cumulative savings divided into each year results in an annual electricity savings potential of 91 GWh for each year between 2012 and 2022. That 91 GWh is 2.3% of the No efficiency programs scenario industrial electricity consumption of 3,965 GWh. The electricity savings potential from 2022–2050 is therefore 2.3% of consumption each year.

This analysis determined that the all cost-effective levels for electricity sales reductions per year are; 1.8% for residential, 2.7% for commercial, and 2.3% for industry. It is important to remember that these percentages are the potential reductions from the No Efficiency programs scenario

To reach the all cost-effective levels in this analysis for all three sectors, a program budget would need to be set at $206 million, assuming a contribution level of 48% from program participants.

Natural Gas

The Connecticut natural gas potential study for the commercial and industrial sectors calculates each sector's ten-year cumulative "program achievable potential" savings[10], which defines all cost-effective energy efficiency for the Expanded efficiency scenario.[11] The ten-year cumulative efficiency potential is divided equally into each year to determine an annual average efficiency potential for each sector. For each year beyond the ten-year efficiency potential study forecast, the efficiency potential across commercial buildings and industry is held constant as 1.8% percent of the No efficiency programs scenario natural gas consumption. This assumes that technology development will replenish the energy savings potential at the same pace it is captured.

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[8] GDS Associates, "Vermont Energy Efficiency Potential Study for Oil, Propane, Kerosene and Wood Fuels." Available at http://publicservice.vermont.gov/pub/other/allfuelstudyfinalreport.pdf.

[9] KEMA, Electric Efficiency Study. Available at http://energizect.com/sites/default/files/CTElectricEEReport05032010FinalKEMAf2.doc.

[10] 5,953,454 Dth for Commercial, 1,359,303 Dth for Industry.

[11] KEMA, "Connecticut Natural Gas Commercial and Industrial Energy-Efficiency Potential Study." Available at http://energizect.com/sites/default/files/CTNGPotential090508FINAL.pdf.

For example, the Connecticut natural gas potential study determined that the ten-year cumulative efficiency potential for commercial is 5,953,454 Dth (Decatherm). That cumulative savings divided into each year results in an annual natural gas savings potential of 595,345 Dth for each year between 2012 and 2022. The 595,345 Dth is 2.0% of the No efficiency programs scenario industrial natural gas consumption of 29,452,160 Dth. The commercial natural gas savings potential from 2022–2050 is therefore 2.0% of consumption each year.

Connecticut does not have a recent natural gas efficiency potential forecast for the residential sector, so a recent Massachusetts residential efficiency potential study is used to estimate Connecticut's residential natural gas savings potential.[12] This study was chosen because Massachusetts' type and vintage of housing stock and applications for natural gas use is similar to Connecticut's. Furthermore, the available efficiency technologies, their cost, and the cost of natural gas will largely be the same across the New England region, meaning that the assumptions underpinning the Massachusetts study will apply to Connecticut. Using the Massachusetts analysis, a potential savings of 2.6% natural gas savings was identified for Connecticut's the residential sector. This estimate for all cost-effective residential savings is multiplied by Connecticut's annual residential natural gas consumption in the No efficiency programs scenario to determine the natural gas savings potential in each year to 2050.

This analysis determined that the all cost-effective savings levels for natural gas sales are 2.6% for residential, 2.0% for commercial, and 1.1% for industry.

To reach the all cost-effective levels in this analysis for all three sectors, a program budget would need to be set at $75 million, assuming a contribution level of 48% from program participants.

Oil

There are currently no existing oil efficiency potential studies for Connecticut, so a recent Vermont oil efficiency potential study is used.[13] This study was chosen because Vermont's type and vintage of building stock and applications for oil use are likely similar to Connecticut's. Moreover, the available efficiency technologies, their cost, and the cost of oil will largely be the same across the New England region, meaning that the assumptions underpinning the Vermont study will apply to Connecticut. However, the 2007 study used fuel price forecasts starting at $7–12 per MMBTU, depending on the type of petroleum, which are much lower than those seen in 2012. As a result, fewer efficiency measures were cost-effective than would be found today, making the potential savings modeled conservative.

[12] GDS Associates, "Natural Gas Energy Efficiency Potential in Massachusetts." Available at http://www.ma-eeac.org/docs/PAcites/GDS_Report.pdf.

[13] GDS Associates, "Vermont Energy Efficiency Potential Study for Oil, Propane, Kerosene and Wood Fuels." Available at http://publicservice.vermont.gov/pub/other/allfuelstudyfinalreport.pdf.

The Vermont oil efficiency potential is converted to a percent of sales for each sector[14]. That percent is multiplied by the Connecticut annual oil consumption by sector in the No efficiency programs scenario to determine the oil savings potential in each year to 2050. This analysis determined that Connecticut's all cost-effective levels for oil sales reductions would be; 1.0% for residential, 2.4% for commercial, 1.0% for industrial.

Given these reduction goals, a program budget would need to be set at $46 million, assuming a 48% contribution level from program participants.

ASSESSING THE IMPACTS OF FUEL SWITCHING

An additional model scenario analyzes the impact of a fuel switching strategy. This scenario is based on selecting the most cost-effective available heating options and scaling investment in these options from 2012–2050.

Identifying Cost-Effective Heating Options

The levelized capital and operating costs (per million BTU of heat delivered) are calculated to evaluate the costs of different heating options. The analysis compared oil furnaces to natural gas furnaces, ground source and air source heat pumps, electric resistance heating, and biodiesel-fueled oil furnaces. The equipment capital costs, lifetime, and efficiency assumptions used are from the technology forecasts in the U.S. EIA's AEO.[15] The added capital cost of natural gas distribution expansion to serve new natural gas customers comes from the Connecticut Department of Economic and Community Development (DECD).[16] The operating cost of each heating systems is based upon the U.S. EIA AEO reference case fuel prices forecast by sector for New England.

The analysis showed that several cost-effective options exist to replace oil. Using the most cost-effective technologies, a fuel switching scenario is developed that replaces all oil use by 2050 with natural gas (the most cost-effective option) and electrically powered ground source heat pumps (the next most cost-effective option). Switching to natural gas requires extending the natural gas distribution system, so data from the State's natural gas local distribution companies is used to define the number of customers that were within a reasonable distance of natural gas and could be considered cost-effective for switching. It is not feasible or cost-effective to extend the natural gas distribution system to all oil customers, and since ground source heat pumps are still less costly than oil, they replace the remainder of oil use in the

[14] Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

[15] Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

[16] Connecticut Department of Economic and Community Development. The Economic Impact of Expanding Natural Gas Use in Connecticut. By Stanley McMillen and Nandika Prakash. Hartford, CT, 2011. Available at http://www.ct.gov/deep/lib/deep/energy/decd_nat_gas.pdf

scenario. The adoption of these two technologies is scaled up using customer penetration levels discussed below to show total fuel switching from 2012–2050.

Scaling Investment in Cost-Effective Heating Options

The model is currently constructed to apply a top-down fuel switching percentage equally across all years of the forecast (Table A-1). Pre-defined percentages of switching oil to natural gas replicate the natural gas expansion proposal currently being considered and will cause the model to stop switching from oil to natural gas after 2022, the end year of the natural gas proposal. The model is constructed to switch the remaining oil consumption after the natural gas expansion to electricity (in the form of ground source heat pumps) so that oil consumption for heating is reduced to zero in 2050. If the fuel switching in any year reduces oil use to zero in a sector, the model will not attempt to switch fuel in the remaining years of the forecast, so oil use cannot go negative.

TABLE A-1: Fuel switching scenario inputs

	Natural Gas		Ground Source Heat Pumps (Electricity)	
	Annual fuel switched	End date for switching	Annual fuel switched	End date for switching
Residential	2.5%	2022	1.0%	2050
Commercial	7.5%		0.0%	
Industrial	4.7%		1.2%	

Source: RMI Vision Model Analysis.

The model is constructed to calculate fuel switching changes before calculating efficiency savings in each year. This structure accounts for the fact that a switch away from oil will reduce potential oil efficiency savings in future years while at the same time increase the electricity and natural gas efficiency potential. Because the total resource cost of efficiency is calculated on a dollar per MMBTU saved basis, shifts in the potential between natural gas and oil will also shift the efficiency budgets for each fuel (raising natural gas budgets at the expense of oil).

The fuel switching calculation itself also takes into account the varying efficiencies of the different heating technologies. The model assumes an existing oil furnace efficiency of 80% across all sectors. When converting oil to natural gas for instance, the model calculates the heating work performed by the existing furnace (80% of the total fuel use), and then calculates how much natural gas would be needed to provide that same work through a new 93% efficient gas furnace. Similarly the model uses an average coefficient of performance (COP) of 4.2 for ground source heat pumps when converting from oil to electricity.[17]

[17] Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

For example, if a residential customer uses 100 million BTUs per year of oil to heat their home, then their 80% efficient oil furnace is delivering 80 million BTUs of heat. To provide that same 80 million BTUs of heat, a 93% efficient natural gas furnace would need 86 million BTUs of natural gas while a ground source electric heat pump with a COP of 4.2 would need 19 million BTUs of electricity per year.

IDENTIFYING THE COSTS AND BENEFITS

Capital costs and energy cost savings benefits are calculated for the Expanded efficiency and Fuel switching scenarios in each sector for each fuel type. The Strategy calculates all costs and benefits in real 2012 dollars and uses a 5% real discount rate for taking future years back to a 2012 present value. The Strategy uses a 5% discount rate to reflect the public-private relationship of many of the investment choices in the State of Connecticut. For cost-benefit analysis, the federal Office of Management and Budget (OMB) recommends using discount rates of 7% for private investment and 3% for public investment with social benefits,[18] and the 5% discount rate is an appropriate midpoint. Past Connecticut efficiency potential studies have also used around a 5% discount to account for a combination of utility and customer discount rates.

CAPITAL COSTS

Expanded Efficiency

The capital costs for the Expanded efficiency scenario for electricity are sourced from the 2012 IRP for Connecticut.[19] The IRP tabulates total participant and program costs for the Expanded efficiency scenario from 2012–2022. The total sector capital costs were divided by the total sector potential electricity savings over this time period to calculate a capital cost in dollars per million BTU of energy saved in each sector. That dollar per million BTU of energy saved value is then multiplied by the annual electricity savings to calculate the capital cost for efficiency in each year of the forecast.

Commercial and industrial sector capital costs for the Expanded efficiency scenario for natural gas are provided in the Connecticut natural gas potential study, and were inflated to real 2012 dollars.[20] These sector capital costs are divided by the sector potential savings to calculate a capital cost in dollars per million BTU of energy saved. The residential sector is not included in Connecticut's potential study, and the Massachusetts residential efficiency potential study used in its place does not provide capital cost estimates for natural gas efficiency. The residential natural gas efficiency capital costs are assumed to be the same as the commercial and industrial sector on a dollar per million BTU of energy saved basis. To calculate the total annual capital cost, the capital cost per million BTU of energy saved is multiplied by the new efficiency that is implemented in each year of the Expanded efficiency scenario from 2012–2050.

[18] U.S. Office of Management and Budget, *Guidelines and Discount Rates.*

[19] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut," p. 37. Available at http://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

[20] KEMA, "Connecticut Natural Gas Commercial and Industrial Energy-Efficiency Potential Study." Available at http://energizect.com/sites/default/files/CTNGPotential090508FINAL.pdf.

Capital costs for the Expanded efficiency scenario for oil are provided in the Vermont oil efficiency potential study, and were inflated to real 2012 dollars.[21] The sector capital costs are divided by the potential sector oil savings to calculate a capital cost in dollars per million BTU of energy saved in each sector. That dollar per million BTU of energy saved value is then multiplied by the annual oil savings to calculate the capital cost for efficiency in each year of the forecast.

Fuel Switching

The natural gas capital costs for the Fuel switching scenario are based upon the total cost of the proposed natural gas expansion as provided by DECD.[22] The total cost per sector is divided by the proposed volume of new natural gas used to determine a cost per million BTU of natural gas expansion. This cost per million BTU of new natural gas is then multiplied by the annual new natural gas switched to determine annual capital costs.

The Fuel switching scenario capital costs for ground source heat pumps is based upon the U.S. EIA AEO.[23] The equipment capital cost needed to serve the average residential, commercial and industrial heating load is divided by the annual heating load per customer in each sector to determine a capital cost per million BTU of fuel switched. That capital cost per million BTU of fuel switched is multiplied by the annual increase in electricity consumption that comes from switching from oil heat to determine the ground source heat pump capital cost in each year.

Combined Heat and Power (CHP)

The capital cost of a new combined heat and power unit is based upon a typical reciprocating engine system from the U.S. Environmental Protection Agency's (EPA's) CHP technology catalog.[24] The capital costs per kW are multiplied by the annual installed CHP capacity over the forecast period, which is 10,000 kW per year to 2031.

BENEFITS

Expanded Efficiency

The electricity benefits from the Expanded efficiency scenario are based on the cumulative electricity savings in each year. The cumulative electricity savings in each year is multiplied by the projected annual electricity price from the U.S. EIA 2012 AEO New England reference case fuel price forecast for each sector. Cumulative efficiency savings are used because an efficiency measure continues to save with each passing year. For example, total savings in year 5 is the sum of incremental savings from efficiency

[21] GDS Associates, "Vermont Energy Efficiency Potential Study for Oil, Propane, Kerosene and Wood Fuels." p. 14. Available at http://publicservice.vermont.gov/pub/other/allfuelstudyfinalreport.pdf.

[22] Connecticut Department of Economic and Community Development. The Economic Impact of Expanding Natural Gas Use in Connecticut. By Stanley McMillen and Nandika Prakash. Hartford, CT, 2011. Available at http://www.ct.gov/deep/lib/deep/energy/decd_nat_gas.pdf

[23] Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

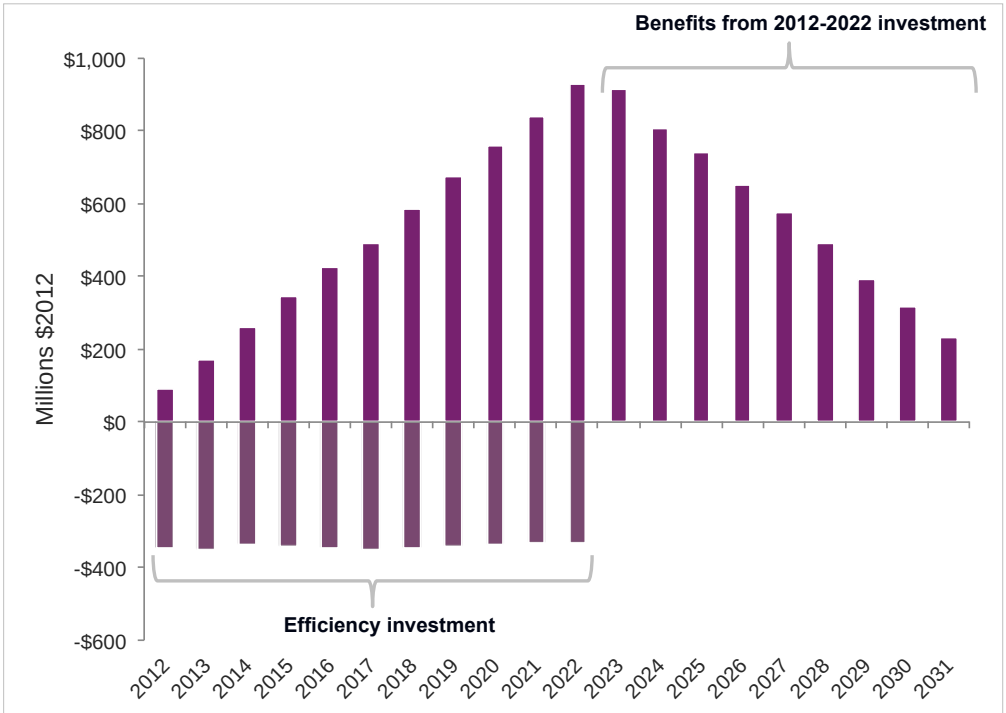
[24] Energy and Environmental Analysis, *Introduction to CHP Technologies*.

measures installed in years 1–4. When the efficiency measure reaches the end of its useful life, it is assumed that it will be replaced either with equipment that performs with similar efficiency or with an incrementally more efficient option. The cost of the like-for-like replacement is not counted as an additional capital cost because it is assumed that codes and standards and/or market forces will make the once efficient technology the baseline or required option. The capital cost and benefits of the subsequent replacement with an incrementally more efficient option is included in the model's calculations of costs and benefits.

For example, if a new 92% efficient residential furnace is installed in 2012, the capital cost in that year is calculated along with the value of the energy savings each year over the twenty year life of the equipment. When that furnace must be replaced in 2032, it is assumed that a 92% efficient furnace is required by code or has become the default choice in the marketplace. If the furnace replacement in 2032 is with a similar 92% efficient unit, the capital costs are not counted in the model. If that furnace replacement in 2032 is with a 95% efficient unit, then the capital costs and the value of the cumulative energy savings would be tallied in the model's cost-benefit analysis.

Because investments in efficiency incur costs only in the first year and provide benefits for each year of the measure life, the model calculates benefits over the lifetime of the investment when determining cumulative benefits for a given time period. This means that when calculating Expanded efficiency scenario electricity cumulative benefits to 2022 for instance, the model calculates the annual cumulative benefits for each year to 2022 and then calculates the cumulative benefits for each year of the remaining life of the measures past 2022 (Figure A-4).

FIGURE A-4: Annual cash flows for Expanded efficiency scenario electricity investments, 2012 to 2022



Source: RMI Vision Model Analysis.

The methodology used to calculate the natural gas and oil benefits in the Expanded efficiency scenario is to the same as the method used to calculate electricity benefits.

Fuel Switching

The Fuel switching scenario benefits are calculated using the same methodology as the Expanded efficiency scenario (i.e., cumulative fuel savings in each year is multiplied by fuel price in that year). The fuel savings are calculated by taking the value of oil saved minus the cost of additional natural gas and electricity consumption. The benefits are calculated over the 20 year lifetime of a ground source heat pump and natural gas furnace.

Combined Heat and Power (CHP)

The benefits from additional CHP capacity are calculated from the electricity cost savings minus the added natural gas costs needed to run the CHP unit. The electricity cost savings are based upon reduced electricity purchases, equal to the CHP system generation, valued at the current average industrial electricity rate.[25] The model uses values for system operating hours, power to heat ratio, heat rate, and boiler efficiency from EPA's CHP technology catalog.[26]

[25] 15 cents per kWh.

[26] U.S. Environmental Protection Agency. Combined Heat and Power Partnership, "Catalog of CHP Technologies." Available at http://www.epa.gov/chp/documents/catalog_chptech.

KEY ASSUMPTIONS

Efficiency potential: the efficiency potential is assumed to remain constant as a percent of sales across the entire forecast period. This assumes that technology development replenishes the efficiency potential at the same rate it is being captured. The Expanded efficiency scenario levels of energy savings result in declining consumption of all fuels. This means that while the efficiency potential as a percent of sales remains constant, the absolute quantity of efficiency potential declines from year to year. It is uncertain if this assumption will hold true as Connecticut, and other states, ramp up to high and sustained levels of efficiency savings. This core assumption should be revisited and re-evaluated in future energy strategies.

Capital costs: the investment cost for efficiency is assumed to remain unchanged across the forecast period on a dollar per million BTU basis. The accuracy of this assumption is impacted by two countervailing forces. As cost-effective efficiency potential is captured, new technologies and approaches will be needed to reload the efficiency potential. It is likely that these new technologies or approaches are more expensive, putting upward pressure on the capital costs of efficiency. At the same time, new programmatic approaches and strategies to capture energy savings, such as behavior modification, will emerge that could offer cost savings. The balance of these two forces will determine if capital costs per million BTU of energy saved increase or decrease in future years.

Connecticut sector energy consumption growth rates and fuel prices: the New England sector growth rates and fuel prices are assumed to equal to Connecticut's.

Lifetime of efficiency measures and heating equipment remain constant: the average lifetime for efficiency measures and heating equipment is assumed to remain constant over the forecast period. The average lifetime of heating equipment is dependent on the construction and durability of each type of heating equipment, and is assumed to remain fairly constant. The average lifetime of efficiency measures depends on the type and mix of efficiency measures installed in the state. So, for instance, as the portfolio of electric efficiency measures switches away from lighting which has relatively short lifetimes to HVAC which has longer lifetimes, the average lifetime of efficiency measures may rise.

DATA TABLES

ENERGY CONSUMPTION

NO EFFICIENCY PROGRAMS SCENARIO
PRIMARY ENERGY BY FUEL TYPE AND SECTOR

	Trillion BTU	2012	2017	2022	2027	2032	2037	2042	2047	2050
Electricity	**Residential**	131	133	146	154	165	173	181	189	193
	Commercial	138	149	169	183	204	219	239	259	271
	Total Buildings	*269*	*282*	*315*	*338*	*369*	*392*	*419*	*447*	*465*
	Industry	38	43	46	44	42	40	39	39	39
Natural Gas	**Residential**	52	50	50	49	48	46	45	44	43
	Commercial	45	46	47	49	50	52	53	55	56
	Total Buildings	*97*	*97*	*97*	*97*	*98*	*98*	*99*	*99*	*100*
	Industry	27	29	31	31	33	35	37	39	40
Oil	**Residential**	82	75	71	68	65	62	58	54	52
	Commercial	16	15	14	14	14	13	13	13	13
	Total Buildings	*98*	*90*	*85*	*82*	*79*	*75*	*71*	*67*	*65*
	Industry	3	4	4	4	4	4	4	4	4

Source: RMI Vision Model Analysis.

BASE EFFICIENCY SCENARIO										
PRIMARY ENERGY BY FUEL TYPE AND SECTOR										
	Trillion BTU	**2012**	**2017**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2050**
Electricity	**Residential**	131	128	137	141	148	152	156	160	163
	Commercial	138	143	158	168	182	193	206	220	229
	Total Buildings	*269*	*271*	*295*	*308*	*330*	*344*	*362*	*380*	*392*
	Industry	38	41	43	40	38	35	34	33	33
Natural Gas	**Residential**	52	49	48	46	45	43	41	39	38
	Commercial	44	46	46	47	47	48	49	50	51
	Total Buildings	*97*	*95*	*94*	*93*	*92*	*91*	*90*	*89*	*89*
	Industry	26	29	30	30	31	32	34	35	36
Oil	**Residential**	82	75	71	68	65	62	58	54	52
	Commercial	16	15	14	14	14	13	13	13	13
	Total Buildings	*98*	*90*	*85*	*82*	*79*	*75*	*71*	*67*	*65*
	Industry	3	4	4	4	4	4	4	4	4

Source: RMI Vision Model Analysis.

EXPANDED EFFICIENCY SCENARIO										
PRIMARY ENERGY BY FUEL TYPE AND SECTOR										
	Trillion BTU	**2012**	**2017**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2050**
Electricity	**Residential**	129	121	123	120	121	118	116	113	112
	Commercial	135	129	133	130	133	130	132	134	135
	Total Buildings	*264*	*250*	*256*	*250*	*254*	*248*	*247*	*247*	*248*
	Industry	38	38	37	31	25	20	18	16	14
Natural Gas	**Residential**	51	42	35	29	25	20	17	14	12
	Commercial	44	41	38	35	33	31	30	29	28
	Total Buildings	*95*	*83*	*72*	*65*	*58*	*52*	*47*	*42*	*40*
	Industry	26	28	28	26	26	27	27	28	28
Oil	**Residential**	81	70	62	55	50	44	38	33	30
	Commercial	15	12	10	9	7	6	5	4	4
	Total Buildings	*97*	*82*	*72*	*64*	*57*	*51*	*44*	*37*	*34*
	Industry	3	3	3	3	3	3	3	3	2

Source: RMI Vision Model Analysis.

FUEL SWITCHING SCENARIO

PRIMARY ENERGY BY FUEL TYPE AND SECTOR

	Trillion BTU	2012	2017	2022	2027	2032	2037	2042	2047	2050
Electricity	**Residential**	129	121	123	120	121	118	116	113	112
	Commercial	135	129	133	130	133	130	132	134	135
	Total Buildings	*264*	*250*	*256*	*250*	*254*	*248*	*247*	*247*	*248*
	Industry	38	38	37	31	26	21	18	16	15
Natural Gas	**Residential**	51	50	50	43	36	31	26	22	19
	Commercial	44	45	45	42	40	37	35	33	32
	Total Buildings	*95*	*96*	*95*	*85*	*76*	*68*	*61*	*55*	*52*
	Industry	26	28	29	28	28	28	28	29	29
Oil	**Residential**	81	61	44	39	34	29	24	19	17
	Commercial	15	7	1	0	0	0	0	0	0
	Total Buildings	*97*	*68*	*45*	*39*	*34*	*29*	*24*	*19*	*17*
	Industry	3	2	1	1	1	0	0	0	0

Source: RMI Vision Model Analysis.

ANNUAL COSTS AND BENEFITS

EXPANDED EFFICIENCY SCENARIO
TOTAL RESOURCE CAPITAL COST - EFFICIENCY

	Million $2012	2012	2017	2022	2027	2032	2037	2042	2047	2050
Electricity	**Residential**	$135	$137	$129	$134	$133	$132	$129	$126	$124
	Commercial	$212	$215	$202	$222	$223	$223	$224	$227	$229
	Total Buildings	*$347*	*$353*	*$331*	*$357*	*$355*	*$354*	*$353*	*$353*	*$353*
	Industry	$55	$56	$53	$46	$38	$30	$27	$23	$21
Natural Gas	**Residential**	$76	$76	$76	$45	$38	$31	$26	$21	$19
	Commercial	$51	$51	$51	$40	$38	$36	$34	$33	$32
	Total Buildings	*$127*	*$127*	*$127*	*$85*	*$76*	*$67*	*$60*	*$54*	*$51*
	Industry	$17	$17	$17	$17	$17	$17	$17	$17	$18
Oil	**Residential**	$77	$77	$77	$53	$48	$42	$37	$32	$29
	Commercial	$13	$13	$13	$7	$6	$5	$4	$4	$3
	Total Buildings	*$89*	*$89*	*$89*	*$60*	*$54*	*$48*	*$41*	*$35*	*$32*
	Industry	$0	$0	$0	$0	$0	$0	$0	$0	$0

Source: RMI Vision Model Analysis.

FUEL SWITCHING SCENARIO										
TOTAL RESOURCE CAPITAL COST - FUEL SWITCHING										
	Million $2012	**2012**	**2017**	**2022**	**2027**	**2032**	**2037**	**2042**	**2047**	**2050**
Electricity	**Residential**	$-	$166	$157	$150	$143	$136	$128	$120	$116
	Commercial	$-	$-	$-	$-	$-	$-	$-	$-	$-
	Total Buildings	*$-*	*$166*	*$157*	*$150*	*$143*	*$136*	*$128*	*$120*	*$116*
	Industry	$-	$6	$6	$6	$5	$5	$6	$6	$6
Natural Gas	**Residential**	$-	$317	$300	$-	$-	$-	$-	$-	$-
	Commercial	$-	$194	$189	$-	$-	$-	$-	$-	$-
	Total Buildings	*$-*	*$510*	*$489*	*$-*	*$-*	*$-*	*$-*	*$-*	*$-*
	Industry	$-	$5	$5	$-	$-	$-	$-	$-	$-

Source: RMI Vision Model Analysis.

PRESENT VALUE CUMULATIVE COSTS/BENEFITS

EXPANDED EFFICIENCY SCENARIO				
2022 CUMULATIVE PRESENT VALUE COSTS/BENEFITS				
	Million $2012	**Investment**	**Gross Savings**	**Net Savings**
Electricity	**Buildings**	$2,850	$6,346	$3,496
	Industry	$455	$695	$241
Natural Gas	**Buildings**	$1,057	$2,964	$1,907
	Industry	$139	$216	$77
Oil	**Buildings**	$741	$3,548	$2,806
	Industry	$2	$93	$91

Source: RMI Vision Model Analysis.

FUEL SWITCHING SCENARIO				
2022 CUMULATIVE PRESENT VALUE COSTS/BENEFITS				
	Million $2012	**Investment**	**Gross Savings**	**Net Savings**
Electricity	**Buildings**	$1,221	$1,598	$376
	Industry	$40	$55	$14
Natural Gas	**Buildings**	$3,767	$5,503	$1,736
	Industry	$36	$326	$289

Source: RMI Vision Model Analysis.

EXPANDED EFFICIENCY SCENARIO				
2050 CUMULATIVE PRESENT VALUE COSTS/BENEFITS				
	Million $2012	**Investment**	**Gross Savings**	**Net Savings**
Electricity	**Buildings**	$5,951	$23,612	$17,661
	Industry	$782	$2,359	$1,577
Natural Gas	**Buildings**	$1,707	$8,610	$6,903
	Industry	$286	$835	$549
Oil	**Buildings**	$1,196	$9,929	$8,734
	Industry	$5	$299	$294

Source: RMI Vision Model Analysis.

FUEL SWITCHING SCENARIO				
2050 CUMULATIVE PRESENT VALUE COSTS/BENEFITS				
	Million $2012	**Investment**	**Gross Savings**	**Net Savings**
Electricity	**Buildings**	$2,448	$4,338	$1,890
	Industry	$88	$182	$93
Natural Gas	**Buildings**	$3,767	$7,374	$3,607
	Industry	$36	$445	$409

Source: RMI Vision Model Analysis.

2013 Connecticut Comprehensive Energy Strategy
Appendix B: Electricity Sector Strategy Analysis

INTRODUCTION

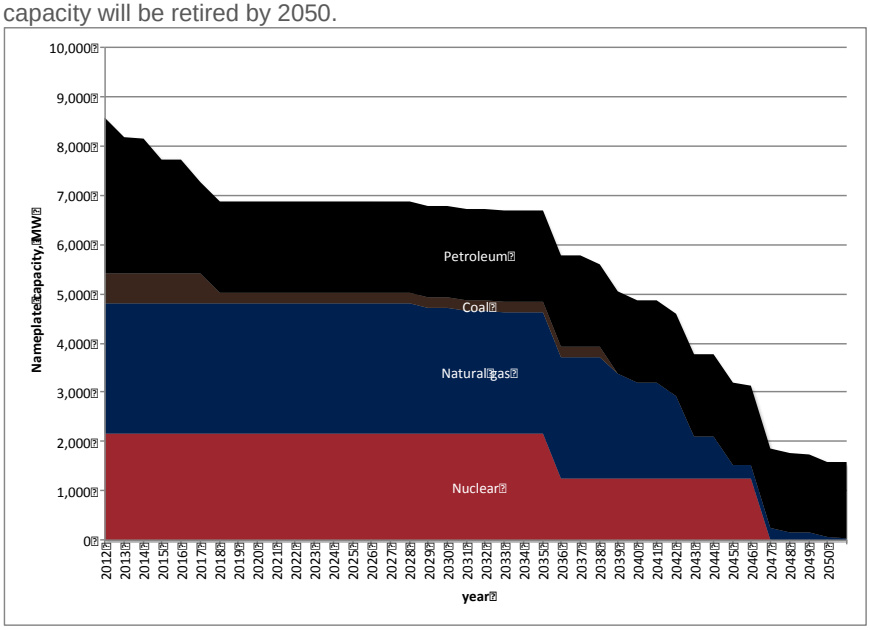
In this appendix, we detail the analytical steps behind four key components, specifically:

- The forecasted thermal generating retirements in Connecticut;
- The amount of Class I renewable energy required in 2020 for Connecticut to meet its Renewable Portfolio Standard;
- The technical potential and levelized costs of renewable resources in the New England region; and
- The costs and opportunity for cost reductions of solar photovoltaics.

FORECASTING THERMAL GENERATOR RETIREMENTS

New England's current generating fleet is aging. DEEP estimates that 99% of Connecticut's nuclear, natural gas, and coal power capacity and 95% of capacity in Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont will exceed average industry lifetimes by mid-century. The forecasted operating thermal capacity in Connecticut through 2050 is shown in Figure B-1.

Figure B-1: Forecasted operating thermal capacity in Connecticut
The U.S. Energy Information Administration lists 8,500 MW of thermal (nuclear, gas, coal, and oil) generating capacity operating today in Connecticut. Assuming industry average lifetimes, nearly all of the nuclear, gas, and coal capacity will be retired by 2050.



Analysis based on: U.S. EIA, Existing Generating Units; and Hodgkins, "Wave of U.S. Retirements."

The primary input for this analysis comes from the U.S. Energy Information Administration's Form-860, "Existing Generating Units in the United States by State and Energy Source."[1] This table lists all existing

[1] U.S. Energy Information Administration (EIA), "Existing Generating Units." Available at http://www.eia.gov/electricity/capacity/.

electrical generators in Connecticut, along with their nameplate capacities (MW), fuel, operational status, and month and year of initial operation, from which DEEP determined the current age of each plant.

The second key input to this analysis is the assumed retirement age of these plants. As reported in the trade journal *SNL Power Daily*, a 2012 Bernstein & Co. report calculated the average retirement ages of U.S. coal-fired, gas-fired (combustion turbines), and oil-fired plants to be 49, 40, and 41 years, respectively.[2] DEEP used these assumed retirement ages for all fossil-fired power plants. For nuclear reactors, DEEP used the actual years when their current licenses will expire, (e.g., 2035 and 2045 for Millstone 2 and 3).[3]

Using the age of each plant and its expected retirement age (should it follow industry norms), a simple calculation gives the retirement year of each plant and the forecasted operating capacity in each year between now and 2050 (when the analysis period ends). However, not all the system operating capacity will necessarily run in any given year. For example, Connecticut currently has 2,900 MW of oil-fired capacity listed as "operational" in form EIA-860, but generated only 408,000 MWh from oil-fired plants in 2010.[4] This amounts to a fleet-wide 2% capacity factor, meaning that the vast majority of these oil-fired power plants are no longer running on any regular basis. This means that the actual operating lifetimes of Connecticut's oil-fired plants may be extended beyond those shown in Figure B-1, although these plants will likely continue to be far underutilized.

CLASS I RENEWABLE ENERGY REQUIRED TO MEET RPS

Connecticut's Renewable Portfolio Standard (RPS), established in 1998, imposes annual requirements on the percentage of retail sales that must be generated from qualifying renewable resources. The terminal requirement is a 20% Class I renewable portfolio by 2020, although there are intermediate targets as well.[5]

The forecasted annual electricity load for Connecticut in 2020 in this Strategy's "Expanded Energy Efficiency" scenario is 30,981 GWh. For more details, see Appendix A (Efficiency and Industry). Meeting the RPS with this load would require 6,196 GWh of Class I generation in 2020.

Because of differing capacity factors, generating this amount of renewable electricity would require different nameplate capacities of wind, solar, or other renewables. The 2012 Integrated Resource Plan (IRP) assumed annual capacity factors of 13% for solar PV, 27.9% for onshore utility-scale wind, and 37% for offshore wind in Connecticut.[6] With a 50/50 split between solar PV and wind (and assuming the wind

[2] Hodgkins, Jay. "Wave of U.S. Plant Retirements Likely Approaching; IPPs Particularly Exposed." SNL Power Daily, April 25, 2012. Available at http://http://publicutilities.utah.gov/news/waveofusplantretirementslikelyapproaching.pdf.

[3] U.S. Nuclear Regulatory Commission. NRC Renews Millstone Nuclear Power Station Operating Licenses for an Additional 20 Years. NRC News no. 05-161. Washington DC: Office of Public Affairs, 2005. Available at http://www.nrc.gov/reading-rm/doc-collections/news/2005/05-161.html.

[4] U.S. Energy Information Administration (EIA), "Existing Generating Units." Data from Form EIA-860. Washington DC: U.S. Energy Information Administration, 2010.

[5] Conn. Gen. Stat. §16-245a.

[6] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

is half onshore, half offshore — much of which will likely be accessed from outside the state), it would take 1.09 GW of wind and 2.72 GW of solar PV to generate 6,196 GWh/year. These figures illustrate technical potential and are only provided for illustrative purposes. It would be highly unlikely that those levels of offshore or onshore wind could be sited or financed in the near term. Of course, many other resource mixes are possible.

POTENTIAL AND COSTS OF NEW ENGLAND'S RENEWABLE RESOURCES

Table B-1 lists the technical potential of renewable resources in the New England region, as well as ranges of the levelized cost of energy from each resource with and without existing Federal subsidies.

TECHNICAL POTENTIAL

For all resources listed in Table B-1 (solar, wind, biomass, small hydro, enhanced geothermal), the technical potential numbers are taken directly from a 2012 study from the National Renewable Energy Laboratory (NREL).[7] This report estimated the state-by-state technical potential of these resources, both on a capacity (GW) and annual energy (GWh/year) basis.

Technical potential is an estimate of the electricity generation potential of a resource based on the availability and quality of the resource, technical performance of current systems, and constraints based on land topography and environmental or other uses. Technical potential does not include economic or market considerations, such as fuel or technology costs, the impacts of policy, or projected market uptake. Additionally, in nascent industries such as these, costs are extremely variable.

As an example, the NREL study calculates onshore wind potential by first taking the wind resource in each state and then removing available sites such as airports, urban areas, wetlands, water, National Park Service Lands, Fish & Wildlife Lands, Federal Parks/Wilderness/National Monument/Recreation Area/Wildlife Refuge, and so on. The study also excludes land with a slope greater than 20%, where construction and maintenance of wind turbines would be challenging. After land exclusions, the study estimates the technical potential for wind power assuming all remaining available land is developed with the best available wind turbine technology today.

While the technical potential gives insight into the amount of a resource that is available, it should be noted that 1) it is very difficult and unlikely that all, or even a large fraction, of the potential could be developed, and 2) the technical potential of a resource is not fixed in time. For example, better turbine technology that allows greater efficiency over a range of wind speeds or denser packing of wind turbines would increase the amount of the wind energy resource that could be captured, and better construction methods may allow development on lands with up to 30% slope.

For full details on state-by-state technical potential of renewable resources and the embedded assumptions, see the referenced report.

[7] Lopez, Anthony, Billy Roberts, Donna Heimiller, Nate Blair, and Gian Porro. U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. NREL/TP-6A20-51946. Golden, CO: National Renewable Energy Laboratory, 2012. Available at http://www.nrel.gov/docs/fy12osti/51946.pdf

The Strategy also highlights Canadian hydropower (not included in the NREL study) as a potential low-carbon generation resource. The resource potential of Canadian hydropower is enormous. Hydro Quebec is currently planning development of 4,500 MW of large-scale hydro projects; much more potential remains untouched.[8] Of course, the vast majority of this resource is inaccessible today due to lack of transmission connections. There is currently a proposal for a large direct current transmission line that would bring hydropower from Quebec into New Hampshire.[9] This line has a proposed capacity of 1,200 MW, meaning that the maximum energy import into New England from this project would be 1,200 MW x 8,760 hr/y, or 10,512 GWh/y. Of course, additional transmission projects would increase the portion of Canadian hydropower potential that New England could utilize.

LEVELIZED COSTS OF ENERGY

The levelized cost of energy (LCOE) divides the present value of all lifetime cash flows (capital cost, operations and maintenance costs, fuel costs, taxes, and rebates or subsidies) of a generating asset by the present value of all lifetime electricity generation to arrive at a $/kWh number.[10] LCOEs can be used to directly compare investments in different technologies, and to compare generation costs against retail or wholesale electricity rates.

Calculating the LCOE for a given generation asset is straightforward, but requires assumptions around fuel prices, capital and operation costs, and discount and interest rates. These can introduce large sensitivities into a project's LCOE.

The ranges of LCOEs in Table B-1 come from a variety of sources. The assumptions and calculations are detailed below.

1. Wind, fuel cell, small hydro, and biopower

DEEP used input assumptions from the 2012 IRP, including assumptions for financing, capital cost, operating lifetime, and operating costs. In addition to these assumptions, DEEP calculated LCOEs for wind and fuel cells using recent capital cost estimates from Lazard, a U.S. investment bank.[11] These are shown below in Table B-1, along with the current value of the Federal production tax credit for these resources.[12] These incentives are paid to the project developer for all electricity generation from the project for the first 10 years.

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[8] Hydro Quebec. "Developing Quebec's Hydropower Potential." Accessed July 21, 2012. Available at http://hydroforthefuture.com/projets/9/developing-quebec-s-hydropower-potential.

[9] Federal Energy Regulatory Commission. *"*Order Granting Petition for Declaratory Order. FERC Docket no. EL09-20-000.*"* Washington DC: Federal Energy Regulatory Commission, 2009.

[10] Calculating the present value of future cash flows requires discounting them using a chosen *discount rate*. In the same way, we can discount future electricity generation, because 1 kWh generated in the future is worth less to us today than 1 kWh generated this year. See the model documentation in NREL, "System Advisor Model."

[11] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

[12] North Carolina State University, "Database of State Incentives for Renewables & Efficiency: Federal Renewable Electricity Production Tax Credit." Last modified May 22, 2012. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1.

TABLE B-1: Input assumptions used in LCOE calculations for renewable energy systems

Resource	*Lazard Capital Cost ($/kW)*	*IRP Capital cost ($/kW)*	*Fixed O&M ($/kW-y)*	*Variable O&M ($/MWh)*	*Annual capacity factor*	*Federal tax credit ($/MWh)*
Onshore wind	1,750	2,498	28.80	-	24%–35%	23.6 (production tax credit)
Offshore wind	4,050	5,508	159.80	-	37%	23.6 (production tax credit)
Fuel cell	5,400	7,081	2.30	35.90	90%	30% of capital cost (investment tax credit)
Small hydro		3,151	13.80	-	48%	11.8 (production tax credit)
Biopower		3,954	103.00	5.10	85%	11.8 (production tax credit)

Source: Connecticut DEEP, *2012 Integrated Resource Plan;* North Carolina State University, "Renewable Electricity Production Tax Credit"; and Lazard, Levelized Cost Energy Analysis.[13]

A 10.8% capital charge rate was applied for all resources. More information on the financing assumptions that underpin this capital charge rate is presented in Appendix D of the 2012 IRP.[14]

2. Solar photovoltaics (PV)

For solar PV, DEEP used capital cost data from real projects installed in Connecticut. These cost data were provided by the Clean Energy Finance and Investment Authority (CEFIA).[15] Since these installations were not utility scale, DEEP did not use the financing assumptions from the 2012 IRP. Instead, DEEP used the National Renewable Energy Laboratory's System Advisor Model and its default inputs to

[13] Lazard. Levelized Cost of Energy Analysis – Version 6.0. New York: Lazard, 2012. Available at http://blog.cleanenergy.org/files/2009/04/lazard2009_levelizedcostofenergy.pdf

[14] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

[15] Clean Energy Finance and Investment Authority. "PowerClerk Data Export." Microsoft Excel file shared with Connecticut Department of Energy and Environmental Protection. May 14, 2012; and Clean Energy Finance and Investment Authority.; "PV "On Site Project Dashboard." Microsoft Excel file shared with Connecticut Department of Energy and Environmental Protection. April 30, 2012.

calculate the levelized cost of energy for rooftop solar PV. The detailed assumptions from NREL's System Advisor Model (SAM) are discussed in the next section of this Appendix.

The average LCOE of commercial rooftop solar PV projects in 2012 is 20.8 ¢/kWh without subsidies and 12.8 ¢/kWh counting the 30% Federal investment tax credit (ITC). The average LCOE of 2012 residential solar PV projects is 35.8 ¢/kWh without subsidies and 28.2 ¢/kWh with the Federal ITC. Thus the Strategy lists the range of installed costs as 17.4–35.8 ¢/kWh with no subsidies and 9.4–28.2 ¢/kWh with subsidies (see section below on *Solar PV Costs and Opportunities* for full details on these calculations, including our financial assumptions).

There are very few utility-scale PV projects in Connecticut, and again, cost data are not available for those that do exist. In 2011 DEEP issued a solicitation for 10 MW of utility-scale solar PV, and accepted two bids with average all-in costs of 22 ¢/kWh. DEEP used this cost range for utility-scale PV with subsidies (because bidding parties included the ITC in their financial calculations before arriving at a bid price), and inflated this cost to get an estimate of the range of costs without subsidies.

ANALYSIS OF SOLAR PHOTOVOLTAICS COSTS AND OPPORTUNITIES

A standard cost metric in the solar industry is the total installed cost of a project on a $/W basis. Typically, this is reported for the nameplate direct current electrical capacity, giving it the units *$/W-dc*. To make the analysis and recommendations of the Strategy more accessible to a wide audience not familiar with $/W benchmarks, and to allow for easy comparison to the retail price of electricity and other generation technologies, all installed costs have been converted to *levelized costs of energy* ($/kWh).

OVERVIEW

The primary data source for the solar PV analysis is a dataset of residential and commercial projects in the Connecticut provided by the Clean Energy Finance and Investment Authority (CEFIA).[16] This dataset includes all projects that applied for CEFIA incentives between 2001 and the present, with detailed information for each project, including:

- Project classification (residential/commercial)
- Application submittal and approval dates
- Details (program name and step) and values ($/W) of incentives given
- Total system cost and incentive amount ($)
- System size, including capacity (direct current and alternating current ratings) and expected annual production (kWh)
- Project cost broken down into: modules, inverter(s), monitoring device(s), engineering & design, installation labor, permitting fees, interconnection fees, municipal and utility inspections, and balance of system. These data were self-reported by installers, and there is some, unknown, variation in the way different installers break down total cost by components.

[16] *Ibid*.

- Manufacturer and model details for key hardware components

A similar dataset, without the component cost breakdown, was downloaded from the website of Go Solar California, California's solar campaign coordinated by the California Energy Commission and Public Utilities Commission.[17]

TOOLS

DEEP used NREL's SAM to convert installed $/W-dc costs to $/kWh LCOEs.[18] In its calculator for solar PV systems, SAM has five key modules that are important for this analysis: climate, financing, tax credit incentives, annual performance, and PV system costs.

1. Climate

Climate is one of the largest factors affecting the LCOE of a solar PV system. Solar insolation varies dramatically across different regions of the United States. For example, Phoenix, AZ receives an average of 2,519 kWh/m^2-yr of direct beam insolation, while Anchorage, AK receives only 857 kWh/m^2-yr.[19] A system built in Anchorage with exactly the same installed cost, incentives, and financing as a system built in Phoenix will have an LCOE that is roughly three times higher.

In this analysis, we assumed all systems were built in Hartford, CT, which has an average insolation value of 1,178 kWh/m^2-yr.[20]

2. Financing

Financing can also have a huge impact on the LCOE of a solar PV system. Figure B-2 shows how the LCOE of a residential system with fixed $/W-dc installation cost varies with the weighted average cost of capital. At an installed cost of $4/W-dc, for example, the LCOE can vary between $0.25/kWh and $0.53/kWh as the WACC goes from 5–13%, a reasonable range for financing residential projects.

[17] Go Solar California. "California Solar Statistics." Accessed May 2012. Available at http://www.californiasolarstatistics.ca.gov/.

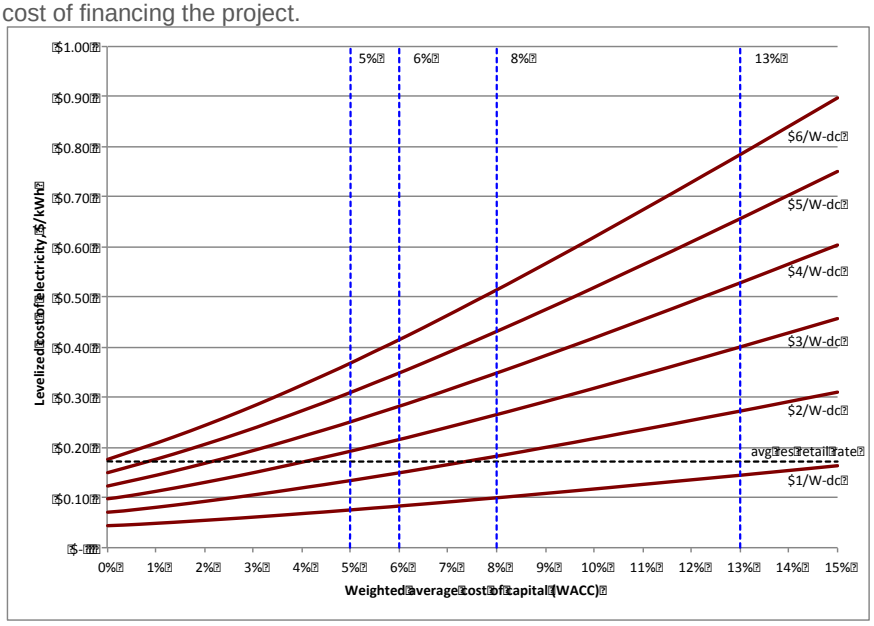
[18] National Renewable Energy Laboratory. "System Advisor Model (Version 2011.6.30)." [Software]. Golden, CO: National Renewable Energy Laboratory, 2011. Available at https://sam.nrel.gov.

[19] *Ibid*.

[20] *Ibid*.

FIGURE B-2: Levelized cost of energy vs. weighted average cost of capital for residential solar PV systems in Connecticut

The LCOE of electricity generating projects (in this case solar PV) is highly dependent on not only the initial capital cost, but also the cost of financing the project.



Analysis based on: CEFIA, "Power Clerk Data Export"; CEFIA, "On Site Project Dashboard"; and NREL, "System Advisor Model."

The strong dependence of the LCOE on the cost of capital means that the LCOEs for solar PV systems presented in this Strategy's electricity chapter are not exact, but are merely representative of typical projects.

To convert installed $/W-dc costs to LCOEs in this analysis, DEEP used the financial inputs in Table B-3. Most of these values are the model defaults used by NREL based on industry standards (for example, a 25 year analysis period/system lifetime). DEEP adjusted the State and sales tax rates to true values in Connecticut (residential solar PV systems are exempt from sales tax). The assumed interest rate for residential systems is 7.75%; this is the NREL default value, and is representative of current interest rates in the new FHA PowerSaver loan for financing residential efficiency or distributed generation projects (100% debt, 6–9% cost of capital).[21] For commercial systems DEEP used an interest rate of 10.68%, resulting in a WACC of 7% (consistent with the assumed WACC in the 2012 IRP).[22] The most critical difference between residential and commercial systems is the inclusion of depreciation in commercial systems, which we assume is handled with 5-yr Modified Accelerated Cost Recovery System (MACRS).

[21] U.S. Department of Housing and Urban Development. Federal Housing Administration (FHA): Notice of FHA PowerSaver Home Energy Retrofit Loan Pilot Program. Docket no. FR-5450-N-03. Washington DC, 2011.

[22] Connecticut Department of Energy and Environmental Protection, "2012 Integrated Resource Plan for Connecticut." Available at http://www.ct.gov/deep/lib/deep/energy/irp/2012_irp.pdf.

TABLE B-3: Financial assumptions used in $/W to LCOE conversions for solar PV systems

Parameter	Value (residential)	Value (commercial)
General parameters		
Analysis period	25y	25y
Inflation rate	2.50%	2.50%
Real discount rate	5.00%	5.00%
Taxes		
Federal tax rate	28.00%	28.00%
State tax	5.00%	9.00%
Sales tax	0.00%	6.35%
Loan parameters		
Loan type	Standard loan	Standard loan
Debt fraction	100%	100%
Loan term	25y	15y
Loan rate	7.75%	10.68%
Depreciation	N/A	5y MACRS

Source: NREL, "System Advisor Model"; Tax Foundation, "Connecticut"; and Connecticut DEEP, *2012 Integrated Resource Plan*.

3. Tax Credit Incentives

Because federal and state incentives for solar PV are provided to the customer (or installer) post-installation, the *installed cost* of a solar PV system is the same with or without counting incentives. However, the inclusion of federal or state incentives affects the lifetime cash flows, which means it will affect the levelized cost of electricity from the project. In the Electricity chapter of this Strategy, LCOE results for solar PV projects are presented without counting state incentives, but counting the Federal 30% ITC.[23] The justification for this is that the Federal ITC is a very real piece of the picture; one over which the state has no control, and which is slated to continue at its current levels until at least 2016.

[23] North Carolina State University. "Database of State Incentives for Renewables & Efficiency: Federal Business Energy Investment Tax Credit (ITC)." Last modified November 28, 2011. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1.; and North Carolina State University, "Database of State Incentives for Renewables & Efficiency: Federal Residential Renewable Energy Tax Credit." Last modified December 20, 2011. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F&re=1&ee=1.

4. Annual Performance, PVWatts Solar Array

Default values were left under annual performance: 0.5% system degradation per year and 100% system availability. The PVWatts Solar Array module lets the SAM user select various system design and performance parameters. We chose to model fixed, south facing, 20 degree tilt systems with a direct current to alternating current derating factor of 0.77 (this includes all inefficiencies including inverter, line losses, shading, and module mismatch). A local installer confirmed this derating factor (NREL's default value) to be a reasonable value for systems in Connecticut.

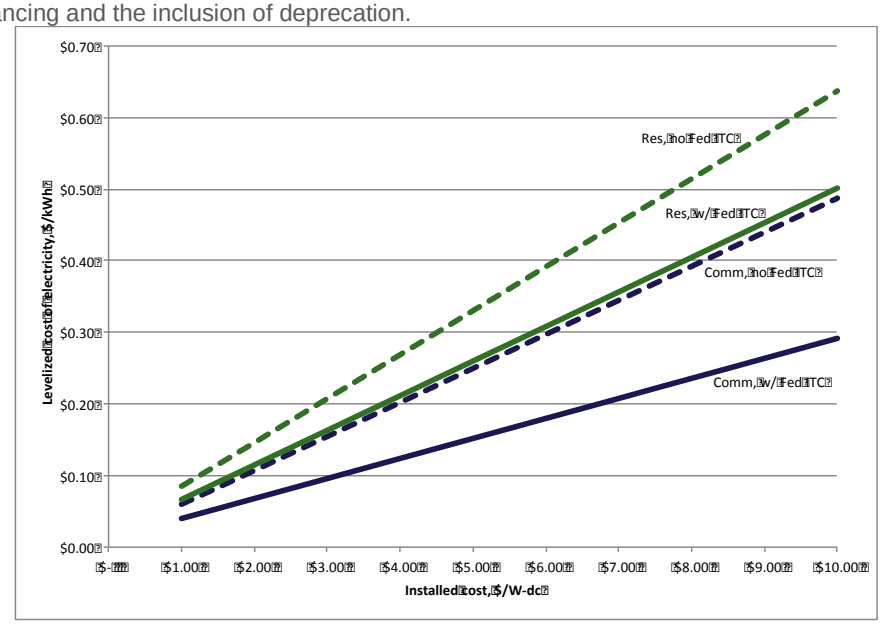
5. PV System Costs

In the PV System Costs module, DEEP adjusted the total system cost to $1/W-dc, $2/W-dc, etc., to calculate the LCOE for a given installation cost with the above climate, financing, incentive, and performance assumptions.

RESULTS

Given the above inputs and assumptions in SAM, DEEP calculated the LCOE of residential and commercial systems in Connecticut at a range of installed costs between $1–10/W-dc. These results are shown below in Figure B-3.

FIGURE B-3: Levelized cost of energy vs. installed cost for solar PV systems in Connecticut
With all climate, financial, and system assumptions fixed, the LCOE ($/kWh) is an (almost) linear function of the installed cost ($/W-dc). At the same installed cost, a commercial system has a lower LCOE than a residential system due to better financing and the inclusion of deprecation.



Analysis based on: NREL, "System Advisor Model"; Tax Foundation, "Connecticut"; North Carolina State University, "Business Energy Investment Tax Credit"; North Carolina State University, "Residential Renewable Energy Tax Credit"; and Connecticut DEEP, *2012 Integrated Resource Plan*.

The relationship between installed cost and LCOE is nearly linear. Thus, for converting all $/W-dc costs (from the CEFIA project dataset) to LCOEs, DEEP used the following slopes $\left(\frac{\$/kWh}{\$/W-dc}\right)$:

- Commercial, no Federal ITC: 0.051
- Commercial, with Federal ITC: 0.031
- Residential, no Federal ITC: 0.067
- Residential, with Federal ITC: 0.053

With the above slopes, converting all installed costs in the CEFIA project database was straightforward and resulted in the LCOE values as discussed in the Chapter 3 (Electricity). These values can then be compared directly against the retail rates for electricity in the residential and commercial sectors, and against LCOEs for other generation technologies, many of which do include fuel or other lifetime operating costs. They cannot be compared against solar PV directly on a capital cost basis.

To create the waterfall chart showing the opportunity available for cost reductions in residential solar PV in Connecticut (Figure 7 of Chapter 3 (Electricity)), DEEP used the component cost breakdowns included in the CEFIA project dataset along with the $/W to LCOE multipliers listed above. Table B-4 shows the numeric results presented in Figure 7.

TABLE B-4: Opportunity for cost reductions in residential solar PV in Connecticut
This table presents the numeric data behind Figure 7 in the Chapter 3 (Electricity).

	$/W-dc	LCOE (no Fed ITC)	LCOE (w/ Fed ITC)
Average total system cost (CT)	$5.24	$0.354	$0.353
Average total system cost (Germany)	$2.24	$0.151	$0.119
Total system cost with best quartile component costs (CT)	$3.07	$0.207	$0.163
Total system cost with best decile component costs (CT)	$2.31	$0.156	$0.123
Hardware			
Module – average	$2.23	$0.150	$0.118
Module – best quartile	$1.50	$0.101	$0.080
Module – best decile	$1.30	$0.088	$0.069
Inverters – average	$0.69	$0.047	$0.037
Inverters – best quartile	$0.50	$0.034	$0.027
Inverters – best decile	$0.41	$0.028	$0.022
Monitoring device – average	$0.11	$0.007	$0.006
Monitoring device – best quartile	$0.07	$0.005	$0.004
Monitoring device – best decile	$0.05	$0.003	$0.003
Design & Installation			
Eng. & Design – average	$0.16	$0.011	$0.008
Eng. & Design – best quartile	$0.06	$0.004	$0.003
Eng. & Design – best decile	$0.03	$0.002	$0.002
Installation labor – average	$0.91	$0.061	$0.048
Installation labor – best quartile	$0.50	$0.034	$0.027
Installation labor – best decile	$0.32	$0.022	$0.017
Permitting & Interconnection			
Pmt & Int'c fees – average	$0.12	$0.008	$0.006
Pmt & Int'c fees – best quartile	$0.06	$0.004	$0.003
Pmt & Int'c fees – best decile	$0.03	$0.002	$0.002
Inspection fees – average	$0.04	$0.003	$0.002
Inspection fees – best quartile	$0.00	-	-
Inspection fees – best decile	$0.00	-	-
Balance of system			
BOS – average	$0.98	$0.066	$0.052
BOS – best quartile	$0.39	$0.026	$0.021
BOS – best decile	$0.17	$0.011	$0.009

Analysis based on data from CEFIA, "PowerClerk Data Export"; CEFIA, "PV On Site Project Dashboard"; and Wesoff, "Germany Solar Installations."

2013 Connecticut Comprehensive Energy Strategy
Appendix C: Natural Gas Sector Strategy Analysis

INTRODUCTION

Chapter 4 (Natural Gas) discusses the economics and emissions reductions for conversion from fuel oil to natural gas. This Appendix provides the methodology and inputs that underpin the numbers in the Chapter. This Appendix covers the following topics:

- Net Present Value (NPV) of conversion
- Economic sensitivity of conversion
- Financing options

NET PRESENT VALUE OF CONVERSION

To calculate the NPV, DEEP took five steps:

1. Define the heating load for fuel oil and natural gas;
2. Calculate oil and natural gas expenditures for the heating load;
3. Identify cost of conversion from oil to natural gas;
4. Determine number of eligible customers; and
5. Calculate NPV of conversion for eligible customers.

1) DEFINE THE HEATING LOAD

Savings from fuel switching will depend on the amount of fuel oil that the customer currently uses. Representative fuel oil use for an average, converting customer in each sector is shown in the first column of Table C-1. These numbers were taken primarily from a report produced by the Department of Economic and Community Development (DECD) in in conjunction with the Connecticut Local Distribution Companies.[50] These numbers are very similar to heating load estimates calculated from U.S. Energy Information Administration data.[51]

As shown in Table C-1, heating load also depends on the efficiency of heating equipment. DEEP assumed 80% efficiency for the current fuel oil boiler/furnace stock. However, DEEP also assumed that when customers convert to natural gas, they invest in new, high efficiency heating equipment (93%). As a result, heating load is reduced in conjunction with the conversion to natural gas due to the increased efficiency of the new heating equipment. The assumption that converting customers will invest in high efficiency

[50] Connecticut Department of Economic and Community Development. The Economic Impact of Expanding Natural Gas Use in Connecticut. By Stanley McMillen and Nandika Prakash. Hartford, CT, 2011. Available at http://www.ct.gov/deep/lib/deep/energy/decd_nat_gas.pdf.

[51] Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

equipment is consistent with in the DECD report.[52] DEEP believes this assumption is valid because converting to a higher efficiency furnace provides the customer a higher return from conversion (i.e., higher NPV), and for a financed conversion, lower cost starting from day one.[53]

TABLE C-1: Heating load for fuel oil and natural gas by sector

	Average delivered Heat for fuel oil Customer (million BTU/year)	Average primary energy consumption at given efficiency (million BTU/year)	
		80%	93%
Residential	77	96	83
Commercial	138	173	149
Industrial	933	1166	1003

Source: Connecticut Department of Economic and Community Development, Expanding Natural Gas.

2) CALCULATE OIL AND NATURAL GAS EXPENDITURES FOR THE HEATING LOAD

Fuel expenditures are calculated by multiplying the heating load for a customer by the fuel price for the (heating) fuel that is being used.

For estimating base-case fuel prices for the various fuel options — most notably natural gas and fuel oil — DEEP used fuel price projections from the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO).[54] DEEP used the AEO reference case, and in particular the supplemental tables for the New England region. Several other fuel price scenarios have been examined in addition to the AEO reference case. These scenarios are described under the "Economic Sensitivity of Conversion" section below.

Savings from conversion/fuel switching are determined by comparison of a customer's fuel expenditure before and after conversion, and depend on both the fuel price and the heating load before and after conversion.

3) IDENTIFY COST OF CONVERSION FROM OIL TO NATURAL GAS

The total cost for conversion includes three main components: heating equipment replacement; service and meter; and estimated natural gas main extension. Conversion costs are summarized in Table C-2 and are described in detail below.[55] They vary (or are unnecessary/avoided) depending on sector, if the customer already has gas service, and if not, whether the customer is on-main (defined as within 150 feet of an existing gas main) or off-main (further than 150 feet).

[52] Connecticut Department of Economic and Community Development. The Economic Impact of Expanding Natural Gas Use in Connecticut. By Stanley McMillen and Nandika Prakash. Hartford, CT, 2011. Available at http://www.ct.gov/deep/lib/deep/energy/decd_nat_gas.pdf; and Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

[53] Using equipment cost numbers from Navigant, "Technology Forecast Updates." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

[54] U.S. Energy Information Administration, "*Annual Energy Outlook 2012*," Available at http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

[55] Total resource cost (TRC) is the required investment for an energy measure from all involved parties/stakeholders — in this case, the conversion cost to the customer plus the service and meter investment by the local distribution company. The TRC is one of three measures used by Connecticut utilities for their conservation programs.

TABLE C-2: Conversion cost summary by customer segment and sector

Segment		Home Heating Conversion Costs (HHC)	Conversions	Total Cost (HHC)	Service Line and Meter Cost (SLM)	Conversions	Total Cost (SLM)	Main Extension
On-main								
	Low	$ 7,500	39,000	$ 292,500,000				
	Residential	$ 7,500	160,852	$ 1,206,390,000	$ 4,283	160,852	$ 688,929,116	$ 7,208
	Commercial	$ 20,300	15,585	$ 316,375,500	$ 7,669	15,585	$ 119,521,365	$ 12,970
	Industrial	$ 40,600	569	$ 23,101,400	$ 11,504	569	$ 6,545,492	$ 87,375
				$ 1,838,366,900			**$ 814,995,973**	$ 107,553
Off-main								
	Residential	$ 7,500	51,506	$ 386,295,000	$ 4,283	51,506	$ 220,600,198	$ 371,255,240
	Commercial	$ 20,300	37,333	$ 757,859,900	$ 7,669	37,333	$ 286,306,777	$ 484,209,010
	Industrial	$ 40,600	430	$ 17,458,000	$ 11,504	430	$ 4,946,505	$ 37,571,250
				$ 1,161,612,900			**$ 511,853,480**	**$ 893,035,500**
				HHC costs	Distribution Costs		Total	
		Total On-main Cost		$ 1,838,366,900.00	$ 814,995,973		$ 2,653,362,873	
		Total Off-main Cost		$ 1,161,612,900.00	$ 1,404,888,980		$ 2,565,501,880	
				$ 2,999,979,800.00	$ 2,219,884,953		**$ 5,218,864,753**	
* Not contemplated as part of the DECD study, or Department adjusted.								

Source: Connecticut Department of Economic and Community Development, Expanding Natural Gas.

Heating equipment replacement

Heating equipment replacement cost includes the following: removal and disposal of old heating equipment including fuel oil tank; purchase of new heating equipment (including a furnace or boiler and hot water heater) and labor and installation. These numbers were taken from the DECD report, but are consistent with costs provided by EIA.[56] For residential conversions, DEEP has also verified costs by asking for quotes from local installers (Table C-3). With the exception of firm B, the costs are roughly consistent.

TABLE C-3: Typical costs of oil-to-natural gas heating system conversions for residential customers*

*Based on a sample of Connecticut-based contractors
**high end of range is the cost of a high efficiency installation

Firm	Location	Price Range
A	East Hartford, CT	$6-12K**
B	South Windsor, CT	$3-5K
C	Plainfield, CT	$5-10K
D	Stonington, CT	$5-8K**
E	Bridgeport, CT	$6-10K

Source: Telephone Interviews with Connecticut based installers, June 2012.

[56] Connecticut Department of Economic and Community Development. The Economic Impact of Expanding Natural Gas Use in Connecticut. By Stanley McMillen and Nandika Prakash. Hartford, CT, 2011. Available at http://www.ct.gov/deep/lib/deep/energy/decd_nat_gas.pdf; and Navigant Consulting, "EIA-Technology Forecast Updates-Residential and Commercial Building Technologies." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf.

4) CALCULATE NET PRESENT VALUE (NPV) FOR ELIGIBLE CUSTOMERS

NPV was calculated for a single customer conversion in each sector and segment, assuming conversion costs are incurred in year 0 and netting them out against 20 years of discounted fuel savings (oil expenditures minus natural gas expenditures). DEEP used a real 5% discount rate to bring fuel savings to present value. The selection of this discount rate is explained in Appendix A (Efficiency & Industry). Sensitivity was also examined for a lower (3%) real discount rate (Table C-5). NPV for an individual conversion in each sector is shown in Table 5. Multiplying by the number of conversions in each segment gives the NPV for each segment.

TABLE C-4: Summary of net present value (NPV) analysis

	Number of conversions	Fuel switch savings	Average Net Savings for a single conversion	Total Net Savings
On-main				
Non-heat	39,000	$22,324	$14,824	$78,136,000
Residential	160,851	$22,324	$10,541	$1,695,587,131
Commercial	15,585	$40,020	$12,051	$187,820,229
Industrial	569	$304,727	$252,624	$143,742,894
Off-main				
Residential	51,506	$22,324	$3,333	$171,654,801
Commercial	37,333	$40,020	$(919)	$(34,317,009)
Industrial	430	$304,727	$165,248	$71,056,674

Source: Connecticut Department of Economic and Community Development, Expanding Natural Gas.

For the purpose of the NPV analysis for the base scenario, DEEP evaluated the opportunity as if all conversions were made at once, instead of phasing the conversions over the test period. The effects of a phased natural gas conversion can be seen in the Chapter 1 (Efficiency) and Chapter 2 (Industry). These Chapters include a phased approach so that the natural gas opportunity is presented in a way consistent with what is used to show the effects of efficiency.

ECONOMIC SENSITIVITY OF CONVERSION

Chapter 4 (Natural Gas) discusses how much the NPV of conversion to natural gas changes across three scenarios. These scenarios are higher natural gas prices, reduced heating load due to building envelope energy efficiency, and the combined effect of higher prices and building envelope efficiency. In addition to these scenarios, several others were examined, including lower oil prices, and the results are highlighted in Table C-5.

TABLE C-5: Results of sensitivity analysis by segment

	Scenario	Sensitivity	*Segment A*		*Segment B*	
			Change	NPV	Change	NPV
Base	**Base:** Uses AEO "Reference case" fuel prices for the New England region.[57]	None	None	$2,620	None	$208
Fuel price[58]	**High gas price:** Uses "Low recovery per play" case from 2011 AEO. Applies % changes in prices from 2012–2035 to the AEO 2012 early release "Reference case". The price rise in this scenario is very close to that of the EIA high/rapid liquefied natural gas export scenario.[59]	Medium	-11%	$2,335	-73%	$56
	Low gas price: Uses "High recovery per play" case from 2011 AEO. Applies percentage changes in prices from 2012–2035 projection to the AEO 2012 early release "Reference case".	Medium	9%	$2,846	58%	$329
	High oil price: Uses "High oil price" case from EIA AEO 2011. Applies percentage changes in prices from 2012–2035 projection to the AEO 2012 early release "Reference case".	Very high	135%	$6,165	876%	$2,034
	Low oil price: Uses "Low oil price" case from EIA AEO 2011. Applies percentage changes in prices from 2012–2035 projection to the AEO 2012 early release "Reference case".	Very high	-122%	($567)	-778%	($1,412)
	Today's prices: Uses current price differential between natural gas and oil (see Table 7 for prices) and holds differential constant in from 2012–2035. Applies differential in prices to the AEO 2012 early release "Reference case".	Medium	16%	$3,026	228%	$684
Misc.	**Natural Gas Efficiency**: Assumes lower heating loads are available for conversion because of efficiency investment (20% natural gas demand reduction in residential sector, 15% in commercial and industrial, not including furnace efficiency).	High	-36%	$1,673	-217%	($243)
	Efficiency + High NG price: Combines the "Natural gas efficiency" and the "High gas price" scenarios to test sensitivity if both scenarios occur.	High	-45%	$1,443	-277%	($370)
	Stock turnover: Uses lower heating equipment replacement capital costs for residential sector. Assumes customer is making a decision between new efficient oil furnace and efficient natural gas furnace, this results in a lower incremental capital cost (capital cost=new gas furnace minus new oil furnace). It also results in lower savings potential because the baseline is a new oil furnace (89% efficient) rather than an existing furnace (80% efficient).[60]	Medium	13%	$2,961	N/A	N/A
	Uptake rate: Uses 15% lower customer adoption, assumes fixed main extension costs.	Medium	-15%	$2,227	-79%	$43
	Discount rate: Uses 3% discount rate instead of 5%.	Medium	38%	$3,616	260%	$747

Source: RMI Analysis.

[57] U.S. Energy Information Administration State Energy Data System, "Annual Energy Outlook 2012." Available at http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

[58] See Table C-7 for more information on Residential Fuel Price Scenarios.

[59] U.S. Energy Information Administration, "Effect of Increased Natural Gas Exports on Domestic Energy Markets," January 2012. Available at http://www.eia.gov/analysis/requests/fe/pdf/fe_lng.pdf.

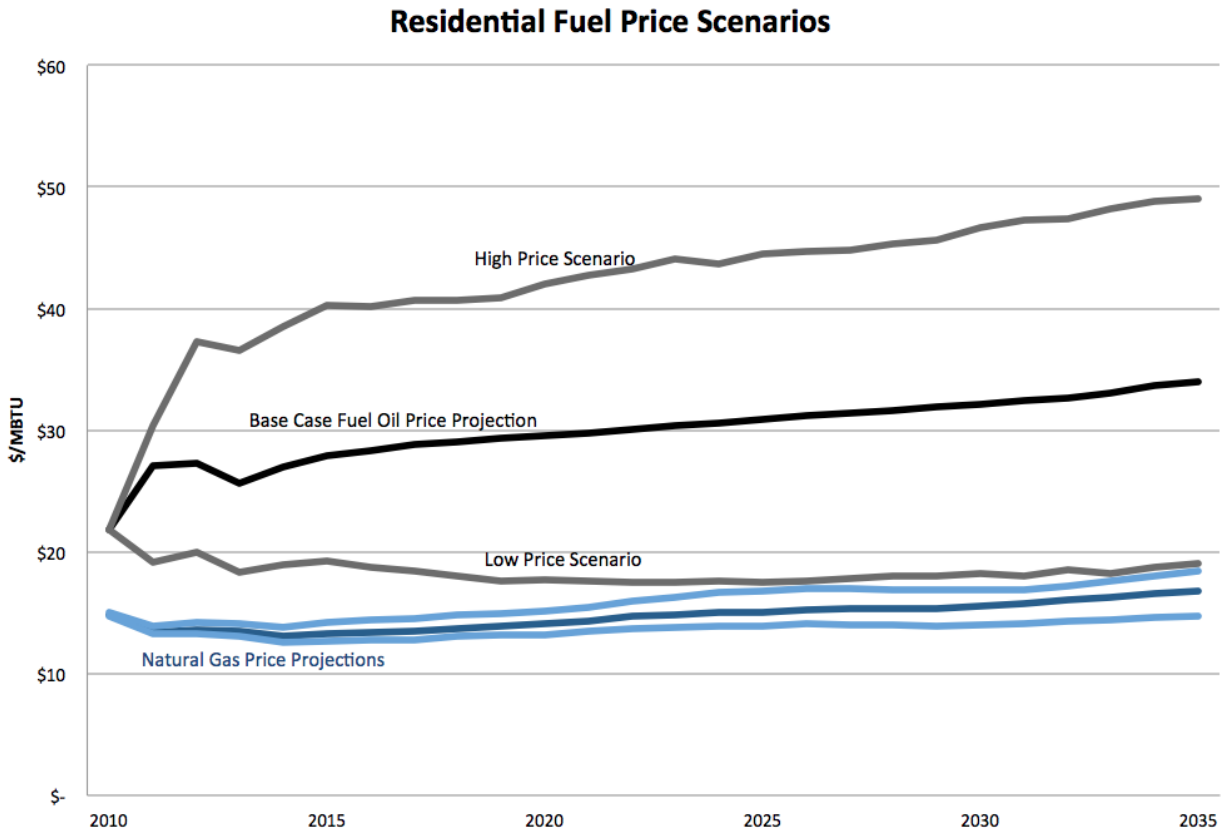
[60] The avoided cost for heating equipment replacement is $2,500 for an oil furnace/boiler and $1,500 for a water heater (Navigant, "Technology Forecast Updates." Available at http://wpui.wisc.edu/news/EIA%20Posts/EIA%20Reference%20Case%2009-2007%20Second%20Edition%20Final.pdf). Equipment lifetime is assumed to be 25 years for furnace/boiler and 15 years for a water heater. DEEP assumes a 10 year conversion timeframe and 10 out of 25 conversions can be timed perfectly to avoid the full cost of boiler/furnace replacement. For the remaining units, the avoided cost of replacement was discounted back to the time of conversion from the anticipated year of replacement (10–25 years).

TABLE C-6: Connecticut delivered fuel prices in July 2012

	Natural gas	Fuel oil
Residential	$14.51	$30.63
Commercial	$7.50	$29.63
Industrial	$7.96	$29.63

Source: U.S. EIA, "Natural Gas Prices"; and U.S. EIA, "Weekly Heating Oil Prices."

Table C-7: Residential Fuel Price Scenarios



Source: U.S. EIA, "Annual Energy Outlook 2012."[61]

FINANCING

The upfront cost that a customer must pay to convert is one of the most significant barriers for increasing conversion rates. For customers in Segment A, this cost is driven almost entirely by the cost of heating equipment replacement.

For customers in Segment B, the customer will also contribute towards the cost of the main extension. As described in the chapter, Connecticut gas companies can cover the cost of a service line, meter, and main extension up to the NPV of 15 or 20 years of revenue from sales to the new customer(s). Service, meter, and main extension costs in excess of this amount must be paid by the customer in a one-time, upfront

[61] U.S. Energy Information Administration, "Annual Energy Outlook 2012." Available at http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf

payment called a contribution in aid of construction (CIAC). The maximum amount that can be covered by the gas companies without a CIAC for a typical load in each sector is given in in Table 2 in Chapter 4 (Natural Gas). The upfront cost to the customer is heating equipment replacement cost, plus service, meter, and main extension costs in excess of the amounts shown in Table 2 in Chapter 4(Natural Gas).

For an initial evaluation of the potential for financing to overcome the upfront cost barrier, it was assumed that this entire amount would be financed over a 10-year period at rates ranging from 0-12%. The required loan payment was then calculated using the Microsoft Excel PMT function for each segment and sector. The payment is then compared to the average fuel bill savings for the customer over the first 10 years after conversion. The net impact of the loan payment and the customer's annual fuel savings is given in the financing tables shown in the chapter for each segment and for the range of interest rates.

For calculating a rough estimate of the incentive required to drive conversion in Segment B, it was assumed that a customer would not convert unless the net effect of the fuel bill savings and the loan payment would be equivalent to a 10% reduction to the customer's fuel expenditure's before conversion. The difference between the actual and the amount for 10% savings was taken as an estimate of the required extra incentive to drive conversion in that segment and sector.

2013 Connecticut Comprehensive Energy Strategy
Appendix D: Transportation Sector Strategy Analysis

INTRODUCTION

This technical appendix for Chapter 5 includes the following background data:

- Connecticut Registered Vehicles by Class
- Connecticut Registered Vehicles by Fuel Type
- Assumptions for Compressed Natural Gas Light-Duty Passenger Vehicle Net Present Value Calculations
- Background to Detailed Analysis for Long-Term Vision
- Technical Assumptions for Long-Term Vision
- Summary Table of Alternative Revenue Sources for the State of Connecticut

CONNECTICUT REGISTERED VEHICLES BY CLASS

TABLE D-1: Connecticut Registered Vehicles by Class, 2011

Vehicle Class	General Description	Technical Description (GVWR = gross vehicle weight rating)	Number of 2011 Registered Vehicles in Class	Rough Estimate 2011 Passenger Vehicle Population CT
HDBS	School buses	School Buses	7,219	
HDBT	Transit/urban buses	Transit/urban buses	2,209	
HDV2B	Large commercial vans and small box trucks	Class 2b Heavy-Duty Vehicles (8501-10,000 lbs. GVWR)	88,440	88,440
HDV3		Class 3 Heavy-Duty Vehicles (10,001-14,000 lbs. GVWR)	26,282	
HDV4	Large box trucks and medium multi-axle trucks	Class 4 Heavy-Duty Vehicles (14,001-16,000 lbs. GVWR)	9,267	
HDV5		Class 5 Heavy-Duty Vehicles (16,001-19,500 lbs. GVWR)	5,974	
HDV6		Class 6 Heavy-Duty Vehicles (19,501-26,000 lbs. GVWR)	8,411	
HDV7		Class 7 Heavy-Duty Vehicles (26,001-33,000 lbs. GVWR)	7,253	
HDV8a	Large multi-axle short & long-haul trucks (e.g. tractor-trailer rigs)	Class 8a Heavy-Duty Vehicles (33,001-60,000 lbs. GVWR)	5,184	
HDV8b		Class 8a Heavy-Duty Vehicles (33,001-60,000 lbs. GVWR)	9,655	
LDT2	Small/medium pick-ups & SUVs	Light-Duty Trucks 1&2 (0-6,000 lbs. GVWR)	770,468	770,468
LDT4	Medium/large pick-ups & SUVs	Light-Duty Trucks 3 (6,001-8,500 lbs. GVWR)	270,077	270,077
LDV	Cars	Light-Duty Vehicles (Passenger Cars)	1,486,706	1,486,706
MC	Motorcycles	Motorcycles	95,371	95,371
Total			2,792,516	2,738,173

Source: Connecticut Department of Motor Vehicles response to DEEP data request (June 29, 2012).

CONNECTICUT REGISTERED VEHICLES BY FUEL TYPE

TABLE D-2: Connecticut Registered Vehicles by Fuel Type, 2012

Fuel types of vehicles registered in Connecticut in 2012 ("Blank" indicates that a customer did not fill in the fuel type and "Unknown" indicates that fuel type information could not be read/determined on registration application.)

Fuel Type	Number of Vehicles
Electric	92
Flexible	31,439
Ethanol	60
Methanol	7
Compressed natural gas	451
Compressed natural gas l/e 8500 wt	128
Propane	96
Hybrid gas/electric	7,292
Convertible	804
Diesel	92,543
Gasoline	2,765,316
Liquefied gas	39
Blank	253,154
Other	0
Kerosene	0
Unknown	15,911
Total records read	4,838,246
Total records listed	3,167,204

Source: Connecticut Department of Motor Vehicles response to DEEP data request (September 28, 2012).

ASSUMPTIONS FOR COMPRESSED NATURAL GAS LIGHT-DUTY PASSENGER VEHICLE NET PRESENT VALUE CALCULATIONS

The assumptions used for the payback calculations for the compressed natural gas (CNG) light-duty vehicle shown in Table 13 in Chapter 5 (Transportation) are detailed below. The assumptions were provided by Northeast States for Coordinated Air Use Management (NESCAUM).

Fuel Economy: (in miles per gallon equivalent): 23 (from U.S. Energy Information Administration, "Annual Energy Outlook 2011" (AEO 2011))

Lifetime: 12 years

Incremental Vehicle Cost: $8,000 (AEO 2011)

Fuel Prices: AEO 2011 High Oil – price of natural gas for transportation sector in New England

AEO's 2011 fuel price forecast for CNG: $1.78/gallon of gas-equivalent (without state taxes); Gasoline: $4.47/gallon

Vehicle Miles Traveled: 12,000 miles, derived from VISION NE Transportation Fleet Model and assumed to be the same as a comparable gasoline internal combustion engine vehicle

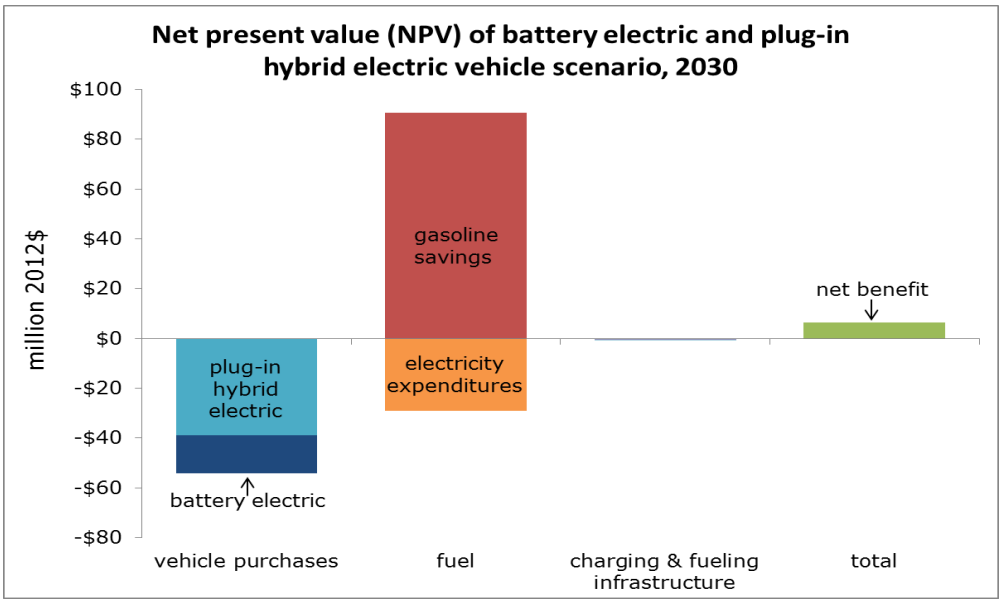
Infrastructure Costs: $0.26/gallon of gasoline equivalent (NESCAUM analysis of DOE/Clean Cities infrastructure costs and other northeastern estimates)

Discount Rate: 5%

BACKGROUND TO DETAILED ANALYSIS FOR LONG-TERM VISION

NESCAUM performed modeling and analysis to support the long-term vision proposed in Chapter 5 (Transportation). The information below provides the background and supporting data for this analysis.

FIGURE D-1: Net present value (NPV) of battery electric and plug-in hybrid electric vehicles in 2030



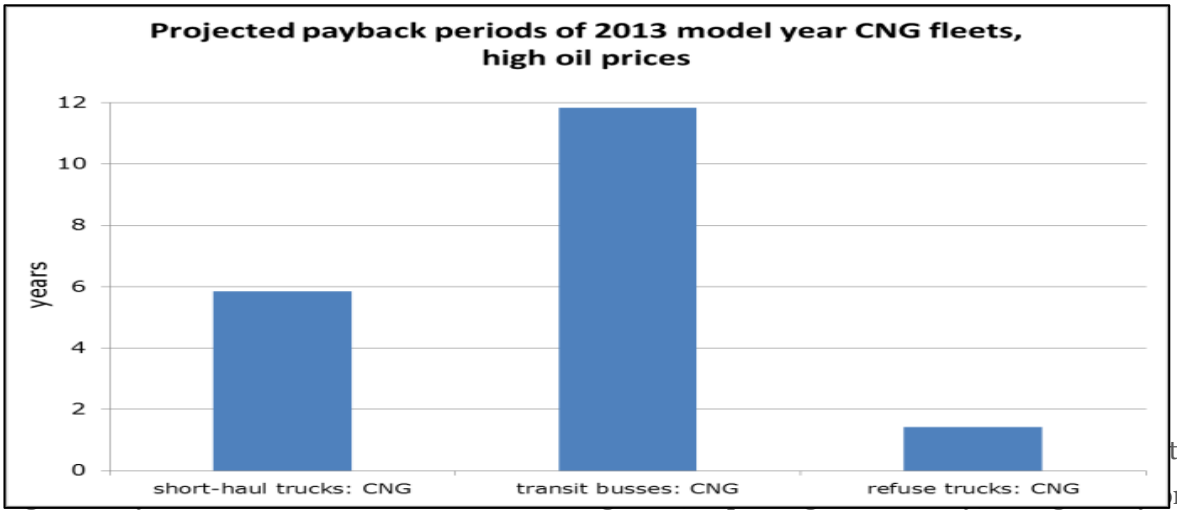
Source: NESCAUM analysis using the EPA Motor Vehicle Emission Simulator (MOVES) model and post-processing tools

In addition to high fuel economy gasoline vehicles, some alternative fuel vehicles also provide economic benefits over the vehicle lifetime. Connecticut's participation in the California Zero Emission Vehicle (ZEV)

program already commits automobile manufacturers to introduce battery electric and plug-in hybrid electric vehicles in the state, but exceeding those commitments by another 1.8% of sales by 2020 would produce $61 million in fuel savings over the vehicles' lifetime, for a net benefit of $6 million after accounting for the increased purchase price of these vehicles. Figure D-1 shows that increased use of battery electric and plug-in hybrid vehicles comes with relatively large upfront costs, but these are outweighed by fuel savings over the vehicle lifetime.[62] The challenge, however, is that these vehicles cost at least $10,000 more each than comparable conventional vehicles. The payback of this upfront investment appears to be longer than the 1-4 year payback period a typical consumer expects when purchasing a new vehicle, as show in Table 13 of Chapter 5 (Transportation). Without incentives, adoption of electric vehicles will proceed at a relatively slow pace until pricing becomes more competitive and other consumer concerns such as range anxiety and safety have been more fully addressed.

Similarly, the payback for compressed natural gas fleet vehicles, using a high oil price scenario, is shown in Figure D-2 below and Figure 14 of Chapter 5 (Transportation). Refuse truck fleets have the quickest payback and pilot projects to convert such fleets should be a priority.

FIGURE D-2: Projected payback periods (in years) for 2013 model year compressed natural gas (CNG) fleets given a high oil price scenario



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n fuel, and reducing reliance on oil. A combined strategy that incorporates high efficiency, plug-in hybrid, battery electric, combined natural gas, and fuel cell vehicles would result in these technologies comprising nearly half the Connecticut passenger vehicle fleet by 2050.

Table D-2 below provides the assumptions for the penetration of high fuel and alternative fuel vehicles used to create the long-term vision scenario as depicted in Figure 14 in Chapter 5 (Transportation).

[62] Neither Figure 13 nor 14 in Chapter 5 (Transportation) include the $7,500 federal rebate in their analyses. Inclusion of this rebate could make these vehicles more economically attractive.

TABLE D-2: Assumptions for passenger fleet mix penetration by 2030 and 2050

Sales Share of Light-Duty Vehicles	2030	2050
High Fuel Economy Sales Share	10.0%	10.0%
Electric Vehicle Sales Share	10.7%	10.7%
Plug-In Hybrid Sales Share	12.0%	12.0%
Compressed Natural Gas Sales Share	10.0%	0.0%
Fuel Cell Vehicle Sales Share	6.0%	20.0%

Source: NESCAUM, scenario assumptions.

As part of the analyses used to calculate the findings and projections presented in Chapter 5 (Transportation), several scenarios were developed and analyzed to understand how vehicle technology breakthroughs and increased penetration of alternatively fueled vehicles can help to achieve significant emission and fuel consumption reductions. In addition to the alternative fuel and advanced technology vehicles discussed previously, Table D-3 shows additional assumptions used to analyze an aggressive set of policy measures that could transform the Connecticut transportation sector by 2050.

Table D-3: Technology and policy assumptions for an "aggressive" Vision scenario

This scenario reflects a lower level of EV penetration was assumed that reflects full compliance with the ZEV mandate, but no additional programs to incent the sale of EVs.

Sales Share by Vehicle Technology	2030	2050
Light Duty High Efficiency Sales Share	10.0%	10.0%
Light Duty Electric Vehicle Sales Share	10.7%	10.7%
Light Duty Plug in Hybrid Electric Vehicle Sales Share	12.0%	12.0%
Light Duty Compressed Natural Gas Sales Share	10.0%	0.0%
Light Duty Fuel Cell Vehicle Sales Share	6.0%	20.0%
Transit Bus CNG Sales Share	66.7%	80.0%
Refuse Truck CNG Sales Share	66.7%	80.0%
School Bus CNG Sales Share	66.7%	80.0%
Short Haul CNG Sales Share	50.0%	66.7%

Source: NESCAUM, scenario assumptions for Passenger Fleet mix penetration by 2030 and 2050.

TECHNICAL ASSUMPTIONS

Subject	Category	Subcategory (If Applicable)	Source Name	Source Citation Information	Notes on Assumptions and Methodology
Charging and CNG Refueling Infrastructure	CNG Vehicle Charging Costs	LDVs: NGVs; HDVs: all CNG	NREL 2010 - Business Case for Compressed Natural Gas in Municipal Fleets	Johnson, Caley (2010). National Renewable Energy Lab (NREL). Business Case for Compressed Natural Gas in Municipal Fleets. Retrieved July 23, 2012, from http://www.afdc.energy.gov/afdc/pdfs/47919.pdf	The cost of CNG infrastructure ($/gallon of CNG) was based on a fueling station with a full capacity throughput of 150,000 GDE (gallon diesel equivalent) per month. A capital recovery factor of 0.12 was applied to the station costs. We put this in terms of $/GGE.
Economic					
	VMT Reduction Strategies	Potential Reduction: New Public Transit	LDV: passenger cars, passenger trucks	Cost-Effective GHG Reductions through Smart Growth and Improved Transportation Choices	Winkleman, Steve, Allison Bishins, and Chuck Kooshian (2009). Cost-Effective GHG Reductions through Smart Growth and Improved Transportation Choices. Center for Clean Air Policy.	Implementation examples were from Winkleman et al., 2009.
		Potential Reduction: Transit-Oriented Development (TOD), Work/ Live/ Shop Neighborhood development	LDV: passenger cars, passenger trucks	Driving and the Built Environment	Transportation Research Board (2009). Driving and the Built Environment. Winkleman et al. (2009).	Implementation examples were from Winkleman et al., 2009.
	Congestion	Congestion Estimates for Specific Traffic Corridors in CT, including Yearly Delay, Travel Time Index, Excess Fuel Use, and Congestion Cost	All	Urban Mobility Report	Texas Transportation Institute (2011). Urban Mobility Report.	Per Urban Mobility Report, travel time index refers to the ratio of travel time during peak and free flow hours. Congestion cost includes the yearly value of delay time (calculated at $16.01/hour in 2010) and wasted fuel.
	Feebates			Best Practices for Feebate Program Design and Implementation	The International Council on Clean Transportation. Best Practices for Feebate Program Design and Implementation. April 2010.	This source provides background information on feebate programs.
Conversion and Emission Factors	Energy Content of Fuels	All	U.S. EIA	Biofuels in the U.S. Transportation Sector. February 2007. http://www.eia.gov/oiaf/analysispaper/biomass.html	
	Emission Factors	gasoline, diesel, CNG, ethanol	EPA MOVES2010b Model	U.S. EPA. Modeling and Inventories. MOVES 2010b (Motor Vehicle Emission Simulator). Available at: http://www.epa.gov/otaq/models/moves/index.htm	

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SUMMARY TABLE OF ALTERNATIVE REVENUE SOURCES FOR THE STATE OF CONNECTICUT

FIGURE D-3: Summary table of alternative revenue sources for the State of Connecticut

TOTAL	*$0-$800M*

Source: Connecticut Office of Policy & Management, "A Strategic Framework for Investing in CT's Transportation: Economic Growth – Infrastructure Growth – Sustainable Communities [Draft, January 2011]."

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SIGNIFICANT PUBLIC COMMENTS SUBMITTED PRIOR TO RELEASE OF THE DRAFT 2012 CES

On April 10, 2012, as part of the early scoping stage of the development of 2012 CES, DEEP conducted the first of two stakeholder meetings at its offices at 79 Elm Street, Hartford, Connecticut. The purpose of that meeting was to obtain preliminary feedback from stakeholders on the scope of the CES. As a follow-up, by Notice of Request for Comments CES Scoping Stage dated April 13, 2012, DEEP invited stakeholders to provide written comments on the CES's objectives with respect to the Electricity, Buildings, Industry, Transportation, and Natural Gas sectors.

In response, DEEP received 16 sets of written comments, representing the views of the following entities: Class III CHP Organization (C3CO); Connecticut Business & Industry Association (CBIA); Connecticut Fund for the Environment (CFE); The Connecticut Light & Power Company (CL&P); Connecticut Natural Gas Corporation (CNG); Element Markets; Environmental Energy Solutions (EES); Environment Northeast (ENE); Integrated Management Controls LLC (IMC); New England Power Generators Association (NEPGA) ; NRG Energy, Inc. (NRG); Office of Consumer Counsel (OCC); Public Utilities Regulatory Authority (PURA); Retail Energy Supply Association (RESA); Sierra Club; The Southern Connecticut Gas Company (SCG); UTC Power; and Yankee Gas Services Company (Yankee Gas).

On May 23, 2012, DEEP held the second of the two stakeholder meetings, at which DEEP and its consultants presented updated information on the strategies under consideration for the five CES sectors, and engaged stakeholders to identify areas of concern, issues for development and/or recommendations. Thereafter, by Notice of Request for Additional Scoping Comments dated May 25, 2012, DEEP requested written comments from stakeholders on the sector presentations.

DEEP received 15 sets of written comments from the following entities: Algonquin Gas Transmission, LLC (Algonquin); CFE; Connecticut Gas & Electric, Inc. (CG&E); Connecticut Geothermal Association (CGA); CL&P; CNG; Covanta Energy (Covanta); Direct Energy Services, LLC (DES); Dominion Retail, Inc. (Dominion); Energy Plus Holdings LLC (Energy Plus); Environment Northeast; EES; Greater New Haven Clean Cities Coalition, Inc. (GNHCCC); Interstate Gas Supply, Inc. (IGS); Kimberly-Clark Corporation (Kimberly-Clark); RESA; Sierra Club; SCG; Spectra Energy Corp. (Spectra); UTC Power; and Yankee Gas.

All 31 sets of written comments submitted on the 2012 CES proceeding, as well as the recordings of the April 10, 2012 and May 23, 2012 stakeholder meetings can be accessed via the DEEP website.[1] The purpose of this scoping stage was to evaluate the need to include additional areas as part of the scope of the CES. DEEP's consideration of these comments is discussed below.

This appendix attempts to provide a summary, organized by sector then by topic, of major comments.

[1] See DEEP Energy Filings, "Public Act 11-80 - Section 51 - Comprehensive Energy Strategy." Available at http://www.ct.gov/deep/energyfilings.

BUILDINGS SECTOR

The written comments for the Buildings sector largely focused on the scope, energy efficiency, boiler/furnace upgrades, and clarification requests resulting from the Buildings sector presentation at the second stakeholder meeting.

Scope

The OCC believes that the discussion in the Buildings sector should be framed by cost consideration and funding sources.

During the second stakeholder meeting, DEEP offered the preliminary analysis that natural gas cannot ultimately meet Connecticut's mandatory carbon pollution reduction targets. Therefore, ENE believes that consideration should be given over the long term to both natural gas and electricity as energy carriers to heat and cool high efficiency buildings of the future.

In the OCC's view, the issue of sub-metering (check which utility service – electric or NG, or both) should be considered in this sector. To this end, the OCC suggested that DEEP review current regulations in Connecticut and perform a thorough study of sub-metering. Both the review and the study should identify obstacles and best practices met in other states. PURA noted that it investigated and analyzed many complex issues and problems related to allowing natural sub-metering, but ultimately its 2007 Decision in Docket No. 06-09-01 did not result in doing so. PURA added that it intends future review of this topic.

Energy Efficiency

CFE recommended that policies should be implemented to require measurement and disclosure of a building's energy performance information in order to motivate investment. CFE added that the resulting data should be incorporated into that building's valuation. The OCC believes that energy efficient building codes and standards for renovations and new construction should be created. ENE proposed that Connecticut consider and evaluate the following complementary policy options: (a) building labeling and time-of-sale disclosure; (b) state or regional appliance/equipment standards; (c) more stringent building codes; (d) minimum efficiency standards for rental housing; (e) utility decoupling (required by law but not yet fully implemented); and (f) water efficiency measures.

The OCC further recommended that current EE programs be analyzed to identify successes and best practices. ENE disagreed. ENE believes that the CES is not the appropriate venue for an analysis of existing EE programs since they are already reviewed annually by DEEP. ENE expressed that the CES could instead identify the areas of potential efficiency not currently covered by existing EE programs. Likewise, the OCC commented that new and proposed EE programs should be identified and considered. ENE suggested that the CES focus on an analysis of potential efficiency investment levels for natural gas and oil programs and corresponding benefits.

ENE stated that the CES should ensure an accounting of all existing building-related EE programs already being implemented in Connecticut, as any omissions or undercounting in the process of developing this sector's baseline will affect the accuracy of DEEP's energy savings projections.

CFE urged Connecticut to encourage greater EE penetration in its large stock of aging, energy-wasting buildings. The OCC recommended the use of the Lead by Example program relative to the renovation of existing buildings.

To fund expanded EE, CL&P believes that DEEP should consider recommending the use of a cost adjustment mechanism (CAM) with lost revenue recovery for all EE expenditures (consistent with the recovery model currently approved for the LDCs) until such time that a decoupling mechanism is made available. Also, CL&P believes that multiple-year budgets should be used to sustain activity over the long term and to avoid cyclical funding that creates staffing and product availability problems for the EE market and delivery infrastructure.

ENE strongly supports expanding the EE scenario for the Buildings sector, thereby placing importance on its approval and full implementation, as proposed in the IRP and the pending CL&M Electric Plan. To help clarify the policy necessity of pursuing an expanded EE scenario, ENE states that macroeconomic benefits for this sector should be addressed in a robust manner.

ENE stated that the analysis of residential buildings should not overly focus on detached single-family homes and should include water efficiency. Also, ENE suggested that any analysis of future residential and commercial buildings should consider future energy consumption as impacted by the types and sizes of future buildings. Additionally, ENE claimed that air source heat pumps have potential for more widespread use than ground source heat pumps, and should be included in any fuel efficiency analysis.

The OCC stated that EE program resources should be publicly available and user-friendly; a "one-stop-shop" approach should be considered. Relative to customer behavior, ENE recommended that any analysis concerning the extent and impact of changes should be realistic.

Boiler/Furnace Upgrades

The LDCs also believe that boiler/furnace upgrades will reduce the payback from efficiency gains, not increase it (as noted in the Buildings sector presentation). The LDCs proposed a more comprehensive analysis of a status quo scenario involving a building using fuel oil with low efficiency equipment, as compared to a new scenario wherein the same building has switched to a high efficiency gas boiler/furnace. The LDCs think that a conversion combined with additional energy efficiency represents a great opportunity, but one that is enabled by the conversion, not the other way around.

Of the challenges noted in the presentation, the LDCs believe two challenges are really not. Firstly, the LDCs think that the issue of failing heating systems is not about whether the equipment is gas-powered or fuel oil-powered. Rather, it is more reflective of whether the given equipment is old or new, or it is properly or not properly maintained. Secondly, relative to the fact that a conversion may take several

weeks to complete, the LDCs argued that that fact neither really impacts the overall economics of the conversion nor the final savings realized by the customer.

Clarification Requests

A few comments requested clarification on certain projections, calculations or assumptions revealed during the Buildings sector presentation at the second stakeholder meeting. Relative to Slide #3 of the Buildings Sector presentation, CL&P asks if the energy consumption projections contained therein include the impacts of CHP as contemplated in the Industry sector presentation. CL&P also asked what specific measures would need to be undertaken to drop from 101 to 18 trillion BTU of oil consumption by 2050, since it is unclear how this amount can be achieved through energy efficiency. Moreover, CL&P questioned whether the use of geothermal heat pumps is considered part of the fuel switching strategy.

ENE sought more detail on how DEEP calculated the 49% energy savings estimate and the $27B net savings estimate it claimed.

CFE wants to know of the underlying assumptions between the "No EE" and the business-as-usual heating scenarios. CFE stated it doesn't understand why the estimated consumption of both heating oil and natural gas are the same in both cases.

CL&P asked how Slide #12 addressed fuel switching; CL&P wondered if the natural gas savings depicted in Slide #12 contains savings for switching from inefficient oil equipment to highly efficient gas equipment.

CNG, SCG and Yankee Gas (together, the LDCs), believe that the projection of a 20% EE improvement and 25% heating load reduction is high. The LDCs stated their preference for a point that is in the mid-range of EE improvement estimates.

DEEP RESPONSE

The scope of the Buildings Chapter, now entitled the "Energy Efficiency Chapter," includes topics raised by stakeholders including: sub-metering and oil efficiency. In response to stakeholder comments on technical clarifications, DEEP will address stakeholder comments as part of the technical meeting on the Energy Efficiency Chapter.

INDUSTRY SECTOR

The written comments for the Industry sector largely dealt with certain issues and concerns relating to combined heat and power (CHP) resources and EE programs.

CHP Resources

Given that CHP has been a successful approach for lowering emissions and energy costs, ENE supports the strong CHP focus in this sector, as well as the goal of increasing the amount of cost-effective CHP potential that is captured. ENE expressed that a valuable planning tool would be an accurate analysis of the potential for additional CHP development in Connecticut. According to ENE, the analysis should include a range of sizes of CHP systems and should involve an assessment of potential costs and benefits. That assessment should not be limited to the industrial segment and should identify specific sites that have high therm loads, thereby resulting in high overall CHP efficiencies.

Kimberly-Clark believes that, in order for Connecticut to maintain its leadership role in CHP policy, it is critical that the CES address the long-term needs of Class III CHP resources. The CES should be developed to be consistent with the policy goals underlying Connecticut's Class III program, including the intended provision of stable revenue stream for the ongoing operating costs of Class III CHP resources. Kimberly-Clark cautions that failure to do so would not only thwart the Class III program policy, but jeopardize the overall competitiveness of Connecticut's CHP policies.

UTC Power commented on the development of CHP-specific programs to be administered by CEFIA and DEEP, as required by PA 11-80. UTC Power noted that there are Class I renewable resources that allow for CHP operation, such as in-state manufactured fuel cell systems. UTC Power expressed that the scope of these programs or the installed megawatt capacity should not be limited to traditional CHP technologies to the exclusion of other technologies outlined in the Industry Sector presentation.

CL&P sought clarification on Slides #4 and #11 of the Industry Sector presentation. Regarding Slide #4, CL&P asked if the electricity use by sector includes electricity use produced by CHP units already in operation. If it is, CL&P questioned whether the natural gas us already takes this energy consumption into account. CL&P also noted that Slide #4 indicated that process loads represent 59% of electric consumption, and Slide #11 projected that a 60% reduction in electric use can be achieved by 2050. CL&P asked if this reduction assumes displacement of electric use by CHP units. Lastly, CL&P clarified that Connecticut's 8th place ranking is for its EE programs and policies, not just its EE programs.

EE Programs

The OCC noted that it would be advantageous of industrial customers to avail themselves to the expanded EE programs offered by Connecticut's EDCs and LDCs through the EEB. In the OCC's view, EE programs that provide low or no interest loans to be better and more sustainable than grant programs, and loan programs that are correctly designed would become self-sufficient with minimal new funding requirements after the initial 3-5 year investment period. Also, the OCC recommended that this sector

consider initiatives that could benefit smaller and medium-sized businesses, since there is a fine line between the commercial customer sector and the industrial customer sector.

ENE stated that the distribution of current industrial EE programs is inaccurately presented in sector presentation, since the two evaluations (cited as the source of figures) measure savings of both commercial and industrial segments combined, rather than just the industrial segment. Since electric use in Connecticut's commercial segment is nearly four times that of the industrial segment, any combined data is likely to be more representative of the commercial segment.

Kimberly-Clark is concerned that implementation of the proposed expansion of EE measures would further deepen the existing Class III imbalance, with the likely possibility of Class III CHP resources not finding any willing buyers for their RECs. Therefore, Kimberly-Clark advocated for the EE expansion's implementation to be designed to avoid any unintended, adverse consequences on Connecticut's already saturated Class III market and the further development and retention of in-state Class III CHP resources.

CBIA expressed an interest in further reduction of barriers for further business investment in EE measures and clean energy.

OTHER INDUSTRY SECTOR COMMENTS

The OCC commented that ratepayers should not be viewed as a source for funding brownfield revitalization, increasing alternative fuel availability and minimizing industrial GHG emissions.

ENE noted that Slide #3 of the Industry sector presentation projected oil consumption to grow over time in the industrial segment. ENE requested the CES to provide justification for that projection, which ENE viewed to be highly unlikely.

DEEP RESPONSE

In response to comments raised by stakeholders, the scope of the Industry Chapter deals largely with opportunities for further tailoring efficiency programs and highlights additional in-state opportunities for CHP. Issues related to Class III RPS will be considered as part of the RPS study and through the public process for that study.

ELECTRICITY SECTOR

Most of the written comments for the Electricity sector focused on issues relating to: the desire for a regional policy approach; infrastructure development; procurement; Connecticut's Renewable Portfolio Standard (RPS); concerns relative to reliability, security and micro-grids; ratepayer cost components; retail providers; and a few other issues.

Regional Policy Approach

CL&P and Yankee Gas recommended that states regionally adopt a "technology agnostic" structure to encourage clean energy development.

ENE believes that any changes to the generation side of this sector should be considered in the context of regional ISO-NE markets. For effective planning purposes, generation emissions should be looked at regionally. Accordingly, ENE recommended that any GHG modeling conducted for this sector should be sensitive to regional realities.

Moreover, ENE believes that any analysis of future energy issues in this sector should involve a review of RGGI. In ENE's view, this review should: (a) involve an assessment of RGGI's performance to date; (b) take into account the significant net benefits RGGI has provided (and will continue to provide) to Connecticut's EE efforts and economy; and (c) include a thorough assessment of how RGGI can best be used going forward to help transform Connecticut's energy system, to decarbonize its electricity sector and to grow the economy.

Infrastructure Development

In CL&P's and Yankee Gas's joint opinion, Connecticut's renewables approach should focus on ensuring the completion of the most cost-effective clean energy projects first. By doing so, this would lead to priority funding for efficiency and C&LM projects, a reduction in region's electric load, and, thus, a reduction in the required amount of renewable energy to meet Connecticut's RPS. The Sierra Club added that focus should be placed on finding ways to reduce permitting and other regulatory barriers to the development of renewable resources.

CL&P commented that the comprehensive view of the renewables strategy should not only look at GHG emissions, but also the cost impact to customers. CL&P believes that any emphasis on renewable development should be "technology agnostic" with a greater discussion of impact of any renewable strategy on customer bills, including moving customers from fuel oil to natural gas. To that end, CL&P suggested that DEEP also consider what opportunities there may be to bring to Connecticut lower cost renewables from outside state.

CFE believes that Connecticut should encourage the deployment of renewable energy throughout the regional grid, while maximizing development of in-state renewable resources. To ensure that cost effective projects are brought to market in the region, CL&P and Yankee Gas asserted that it is key for

each state in New England and the neighboring regions to work with each other to identify options and solutions for meeting renewable energy needs. NEGPA stated that the CES should examine and recognize the important benefits that accrue from local and regional generation development.

Relative to renewable development goals, CL&P suggested that these goals should be based on a variety of metrics without an emphasis on a particular metric, such as GHG emissions. CL&P stated that even before new renewable development goals are met, DEEP should take a fresh look at the existing RPS for Connecticut, and solicit comments from interested stakeholders prior to making any recommended changes to state legislature.

ENE suggested that the latest IRP should guide the further analysis of electric generation. NRG expressed that the CES should create a level playing field for the evaluation, procurement and financing of various electric supply resources. NEGPA commented that a balance must be struck to ensure that ratepayers receive the full benefits of a wholesale competitive electricity market rather than furthering guaranteed utility investment returns.

CBIA noted that natural gas and large-scale hydro are two energy sources that meet the "cheaper, cleaner and reliable" criteria for the near term. Accordingly, CBIA believes that these sources merit strong focus for the interim period in the CES.

NRG stated that the CES should address the planned replacement of aging generation infrastructure, while recognizing the very long lead times for new generation, and even longer lead times for completing transmission resources proposed for a potential import power strategy. NRG added that the Montville Biomass project would provide 40 MW in renewable generation and would have the most significant impact on stated CES goals over the next 12-18 months.

ENE pointed out that 50% of Connecticut's electricity generation comes from Millstone's Units 2 and 3. Accordingly, ENE recommended that that the analysis for the Electricity sector reflect the scheduled license expiration of Units 2 and 3 in 2035 and 2045, respectively. Should Millstone not be relicensed, ENE believes it could have significant impact on state and regional profiles for GHG emissions. Therefore, ENE proposed that any GHG emissions modeling for the CES should include a scenario reflecting the possible retirement of those units.

Procurement

NEGPA commented that any procurement of new resources should be done through an open, transparent and competitive process.

RESA stated that DEEP should determine first what precipitated its review of Connecticut's approach to Standard Service procurement, and then, if changes are determined necessary, evaluate what changes will best achieve Connecticut's energy goals. In RESA's opinion, DEEP should not mistake changes in market prices for deficiencies in current procurement practices. If market changes warrant changes, DEEP should ensure that those changes are designed to maximize market participation, provide accurate price

signals and avoid passing unnecessary risk onto ratepayers. Moreover, RESA believes that, rather than making wholesale changes to procurement strategies in response to market changes, DEEP should review whether modifications to timing, frequency, duration and layering of procurements will allow consumers to receive benefits of positive market changes.

Connecticut's Renewable Portfolio Standard (RPS)

DEEP received comments relative to Connecticut's RPS from CL&P, Yankee Gas, NRG, C3CO, ENE, Kimberly-Clark, NEGPA and Covanta.

CL&P and Yankee Gas stated that Connecticut's RPS goals should be reviewed to ensure that they are correctly sized to meet clearly defined and broadly accepted objectives. NRG commented that the CES should meet Connecticut's RPS targets while minimizing risk, maximizing reliability and providing maximum benefit to ratepayers and the economy.

C3CO expressed that Connecticut's RPS policy drives the development of out-of-state renewable resources at the expense of the customers and the developers of in-state combined heat and power (CHP) projects. C3CO believes that changes to the RPS are necessary to facilitate continued investment in CHP installations.

In light of the current oversupply of Class III RECs (due to the steep price decline for those RECs) and the shortage of Class I RECs, C3CO stated that solutions must be developed to stabilize Connecticut's RPS. Rather than finding ways to change RPS goals, ENE recommended that Connecticut instead focus on finding the best solutions to meet the established RPS goals.

Kimberly-Clark suggested that the CES should reflect the ability of CHP resources to mitigate the impact of Class I RECs shortage on ratepayers. Kimberly-Clark proposed an approach that would use green in-state DG resources (including Class III CHP resources) as a means to develop micro-grids as an offset to the Class I requirement. Alternatively, Kimberly-Clark proposed consideration of creating a new RPS class for C&LM resources, an approach that C3CO also recommended. Kimberly-Clark added that this new class should be comprised entirely of CL&M projects; this would remove such resources from the Class III definition, thereby enabling Connecticut to realize RPS goals without negatively impacting Class III CHP resources.

Kimberly-Clark proposed that the CES's recommendations should reflect the ability of CHP resources to mitigate the impact of the Class I shortage on ratepayers. To that end, Kimberly-Clark gave its support to the use of in-state DG resources that meet certain environmental standards (including Class II CHP resources) as a means to develop micro-grids as an offset to Connecticut's Class I RPS requirement. According to Kimberly-Clark, doing so would permit these resources to satisfy a defined portion (e.g., 25%) of Class I requirements.

NEGPA argued that material changes to the RPS's Class I definition undermines regulatory certainty, has chilling effect on potential for private investment in new energy efficiencies and jobs, and "effectively kills

attempts to create incentives for new local, Class I resources." NEGPA argued that out-of-region large-scale hydro projects should not be included as Class I RPS resources.

Covanta recommended including Energy-from-Waste facilities as Class I RPS resources. Covanta states that, given the need for huge investments in transmission line infrastructure and the lack of support for in-state jobs, the proposal to use out-of-region resources (e.g., large hydro projects) should be replaced with the option of making Energy-from-Waste a Class I renewable for RPS. Covanta believes that the current state policies have continued to disadvantage Energy-from-Waste facilities by incentivizing landfills, which it characterized as an "inferior technology." Covanta is critical of the fact that RPS places landfill gas recovery systems in Class I, while Energy-from-Waste facilities are relegated to Class II.

Covanta noted that moving Energy-from-Waste from Class II to Class I would allow such facilities, a total of six in Connecticut, to maintain their viability as they transition off their expiring long-term PURPA power contracts into today's markets. According to Covanta, such a move would: (a) help solve the shortage of Class I RECs; (b) avoid increases in generation costs; (c) support in-state jobs; (d) lower the state's reliance of fossil fuels; (e) mitigate GHG emissions; (f) operate 24 hours per day, 365 days per year; and (g) avoid need for costly transmission line upgrades.

Reliability, Security and Micro-Grids

EES urged the CES to consider and incorporate reliability and security concerns in this sector as well as all other sectors. (EES's recommendations and comments relative to reliability and security are provided in more detail in the Section for Non-Sector-Specific Comments, below.)

The OCC stated its concern that an overreliance on natural gas, as abundant, reliable, and cost-effective, without addressing current system constraints, could compromise reliability. Moreover, the OCC expressed that energy security may be impacted by a lack of fuel diversity if Connecticut overly relies on natural gas. In the short to intermediate term, IMC recommended that priority be placed on electric energy reliability and security concerns over increased supply. PURA stated that increased demand for natural gas would potentially have greater impact on availability, electric reliability and the natural gas price.

Currently, CL&P's proposed Interstate Reliability transmission project is the subject of an ISO-NE needs analysis. The OCC recommended that forecasts in this sector should track that project.

When energy or capacity deficiency beyond what is signaled in regional marketplace is identified, NEGPA advised that markets must first be ensured to be producing accurate outcomes to best support supply needs. Otherwise, NEGPA stated that the use of competitive procurement is critical to providing the best options for desired resources at the lowest costs.

C3CO proposed that in-state green DG resources should be promoted to support energy security and to encourage the development of micro-grids as an offset to the Class I RPS requirement. Kimberly-Clark stated that the use of existing Class III CHP resources to support micro-grid development would be of

benefit to Connecticut. In Kimberly-Clark's view, doing so would enhance system reliability and likely minimize the potential costs and delays related to siting, interconnections and permitting requirements, among other things.

When selecting locations for micro-grids, UTC Power suggested that grid reliability issues be consideration.

CFE gave its support to the further study of smart-grid technology in city centers, as well as the use of energy improvement districts as a mechanism to support micro-grids.

Ratepayer Cost Components

NRG recommended that the CES establish effective analysis and analytical tools in order to critically analyze full cost over time of delivered electric resources in Connecticut (i.e., electric rates, overall economic impacts). In addition, NRG suggested that the CES address the growing burden of new transmission on consumers. NRG expressed concern that proposed transmission projects may result in greater costs for Connecticut consumers than the IRP anticipated. Moreover, according to NRG, these projects may have higher overall costs in comparison to a locally-sited generation alternative, which would maintain and increase Connecticut's manufacturing workforce and enhance its economy and the reliability of the local grid.

NEGPA proposed that Connecticut add a "public policy" ratepayer cost component (in addition to the generation, transmission and distribution cost components) when analyzing ratepayer costs. The public policy cost component would include such items as the C&LM charge, the renewable energy investment charge, the system benefits charge and the stranded cost component. In NEGPA's view, doing so would allow for transparency and a more complete understanding of the drivers behind Connecticut's electric costs and the impact of public policy choices on electric rates in Connecticut. Also, NRG noted that the IRP only analyzes over time the rate trends of the Generation Service Charge (GSC). NRG argued that limiting the IRP's rates outlook to just the Generation Service Charge would not demonstrate the likely increases in non-GSC cost components that would result from EE program expansion.

C3CO noted that, since increases in Connecticut's RPS targets are expected to outpace renewable resource development, the state's ratepayers are projected to experience rate increases from Alternative Compliance Payments in the near future.

Retail Providers

RESA stated that DEEP should establish a paradigm that allows for a more efficient market structure wherein the competitive retail providers concentrate on providing market-based generation supply options, while the EDCs concentrate on providing reliable and cost effective transmission and distribution services. To this end, RESA believes the CES needs to recognize and account for the role of the competitive market. In its view, the CES should provide the competitive market the opportunity to offer

solutions before regulatory programs are created. RESA argued that regulatory programs impose greater ratepayer costs and can create unintended barriers to high value competitive offerings. Furthermore, RESA believes that the CES should evaluate certain retail market enhancements, namely, improved/timely access to customer data, enhanced customer choice parity, and alternate billing arrangements.

OTHER ELECTRICITY SECTOR COMMENTS

The OCC stated that the scope should include a listing of all current and near-future programs/initiatives being funded by ratepayers. CL&P and Yankee Gas recommended that program initiatives that result from this sector be consistently applied in the long-term and be maintained to remain attractive to investment.

CL&P and Yankee Gas also noted that certain federal subsidies are scheduled to expire over the next two years (e.g., Investment Tax Credit, Production Tax Credit). They believe it is important for these federal subsidies to continue.

RESA believes that the CES should address the role that smart meters can play in shaping customer behavior. In RESA's view, the CES should set forth the policy guidelines regarding the deployment and use of smart metering infrastructure, and provide recommendations for administrative actions to implement the identified policies, objectives and strategies.

CGA believes that geothermal should be recognized as a renewable energy source by the State of Connecticut, CEEF and the EDCs.

DEEP RESPONSE

The scope of the Electricity Chapter of the CES touches on all of the issues raised by stakeholders including: regional policy approach; infrastructure development; procurement; Connecticut's RPS; reliability, security and micro-grids; ratepayer cost components; and retail providers. DEEP will also be initiating an RPS Study as discussed in the Electricity Chapter and many of the comments and issues raised with respect to the future of RPS will be addressed as part of the public review and comment period for the RPS study. As part of the CES public review and comment process, DEEP will provide more detailed responses to specific comments raised by stakeholders that are not specific to the overall scope of the CES.

NATURAL GAS SECTOR

Most of the written comments for the Natural Gas sector largely focused on issues and concerns about the increased reliance on natural gas, infrastructure expansion, price projections, and natural gas retail choice. Other comments were received concerning micro-grids, the regional pipelines, liquefied natural gas (LNG) imports, the hurdle rate and CIAC policies, capacity release and storage, cost-benefit analyses, and suggested research sources for use in this sector's analyses.

Increased Natural Gas Reliance

CFE believes that in the short term, Connecticut and the region will need a transitional strategy from fossil fuels to renewables. Due to natural gas's current price advantage and lower emissions over other fossil fuels, CFE accepts that natural gas can play a role in that transition. Indeed, the LDCs have professed that the lower cost of natural gas production, coupled with the expanded use of natural gas in lieu of alternative fuels, provides benefits in terms of economic growth and cost. Algonquin and Spectra believe that natural gas will be available for power generation and other uses over the long-term.

However, CFE, IMC, the OCC, PURA and the Sierra Club expressed concerns about placing increasing reliance on natural gas in the long term. CFE believes that Connecticut should be cautious about committing to long-term over-reliance on natural gas. IMC recommended that DEEP assume the current depressed natural gas price is a transitory phenomenon. In IMC's view, natural gas's price advantage is likely to end in the short-term as the old price escalates and the infrastructure expands to take advantage of the currently low NG price. The OCC warned that overreliance on natural gas as "abundant, reliable, and cost-effective" without addressing current system constraints could compromise reliability. Similarly, PURA believes that the increased demand in natural gas resources has the potential to have greater impact on availability, electric reliability and the natural gas price.

The Sierra Club commented that the professed benefits associated with greater reliance on NG are questionable. Like CFE, the Sierra Club feels that natural gas should be relied upon as a transition fuel and not as a long-term solution to Connecticut's energy needs. The Sierra Club expressed that the conditions that currently produce low natural gas prices are likely to change in the future and result in rising gas prices. Should DEEP pursue increased natural gas reliance (particularly in the Electricity sector), the Sierra Club urged DEEP to ensure that this gas generation is counterbalanced by significant new renewable generation. According to the Sierra Club, new renewable generation can help offset risks associated with rising natural gas prices by diversifying Connecticut's fuel mix and providing predictable power prices for Connecticut's ratepayers.

Natural Gas Infrastructure Expansion

CL&P, Yankee Gas, CNG, SCG, ENE, the Sierra Club, CFE, the OCC, PURA, Algonquin and Spectra provided their viewpoints on the benefits, planning process concerns, and cost impacts engendered by the proposed expansion of the natural gas infrastructure.

CL&P, Yankee Gas, Spectra, the LDCs (CNG, SCG and Yankee, jointly), Algonquin and Spectra touted the many benefits that investment in expanding the natural gas infrastructure would bring to Connecticut's residents. CL&P and Yankee Gas jointly asserted that natural gas investment would lower customer costs, address space heating concerns, drive reduction in petroleum usage in relatively short time frame, leverage a growing source of indigenous fuel, increase the competitiveness of Connecticut's businesses, add long-term productivity to the Connecticut economy. The LDCs recommended that DEEP should consider certain policy goals that will help expand the availability and deliverability of natural gas in Connecticut. The LDCs stated that doing so would stimulate short-term job creation, reduce ratepayer costs and GHG, and achieve greater energy independence. Moreover, the LDCs believe that additional heating opportunities should be considered separately as an added benefit of the natural gas system expansion. According to the LDCs' analyses, natural gas penetration at 50% for residential customers and 75% for commercial and industrial customers would lead to a 0.9 MMT carbon emission reduction.

Algonquin and Spectra believe that a model of coordinated energy supply for residential, commercial, and industrial consumption of natural gas and gas-fired electric generation should be the foundation in the CES. They claimed that new pipeline infrastructure would: (1) provide diversity, reliability and system integrity; (2) provide access to new supply sources, increase competition and provide new purchase options that yield significant cost savings; (3) ensure reliable, flexible, reasonably priced supply; (4) support the increasing role of natural gas as part of the solution to CT's economic development, energy security and environmental policy objectives; (5) provide opportunities such as alternative fuel development, such as for a natural gas vehicle fleet; (6) help meet fundamental goals of lower cost/more reliable energy; and (7) support Connecticut's policy objectives regarding GHG reductions. According to Algonquin and Spectra, while natural gas provides lower cost and reduced volatility, it only does so where customers have access to the supply. In New England, this requires new infrastructure, particularly during peak demand periods. Algonquin and Spectra stated that pipeline companies won't build, nor will FERC approve projects, based on the assumption that there will be a future market for transportation or storage services. Capital investments in pipeline infrastructure must be supported by market demand and revenue from firm service agreements. Algonquin and Spectra noted that LDCs generally support an infrastructure build-out because they are protected from the market area price swings that are symptomatic of a lack of pipeline infrastructure. The LDCs will benefit from minimized pipeline demand charges by subscribing to capacity that expands the Algonquin Gas Transmission and allows incremental access to natural gas supplies.

ENE stated that an analysis of Connecticut's current natural gas distribution network and potential for expansion would be appropriate and useful for long-term energy planning. ENE believes that Connecticut should move carefully on any natural gas expansion because: (a) there is significant uncertainty on the supply and demand sides, including the potential for increasing exports and higher prices; and (b) the federal and state regulatory framework around shale gas is evolving rapidly and could limit natural gas domestic production (or increase prices) more than currently projected. ENE added that natural gas

expansion should be incremental, cost-effective and focused on near-term actions. Furthermore, ENE stated that policy options for the problem of heating system "replace on failure" should not be focused only on natural gas expansion and should extend to high efficiency equipment when no fuel switching is involved.

CL&P and Yankee Gas believe that Connecticut should direct the LDCs to develop a collaborative 5-year plan to provide a gas service option to every Connecticut residence.

For the CES, the LDCs expressed that the analysis of off-main expansion projects should be adjusted in two principal ways. First, the analysis's timeframe should be expanded since a gas main can last as long as 75 years. Second, the analysis should take into account the additional economic benefits (e.g., the number of construction jobs) that were identified in the REMI Study.

PURA states that the potential to convert existing non-heating customers to heating customers should be explored prior to significant system expansions. CFE concurred that natural gas infrastructure expansion should occur in key segments (on-main and economically attractive off-main customers) in conjunction with an aggressive heating efficiency program and the deployment of renewable heating resources.

In addition, PURA suggested that DEEP consider past DPUC Decisions and records involving natural gas system expansions. PURA noted that incremental capacity is currently unavailable, as Algonquin's AIM project will not be in-service until November 2015 at the earliest. Lastly, PURA stated that recent additions of large gas-fired electric generation facilities and DG units have significantly increased natural gas demand, which further limits primary firm capacity and may impact natural gas price.

ENE urged Connecticut to consider the impact of increased natural gas use in other sectors to ensure that any potential cost or emission savings are not offset by increases of cost or emissions in the electricity or transportation sectors. ENE recommended that the cost-effectiveness (and emissions) of larger investments (i.e., substantial additions in gas main or pipeline) be compared to a range of available alternatives (i.e., efficiency, electric heat pumps, solar), and that the cost-effectiveness of these options be evaluated using a wide range of natural gas prices.

The OCC expressed that the natural gas infrastructure expansion must be done in economic manner to not burden existing gas ratepayers. The OCC suggested that DEEP and/or PURA should review current alternatives that balance the needs of infrastructure investment and the rate impact on existing natural gas customers.

Algonquin and Spectra stated that demand growth highlights the need for additional pipeline infrastructure. They pointed out that EIA has projected an increase in demand growth, with the LDCs representing ~26% of projected incremental design day demand growth by 2021. In New England, cost savings could be in the hundreds of millions annually ($240M - $310M). With an annual cost of expansion of $100M to $150M, the pipeline infrastructure would pay for itself. Algonquin and Spectra noted that they have proven track records of building infrastructure in timely, market-responsive

manners, and are planning on attaching significant additional volumes of new natural gas supplies to their Northeast pipeline systems.

Price Projections

Relative to projected natural gas prices, the LDCs emphasized that the important element is not the future price of natural gas, per se, but rather the differential between natural gas and oil. The LDCs suggested that DEEP strengthen its analysis on natural gas projections by including other well-established price forecasts beyond that of the EIA.

According to ENE, the natural gas price projections used in Natural Gas sector presentation conflicted to some extent with those used in Electricity sector presentation. ENE recommended that DEEP rely on the price projection used in Electricity sector presentation. In ENE's view, for long-range policy planning, it is preferable to use natural gas price projections with upper and lower confidence bounds to more accurately reflect pricing uncertainty and potential volatility.

Furthermore, ENE believes that the CES should conduct a cost-benefit analysis that encompasses low, medium and high natural gas price scenarios for the different sectorial uses of natural gas. According to ENE, this would help identify the lowest risk, most cost-effective policy options for natural gas in Connecticut.

Natural Gas Retail Choice

PURA thinks that any consideration of natural gas unbundling must resolve the numerous complex issues and concerns engendered by such action. PURA believes that natural gas unbundling necessitates the development of codes of conduct. In PURA's view, these codes of conduct should establish the standards governing the relationship between the LDCs and the marketer affiliates, as well as the standards for educating and protecting customers. If residential natural gas unbundling is contemplated, PURA recommended that it ease the transition for Connecticut customers by implementing a pilot program and a phase-in of the availability of unbundled service.

DES, Dominion and Energy Plus jointly believe that a competitive natural gas retail market can enhance the CES goals by bringing more natural gas into Connecticut, and by contracting for capacity in addition to capacity commitments made by the LDCs as the pipelines conduct their open seasons.

RESA recommended that the CES require an evaluation of natural gas retail choice for residential customers in Connecticut. DES, Dominion and Energy Plus jointly urged Connecticut to develop a natural gas retail choice program to complement its electric supply choice program. By allowing retail choice for both electricity and natural gas, DES, Dominion and Energy Plus envisioned that this would allow marketers to integrate an all fuels option for the benefit of energy consumers. Moreover, in areas where marketers can offer both supply commodities, DES, Dominion and Energy Plus believe that electric

customers who have migrated to competitive electric supply would be more interested in bundling their electric service with natural gas service.

DES, Dominion and Energy Plus jointly advocated for Connecticut to design an efficient and effective residential natural gas supply choice program that would attract retail marketers to adequately service residential customers, and yield value and benefits (i.e., savings, alternative pricing, new products). DES, Dominion and Energy Plus suggested that Connecticut draw upon experience and program design elements in other state jurisdictions such as New York, New Jersey and Massachusetts, which have statewide programs of varying degrees of success.

Micro-Grids

UTC Power urged Connecticut to strongly consider the relationship between the expansion of the natural gas infrastructure and the deployment of micro-grids. UTC Power pointed out that a majority of the low-emission technologies in the Class I market operate using natural gas and represent likely candidates for micro-grid construction. UTC Power suggested that the natural gas-fed DG for micro-grids could be the lead load for the expansion of the NG infrastructure. This would also allow newly served communities to benefit economically and environmentally from the availability of natural gas as opposed to heating oil.

Regional Pipelines

PURA believes that standards should be established to protect and maintain the operational integrity of the regional pipelines and systems. The OCC stated its concern about the strict limits that the current regional pipeline infrastructure places on additional winter uses.

LNG

PURA projected that LNG imports to New England will likely be limited due to the pricing differential between the United States market versus the European and Asian markets.

Hurdle Rate/CIAC Policies

In the event that any proposed changes to the Hurdle Rate and CIAC policies are considered, PURA expressed that those changes should not increase cost or interject risk to existing ratepayers, and that benefits and energy policy implications should be examined.

Capacity Release and Storage

In a competitive natural gas market, CGE, Energy Plus and IGS jointly believe that it is critical that capacity be released in a competitively neutral manner. As a fundamental principle, they urged that the assets of gas pipeline and storage capacity follow the customers in each utility territory, regardless of which company the customers purchase their natural gas from. CGE, Energy Plus and IGS recommended that no utility incentives be allowed in rate design that encourages a utility-only model of capacity and

storage management. Rather, incentives should be provided to the LDCs to encourage cooperation with marketers and ensure seamless supply service to customers.

Natural Gas Cost-Benefit Analyses

ENE believes that building efficiency should become the CES base case for all natural gas cost-benefit analyses since it is more accurate and it reduces the net present value of natural gas expansion. ENE suggested that DEEP's analytical goal should be to capture the benefits of building efficiency and low-cost natural gas expansion simultaneously.

Kimberly-Clark recommended that the CES's consideration of natural gas matters include assessment of impact of increasing transportation costs for natural gas supply.

Research Sources

The LDCs believe that natural gas represents a good opportunity for Connecticut to implement short-term actions that would achieve savings and decrease its carbon footprint. The LDCs believe that NG expansion can help with near-term GHG reduction goals (2020), and that failure to capture them will reduce Connecticut's economic competitiveness. To help develop those short-term actions, the LDCs suggested that the CES analyses for the Natural Gas sector take into consideration: the REMI Study; the Secretary of Energy Advisory Board's final report dated November 18, 2011; and the report dated November 18, 2011 and ongoing information from President Obama's task force.

NON-SECTOR-SPECIFIC COMMENTS

DEEP also received a host of written comments that are not necessarily sector-specific. A number of stakeholders submitted recommendations for the CES's focus and development process (i.e., GHG emission reduction as the key focus, approaches to be considered, assumptions to be used for analyses, regulatory concerns, and general recommendations regarding the EE programs). Other non-sector-specific comments received by DEEP relate to reliability and security concerns, and requests to broaden Connecticut's energy market by accommodating retail providers and adopting a Renewable Natural Gas (RNG) standard that incorporates biogas use.

CES Focus and Development Process

Given the CES's long-term planning horizon, the Sierra Club urged Connecticut to focus on factors (e.g., climate change, existing/future regulation of GHG emissions) that will drive long-term energy prices and to develop energy strategy with attention to these drivers. In analyzing the challenges and opportunities presented by the CES, the Sierra Club believes that DEEP should maintain regional focus and actively pursue opportunities to coordinate and collaborate with other New England states. CFE stated that framing the need to reduce GHG emissions as central to the CES planning process will keep the long-term goal of transitioning to a clean, renewable energy system firmly in focus. ENE recommended that the CES model current and projected GHG emissions for each sector with clearly defined baselines. Those

baselines should additionally reflect the existing EE policies for the given sector. ENE further suggested that the CES compare energy resources based on their life-cycle GHG emissions to provide the most accurate assessment of actual climate impact of an energy resource.

ENE expressed that the approaches recommended within and across sectors of the CES should be prioritized and weighted for appropriate consideration by policymakers. ENE added that those weighted recommendations should clearly identify and prioritize the policy actions that would result in the greatest net benefits to Connecticut. In ENE's view, the CES must employ a robust cost-benefit analysis that monetizes all benefits (through published values or alternative compliance costs), including key environmental benefits (e.g., economic value of avoiding carbon pollution from reduced emissions).

ENE stated that the CES needs to be a holistic assessment of Connecticut's energy future that includes dynamic, cross-sector analysis, especially when considering policies that could substantially increase natural gas or electric consumption. In CL&P's and Yankee Gas's joint view, responsible clean energy policy must balance four objectives (ranked in order of priority): the impact to customer rates, the impact on carbon emissions, the impact to local economic development from new clean energy project jobs, and the impact to overall economy due to increased rates. Given the ratepayers' existing commitments and obligations for other initiatives, the OCC advised that each sector should incorporate a full discussion of funding options.

NEGPA commented that any contracting that is part of the CES process should be done competitively.

IMC and ENE suggested a few general assumptions to take when developing the CES. IMC urged DEEP to assume progressive energy scarcity over the planning horizon and to build contingencies accordingly. Additionally, IMC advised DEEP to assume a transitional process and not presume a specific destination in Connecticut's energy profile. ENE recommended that realistic ranges for future fossil fuel prices, especially natural gas, must be used for sensitivity analysis. To enable stakeholders to better understand how DEEP arrived at its analytical conclusions, ENE requested that the draft CES report provide detailed information on the specific assumptions, data and sources actually used by DEEP in its analyses.

IMC recommended that Connecticut update relevant state regulations (i.e., energy, land use and zoning) to reflect current realities and future possibilities regarding energy policies throughout pertinent regional structures in associated communities. In addition, IMC advocated for state agencies with certain strategic management responsibilities (i.e., land use, economic development, governmental service provision, and transportation) to initiate a coordinated definition of "optimized regional structure" for Connecticut's 169 municipalities. Moreover, IMC suggested that core technical competencies be provided to facilitate planning, transition and practice of energy policies throughout relevant regional structures in associated municipalities.

The CES is required by PA 11-80 to include recommended administrative actions for implementing policies, objectives and strategies recognized therein. Therefore, RESA wants to ensure that the CES

clearly identify the regulatory actions (if any) to be taken to implement each CES component, the entity responsible for taking such further actions, how those actions will be undertaken, and the completion deadlines for those actions. PURA commented that policymakers should refrain from modifying existing standards of conduct with regulated utilities unless there is strong justification. However, in the event that such action is necessitated, great caution should be exercised. CL&P and Yankee Gas urged that the CES prioritize execution of regulatory mandates by PURA (e.g., decoupling, performance incentives for LDCs) to remove disincentives and to provide appropriate incentives to achieve all cost-effective EE.

ENE, C&P and Yankee Gas recommended that the CES give priority to all cost-effective EE and conservation measures. By giving EE top policy priority, ENE contended that considerable macroeconomic benefits will accrue to Connecticut and its citizens. CL&P and Yankee Gas advocated for the CES to make multi-year commitment to maintain funding of all cost-effective EE programs. CL&P and Yankee Gas also proposed that the CES mandate that all future CL&M plans be developed as joint electric, natural gas and deliverable fuel plans. Moreover, for jurisdictions where waste treatment savings could be obtained, CL&P and Yankee Gas suggested that the CES recommend the expanded use of water-saving measures as a part of EE programs.

RESA commented that DEEP should ensure that interested stakeholders have an opportunity to provide meaningful input before particular actions are proscribed that may not be technically feasible or may unnecessarily increase costs.

Broadening Connecticut's Energy Market

RESA recommended that the CES evaluate solutions that would provide regulatory fairness and consistency, reduce non-bypassable programs, enhance retail electric market programs, and institute retail natural gas choice for residential customers.

Element Markets requested consideration of adopting a broader RNG standard for Connecticut to bring the benefits of biogas to each CES sector. Element Markets contended that an RNG standard would: (a) integrate the individual CES components into a comprehensive renewables program; (b) provide opportunity for systematic evaluation and development of in-state biogas resources for optimal use; and (c) promote development of Connecticut's natural gas infrastructure by delivering multiple environmental benefits without requiring any unique modifications to accommodate this renewable fuel.

CGE, Energy Plus and IGS noted that energy competition among residential and C&I consumers is a critical trend that has been gaining momentum in many states over the past 10-15 years. They view energy competition as being important to long-term energy strategy, primarily because it gives consumers control over decisions that affect them, provides accurate and market-based prices information, and doesn't decrease system reliability. As energy choices emerge, consumers would need access to information to help understand energy choices as they emerge.

CGE, Energy Plus and IGS deem that certain business practices would need to be in place to ensure a properly functioning market for energy competition. In their view, everyone benefits when marketers are held to a set of basic, accountable standards to ensure compliance with credit requirements, marketing guidelines, and other sound business practices. They asserted that credit requirements for natural gas and electricity are critical. They think it is ethical for DEEP to develop a set of uniform business practices that would apply to both natural gas and electricity providers. These standards and business practices would provide customers with fair practices, signal the continuing viability and existence of a competitive market, and level the playing field between competitors. Moreover, DEEP would be empowered to revoke a license when a given marketer fails to ensure reliability and integrity.

CGE, Energy Plus and IGS value the use of Purchase of Receivables (POR) program as part of a utility consolidated billing system. They stated that POR programs provide a jumpstart to consumer confidence, enable the marketer and utility to work together for a common purpose, help leverage utility building systems, reduce redundancy, and send a clear message to consumers about the reliability of energy supply services.

Lastly, CGE, Energy Plus and IGS argued that the current utility price comparison models are too complicated. In their opinion, these models should be completely unbundled with all the specific components (e.g., taxes and surcharges) detailed, as price disclosures enable true commodity comparison. Moreover, they recommended that the use of such models should be considered temporary until a critical mass of customers has migrated from utilities and is engaged in the free, transparent marketplace.

Reliability And Security Concerns

EES recommended that the CES should include consideration of reliability and security-related concerns, either as a specific sector section on energy security or as a cross-cutting approach with a security section for each sector. EES states that not a lot of attention has been paid to potential of cyber threats and other vulnerabilities of the grid. At the least, EES suggested that the Energy Assurance Plan (which has not been updated since 1994 but has been under redevelopment since 2009) should be included as a portion of the CES. According to EES, even in draft form, the Energy Assurance Plan is lacking and needs to consider even low probability but extremely high risk events.

OTHER NON-SECTOR-SPECIFIC COMMENTS

CL&P and Yankee Gas proposed that the CES should call for the deliverable fuel association and the water companies to contribute in any related initiatives. PURA recommended that policymakers direct the natural gas pipeline industry and electric generation industry to harmoniously resolve any supply issues and objectives between the two markets.

DEEP Response: The Natural Gas Chapter focuses largely on the opportunities for Connecticut in pursuing natural gas expansion. As part of DEEP's consideration of the natural gas expansion opportunity issues such as increased reliance on natural gas, infrastructure expansion, price projections, and natural

gas retail choice, the hurdle rate and CIAC policies, capacity release and storage, and cost-benefit analyses are also covered. As part of DEEP's consideration of natural gas expansion opportunities DEEP expects to address the technical and analytical details outlined in this chapter at the technical meetings that will be held during the CES public comment period.

TRANSPORTATION SECTOR

The written comments for the Transportation sector mostly concentrated on: the scope for this sector; the potential to reduce vehicle miles traveled (VMT); the potential for and concerns about alternative fuel vehicles; infrastructure investment; and issues concerning fleets, public rail transit and ground freight.

Scope

CL&P and Yankee Gas noted that transportation is the largest source of foreign oil dependency. For that reason, CL&P and Yankee Gas recommended that transportation be a top priority for reform given economic, environmental and national security concerns. DEEP received advice from several stakeholders for consideration in developing Connecticut's energy strategy in this sector.

CFE suggested that DEEP look at the potential to establish a comprehensive approach to transportation and land use planning that would incorporate smart growth principles, transit-oriented development, and expanded mass transit opportunities to break dependency on single-occupancy motor vehicle use. The OCC recommended consideration of cost and finance relative to technology and alternative fuels (e.g., the best business models for distribution, supply and fueling infrastructures; ownership and financing of alternative fuel infrastructures; providers of alternative fuels; fuel provision as a self-sustaining business). The OCC added that the discussion in this sector should also consider fuel diversity and impact of heavy reliance on any particular alternative fuel. IMC offered that this sector should include consideration of expanding the communication infrastructure as an alternative to energy-intensive and time-intensive transportation.

ENE requested that the CES assess whether Connecticut is currently maximizing possibilities for driving transportation policy change on a regional basis, rather than on just a statewide basis.

Furthermore, ENE recommended that DEEP assess the potential to achieve energy savings through innovative new state efforts that adopt lessons learned in other states from successful smart growth, land use and public transit programs. ENE stated that the CES should give analytical treatment on a regional low carbon fuel standard as a policy option.

GNHCCC noted that today's family is paying more for transportation energy than home energy, and fuel cost is the second biggest expense for fleets next to personnel cost. GNHCCC recommended that guiding principles and priorities be determined at the state level, and that priorities and justification of alternative fuels should be ranked to ensure state objectives are met. (GNHCCC noted that its top three priorities are: (1) return on investment; (2) reduction of toxic mobile source emissions; and (3) reduction in the use of foreign fuels.) In GNHCCC's view, the development process of the CES's Transportation sector should engage the industry and those organizations and individuals with practical experience in the areas of transportation energy and alternative fuels.

GNHCCC also suggested that Connecticut should consider legislation and resources that would enforce current anti-idling regulations and laws. GNHCCC further pointed out that Connecticut lacks state

educational institutes, especially at the community college level, that provide nationally recognized certifications for many technical positions (especially for emerging technologies related to alternative fuels and vehicles) at manufacturing companies. GNHCCC suggested that this may be an area where unions can have an impact on through their apprentice programs.

Lastly, GNHCCC noted that the prior State Energy Plan contained very little about transportation energy. GNHCCC stressed that, with volatile energy costs triggered by unrest in the Middle East and increased growth in third world economies, all energy budgets (both transportation and stationary) will continue to affect future business grown planning and projections.

VMT Reduction

As a prerequisite to suggested short-term strategy, IMC asks that a study be performed of current commuting patterns. IMC adds that short-term strategy should include increasing public rail transit to better leverage rail infrastructure and to reduce VMT.

In ENE's view, any analysis of VMT reduction potential should include potential additional economic development benefits of compact development and transit in terms of interstate competition for employees and employers. ENE added that the list of VMT reduction options for analysis should include wider range of pricing strategies. CFE is concerned that there are not more specific VMT reduction targets or policies to achieve the targets beyond those that are already in the pipeline. CFE believes that one area of focus should be on developing methods to encourage greater regional and country-wide cooperation in the developments of sustainable land-use patterns.

Alternative Fuel Vehicles

CL&P and Yankee Gas stated that the use of EVs and/or NGVs in Connecticut will result in customer savings. The significant use of EVs can substantially reduce carbon emissions from transportation in the Northeast. They added that electric and natural gas transportation hold significant long-term potential to improve the environment and lessen foreign fuel dependence. Properly incented charging will minimize impact on electric distribution system and may help lower rates through better system utilization. CL&P supports consideration of policies and approaches that are geared to minimizing fuel cost and infrastructure cost, and maximize convenience for plug-in EVs.

GNHCCC expressed that Connecticut should be mindful of the several variations of EVs (i.e., plug-in hybrids, battery electric models and the Chevrolet Volt), and the recent growth of EVSEs and technological advances associated with EVSEs. GNHCCC suggested that Connecticut should evaluate the lessons learned by western states that received large grants to install their EVSEs.

UTC Power asserted that vehicles powered by fuel cell technology would offer longer travel distances between refueling than EVs. GNHCCC noted that fuel cell technology has made many strides over recent years (e.g., fuel cell stack life is increasing, and a total of four hydrogen fueling stations will be in

operation by the end of 2012). According to GNHCCC, economic feasibility is within reach, but is yet to be attained. GNHCCC suggested that the hydrogen-powered bus is the best way to research and explore hydrogen as a commercially viable transportation fuel.

In ENE's view, any analysis of alternative fuel vehicles must go beyond simple economic lifetime costs. ENE stated that the potential for uptake of alternative fuels and their associated technologies should be based on realistic trends and past experiences. The OCC recommended that the consideration of alternate fuel vehicles for the CES involve a study of past state experience with NGVs and lessons learned. Additionally, ENE advocated for analytical treatment to the low adoption rates for EVs and consideration of policies that might remedy this. Furthermore, ENE recommended that the CES consider how a large increase in NGVs or EVs might impact other sectors and the electric infrastructure.

GNHCCC reported that propane has greatly improved as a transportation fuel in the last decade. Propane ranks below natural gas in emission reduction, but has more energy density and is under relatively low pressure. GNHCCC believes that propane has the potential to be on the same price level as natural gas, depending on the suppliers.

GNHCCC also sought consideration of biodiesel. According to GNHCCC, biodiesel is a true renewable transportation fuel, one that can be dispensed from a traditional diesel fueling facility. It is expected to become more competitive by 2013, especially if some of the incentives for biodiesel are reinstated. GNHCCC stated that while biodiesel has 10% less energy than diesel fuel, that fact becomes insignificant at the B-20 blend level. Moreover, biodiesel use results in reduced emissions and no NO_x.

Lastly, GNHCCC pointed out that the claim that ethanol has a negative energy balance is not true. According to GNHCCC, the USDA and the US DOE Argonne Lab both found that ethanol has a positive energy balance of 1.9 to 2.3, with potential of 2.8 under certain production practices in current production facilities.

Infrastructure Investment

PURA envisions that significant capital investment in infrastructure and associated facilities would be required to make natural gas a viable transportation fuel source. PURA is concerned that NG infrastructure investment would pose significant risk to the LDCs and would likely end up being subsidized by ratepayers through higher rates. PURA believes that investments in developing NGV fueling stations (and associated risks) should instead be borne by the LDCs' shareholders. For its part, Yankee Gas stated that it would continue to work in deploying proper natural gas infrastructure to support the increased penetration of NGVs.

UTC Power noted that building the hydrogen infrastructure in Connecticut to support fuel cell vehicles would help create jobs.

According to GNHCCC, in the last two years, EVSE infrastructure grants and pilot programs have focused on Level 2 EV charging. However, as GNHCCC noted, a groundswell of stakeholders are openly

promoting Level 1 EV changing under certain conditions, which is in line with concerns that the utilities have in keeping grid demand down. GNHCCC stated that Level 2 charging is less attractive in lots with short parking periods due to the length of time needed to fully recharge, and that Level 1 charging is more justifiable for long-term commuter parking areas.

GNHCCC expressed that the main advantage of propane as a transportation fuel is that the infrastructure can be provided free on site to fleets that want to convert to propane. According to GNHCCC, propane fuel dealers will install infrastructure based on fuel usage, which is possible due to the absence of high pressure storage vessels and compressors.

Fleets, Public Rail Transit, Ground Freight And Outreach

In IMC's opinion, the intermediate to long-term focus in the Transportation sector should concentrate on enhancing public transit opportunities around regional centers and maintaining existing rail and highway corridor links.

UTC Power emphasized that EVs would introduce additional demand to the electric grid. Accordingly, UTC Power recommended that a demand should be performed before Connecticut elects to support this type of technology for fleet and light duty vehicles on a large scale. Also, UTC Power believes that extensive deliberation needs to occur on the alternatively fueled technologies to be funded, implemented and deployed for fleet vehicles. ENE voiced its desire for the CES to be more explicit on the technical potential for natural gas-powered fleet vehicles.

UTC Power submitted that the wide scale deployment of zero emission fuel cell buses in Connecticut would create in-state jobs while reducing total fleet emissions.

ENE recommended that any analysis of ground freight initiatives should consider mode switching to rail and water, consider additional infrastructure needs and identify areas needing regional coordination.

GNHCCC urged Connecticut to be as aggressive in outreach activities for cleaner transportation energy as it is currently in activities to reduce emissions from power plants and other non-transportation sector pollution emitters.

DEEP Response: The Transportation Chapter covers all of the topics raised by stakeholders including: the potential to reduce vehicle miles traveled (VMT); the potential for and concerns about alternative fuel vehicles; infrastructure investment; and issues concerning fleets, public rail transit and ground freight.

2013 Connecticut Comprehensive Energy Strategy
Appendix F: Post-Draft CES Public Comments

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SIGNIFICANT PUBLIC COMMENTS SUBMITTED AFTER RELEASE OF THE DRAFT 2012 COMPREHENSIVE ENERGY STRATEGY DRAFT

On October 5, 2012 DEEP issued a draft of the 2012 Comprehensive Energy Strategy (CES) for public comment. DEEP solicited written comments from stakeholders and interested persons, with an initial filing deadline of December 14, 2012, subsequently extended to December 21, 2012 at the request of certain stakeholders. All written comments received by DEEP on the draft 2012 CES can be accessed on its website at:

DEEP Energy Filings, "Public Act 11-80 - Section 51 - Comprehensive Energy Strategy - Comment." Available at http://www.ct.gov/deep/energyfilings.

DEEP also held six technical meetings64 at its New Britain Office, at which the public and stakeholders were given the opportunity to present oral testimony and to ask DEEP staff and consultants questions about the analyses underlying the findings and recommendations in the draft 2012 CES. In addition, DEEP conducted five public hearings at locations around the state65 to receive further public comments on the draft 2012 CES.

ENERGY EFFICIENCY SECTOR COMMENTS

DEEP received over 50 comments on the Draft's Efficiency sector strategy. The majority of these comments can be separated into the following categories: energy efficiency program financing, building codes and benchmarking, and the C-PACE program. Many comments broadly supported energy efficiency.

ENERGY EFFICIENCY PROGRAM FUNDING

Many comments support all cost-effective efficiency for all fuels. Multiple organizations, including the Office of Consumer Counsel, Clean Water Action, Environment Northeast, New England Clean Energy Council and Connecticut Fund for the Environment support an oil heating surcharge for energy efficiency programs. The Wilton Energy Commission and John Stewart recommended that the Home Energy Solutions (HES) Program be given increased funding to enable programs to achieve broader and deeper energy savings.

[64] November 14, 2012 – Transportation Sector; November 15, 2012 – Electricity Sector; November 16, 2012 - Natural Gas Sector; November 27, 2012 - Buildings Sector; and November 28, 2012 – Industry Sector. See DEEP Energy Filings, "Public Act 11-80 - Section 51 - Comprehensive Energy Strategy – Audio Recording." Available at http://www.ct.gov/deep/energyfilings.

[65] November 14, 2012, at Bridgeport City Hall; November 19, 2012, at Kennedy Mitchell Hall of Records, New Haven; November 20, 2012, in the Phoenix Auditorium, at DEEP's offices, Hartford; November 20, 2012, at UCONN – Center for Environmental Sciences and Engineering, Storrs; and November 26, 2012, at City Hall Auditorium, Torrington. See DEEP Energy Filings, "Public Act 11-80 - Section 51 - Comprehensive Energy Strategy – Audio Recording." Available at http://www.ct.gov/deep/energyfilings.

Other stakeholders including Northeast Utilities suggested regulatory changes to meet Connecticut's ambitious energy efficiency goals. These changes included timely program cost recovery, recovery of lost revenues, performance incentives for utilities to meet or exceed Strategy goals, including direct financial incentives. UIL Holdings recommended that any changes to the HES program keep the existing cost-effective savings measures and DEEP should work with the Energy Efficiency Board to evolve the program to include deeper energy savings.

BUILDING CODES & BENCHMARKING

Many comments concerned building standards and codes and the role of energy efficiency and green building design in moving the residential market to higher energy efficiency goals. Some of the recommendations received include:

- Voluntary adoption of the 2012 National Green Buildings Standards;
- Creation of incentives, such as lower real estate conveyance taxes, sales tax or permitting fees;
- Delaying adoption of the 2012 IECC until late 2013 or 2014;
- Approval of a regular six-year code adoption cycle after the 2012 codes are in place;
- Rejection of local variances for stretch codes;
- Educating the appraisal industry as to the value of green building and energy efficiency practices to better inform financial markets regarding the value these attributes within the real estate market.

Specific building code issues and recommendations are beyond the purview of the CES and therefore this Strategy recommends that these matters be addressed by the Energy Efficiency Board in 2013.

MARKETING

Many organizations recommended community-based grassroots marketing efforts to promote energy efficiency. In addition to traditional marketing channels, the Department believes local, trusted, grassroots groups must be engaged to spread the word about these programs and Connecticut's goals. These organizations are an important link in promoting a comprehensive energy strategy and their role must not be overlooked or underestimated. Other stakeholders,suggested marketing efforts expand to condominiums, multifamily housing, small businesses and oil heating customers. DEEP plans to take these recommendations into account as the EnergizeCT initiative moves forward in 2013.

C-PACE

The Connecticut Conference of Municipalities and Institute for Sustainable energy both support the expansion of C-PACE to other types of buildings, including multifamily homes and low-income properties. The Department will actively consider these recommendations in the future, as the C-PACE program becomes more established.

INDUSTRY SECTOR COMMENTS

DEEP received approximately 15 comments on the Draft's Industry sector strategy. The majority of these comments concerned alternatives to fuel switching.

ENERGY EFFICIENCY PROGRAMS

Malkin Holdings, Inc. recommended that cogeneration be the cornerstone of the Strategy. The existing tariff structure places significant and artificial limitations on project developers and is an insurmountable obstacle to capital sources needed to develop new projects in Connecticut. Clean Water Action argued that the PRIME program should be expanded and act as a model for Connecticut industry to shift to safer chemical alternatives and manufacturing processes.

Alternatives to Fuel Switching: Combined Heat and Power (CHP), Ground Source Heat Pumps, Alternative Fuels

UIL Holdings recommended that DEEP investigate the potential for CHP to be most successful for heat utilization. Mitch Kennedy highlighted a lack of studies of CHP penetration into the industrial sector. The Northeast Clean Heat & Power Initiative argued that meter aggregation was necessary to move forward with multi-facility CHP.

Many individuals and organizations outlined a lack of focus on ground source heat pumps and other geothermal options. Peter Tavino urged DEEP to update policy and regulation by bringing in an advisory committee with ground source representatives from the private sector. Steven Winter Associates suggested including air source heat pumps as well.

Environment Northeast (ENE) supports the recommendation for fuel switching, so long as it remains a cost-effective one, lower carbon fuels are not more-cost effective, and high efficiency measures are implemented concurrently. ENE further suggested that DEEP perform a cost-benefit analysis for all fuel and non-fuel options in each sector. Santa Energy Corporation as well as other stakeholders argued that the Strategy lacked focus on propane as a fuel in the state's energy portfolio.

ELECTRICITY SECTOR COMMENTS

Most of the written comments concerning the Electricity Sector Strategy focused on issues relating to: (1) peak demand reduction and load factor improvements through technology and dynamic pricing; (2) decoupling; (3) utility rates of return; (4) State participation in regional and Federal regulatory processes; (5) reduction of soft costs of in-state renewable resources; (6) Connecticut's RPS, waste-to-energy facilities and other renewable energy opportunities; (7) virtual net metering; (8) the Regional Greenhouse Gas Initiative, regional carbon dioxide cap and GHG emissions reductions; (9) electric submetering and the use of renewable energy and CHP in multi-tenant buildings; (10) microgrids and fuel cells; and (11) reliability, security and cyber-security.

Peak Demand Reduction and Load Factor Improvements through Technology and Dynamic Pricing

ENE, UIL Holdings, Northeast Utilities, the Institute for Sustainable Energy (ISE), the Office of Consumer Counsel (OCC), the Wilton Energy Commission, the Berkshire-Litchfield Environmental Council (B-LEC) and the Housatonic Environmental Action League, Inc. (HEAL), and the Retail Energy Supply Association (RESA) offered relevant comments, as well as individuals as Roberta Paro.

ENE believes that the positive consequences of a full investment in all cost effective energy efficiency should be recognized by the CES. In ENE's view, DEEP should engage in further technical and economic analyses, perhaps in combination with a stakeholder working group to determine the most cost-effective policy course. According to ENE, recent studies and evaluations have found that dynamic pricing pilots and programs can generally achieve peak load reductions, the impact of which may vary by the customer mix, price differential, weather, use of technology, and category of dynamic pricing offered.

Both UIL Holdings and Northeast Utilities recommended that any decision to enable dynamic pricing options should warrant additional evaluation on a cost/benefit basis. While supportive of time-of-use rates and dynamic pricing, UIL Holdings cautioned that these pricing policies should not be mandatory for customers, but rather voluntary. UIL Holdings urged that customers be given a menu of options under these policies. Northeast Utilities sees potential advantages from dynamic pricing, but believes there is no consensus on "engagement" levels. According to results from CL&P's 2009 pilot program, very low penetration rates were achieved (e.g., in the 2%-5% range); however, in order to drive significant peak load reductions, Northeast Utilities maintain that a large number of customers would need to be engaged. According to Northeast Utilities, the low value of capacity prices in New England and the relatively low penetration of central air conditioning negate much of the value of dynamic pricing and its impact on peak load reduction in today's market. Moreover, should Connecticut implement dynamic pricing, Northeast Utilities urged exploration of other options that could provide utilities greater flexibility at a lower cost (i.e., the use of AMR technology that leverages existing broadband connections, more advanced AMR meters). Northeast Utilities added that smart meter deployments experience a set of high "fixed" upfront costs that require broad deployments to improve economic. Indeed, according to Northeast

Utilities, most cost-effective tools can be used to achieve several of the benefits (e.g., energy conservation, operational benefits) that smart meters provide. Therefore, Northeast Utilities is of the position that a broad-based deployment or a multi-stage roll-out of smart grids/meters in Connecticut would not be a cost-effective endeavor at this time.

ISE believes that the CES should recommend optional, more aggressive time-of-use pricing that would truly reflect real-time electric market costs, thereby encouraging a flattening of on-peak energy use and load management to reduce avoidable demand charges. Also, ISE supports the installation of smart meters, which would provide ratepayers with real-time energy consumption data, permit a higher level of control, and potentially reward customers who modify their energy use behavior with lower cost power and lower energy bills.

The OCC expressed that, depending on the cost/benefit analyses, it may support demand response promotion, advanced metering opportunities and the potential benefits of dynamic pricing. The OCC said that one must proceed with caution when considering such initiatives in order to avoid overpayments or working at cross-purposes. The OCC believes that the existence of the CES process (and the IRP) will encourage implementation of the tracking systems necessary to review the interaction between dynamic pricing/advanced metering goals and demand response goals.

The Wilton Energy Commission supported the further development of time-of-use and variable peak pricing to encourage the shifting of usage to off-peak hours. Roberta Paro stated that time-of-use pricing must be implemented so customers can shave peak demand and balance loads. She added that all utilities must be engaged in implementing this.

Both HEAL and B-LEC expressed adamant opposition to smart grids/meters and time-of-use pricing. In HEAL's view, the proposed smart grid system is nothing more than "another green washed Wall Street model, with an inevitable huge transfer of taxpayer dollars into the coffers of multinational corporations." B-LEC argued that no one has shown significant energy savings with either near-real-time energy use knowledge on the part of consumers or tiered pricing. Heal and B-LEC argued that time-of-use pricing automatically penalizes those who are elderly, self-employed, infirmed or unemployed, as well as stay-at-home parents with young children, and others who function on a normal daylight schedule. B-LEC contended that there is an "overwhelming resistance" to smart metering in at least 18 states, and noted that think-tanks and key agencies at the federal level are re-examining the advantages and disadvantages of the entire smart grid concept. Moreover, HEAL claimed that the installation of smart meters (for every electric meter) would result in a total radio frequency public health disaster. B-LEC bemoaned the draft CES's silence on: (1) health concerns relative to radio frequency radiation; (2) privacy and constitutional issues raised by smart grids/meters; and (3) fire safety and billing error concerns about smart meters.

With smart meter data collection, RESA suggested that an internet-based system would make programming easier than traditional code-based programming, thereby reducing the amount of intervention required by EDC personnel. RESA also proposed requiring PURA to reinvigorate the

Electronic Business Transactions Working Group to allow for the evaluation of current customer data elements and data access methods, and to require the EDCs to improve access to customer data so that competitive electric providers are assured that ability.

The draft CES already acknowledges that industrial customers can decrease their energy costs by switching to competitive retail suppliers. On top of that, RESA requested that the CES acknowledge that commercial and residential electrical customers can equally benefit. According to RESA, the ability to access real-time customer data available from smart meters enables suppliers to offer consumers price-responsive demand products, as well as other new and innovative products.

Decoupling

DEEP received comments on decoupling from several stakeholders such as UIL Holdings, Environment Northeast (ENE) and The Connecticut Water Company (CWC), and from individuals such as Henry Link and Roberta Paro, all of whom added their support for decoupling. Based on its experience with UI, which has had decoupling since 2009, UIL Holdings advocated for full revenue decoupling for all distribution companies, including its own LDCs (CNG and SCG). ENE agreed, and further recommended legislation to require PURA to achieve full decoupling for all EDCs and LDCs in Connecticut, which it sees feasibly possible by the end of 2013. ENE added that Connecticut's current statutory provision is flawed in that it allows for something less than full decoupling, and it ties decoupling to rate proceedings that happen at irregular intervals. Mr. Link supported implementing decoupling, and Ms. Paro suggested using California as a beneficial case study, since in her view California has kept electricity use flat for 20 years.

Utility Rates of Return

The OCC expressed that it has not seen any evidence to support the draft CES's assertion, at page 74, that electric utility returns on capital have been a cause of under-investment or have led to other negative consequences. Although the draft CES referenced a national survey as the April 2012 Regulatory Research Associates study, the OCC contended that use of such studies is no substitute for an actual rate case on the issue. According to the OCC, the sufficiency of rates of return on capital is a complicated and multi-faceted financial issue based on such matters as financial formulae, market conditions and interest rates, proxy groups of similar utilities and other information. Therefore, the OCC advocated for the removal of references to the sufficiency of utility rates of return from the CES.

State Participation in Regional and Federal Regulatory Processes

Northeast Utilities expressed that State, utility and other stakeholders should actively participate in current and future discussions with ISO-NE on how the value of demand response can be preserved and grown as the design of the New England wholesale market continues to evolve.

ENE proposed three specific areas for the State's engagement in regional and Federal energy regulatory proceedings. First, ENE stated that the Connecticut should work with ISO to ensure that non-transmission alternatives are considered so that wire construction is the last resort. To that end, ENE recommended that non-transmission alternatives should be compensated in a manner that encourages their development and parallels what is available for transmission lines. Secondly, ENE said that the State should work with ISO-NE in its planning process to ensure that all benefits of energy efficiency are realized and investments are evaluated to determine if they defer the need for transmission investments. Moreover, Connecticut should work with ISO to ensure that distributed generation and investments in generation, energy efficiency, demand response and microgrids are evaluated for their role in deferring transmission investments. Thirdly, ENE stated that Connecticut should monitor NERC and FERC proceedings to ensure that the costs of complying with particular reliability standards do not exceed the system benefits.

The Sierra Club expressed that the best way to obtain information about the costs and benefits of regional renewable energy development is to participate in NESCOE's coordinated regional RFP, which is scheduled to be issued by year end 2013. Henry Link recommended that Connecticut send senior DEEP staff to participate in all ISO-NE and National Energy Policy Plan meetings, as well as relevant FERC meetings.

Reduction of Soft Costs of In-State Renewable Resources

The Connecticut Council of Small Towns voiced its continued support of renewable energy programs that would assist municipalities in using solar power, fuel cells and other energy efficient technologies to help drive down their electric bills.

DEEP also heard from stakeholders such as The Vote Solar Initiative (TVSI), Environment Connecticut (Environment CT), SunEdison LLC, the Connecticut Siting Council (CSC), CEFIA, the Sierra Club, New England Clean Energy Council and CFE, as well as from individuals such as John Liseo, on the draft CES's recommendations to take step to drive the average installed cost of solar PV below residential rates, to have the State and municipalities work together to streamline permitting, siting and other requirements to help reduce soft costs involved in solar PV installations. Lessons learned would, over the long-term, be considered for application to other renewable energy and energy efficiency technologies. TVSI believes that cutting red tape (i.e., paperwork and administrative processes for permitting and interconnections) would help accelerate solar PV cost reduction. To that end, TVSI recommended that DEEP explore all possible options (ranging from legislation to guidelines for municipalities) to do so. Moreover, TVSI supports the CES's call for property tax reform for solar PV projects. Environment CT suggested that municipalities should have the option to exempt solar PV projects from property taxes if they deem it is in the best interest of their citizens. SunEdison expressed a need for the standardization of permitting fees, property taxes, financing costs and other distinct local factors in order to reduce the variability across the state and to create a more level playing field. In recognizing that fragmented rules governing permitting,

siting and other requirements do exist and need clarification, the CSC offered that it stands ready to help streamline these processes. CEFIA agreed that local jurisdiction and state level changes to reduce (and potentially cap) permitting fees would encourage deployment of solar PV installations, as would the adoption of guidelines and practices to streamline permitting practices and processes. CEFIA also recommended that PURA task the EDCs to review the interconnection processes for rooftop solar PV to eliminate any unnecessary requirements and costs. The Sierra Club, New England Clean Energy Council and CFE are supportive of DEEP pursuing strategies that lower the soft costs of in-state renewable resources. Mr. Liseo raised questions on property tax exemptions for solar panels and associated equipment, and suggested that Connecticut could do more to promote solar PV installations.

CEFIA stated that, in order to continue to drive down the costs of clean energy deployment in Connecticut, it is necessary to identify and take advantage of opportunities to reduce soft or non-hardware costs along with hardware costs. Development and implementation of streamlined and standardized processes and fees at the local jurisdiction and at the state level will allow installers to offer – and consumers to access – more affordable clean energy sources.

The New England Hydropower Company LLC (NEHC) stated that it is vital that CEFIA continue to receive and even expand the policy and financial support needed to achieve its mission and vision. NEHC added that continued support should be affirmed for the maintenance and, if needed, expansion of funding through rate reduction bonds for direct disbursement to CEFIA, rather than to the General Fund, as an offset to declining stranded cost payments and transition assessments.

In a related matter, the Sierra Club expressed that public understanding of the importance of energy issues is critical for both public acceptance of state infrastructure programs and willingness to take individual action. Accordingly, the Sierra Club believes that the CES should stress the importance of education programs and outreach, and recognize and support the role of municipal energy commissions and task forces. Letty McPhedran, an individual, expressed that support and acknowledgement of local initiatives should be a part of the CES.

Connecticut's Renewable Portfolio Standard (RPS), Waste-To-Energy Facilities and Other Renewable Energy Opportunities

DEEP received an abundance of comments relating to Connecticut's RPS. Remarks, concerns and observations came in from several stakeholders and entities such as the Brookfield Renewable Energy Group, North American Gas & Power, ReEnergy Holdings, Element Markets, Bristol Resource Recovery Facility Operating Committee, the Sierra Club, Northeast Utilities, UIL Holdings, the Connecticut Thermal-Renewable energy Coalition, Fairvue Farms, LLC, Harvest Power, Inc., the Connecticut Geothermal Association, Hydro Dynamic Engineering, LLC, New England Hydropower Company LLC, New England Power Generators Association, Inc., H.Q. Energy Services Inc., Renewable Energy New England, First Wind, Covanta Energy, and the Connecticut Coalition for Environmental Justice. DEEP also received comments from numerous individuals around the state (including Susan Eastwood, Aaron

Danenburg, Henry E. Auer, Judi Friedman and Stephen Meno, among many others), as well as a group of over 120 citizens (including Noreen P. Cullen, Cate Grady-Benson, Iris Slotkin, Etta Kantor, Daniel Proctor and many others) whom had signed onto a letter urging DEEP to make regional wind and solar projects a central part of the CES's long-term vision, and to commit to a date by which Connecticut and New England will be entirely powered by renewable electricity.

These comments covered a wide range of issues and concerns, including, but not limited to: (1) how best to achieve Connecticut's RPS goals; (2) concerns, suggestions and proposals about maintaining or improving the integrity of the RPS program, as well as how the RPS program affects the REC markets, customers, the state economy and economic development; (3) procurements and long-term contracting opportunities with renewable energy developers; (4) how the definitions of qualifying renewables should be expanded or amended (such as recognition of technologies as anaerobic digestion) ; (5) demonstrations of support or opposition for certain renewable resources (i.e., anaerobic digestion, biomass, geothermal, hydro, solar PV, waste-to-energy and wind, as well as energy efficiency) over others in that group; (6) preferences of Connecticut-based and/or regional renewable energy systems over those that are out-of-state or out-of-country; (7) retirements of certain in-state generation facilities (displacement of fossil fuel power generation).

While the draft CES does specifically put forth, at page 104, a recommendation that options for waste-to-energy facilities in Connecticut should be evaluated, DEEP must reiterate that the consideration of waste-to-energy facilities and other issues concerning Connecticut's RPS, including the ones mentioned above, will be further explored as part of DEEP's RPS study. DEEP has openly stated this planned course of action on many occasions, at the hearings and technical sessions and meetings it has held, and within the draft CES itself. Indeed, the CES states, "As part of its [RPS] review DEEP will consider the appropriate balance between renewable energy and environmental policy goals and consider the statewide transformation efforts currently underway through the work of Governor Malloy's Recycling Task Force." DEEP encourages all interested entities and persons to participate in that upcoming study.

Virtual Net Metering

The Connecticut Council of Small Towns, the New England Clean Energy Council, SunEdison and Matthew Lesser separately voiced their general support of virtual net metering, but offered no further elaboration.

UTC Power, Fairview Farms, LLC, the Connecticut Fund for the Environment (CFE), the Connecticut Water Company (CWC) and the South Central Connecticut Regional Water Authority (SCCRWA) also supported virtual net metering but also recommended its expansion. UTC Power stated that virtual net metering should be expanded beyond municipalities to include any EDC customer. Fairvue Farms, LLC advocated for the expansion to include farms. CFE contended that virtual net metering (and submetering) will make it easier for building owners to capture the full value of installing renewable generation. CWC strongly supported expansion of virtual net metering to encourage more individual

power generating projects. CWC contended that, by doing so, the capital investment in fuel cell and similar technology becomes more economically viable by large volume, widely distributed energy consumers (such as water utility operations like itself). SCCRWA noted that many water treatment facilities are sited on or near large land tracts ideally suited for renewable and/or alternative energy projects. According to SCRWA, virtual net metering would greatly incentivize such projects by providing opportunities for water utilities to lower system-wide electrical costs while also benefitting ratepayers, the environment and emergency preparedness.

DEEP also received comments from Northeast Utilities, CEFIA and UIL Holdings specifically addressing the three alternative options for virtual net metering suggested in the draft CES. In general, Northeast Utilities believes that any investigation of options to reduce subsidies should be viewed from the perspective of all customers. Relative to Alternative Option #1 (PURA Establishes a Variable Power Purchase Schedule), Northeast Utilities believes that Option #1 would be administratively simple for both customers and the utilities when compared with net metering and virtual net metering programs. In addition, Option #1 provides greater pricing transparency and reduces the extent to which recovery for lost distribution revenues and other components of service would need to be addressed, when compared to current net metering and virtual net metering programs.

Relative to Alternative Option #2 (State Adopts the Varied Rate Schedule Model Used in Massachusetts), CEFIA commented that consideration should be given to standardize net metering policies between Connecticut and Massachusetts (given the merger between Northeast Utilities and N-Star), thereby taking the best practices from each state and creating a uniform policy approach across the border on net metering. An area of opportunity for Connecticut would be to consider allowing neighborhood net metering – which Massachusetts has enacted – which would allow residents, businesses and municipalities to invest in and benefit from the most efficient distributed generation sites. Northeast Utilities believes that a varied rate schedule under Option #2 is more complex, and produces greater pricing and payment variability, which have been viewed unfavorably by project developers.

Lastly, relative to Alternative Option #3 (Generators are Modeled in the ISO New England Market System as Settlement Only Generators), Northeast Utilities stated that Option #3 would increase the direct costs of metering, administration and O&M to net metering customers. This option also places additional burdens on customers and utilities associated with market system administration such as data validation, monitoring, and reporting, as well as supply obligations. These added responsibilities and potential risks raise the question of whether the associated payments for deliveries of renewable power to the market under this proposal are sufficiently offset by the lost benefits of administrative simplicity and lower market costs enjoyed by all customers under the prior proposals or compared to current net metering and virtual net metering programs. UIL Holdings commented that the use of Settlement Only Generators in the ISO-NE market system may provide a revenue stream to support the virtual net metering initiative.

However, UIL Holdings thinks that doing so would be unlikely to eliminate the subsidy from other customers to the virtual net metering participants.

Specific comments recommending revision to and/or expansion to the virtual net metering program were further submitted by The Vote Solar Initiative, New England Hydropower Company LLC, CEFIA, Harvest Power, Inc., UIL Holdings, UTC Power, CFE and SunEdison. TVSI supported the conclusion in the CES that the current virtual net metering program for municipal customers requires modification in order for municipalities to be able to effectively take advantage of it. TVSI strongly recommended that the State look to virtual energy crediting as a mechanism for broadening access to solar energy to customers who are unable to install solar on their own property. New England Hydropower Company LLC stated that the CES should consider adopting a more focused and directed approach to creating incentives for expanded development and strategic deployment of small hydropower projects. Small hydropower projects should be specifically targeted for promotion of greater distributed generation through proposals to expand virtual net metering. CEFIA suggests a modification to the existing virtual net metering law (which limits virtual net metering to municipalities and further limits its use to clean energy projects that are owned by the municipality) that would reflect that most municipalities opt to lease or deploy a clean energy project through a third-party ownership model, as to achieve tax credit and other benefits and value that would otherwise not be realized by a municipal project. Harvest Power, Inc. voiced its support to changes to the virtual net metering program that would: (a) base program size on the percentage of IOU load rather than the dollar value; (b) extend availability to private customers as well as public customers; (c) provide flexibility to allow private ownership of assets that serve public customers; and (d) consistently provide for netting at the retail price.

UIL Holdings believes it is critically important that only the generation portion of customers' bills be subject to the virtual net metering offset credit. According to UIL Holdings, that is the way the virtual net metering statutes are written now, and it believes this is how it should be to make sure there is no free use of the system by non-participating customers. UTC Power sought a clarification of the definition of "virtual net metering facility" in Section 121(a)(6) of PA 11-80. According to UTC Power, the definition should clearly refer to the five meters that constitute the virtual net metering facility, rather than the "energy source." If the definition and the ownership requirement are placed on the power source, and not the facility and meters, UTC Power believes that opportunities for a municipality to utilize virtual net metering would be eliminated. CFE noted that green-building developer Bruce Becker testified at the Hartford technical meeting about the numerous difficulties he has encountered in attempting to receive PURA approval on issues related to his building projects. Based on that experience, CFE believes it will be important for legislation on submetering and virtual net metering to give clear standards and deadlines in order to overcome any reluctance at PURA. Lastly, SunEdison advocated for increasing scale through municipal net metering aggregation. However, SunEdison believes the requirement that municipalities own the virtual net metering system presents an insurmountable barrier, and that the statewide $1 million cap on virtual net metering credits is prohibitively small.

UIL Holdings further noted that there are instances where the draft CES recommends initiatives that could lead to cost shifting from participating customers (those who directly benefit from such initiatives) to non-participating customers. Among these initiatives is the expanded applicability of sub-metering and expanded virtual net metering for behind-the-meter renewable generation. In both cases, UIL Holdings believes that costs would likely be shifted from participating customers to non-participating customers. While there is ample analysis (from three separate IRP documents) to support such cost shifting for the expansion of energy efficiency programs, UIL Holdings stated it is unaware of any rigorous analysis that supports the expansion of these other initiatives, and believes that such analysis may be beneficial before proceeding further.

The Regional Greenhouse Gas Initiative (RGGI), Regional Carbon Dioxide Cap, and Greenhouse Gas (GHG) Emissions Reductions

DEEP received comments concerning RGGI and the ongoing programmatic review from several stakeholders including the Sierra Club, Toxics Action Center, the Clean Energy Finance and Investment Authority (CEFIA), Clean Water Action, Connecticut Fund for the Environment (CFE), the Conservation Law Foundation, ENE, and the Wilton Energy Commission, and individuals like Susan Eastwood. By and large, these stakeholders and individuals support the State's participation in RGGI and the recommendations put forth by the draft CES. However, the Sierra Club , Toxics Action Center and Clean Water Action, among numerous other regional groups, contended that the draft CES fails to address the opportunities provided by the review to increase the funding available for the State's clean energy initiatives and to drive meaningful progress towards Connecticut's GHG commitments. These groups and stakeholders, and citizens as Ms. Eastwood, specifically called for a 20% reduction below actual GHG emissions limits by 2020 as part of the present RGGI review process. ENE, Clean Water Action and the Conservation Law Foundation recommended that the State push approval of the lowest regional carbon dioxide cap proposed by the review process to place Connecticut on track to an 80% reduction by 2050.

Further comments about the challenge of meeting GHG emissions reductions were received from stakeholders such as Bike/Walk Connecticut, Environment CT, CFE and ENE, as well as individuals like Dan Fischer. Of note, CFE and Environment CT contended that the draft CES fails to articulate a clear commitment and roadmap to Connecticut's RPS goal as it never fully frames the overall challenge of steadily decreasing GHG emissions from now until 2050. According to CFE, the CES should, realistically, perform a more robust overall framing of GHG issues, and examine the major policy proposals for their impacts on GHG in order to demonstrate the additional scale of this challenge for 2020, 2030, 2040 and 2050. At the very least, CFE said that the CES must not advocate for any policies that are flatly inconsistent with meeting the legally binding targets for 2020 or 2050. Environment CT stated that, at best, the CES should be a roadmap for Connecticut with concrete strategies and interim benchmarks clearly detailed. ENE believes that the CES needs to incorporate five analytical approaches: (1) performance of an apples-to-apples cost/benefit analysis for all fuel and non-fuel options; (2)

identification of long-range planning risks; (3) synchronization with GHG emissions targets; (4) analysis of life cycle GHG emissions; and (5) clear identification of formal recommendations. While lamenting that the draft CES would not even come close to achieving the statutory 10% by 2020 target, Mr. Fischer advocated for the CES to facilitate a just transition to a low-carbon, zero-waste Connecticut.

To allow CEFIA to make investments in projects that further the State's energy and environmental goals, CEFIA suggested an amendment to the RGGI regulations as they apply to it. According to CEFIA, current regulations limit its use of RGGI proceeds to the Class I resources defined in Conn. Gen. Stat. § 16-1(26). Therefore, CEFIA seeks the ability to support other clean energy resources and projects within the definition of Conn. Gen. Stat. § 16-245n, which captures all of the resources referenced in Conn. Gen. Stat. § 16-1(26) as well as thermal energy, energy efficiency financing, and alternative fuel vehicles and associated infrastructure.

Electric Submetering, and the Use of Renewable Energy and CHP in Multi-Tenant Buildings

Comments regarding the issue of electric submetering were submitted by stakeholders including ISE, PMC Property Group Inc. (PMC), UTC Power, the Northeast Clean Heat and Power Initiative (NECHPI) and CFE, as well as individuals such as Henry Link. Both ISE and UTC Power believe that when a developer includes large Class I renewable energy systems within a multi-family or building complex, the owner should be allowed to permit tenants to purchase the energy from those systems through submetering. PMC stated that DEEP should support legislation or policies that would permit submetering in buildings converted to residential use from prior commercial or industrial use. PMC added that the CES should expand submetering to include adaptive re-use projects where the installation EDC metering and related infrastructure would adversely impact the building's economics. NECHPI advocated for a review of current submetering regulations (as well as those for net metering), and suggested consideration of New York's long standing precedent for a progressive DG tariff model. Mr. Link also recommended allowing submetering in multi-tenant buildings, by either public or private funding.

Microgrids and Fuel Cells

DEEP received strong encouragement to expand the State's microgrid pilot program beyond the initial $15 million allotment to speed the transition to a more reliable energy grid, from a number of stakeholders such as ConnPIRG, Clean Water Action, Citizens Action Group, Environment CT, the Sierra Club, RENEW, the Working Families Organization, the Conservation Law Foundation, the Inter-Religious Eco-Justice Network, and 350 Connecticut, as well as from individuals such as Henry Link and John Liseo. The above stakeholders also recommended that DEEP investigate the best practices for renewable energy and storage for both microgrids and individual users.

Further comments were submitted by stakeholders such as ISE, CEFIA, the Connecticut State Council of Machinists (CSCM), Nanotech Plus LLC (Nanotech), and individuals like Lynne Bennett. ISE noted that customer-owned CHP can also form the distributed backbone for microgrids. Accordingly, ISE recommended that the CES encourage the development of programs that offer technical support, interconnection standards, incentives, financing and streamlined permitting for CHP, as well as a program that would promote high efficiency CHP and microgrids. For its part, CEFIA advised DEEP that it has established a placeholder budget for microgrids for Fiscal Year 2014. And CSCM looked to the State to find ways to invest in Connecticut-manufactured renewables, including, but not limited to, in-state industry sectors for fuel cells and hydrogen. Ms. Bennett suggested that microgrids and small cogeneration units could be technologies that may be appropriately applied to low-income affordable housing.

Conversely, Nanotech claimed that microgrids are a poor solution for Connecticut. Nanotech argued that the existing energy grid is simply showing its age, not its fundamental flaws. Nanotech pointed out that urban microgrids require the use of fuel cells, which are difficult to retrofit and have no advantages over gas turbines (unless the waste heat is utilized).

Relative to fuel cells, UTC Power noted that stationary fuel cells, through the use of renewable and non-renewable fuels, can help provide grid stability and manage the intermittency of "traditional" renewables at the micro level. According to UTC Power, expanding focus beyond solar PV to a discussion about levelized cost of energy for base load technology would create a more balanced approach for the production of clean energy during off-peak times (when solar PV would require large scale battery storage to operate efficiently). John Liseo noted that manufacturers of fuel cells are local to Connecticut. With natural gas becoming more plentiful and affordable, Mr. Liseo believes it makes sense to promote fuel cells as a source of distributed power generation in the microgrids, thereby creating local jobs.

Reliability, Security and Cyber Security

Environmental Energy Solutions (EES) strongly recommended that the CES include a greater degree of robust security considerations, rather than "scant, generalized and disconnected references." EES argues that a less than vigorous treatment of security issues could negatively impact the electric grid and the liquid and gaseous fuels infrastructure, as well as the health and safety of Connecticut's citizens. Accordingly, EES believes the CES needs more in-depth, critical analyses, and should present grid security in a more holistic, cross-cutting and a truly "all hazards" manner.

To enhance storm preparedness and response, the Connecticut Council of Small Towns advocated for four measures: (1) ensure greater grid resilience through tree trimming, and the hardening of wires and poles; (2) support the use of information technologies that allow electric suppliers to track and restore outages more quickly and improve communications with municipal officials and residents; (3) ensure that electric, gas and telecom utilities meet performance standards; and (4) assist smaller communities in using microgrids to ensure that critical facilities remain in service during outages. The OCC urged the

development of strategies to address potential calamity, including a program to relocate or "harden" facilities susceptible to flooding and storm surges. Clean Water Action expressed that the CES should recommend that each Connecticut municipality should have shelter facilities that are able to house residents, conduct emergency operations, and meet basic food and medicinal needs in the event of disruptions in electricity, natural gas and gasoline supplies. CWC expressed that encouraging more on-site generation projects, particularly at critical utility and municipal facilities, would provide greater reliability during a major storm event or power outage when commercial power is unavailable.

The Garden Club of New Haven (Garden Club) and the New Haven Urban Resources Initiative (NHURI) bemoaned that the draft CES does not set forth a long range plan for placing electric distribution lines underground to the maximum extent possible in order to achieve maximum reliability. Also, the Connecticut Siting Council (CSC) questioned the draft CES's statement, at page 98, that the cost of undergrounding power lines "averages about $11 million/mile." Accordingly, CSC requested that this figure be qualified for transmission or distribution. The Garden Club and NHURI, however, believe that the $11 million/mile figure is a typo since, according to them, $1 million/mile is often cited as the average cost. The Garden Club and NHURI noted that a 2009 study by the Edison Electric Institute reported that the cost for undergrounding ranges from $80,000/mile in rural areas to $2.13 million/mile in urban areas.

EES further expressed that an intentional cyber-attack has the potential to inflict great harm, possibly resulting in incapacitating crucial aspects of the electric grid (i.e., command, control and communications) as well as most other aspects of our increasingly digital society. B-LEC contended that, in large part to new IT connectivity, the smart grid/meters initiative would create security vulnerabilities that never existed with the old hardened utility grid. B-LEC stated that many experts have expressed that the smart grid, as currently designed, cannot be made safe from a cyber-attack and is more vulnerable to solar storms than the older utility grid.

NATURAL GAS SECTOR COMMENTS

DEEP received over 200 comments on the Draft's Natural Gas sector strategy. The majority of these comments could be parsed out into the following categories: increased reliance on natural gas, infrastructure expansion, price projections, and natural gas retail choice. The remaining comments addressed the hurdle rate and Contribution in Aid of Construction (CIAC) policies, and cost-benefit analyses.

Increased Reliance on Natural Gas

The range of individual responses concerning the Draft's natural gas expansion recommendations was expansive. Many home heating oil companies and their employees, as well as certain stakeholders in the propane industry interpreted the Draft recommendations as providing a subsidy to the natural gas industry and thereby creating an uneven playing field for other fuel sources to compete upon. These individuals tended to suggest that DEEP allow free markets to function without state intervention or alternatively give greater attention in the Strategy to a wider variety of fuel sources. These stakeholders voiced concern that the Draft's natural gas expansion plan would put small companies out of business. There was also a common misconception among many individuals that they will be compelled to switch to natural gas as part of the Strategy's expansion plan.

Other stakeholders, including PurePoint Energy, Environment Connecticut, the Berkshire-Litchfield Environmental Council, and the National BioDiesel Board, People's Action for Clean Energy, and a significant number of Connecticut residents were opposed to the expansion of natural gas due to its environmental implications. These stakeholders viewed the Draft's assertion that an increased reliance on natural gas would benefit the environment. In support of their opposition, these stakeholders cited many of the negative effects of hydraulic fracturing ("fracking") as well as studies suggesting that the lifecycle emissions of natural gas use are much higher than initially thought. Many of these same stakeholders noted that if natural gas expansion is recommended, it should only be seen as a temporary bridge to the mainstream and widespread use of truly "clean" sources of energy. These stakeholders claimed that the strategy failed to recommend greater investments in renewable energy, and instead perpetuating the State's reliance on fossil fuels.

Infrastructure Expansion

DEEP received comments regarding infrastructure expansion from stakeholders including Iroquois Gas, New Canaan's Utility Commission, several Connecticut municipalities, Northeast Gas Association, GZA Geoenvironmental, Connecticut Business Investment Authority, the Berkshire-Litchfield Environmental Council, Santa Energy Corp, Environment Connecticut, the Manufacturing Alliance of Connecticut, the Institute for Sustainable Energy, and several residents. Some of these comments supported and others opposed the plans for infrastructure expansion as laid out in the Draft. Iroquois Gas offered several ways it would be able to support efforts to minimize the costs of infrastructure expansion including: re-

deployment/repackaging of existing assets, offering access to additional sources of supply, and adding compression to existing pipelines. The New Canaan Utility Commission noted that it supported extended payback periods and/or rate flexibility to assist with new construction costs. The Institute for Sustainable Energy recommended that DEEP conduct a study to modify the formula so that the cost of main extensions is not the sole responsibility of a customer requesting service or the anticipated revenue of that customer alone. The formula should consider "cluster add-ons", which are revenues anticipated from new customers likely to connect to natural gas once the main extension is completed. In addition, a subsidy for main extensions should be created to encourage and compensate the distribution companies for the societal benefits of reducing our dependence on foreign oil and lower state emission levels. Several commenters opposed infrastructure expansion that relied on taxpayer money. The remaining comments conveyed general support for the concept of infrastructure expansion.

Natural Gas Retail Choice

Stakeholders such as Direct Energy Services, Warren Corporation, North American Power and Gas, and several municipalities submitted comments conveying overall support for natural gas decoupling and retail choice. North American Power and Gas submitted specific recommendations to establish unbundling for residential natural gas customers, including: 1) establish a collaborative to use existing Tariffs, gas transportation and operating procedures, codes of conduct, etc. to expand retail choice, 2) compare practices held in common between CT's electric and NG market, 3) review best practices from other states that have unbundled natural gas, and 4) revise existing Tariffs, including Capacity Release Service, and identify incremental cost to accommodate 100% residential choice.

Price Projections

Among the stakeholders opposed to the Draft's natural gas price projections were Renewable Energy Group, Cromwell Energy, New England Fuel Institute, Standard Oil of Connecticut, Sippin Energy Products, Madison Oil Company, National Federation of Independent Businesses, and Bantam Fuel. These stakeholders all noted that future natural gas prices cannot be predicted with enough certainty to justify such a large endorsement by the state. One commenter noted that DEEP's assumption that new conversions will be performed with the most efficient equipment available is not accurate in the real market, and therefore estimated consumer savings would be much less than projected in the Draft.

Cost-Benefit Analyses

Several stakeholders including the Connecticut Attorney General, the Berkshire-Litchfield Environmental Council, and various residents recommended that DEEP conduct a cost-benefit analysis of the proposed natural gas expansion before endorsing such a large financial investment. The Berkshire-Litchfield Environmental Council stated that the Draft should properly address the tradeoffs involved in an expansion plans such as the one proposed, including the environmental disruption involved with laying additional pipeline, and the increased state regulatory oversight required afterward. The Attorney

General noted that given increasing ratepayer costs, DEEP should include a sharper focus on the costs involved, and weigh those costs against the benefits of each recommendation.

Changes to Hurdle Rate Calculation and CIAC Policies

Standard Oil of Connecticut submitted comments related to the Draft's recommendations involving changes to the hurdle rate calculation and CIAC policies. In specific, Standard Oil took issue with the 5% hurdle rate—which it asserts is artificially low—used in the Draft to arrive at the favorable net present value calculations. Standard Oil asserts that the hurdle rate should reflect the financing costs and therefore, the proper hurdle rate is really 8% and if the 8% hurdle rate were used, the $3 billion cost to convert would be a very bad investment.

TRANSPORTATION SECTOR COMMENTS

The written comments for the Transportation sector concentrated on: expanding the clean vehicles, clean fuels platform; addressing barriers to adoption and deployment of the clean fuels, clean vehicles platform; transit oriented development; multi-modal transportation options; regional initiatives; requests that require federal action; and climate change mitigation goals.

Expanding Clean Fuels, Clean Vehicles Platform

While DEEP received many comments in support of the Draft Strategy clean vehicles, clean fuels platform, several commenters identified a need to diversify the fuel types considered. The Office of Consumer Counsel requested that DEEP create an open platform for alternative fuels to prove themselves. They urge DEEP to avoid reliance on any one fuel. The National Propane Gas Association, Hocon Gas Inc., and numerous others voiced concern that the use of propane as a potentially cleaner heating fuel was not referenced in the Draft CES. As a result, DEEP considered the benefits of propane as an alternative fuel and included it in the clean vehicles, clean fuels platform.

In addition to propane, several stakeholders noted the absence of biofuels in the Draft CES. The Institute for Sustainable Energy at Eastern Connecticut State University reflected on the State's capacity to be a leader in advanced biofuel research and production. In response, DEEP reviewed the current state of biofuels research and development within the industry and within Connecticut specifically. Following this review, advanced biofuels were included in the clean vehicles, clean fuels platform.

Addressing Barriers to Adoption and Deployment of Clean Vehicles, Clean Fuels Platform

Environment Northeast and UIL Holdings on behalf of Connecticut Natural Gas Company, UI Company, and Southern Connecticut Natural Gas Company suggested that DEEP conduct an education and outreach campaign to aid Connecticut residents and fleet owners in making decisions about future vehicle purchases.

Many stakeholders recommended that DEEP incentivize alternative fuel vehicle purchases. For example, the Conservation Law Foundation, Environment Northeast, Clean Energy Fuels, and New England Electric Auto Association, and UIL Holdings on behalf of Connecticut Natural Gas Company, UI Company, and Southern Connecticut Natural Gas Company encouraged the State to offer incentives in various forms to reduce the current incremental cost of alternative fuel vehicles.

Supply of alternative fuels was addressed by many as a barrier to adoption, specifically regarding natural gas and electric vehicles. The Office of Consumer Counsel questioned the ability of the State's natural gas supply to meet the needs of the growing use of natural gas vehicles. Further, UTC Power cautioned about the impact of electric vehicle charging on the grid resiliency and reliability.

Additional stakeholders requested that DEEP consider rate structure development for natural gas and electric vehicles. In terms of rate design changes for fueling/charging station applications, Connecticut Natural Gas Company and Southern Connecticut Natural Gas Company recommended that natural gas fueling station rates be based on firm service, cost-based rates rather than value-of-service, interruptible rate linked to the price of gasoline. UI Company recommended that new electric vehicle tariffs for Level 2 and Level 3 charging stations be developed.

Further, Conservation Law Foundation, Environment Northeast, and the Institute for Sustainable Energy at Eastern Connecticut State University encouraged DEEP to consider and develop dynamic pricing for electric vehicle charging (for example, Time of Use pricing, or off-peak charging).

In order to address the multitude of barriers that exist to adoption and deployment of the clean vehicles, clean fuels platform, several stakeholders suggested that DEEP create an interagency working group required to advancement of alternative fuel vehicles. Of this stakeholder group were, Clean Energy Finance & Investment Authority (CEFIA), Environment Northeast, and the UIL Holdings on behalf of Connecticut Natural Gas Company, UI Company, and Southern Connecticut Natural Gas Company. In response to this recommendation those detailed above, DEEP, with interagency coordination, will strive to overcome the potential barriers to adoption and deployment.

Transit Oriented Development (TOD)

In general, most comments DEEP received were supportive of the inclusion of TOD in the Draft CES. Connecticut Fund for the Environment, Save the Sound, and (in a joint letter) ConnPIRG, Clean Water Action, CT Citizens Action Group, Environment CT, Sierra Club CT Chapter, National Sierra Club, RENEW, Working Families Organization, Conservation Law Foundation, Inter-Religious Eco-Justice Network, and 350 CT urge DEEP to show leadership and further promote TOD.

More specifically, the Connecticut Fund for the Environment and Save the Sound submitted many detailed recommendations to DEEP that suggest streamlining the TOD application process for municipalities in the State, creating an inventory of available TOD funding sources, developing a proactive station planning and zoning , and others. Environment Northeast also suggested that DEEP remove regulatory barriers to high density housing in TOD projects. Tri-State Transportation Campaign recommends that DEEP take a long-term and holistic stance to plan TOD projects with other additional infrastructure projects (like sewer construction) and vice versa.

Additionally, Connecticut Fund for the Environment and Save the Sound requested that DEEP provide a uniform and clear definition of TOD for municipalities of the State.

In a similar vein, DEEP received many comments in support of public transit projects. However, the Conservation Law Foundation, Environment CT, Bike/Walk CT facilitating 41 citizen letters, and the Regional Planning Association, CT expressed a need for increased commitment to public transit systems from DEEP.

While DEEP inherently supports recommendations to strengthen and support TOD and public transit in the State, ConnDOT is better suited to handle specific TOD recommendations and requests. In December 2012, Governor Malloy created an Interagency Working Group on TOD within Connecticut. It is anticipated that this working group will address, either directly or indirectly, many of the TOD comments submitted to DEEP.

Multi-Modal Transportation Options

DEEP received several comments reflecting on multi-modal transportation options. In general, there was support for Transportation Demand Management (TDM) and Vehicle Miles Travelled (VMT) reduction policies that include multi-modal options. Regional Plan Association, CT, Tri-State Transportation Campaign, and the Connecticut DEEP Green Team were among those urging DEEP to further encourage and develop both TDM and VMT reduction polices.

Additionally, many stakeholders requested that DEEP promote bicycling and walking to a greater extent in the CES. Tri-State Transportation Campaign, Laurie Gianotti (DEEP employee), Bike/Walk CT, and 41 citizen advocates recommended that DEEP consider both the inclusion of and funding for the creation of bikeable and walkable areas.

Regional Plan Association, CT and Bike/Walk CT suggest that DEEP should include and implement the Complete Streets Law (Connecticut Public Act 09-154 (2009) and Conn. Gen. Stat. §§ 13a-153f and 13b-13a). Bike/Walk CT also urged DEEP to include and implement the Share the Road Campaign (Conn. Gen. Stat. § 14-232(13)(a)) and the recommendations of the Bicycle & Pedestrian Advisory Board.

DEEP and the CES strongly support municipalities building walkable and bikeable communities. As a result of comments received, DEEP will continue efforts with ConnDOT and others to implement the Complete Streets Law and effective complete streets policies and practices.

Regional Initiatives

Environment Northeast, the Conservation Law Foundation, and in a joint letter ConnPIRG, Clean Water Action, CT Citizens Action Group, Environment CT, Sierra Club CT Chapter, National Sierra Club, RENEW, Working Families Organization, Conservation Law Foundation, Inter-Religious Eco-Justice Network, and 350 CT urged DEEP to advance a regional market-based Clean Fuels Standard. The CFS would limit the carbon content of fuels in the area.

Connecticut has participated in regional efforts to promote low carbon fuels, with the goal of establishing a low carbon fuel standard at the federal level. In general, DEEP supports lower carbon fuels, as described in the clean fuels, clean vehicles platform of the CES.

Requests Requiring Federal Action

DEEP received several requests that will require federal action. For example, the DEEP Green Team and Kevin T. Sullivan (DEEP employee) suggested that DEEP pursue changes to the Qualified Transportation accounts under Internal Revenue Service tax rules to encourage and support bicycling as a commuting option. James Matthew Callahan suggested that DEEP implement a new highway maximum speed limit based on the metric system of 100 km/hr. (or 62 miles per hour). As DEEP moves forward with implementation of the CES and coordinates with Federal officials, it will take these comments into consideration.

Climate Change Mitigation Goals

Environment Northeast, Connecticut Fund for the Environment and in a joint letter ConnPIRG, Clean Water Action, CT Citizens Action Group, Environment CT, Sierra Club CT Chapter, National Sierra Club, RENEW, Working Families Organization, Conservation Law Foundation, Inter-Religious Eco-Justice Network, and 350 CT requested that DEEP take into consideration the impact of recommended policies of the CES on climate change mitigation (e.g. greenhouse gas reductions). These groups suggested that DEEP use climate change mitigation potential as a comparative tool to assess policy options.

Further, several stakeholders recognized Connecticut's existing legislation that contain climate change mitigation goals: the Global Warming Solutions Act, the Renewable Portfolio Standard, and Public Act 08-98. These stakeholders – Environment Northeast, Sierra Club, Connecticut Fund for the Environment, Environment CT, and Bike/Walk CT – recognize that the CES can be synchronized with these existing laws.