CONNECTICUT ENERGY MARKETERS ASSOCIATION

March 7, 2013

Co-Chair Bob Duff
Co-Chair Lonnie Reed
Senator Clark J. Chapin
Representative Laura R. Hoydick

Energy and Technology Committee:

We are submitting testimony on **sections 18 and 19 of H.B. 6360**, AN ACT CONCERNING IMPLEMENTATION OF CONNECTICUT'S COMPREHENSIVE ENERGY STRATEGY and **sections 3(m) and 7(b) of S.B. 839**, AN ACT CONCERNING STATUTORY CHANGES TO ADVANCE CONNECTICUT'S ENERGY POLICIES.

The Connecticut Energy Marketers Association (CEMA) represents 576 petroleum marketers, principally made up of home heating oil dealers and gasoline distributers, located in Connecticut. CEMA members employ over 13,000 people in our state.

CEMA **supports the language in section 18 of H.B. 6360** that would reduce the sulfur content of home heating oil from 3000ppm to 15ppm, and removes the language in the law that would require Connecticut to wait for the states of New York, Massachusetts and Rhode Island to have a similar standard. We ask that the committee work with us on language that would add a requirement so that a renewable content could also be added to heating oil.

Studies show that a 15ppm heating oil with a 15% to 20% bio component (ULSD B20) would make it the cleanest burning fossil fuel in the country. Requiring this fuel would result in a reducing the sulfur content of heating oil by 99.93%. This reduction would leave heating oil with a sulfur content that is 75% less than natural gas.

CEMA is opposed to section 19 of H.B. 6360 that proposes to set into law a 25 year "hurdle rate". In 2012 PURA rejected a similar proposal to increase the hurdle rate in what we believe was an effort to protect ratepayers from higher natural gas rates.

In the past the hurdle rate was reviewed by DPUC/PURA and more recently they made adjustments allowing the utilities to increase it to 20 years for SCG and

CNG. A technical review (by PURA) of the impact that an extended hurdle rate would have on ratepayers is the only responsible way to determine what it should be set at.

Setting the hurdle rate in statute is inappropriate and lacks the expertise required to find out what the real cost would be to ratepayers. DEEP stated on page 143 of their draft Comprehensive Energy Strategy (CES) that *"expanding the hurdle rate payback period to 25 years would increase the rate base of the gas companies by approximately $339 million."* On page 15 of PURA's comments in response to the draft CES a utility employee was quoted saying *"If anyone thinks we are going to implement this plan without increasing rates or having to charge more, then, you know, let's just kind of all leave, because that ain't happening."*

Our association does not have expertise in setting utility rates, but we would ask that the committee allow the specialists at PURA to do their job so that ratepayers are not overly burdened with costs that they will incur if the hurdle rate is set in statute.

We recommend that language be added to this section that prohibits the utilities from passing the cost of expanding their infrastructure to existing ratepayers. We ask this in response to a "data request" from PURA (attached) that suggests a *"new rate"* would need to be created to pay for the expansion of their gas lines. In that same document the utilities acknowledge that the expansion will require *"new long term capacity"* so that they can provide "*reliable service"* at *"higher rates"*! And all these new costs and higher rates without any guarantee that natural gas will remain less expensive in the future. If you want o see a quick example of this, take a look at table C-5 in the appendix of DEEP's 2013 CES, which indicates a negative NPV for conversion from oil to gas.

If my math is correct, and you allow the hurdle rate to be expanded, you get 2 NEW natural gas rates (one for new customers and one for existing ratepayers) and higher base costs so that the utilities can provide reliable service.

CEMA absolutely agrees with Governor Malloy when he states that he wants a ***"cleaner, cheaper and more reliable"*** fuel to our state. The only problem is that natural gas is not that fuel. A 15ppm B20 heating oil is cleaner that natural gas! 24 out of the last 28 years oil has been less expensive than gas and since no one can predict future energy prices natural gas does not meet the "cheaper" test! Finally, the utilities even admit that their existing supply can not support the expansion of 300,000 new customers not to mention ISO New England's warnings about the "overreliance" on natural gas. Now that does not sound very reliable!

Connecticut needs fuel neutral energy policies that promotes conservation not fuel conversion. If the utilities want new customers make them go out and pay for it with their shareholders money – not your constituents money.

Sections 3(m) and 7(b) of S.B. 839 would diminish the Public Utility Regulatory Authority's (PURA) autonomy by requiring them to follow policies that are developed by the Department of Energy and Environmental Protection (DEEP) through the CES and other plans. The language in these sections should be removed so that PURA can make decisions based on the impact that proposed policies would have on ratepayers. A totally independent PURA ensures that ratepayers are protected.

3(m) Notwithstanding any provision of the general statutes, the decisions of the **Public Utilities Regulatory Authority**, including, but not limited to, decisions relating to rate amendments arising from the **Comprehensive Energy Strategy**, the Integrated Resources Plan, the Conservation Load Management Plan and policies established by the Department of Energy and Environmental Protection, **shall be guided by such strategy, plans and policies.**

7(b)...The authority shall require the utilization of such new principles and structures to the extent that the authority **determines that their implementation is in the public interest, as identified by the Department of Energy and Environmental Protection** in the Integrated Resources Plan and the **Comprehensive Energy Strategy**, and necessary or desirable to accomplish the purposes of this provision without being unfair or discriminatory or unduly burdensome or disruptive to any group or class of customers, and determines that such principles and structures are capable of yielding required revenues. In reviewing the rates and rate structures of electric and gas companies, the **authority shall** [take into consideration appropriate energy policies, including those of the state as expressed in subsection (c) of this section] **be guided by the goals of the Department of Energy and Environmental Protection, as described in section 22a-2d, the Comprehensive Energy Strategy...**

When local family owned home heating oil dealers want to expand their businesses they have to do so without the benefit of increasing costs to their customers. We ask that the committee allow for a level playing field so we can fairly compete.

CEMA asks that the Energy Committee amend the language in **H.B. 6360**, AN ACT CONCERNING IMPLEMENTATION OF CONNECTICUT'S COMPREHENSIVE ENERGY STRATEGY and **S.B. 839**, AN ACT CONCERNING STATUTORY CHANGES TO ADVANCE CONNECTICUT'S ENERGY POLICIES to reflect the changes we have suggested in our testimony.

Respectfully,

Vice President

Docket Public Act 11-80 - Sec. 51 - Comprehensive Energy Plan

Witness: Camilo Serna, Gregg Therrien
Request from: Public Utilities Regulatory Authority

Question:
(REGULATORY CHANGES) Draft CES, Natural Gas Sector Strategy, pp. 143-148. Discuss each of the regulatory changes proposed by the draft CES in this section and include the potential impact on ratepayers. Include resource cites.

Response:
The LDCs provided a set of detailed comments to DEEP on their proposed regulatory changes. Below is a copy of the comments provided on December 21,2012 by the LDCs.

"The Draft proposes the establishment of a planned natural gas expansion process, to more effectively help potential customers switch to natural gas over a seven year time period. The goal of this program would be to provide customers who can cost-effectively switch to natural gas the choice to switch more quickly and efficiently, and cut their heating bills significantly. Savings that, in all likelihood, will flow back to the local Connecticut economy. To accomplish this, the Draft proposes a set of regulatory changes and economic incentives that, when implemented as part of a coordinated natural gas expansion process, can reduce the costs of fuel switching, ensure a more reliable gas supply, and help more Connecticut homeowners and businesses take advantage of fuel savings.

The level of potential gas conversions envisioned in the Draft represents a significant increase compared to current levels. The Gas LDCs stand ready to invest the required capital and resources to ramp-up conversions and meet the targets laid out in the Draft. In order to ensure the opportunity can be captured as quickly as possible to deliver the customer, economic and environmental benefits identified in the Draft, the Gas LDCs have developed four very specific recommendations that, if adopted in the final CES, will significantly increase the chances of success.

1. Strengthen new project evaluation guidelines (hurdle rate model)
   The Gas LDCs support DEEP's recommendations to introduce changes on how the hurdle rate model is used and calculated (recommendations 7 & 9), including the use of a 25 year timeframe for all types of customers and allowing greater flexibility when calculating customers' main extension costs by allowing a "portfolio view" and allowing the Gas LDCs to forecast revenues. This support hinges upon the ability of the Gas LDCs to recover prudent capital investments in a timely manner, outside of a rate proceeding. Details of such rate recovery should be included in the planning document with PURA, but should be fundamentally supported by DEEP as part of this expansion strategy.

The Gas LDCs propose the following additional recommendations on this topic:

- Using 3 years of potential revenues from adjacent prospects who are likely to switch to natural gas once the new main is installed. When forecasting revenues, the Gas LDCs will include magnitude and certainty of potential load additions over time and the level of prospects' motivation to convert.
- Expand evaluation metrics to include societal considerations such as jobs created, savings to the State, economic development opportunity and others jointly identified and quantified with DEEP. In addition, the Gas LDCs recommend including an assessment of environmental benefits and benefits from economies of scale for each of the potential expansion projects.
- Focus on the following types of projects to consolidate:
  - Downtown areas without access to natural gas
  - Road reconstruction being planned by the local government or by DOT
  - Business parks and industrial parks
  - Multi-family housing, including HUD managed facilities; and
  - Residential neighborhoods with high level of interest as evidenced by factors such as high call volume, letter of interests, etc.

2. Implement a new rate design to fund system expansion

Changing the landscape to allow more customers to have access to natural gas will require enhancing the current regulatory framework. The Draft provides an initial outline of a new rate design that will allow the expansion of the natural gas distribution system (recommendations 8, 10 & 11). The Gas LDCs believe that these recommendations need to be enhanced in the final CES in order to provide greater clarity and certainty on how this new rate design will help fund the system expansion envisioned in the Draft.

The Gas LDCs agree with DEEP that the recovery of the revenue requirements associated with the expansion plan (return of and on capital investment, depreciation expense, associated incremental O&M costs, uncollectibles, income and property taxes) be done on a timely manner and propose that this be set via an annual tracker that is fully reconcilable. Gas LDCs also recommend that target return on equity ("ROE") for the expansion program needs to be sufficient to attract incremental capital and shall be based on the gas LDCs existing ROE and include an additional variable ROE component based on certain pre-defined performance goals to be agreed upon with DEEP.

In order to recover these revenue requirements, the Gas LDCs propose that a new rate design should be put in place. This new rate design would have two different rate components. First a "Shared Savings Rate" that would have the following characteristics:

- New customers would be placed on a different rate schedule (e.g., rate schedule 2A for a residential heating customer) that in effect will have its distribution rates increased by a pre-determined percentage.
- This rate may take the form of an increased monthly customer charge, an increase on the volumetric charge or a combination of the two.
- A separate Shared Savings Rate would be established for different classes of customers (e.g., residential, small business, and large business) since the economics for different classes may be different.
- The Shared Savings Rate will be calculated to allow each class of customers to retain the majority of the differential between oil and gas prices. In this manner, the proposal allows customers to recoup their initial investment over time.
- The duration of the new rate schedule would be linked to the size of the program.
- The rate schedule would remain with the premise for its required duration, transferrable from one occupant/owner to the next.

Second, the revenue requirements dollars not collected through the Shared Savings Rate would be collected monthly from all existing customers through a new rate, the "System Expansion Rate". The System Expansion Rate would be:

- Reviewed annually and trued up at the end of the expansion program;
- Have a duration linked to the size of the program.

The System Expansion rate mechanism provides benefits not only to the participating customers, but to all other customers as well. Those benefits are enumerated below:

- Provides participating customers with a level of certainty around achieving a payback for their investment.
- All customers receive the benefits of greater economic activity, more jobs, and a cleaner environment.
- As gas expansion occurs, economies of scale are realized as the LDCs fixed costs of providing delivery service will be spread among greater volumes and customers.

The Gas LDCs request that DEEP considers and studies this proposed new rate design and incorporates it into the final CES in order to ensure the Governor and DEEP's public policy goals are attained in a timely manner.

3. Support implementation of new customer financing options by Gas LDCs

The Gas LDCs concur with DEEP in its assessment that providing financing options to customers is a critical success factor in meeting the goals outlined in the Draft (recommendation 3). The Gas LDCs stand ready to support the State in providing these new financing options to customers. As such, the Gas LDCs advance the following specific recommendations to kick start the efforts as soon as the CES is finalized:

- The Gas LDCs propose to launch a gas conversion financing program focused on the residential segment to fund initial customer conversion costs (equipment and labor). The program would be administered directly by the Gas LDCs to ensure it is quickly implemented and linked to the expansion plan envisioned by DEEP.
- The Gas LDCs believe that commercial and industrial customers have multiple alternatives to finance a conversion, including C-PACE, CL&P's Small Business Program, the recently launched C&I Altus Conversion Financing and traditional private financing.
- The Gas LDCs would develop partnerships with third parties willing to finance the conversions such as credit unions, local banks and private investors. The Gas LDCs will be replicating similar models used in Massachusetts by Northeast Utilities' subsidiary NSTAR.
- The key feature of the program would be an interest rate buy-down to bring customer financing rates to 1%. The Gas LDCs propose to fund the buy down from a funding pool created through the allocation of a portion of certain purchased gas adjustments ("PGA") credits such as interruptible sales margin, capacity release margin, off system sales margin and pipeline refunds as outlined by DEEP in the Draft (recommendation 11). The Gas LDCs believe that the use of these credits to buy down the interest rates can have a significant impact on establishing a sustainable financing program. For example a $15 million annual fund, could support close to 15,000 residential buy downs Assumes buying down rates from 7% to 1%, for an average loan of $5,625 (75% of the conversion cost of $7,500) and paid over 5 years.
- Interest rate buy-downs could also be offered under a tiered structure, where customers that choose more energy efficient equipment would get a lower interest rate than those selecting less efficient heating equipment.
- The Gas LDCs would offer an on-bill repayment option if so desired by third parties and end-customers and after such an option is proven to be operationally and technically feasible.
- The buy-down program could be adjusted to offer longer-term payment schedules for low income customers and/or landlords with 2-4 units.

4. The support of Gas LDC capacity acquisitions is necessary to ensure sufficient flexibility and reliability exists in portfolio to meet firm growth scenarios

The process of adding interstate pipeline infrastructure represents a significant undertaking for pipelines, gas utilities, energy policy makers and regulators. The project sponsor applies significant capital and resources to a project. The regulated structure of the natural gas industry requires long term contracts supporting such capacity prior to its construction. Any project must be deemed to be in the "public convenience and necessity" to comply with the Natural Gas Act and the Federal Energy Regulatory Commission ("FERC") must give formal approval of all aspects of an expansion, after rigorous review.

Currently the Connecticut LDCs project a need for new long term capacity in order to continue to provide reliable service to growing firm markets. These commitments will require long term contracts (generally 15 years) at higher rates than "rolled in" contracts. The addition of capacity to the region reaches back decades and is the reason the current infrastructure is in place. Significant state benefits accrue as a result of adding capacity into Connecticut by enabling the ability to expand utilization of natural gas to leverage the economic and environmental advantages natural gas can bring to a heavily oil dependent state.

The Gas LDCs are dedicated to fulfilling DEEP's gas expansion goals and intend to make necessary long term capacity commitments to ensure that the gas policy objectives can be achieved, and not be limited by inadequate capacity. After weighing the pros and cons of capacity decision strategies, aggressive and proactive capacity decisions are deemed integral to the fulfillment of the State's energy goals. The need to make a pipeline project commitment will be necessary prior to the development of the gas expansion plan envisioned by DEEP in the Draft. As such, in the final CES, DEEP should indicate its support of the Gas LDCs to:

- Plan on a best cost basis using the growth projections outlined in the Draft.
- Take into account where potential system growth will occur as well as existing system constraints to identify capacity commitments.
- Enter into the necessary commitments and agreements in order to ensure that DEEP's policy objectives can be achieved, and not be limited by inadequate capacity.
- Work to get the necessary support from PURA for capacity commitments."

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http://www.clean-diesel.org/nonroad.html

Locomotive, marine and non-road diesel fuel standards begin at later dates (except in California).

EPA fuel standards for locomotive, marine and non-road diesel fuel engines and equipment, such as farm or construction equipment, become effective at dates later than those for highway vehicles:

- Diesel fuel intended for locomotive, marine and non-road engines and equipment is required to meet the Low Sulfur Diesel fuel maximum specification of 500 ppm sulfur in 2007.
- By June 2010, the ULSD fuel standard of 15 ppm sulfur will apply to non-road diesel fuel production.
- Beginning in 2012, locomotive and marine diesel fuel must meet the ULSD fuel standard of 15 ppm sulfur.

Click here for EPA Winterization Standards Letter 11-30-07 (PDF).
Click here for Non-road ULSD Use Fact Sheet (PDF).
Click here for Non-road Diesel Pump Labels (PDF).

Non-road Diesel Fuel Standards										
Who	**Covered Fuel**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Large Refiners & Importers	NON-ROAD	500+ ppm	500 ppm	500 ppm	500 ppm	15 ppm	15 ppm	15 ppm	15 ppm	15 ppm
Large Refiners & Importers	LOCOMOTIVE & MARINE	500+ ppm	500 ppm	500 ppm	500 ppm	500 ppm	500 ppm	15 ppm	15 ppm	15 ppm
Small Refiners & Other Exceptions	NON-ROAD, LOCOMOTIVE & MARINE	500+ ppm	500+ ppm	500+ ppm	500+ ppm	500 ppm	500 ppm	500 ppm	500 ppm	15 ppm
Except in California, compliance dates for Non-Road, Locomotive and Marine fuels in the years indicated are: June 1 for refiners and importers, August 1 downstream from refineries through fuel terminals, October 1 for retail outlets, and December 1 for in-use.										
In California, all diesel fuel transitioned to ULSD in 2006. Locomotive and Marine diesel fuels were required to transition to 15 ppm ULSD effective January 1, 2007.										

Connecticut Full Fuel Cycle Efficiency and Carbon Emissions

Residential Hydronic Heating and Domestic Hot Water Systems

Energy Efficiency and Life Cycle Carbon Emissions

A Consortium of State Oilheat Associations commissioned a Greenhouse Gas Project to study[1] the full fuel cycle efficiency to determine the energy efficiency and GHG emissions impact for hydronic heating systems which also provide domestic hot water. The research concluded that focusing on sustainability in the built environment requires life cycle assessments of operational building energy systems. Sustainable energy production and consumption should also require life cycle assessments from wellhead to burner tip.

Fuel Mix

Connecticut is projected to experience significant changes in its natural gas supply mix by 2020. Connecticut will see a significant decrease in gas from Western Canada and the Gulf Coast, increase in gas from the Rocky Mountains, Midcontinent and the Southwest, increase of Gulf Coast LNG and LNG shipments into regional terminals.

Fuel Cycle Emissions

Figure 1 shows the fuel cycle emissions in pounds of CO_{2e} per MMBtu of fuel delivered (not including end-use equipment efficiency) for each fuel type in 2006 and 2020. This graph provides CO_{2e} emission up to the burner tip and gives an emissions impact understanding of potential changes in fuel mix between 2006 and 2020. Marginal comparisons between heating oil and biofuel blends should be made versus the marginal LNG supply. Figure 1 shows that delivered bio-blends can provide less CO_{2e} emissions than marginal LNG without taking into account system efficiencies.

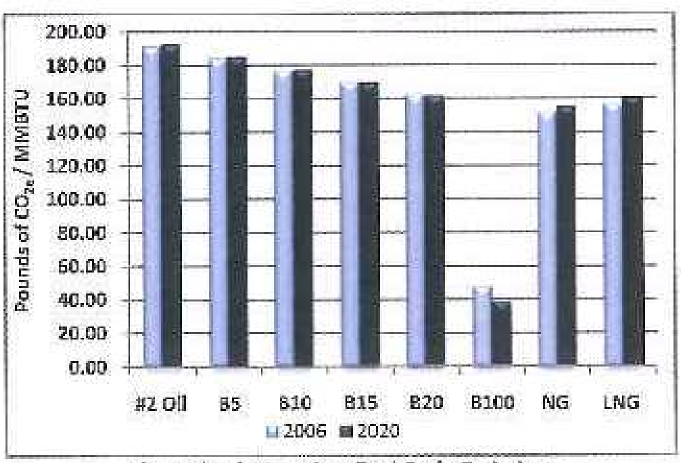

Figure 1 – Connecticut Fuel Cycle Emissions

System Energy Efficiency (Resource Conservation)

Brookhaven National Laboratory[2] (BNL) developed an accurate method to determine system efficiency for integrated heating and domestic hot water residential systems[3]. The BNL model is more accurate in predicting actual building heating and DHW performance and the commonly used AFUE methodology. Three boiler configurations were examined: an average boiler currently sold, a high efficiency boiler and a condensing boiler. The comparison was performed on a 2,500 ft^2 ranch home with a basement with typical "code" construction. Figures 2 and 3 provide the total annual resource energy requirements to provide heating and hot water services to the modeled 2,500 square foot house (including energy use along the fuel cycle and end use equipment efficiency). Total energy requirements to provide the annual heating and hot water services is higher for natural gas for both the average, high efficiency non-condensing units in 2006 (Figure 2), reflecting two important factors: 1) large amount of Gulf Coast and Western Canadian gas supply, and 2) the appliance and system efficiency advantage oil and biofuel blends have versus natural gas and LNG through less water content[4].

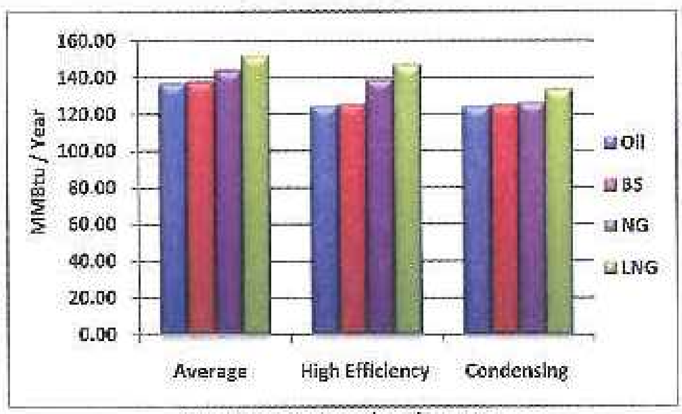

Figure 2 - 2006 Fuel Cycle Energy

Figure 3 shows that ultra low sulfur diesel (ULSD) and B20 have higher source energy efficiency than the natural gas supply and marginal LNG across the board in 2020.

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1 "Final Report Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water", Bruce Hedman and Anne Hampson, ICF International, August 2008.

2 Performance of Integrated Hydronic Systems, Project Report, May 1, 2007, Thomas A. Butcher, Brookhaven National Laboratory.

3 AFUE leads to low estimates of the energy savings potential of modern, integrated systems, particularly where advanced controls are used.

4 With respect to current non-condensing appliances - natural gas maximum boiler AFUE efficiency is 83% and oil maximum boiler AFUE efficiency is 88% with the reason for this differential being the water content in the fuel and resultant combustion gas dewpoint affecting performance.

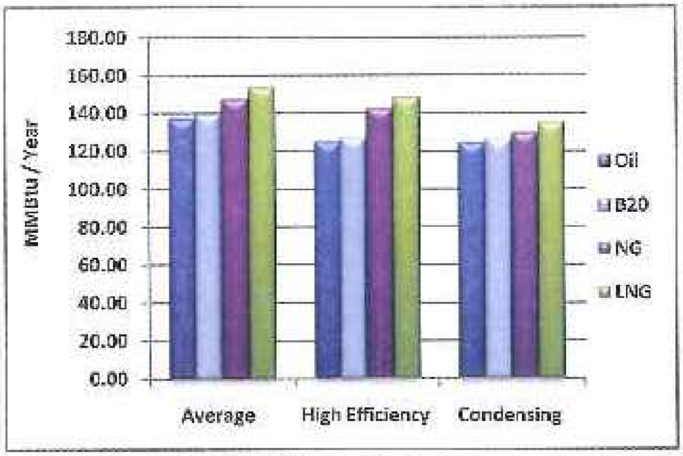

Figure 3 - 2020 Fuel Cycle Energy

Life Cycle Emissions Comparison

Figures 4 and 5 show a condensing boiler using marginal LNG supply produces 8% less CO_{2e} per year than heating oil in 2006 and only 6% less CO_{2e} emissions than ULSD in 2020. Remarkably, if you compare a high efficiency non-condensing boiler using LNG supply you find it produces 4% less CO_{2e} per year than heating oil in 2006 and 2% more CO_{2e} emissions than ULSD in 2020. In 2006, a high efficiency B10 boiler produces the same CO_{2e} emissions per year as a high efficiency boiler using LNG and in 2020 a condensing B20 (ULSD) boiler produces 2% less CO_{2e} emissions per year than a condensing boiler using LNG.

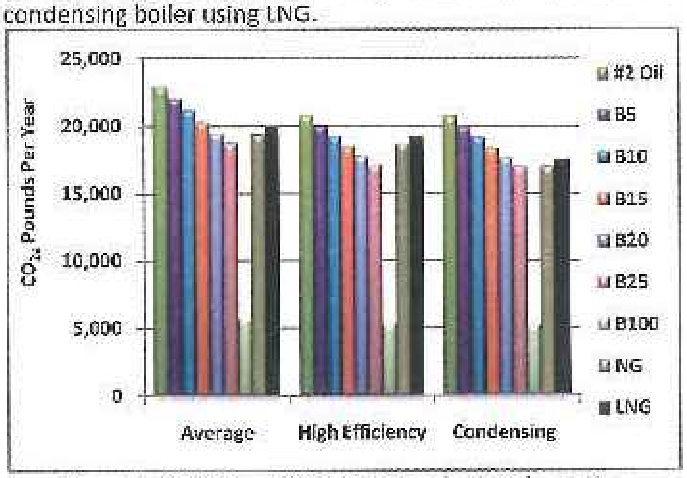

Figure 4 - 2006 Annual CO_{2e} Emissions in Pounds per Year

Life Cycle Emissions Planning

Fuel delivery characteristics will vary dramatically over time, as supply sources vary and sustainable alternatives enter the market, creating complexity regarding fuel switching policy designed to reduce carbon emissions. Figure 6 assumes a linear shift in emissions from 2006 to 2020. The liquid fuel bio-blend (between B10 and B15) is projected to emit less CO_{2e} emissions than LNG going forward from around 2015 based upon this projection.

Clearly, today's policies and regulations must take future fuel diversity into account to prevent unintended consequences and to deliver the lowest potential emissions solutions.

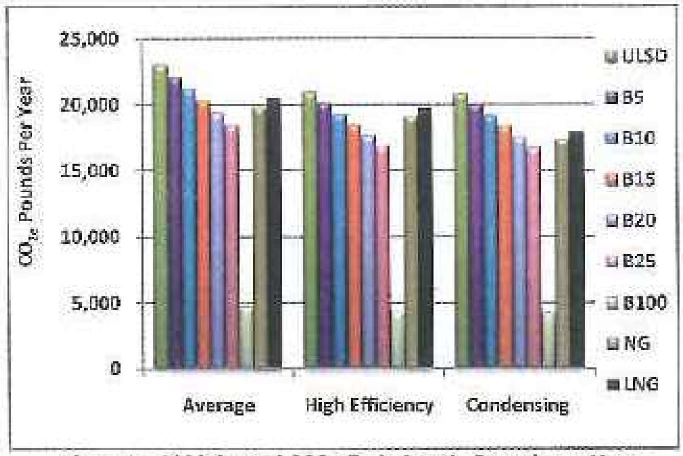

Figure 5 - 2020 Annual CO2e Emissions in Pounds per Year

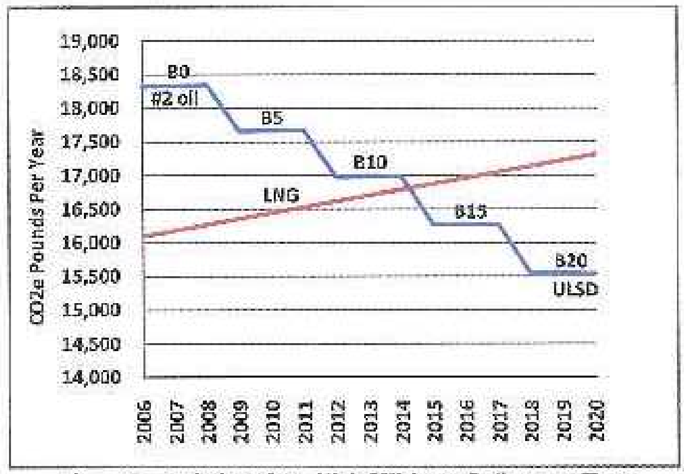

Figure 6 – Emissions for a High Efficiency Boiler over Time

Conclusions

Resource energy analysis and full fuel cycle emissions analysis are more comprehensive and accurate methods to assess the total energy and emissions impacts of residential energy consumption. Site energy analysis only takes into consideration the ultimate consumption stage. Significant energy is consumed, with resulting CO_{2e} emissions, during all stages of energy use.

There are strong energy and environmental reasons, for combined hydronic heating and DHW systems, to encourage the development and/or use of:

- Sustainable biofuels – B5 today, B10 in the near future and B20 as supply and technology permit
- ULS Diesel as it becomes available
- High efficiency non-condensing oil-fired boilers
- Condensing gas and oil-fired boilers

Care should be taken selecting policy approaches that provide either regulatory mandate or consumer incentive to change behavior that may foreclose future innovation. Eliminating oilheat dealers of today will also eliminate the B20 dealers of tomorrow.

March 4, 2013

Commissioner Daniel Esty
CT Department of Energy & Environmental Protection
79 Elm Street
Hartford, CT 06106-5127

Senator Bob Duff, Co-Chair
Representative Lonnie Reed, Co-Chair
Senator Clark Chapin, Ranking Member
Representative Laura Hoydick, Ranking Member
Energy and Technology Committee
Room 3900 Legislative Office Building
Hartford, CT 06106

Re: Draft 2012 Comprehensive Energy Strategy for Connecticut

Public Act 11-80, An Act Concerning the Establishment of The Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future §51, codified as §16a-3d of the General Statutes of Connecticut (Conn. Gen. Stat.) directed the Commissioner of the Department of Energy and Environmental Protection, in consultation with the Connecticut Energy Advisory Board to prepare a Comprehensive Energy Strategy (CES) plan. In that same statute, the Public Utilities Regulatory Authority (Authority or PURA) was tasked with commenting on the proposed plan's "impact on ratepayers."

The Authority appreciates the opportunity to comment on the draft CES. In the attached comments, the Authority does not attempt to argue the merits of the many issues addressed in the CES, but rather to assess the impact on ratepayers. As a regulatory and rate-setting authority, the PURA does not have broad authority to allow ratepayer funds to be used for non-utility related purposes. Ratemaking principles generally do not allow recovery of investment that is not currently used and useful. However, much of the CES is aimed at societal benefits and investing in the future. The PURA leaves those important issues to the wisdom of the Legislature.

In complying with Conn. Gen. Stat. §16a-3d(b) directing PURA to comment on the proposed plan's impact on ratepayers, the Authority interprets the directive as intended to measure the impact on ratepayers as ratepayers not the impact to the general citizenry.

Sincerely,

Kimberley J. Santopietro
Executive Secretary
PUBLIC UTILITIES REGULATORY AUTHORITY

cc: Mailing List

STATE OF CONNECTICUT

DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION
BUREAU OF ENERGY AND TECHNOLOGY POLICY

COMMENTS ON THE DRAFT COMPREHENSIVE ENERGY STRATEGY

FROM THE PUBLIC UTILITIES REGULATORY AUTHORITY

March 4, 2013

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PURA COMMENTS ON THE DRAFT COMPREHENSIVE ENERGY STRATEGY

EXECUTIVE SUMMARY

The draft Comprehensive Energy Strategy for Connecticut (CES) enumerates many societal goals and concurrently has the potential to cost ratepayers more for service than they currently pay. Many of the CES proposals rely on assumptions that must be closely reviewed to avoid uneconomic outcomes. In some instances, many costs are not considered when evaluating the appropriateness of investment, and details are not provided to support conclusions.

The PURA addresses the impact that the CES will have on the general body of ratepayers or non-participants who are unable to, or choose not to, participate in any of the initiatives. One of the aims of the CES is to lower utility bills for Connecticut residents and businesses. In the long term, such reductions may be possible, but in the near term, the effects of the CES and other factors, such as normal utility rate increases, system hardening and resiliency expenditures, storm response expenses and New England electric transmission expansion expenditures that also impact ratepayer bills will be to increase rates. The general body of ratepayers would provide funding to subsidize programs that target individuals' specific energy use, and would be assigned the risk if the initiatives do not meet projections. Notwithstanding the above, the number of variables going forward that could affect the PURA's analysis makes any prediction of future savings for the non-participants speculative.

Due to the unprecedented, large number of electric and gas programs scheduled to begin almost simultaneously, the Public Utilities Regulatory Authority (Authority or PURA) can only properly assess ratepayer impact by viewing the CES as a single program and recognizing the many concurrent electric initiatives that ratepayers may be required to fund. The CES programs are not the only drivers that will place upward pressure on utility rates as stated above.

The OCC supported a comprehensive cost evaluation as well. It requested that the DEEP engage in an analysis of the impact on bills of all of the various programs and initiatives that are on the horizon, rather than evaluating each in isolation.[1] As concrete initiatives come before the PURA, it will review and decide upon proposals that will have specific ratepayer impact. The Authority provides the following points on the major issues discussed in the CES that will have an impact on the electric distribution companies' (EDCs) and gas local distribution companies' (LDCs) ratepayers.

- The EDCs and LDCs proposed three-year Conservation and Load Management (C&LM) budgets totaling $1.246 billion, which would be reflected in ratepayers' monthly bills if approved. See, Section III.A. Conservation Budgets and Programs.

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[1] OCC December 21, 2012 Written Comments concerning the draft 2012 Comprehensive Energy Strategy, p. 9.

- The CES stated that ratepayers cannot indefinitely support the bulk of energy efficiency program budgets. Energy efficiency proposals should center on a shift from a reliance on ratepayer funding to one that has a much greater focus on private capital leveraged by limited government funding, which lessens the impact on public utility rates. See, Section III. Energy Efficiency Strategy.

- The CES stated that bill financing must have enforcement mechanisms that lower lenders' risks. With or without enforcement mechanisms, on-bill financing may have the potential to increase uncollectible accounts that would affect the general ratepayer rates. Service termination, as a part of these programs, should be limited to what is contained in current statutes related to non-payment. See, Section III.D. Upfront Capital Outlay.

- The CES suggested that landlords may be reluctant to participate in the state's energy efficiency programs if their properties have health and safety-related code violations, such as asbestos, mold, or "knob-and-tube" electric wiring. These code violations would have to be remedied before a home energy audit could be performed. Although the details of any such program are not stated in the CES, the PURA is concerned with the potential of ratepayer funds being used to remedy landlord code violations. See, Section III.D. Upfront Capital Outlay.

- Connecticut has the highest renewable portfolio standards (RPS) and the least renewable sources of any New England state. The CES recommended a rapid expansion of in-state renewable power. Additional renewable sources of energy are likely to raise costs and ultimately rates as a result of the subsidies that are given to renewables. See, Section IV.B. Renewable Power.

- The proposed expansion of an estimated 900 miles of new gas mains to the LDCs' distribution systems and the addition of 305,000 new firm customers would be a 53% increase in customers. Such growth is in contrast to the LDCs' addition of 57 miles of main in 2012 and the average growth rate over the past seven years of approximately 1.1% per year. See, Section V. Natural Gas Expansion Plan.

- The LDCs stated that the implementation of the CES's proposed gas expansion plan could not be done without increasing customer rates or charges. See, Section V. Natural Gas Expansion Plan.

- For the proposed off-main customer expansion, the average capital cost to connect one new off-main customer would be $16,180, which is approximately four times higher than the CES estimated cost of $4,283. See, Section V.B. Off-System Capital Investment – Segment B.

- The Authority conducted its own analysis and compared today's average distribution-only bill for all three LDCs combined with the average bill that would exist for all 883,890 customers in year seven. The increase in the average distribution-only bill would be 37%. See, Section V.C.3. Increase to Average Distribution-Only Bill.

- The substantial proposed expansion of the natural gas system could result in an additional increase of $2.26 billion in rate base and may not occur without funding from all natural gas ratepayers and potentially all state residents. Historically, the Authority has made every effort to prevent subsidies between customers and customer classes including minimizing existing ratepayers being responsible for reducing the cost to connect new customers. See, Section V.C.2. Revenue Requirements.

- It is premature to provide a full revenue requirement calculation for the estimated $813 million cost to provide services to 177,000 potential new on-main customers and for the estimated $1.4 billion cost to provide services to 89,000 potential new off-main customers. However, the LDCs estimated that the additional annual revenue requirement associated with the proposed on-main expansion is approximately 20% of the additional annual rate base amount. Hence, the LDCs calculated an estimated peak annual revenue requirement of approximately $163 ($813 x 20%) million for the on-main expansion and approximately $288 ($1,400 x 20%) million for the off-main expansion. See, Section V.C.2. Revenue Requirements.

- At present, there are not enough construction crews in Connecticut to implement the proposed expansion plan as described in the CES. The LDCs indicated that it could take a year to train new construction crews plus contractors from outside the state want long-term contracts before committing to a project. During 2012, the three LDCs installed a total of 57 miles of mains for new business and 6,250 services. The Authority estimates that the LDCs would need to add approximately 200 new crews to install the 900 miles of new main and 305,000 services, which would increase cost and impact ratepayers. See, Section V.C.4. Construction Crews.

- Under the proposed expansion plan, the minimum estimated incremental capacity required to meet the increased demand for 305,000 new customers would be approximately 280,000 Mcf and cost an additional estimated $91 million annually for which all existing ratepayers would be responsible. See, Section V.D. Gas Supply.

- To the Authority's knowledge, the LDCs have not had any reliability issues in the recent past, and it only becomes an issue when a LDC does not have enough peak day supply to meet existing firm demand or uses interruptible supply to meet firm load. See, Section V.D.3. Reliability of Natural Gas.

- Electric reliability issues related to large gas-fired generators in New England have occurred in the recent past due to interruptible gas supply being used by a number of generators instead of firm supply to produce electricity. These issues currently are being discussed in the Federal Energy Regulatory

Commission's Docket AD12-12-00, Coordination between Natural Gas and Electric Markets. See, Section V.D.3. Reliability of Natural Gas.

- Some of the CES's proposals would result in an increase in pipeline demand charges, a reduction in non-firm margins (NFMs), and a $5 month additional distribution charge. The proposed 87% decrease in NFM to subsidize the addition of the new customers would result in a $35.5 million increase in the gas costs for all ratepayers based on 2012 data. These specific proposals would result in an increase of $18.18 to $27.62 for one specific month for an average residential customer. See, Section V.D.5. Impact of Certain Items on All Natural Gas Ratepayers.

- The total estimated cost for the connection of the proposed Segment B, 89,000 off-main customers is $2.04 billion, which does not include any other costs such as system costs, operation and maintenance costs, gas costs, and administrative costs. At the completion of the expansion, the estimated cost of connecting a new residential heating customer would be $15,126 and for a large C&I 75 kW co-generator, $2.8 million. See, Section V.E. Segment B – 89,000 Customers.

The CES focused on strategies for energy efficiency, renewable power, industrial energy needs, electric supply, natural gas, and transportation. The PURA issued discovery requests to the EDCs and the LDCs in an effort to evaluate the CES proposals and the impact on ratepayers. Answers to these discovery requests were the subject of technical meetings held on January 28, 2013 and January 29, 2013. During the Authority's review of the information provided by the utilities, it became apparent that the ability to quantify individual program costs with precision is limited. The totality of program costs will need to be understood before funding is advanced for individual programs. The Authority provides comments on the impact on ratepayers regarding all of these areas and, in particular, the natural gas expansion plan.

PURA COMMENTS ON THE DRAFT COMPREHENSIVE ENERGY STRATEGY

I. ENERGY EFFICIENCY STRATEGY

The CES contemplated substantial increases in energy efficiency spending for all customer sectors.[2] The effectiveness of any expended conservation dollars must be evaluated through proper cost benefit analysis to ensure that customers are receiving greater benefits on conservation programs. The Authority agrees that the energy efficiency proposals should center on a shift from a reliance on ratepayer funding to one that has a much greater focus on private capital leveraged by limited government funding.[3] The PURA assumes that the more expensive options that would either involve taxpayer funds or result in unacceptably high rates will not proceed. The Authority notes that The Connecticut Light & Power Company (CL&P) asserts that the five proposals in the CES, if implemented, may affect the reliability of the CL&P electric distribution system. In addition, CL&P argues that all of its distribution system customers should not subsidize the costs to provide premium reliability service to a select few customers and/or municipalities.[4] While additional conservation, if successfully implemented, could lower bills, the PURA's recent experience indicates that this has not occurred.

Finally, the Authority agrees with the OCC that over the next three years, electric bills paid by Connecticut's EDC customers will experience upward financial pressure from many different sources. These include a wide range of renewable energy project initiatives under development, system hardening and resiliency expenditures, storm response expenses, additional investments in electric transmission system projects throughout New England, potential distribution rate increases, and over-market purchased power contracts for new gas-fired generating facilities. According to the OCC, these initiatives are estimated to increase overall electric rates for Connecticut customers by a total of $1 billion for the period 2013 to 2015, yet they do not appear to be factored into the DEEP's analysis in the Efficiency Sector of the CES.[5]

A. CONSERVATION BUDGETS AND PROGRAMS

On November 2, 2012, the EDCs and the LDCs filed their respective proposed three-year conservation budgets in the Connecticut Energy Efficiency Fund's Conservation and Load Management Plan for 2013 through 2015 (C&LM Plan).[6] The three-year CL&M Plan contains two related yet distinct plans comprised of two different levels of proposed funding, a Base Plan and an Expanded Plan. The Base Plan reflected the standard three-year budgets and savings associated with the traditional

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[2] CES, p. 11.

[3] CES, p. 13.

[4] CL&P Response to DR-61, pp. 1-3.

[5] OCC Comments, pp. 8 and 9.

[6] Docket No. 12-11-04, PURA Review of the Connecticut Energy Efficiency Fund's Gas Conservation and Load Management Plan for 2013 through 2015.

funding, and the Expanded Plan described increased funding levels.[7] On February 25, 2013, the EDCs and LDCs refiled the entire C&LM Plan with certain revisions that increased the combined three-year budgets by $11.7 million. For the next three years, the EDCs proposed a combined Base Budget of $307 million, an Expanded Budget of $743 million, and a total budget of $1.1 billion. The LDCs proposed a combined Base Budget of $72 million, an Expanded Budget of $124 million, and a total budget of $196 million. The proposed total EDC's and LDC's conservation budgets over the next three years is $1.246 billion. The following is a breakdown of the EDCs and LDCs proposed base and expanded budgets for the next three years.

EDCs REVISED PROPOSED COMBINED BUDGETS

Year	Base Budget	Expanded Budget	Total Per Year
2013	$101,454,742	$195,432,432	$296,887,174
2014	$102,275,794	$246,142,964	$348,418,758
2015	$102,838,953	$301,745,735	$404,584,688
Totals	$306,569,489	$743,321,131	$1,049,890,620

LDCS REVISED PROPOSED COMBINED BUDGETS

Year	Base Budget	Expanded Budget	Total Per Year
2013	$24,118,792	$37,422,835	$61,541,627
2014	$23,539,159	$41,962,303	$65,501,462
2015	$24,061,516	$45,038,883	$69,100,399
Totals	$71,719,467	$124,424,021	$196,143,488

C&LM Plan, pp. 24, 93, 320, & 397.

Funding for conservation programs currently allowed to be recovered in customer rates include only the base budget amounts approved for 2012. Base levels for electric C&LM are funded through a 3 mill / kWh charge on CL&P and The United Illuminating Company (UI) customers' bills. Natural gas expenditures are funded through a conservation adjustment mechanism (CAM) imposed on Connecticut Natural Gas Corporation (CNG), The Southern Connecticut Gas Company (Southern), and Yankee Gas Services Company (Yankee) customers.

The proposed expanded portion of electric C&LM funding represents a 243% increase above base spending. Below is an illustration of the annual impacts under average levels of consumption for various rate classes. This impact is at the base proposed levels of electric C&LM spending for CL&P and UI customers.[8] The CES estimated that all cost-effective spending could be approximately $327 million annually, an increase of $65 million above the total proposed base and expanded budget through

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[7] C&LM Plan, pp. 1 and 2.

[8] Id.

2022.[9] Approximately $22 million is funded from sources other than the 3 mill / kWh charge.[10] These additional funding sources are held constant and removed from the total in determining a going forward conservation charge. As the current 3 mill / kWh charge is set to generate approximately $84 million, an increase to $271 million ($327 million - $22 million of other funding - $34 million natural gas conservation) would represent a 223% increase in the mill rate. Below are the annual and 10-year projections under the all cost effective scenario, which equates to a rate of $.00969 / kWh.

All Cost Effective Budget Conservation Contributions from CL&P Customers

A	B	C	D
Customer type or class	**Average Annual 2011 Consumption (kWh)**	**Annual Conservation Contribution (B * $.00969 kWh)**	**2013-2022 Conservation Contribution (C * 10 yrs)**
Residential Customers			
Income Eligible	9,665	$93.56	$935.57
Electric Service	8,610	$83.34	$833.45
Electric Heating	13,215	$127.92	$1,279.21
Time of Use/Day	12,750	$123.42	$1,234.20
C&I Customers			
Average C&I	Not Provided	Not Provided	Not Provided
High C&I (actual usage)	126,422,308	$1,223,697.94	$12,237,679.41

2012 Electric C&LM Decision, p. 9.

All Cost Effective Budget Conservation Contributions from UI Customers

A	B	C	D
Customer type or class	**Average Annual 2011 Consumption (kWh)**	**Annual Conservation Contribution (B * $.00969 kWh)**	**2013-2022 Conservation Contributions (C * 10 yrs)**
Residential Customers			
Income Eligible	6,726	$65.11	$651.08
Average Residential	6,804	$65.86	$658.63
Time of use	13,028	$126.11	$1,261.11
C&I Customers			
Low use C&I	30,942,000	$299,518.56	$2,995,185.60
Average C&I	60,048,748	$581,271.88	$5,812,718.81
High C&I	120,229,255	$1,163,819.19	$11,638,191.88

Id.

The 2012 base and expanded budgets for the natural gas conservation programs are listed below. Charges for natural gas conservation under the CAM are determined by an approved natural gas conservation budget spread over the forecast sales for which the budget will be in place. The percentage increase listed below reflects the CAM line item increases for the expanded budget by rate class.

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[9] CES, p. 11.

[10] Decision dated August 8, 2012, Docket No. 12-02-01, PURA Review of the Energy Efficiency Fund's Electric Conservation and Load Management Plan for 2012 (2012 Electric C&LM Decision), p. 7

Yankee	Base	Expanded Budget	% Increase
Residential	$3,814,000	$ 6,198,359	63%
C&I	$2,850,000	$ 6,257,075	120%
Administrative	$ 394,500	$ 591,750	50%
Total	$7,058,500	$13,047,184	85%

CNG	Base	Expanded Budget	% Increase
Residential	$3,371,172	$ 5,556,820	65%
C&I	$2,350,000	$ 4,555,751	94%
Administrative	$ 355,500	$ 533,250	50%
Total	$6,076,672	$10,645,821	75%

Southern	Base	Expanded Budget	% Increase
Residential	$3,436,803	$ 5,993,173	74%
C&I	$2,200,000	$ 3,984,561	81%
Administrative	$ 355,500	$ 533,250	50%
Total	$5,992,303	$10,510,984	75%

Decision dated January 4, 2012, Docket No. 11-10-03, PURA Review of the Connecticut Energy Efficiency Fund's Gas Conservation and Load Management Plan for 2012, pp. 6 and 7.

The CES proposed a dedicated surcharge on fuel oil prices to fund oil efficiency programs that increase efficiency for oil customers. Under this proposal, customers that are on-main and do not fully convert to natural gas (non-heating only), would be subject to three conservation charges (electric, natural gas and fuel oil). This is noteworthy as there are approximately 63,000 non-heating customers among the three LDCs.

B. FINANCING ENERGY EFFICIENCY INVESTMENTS

The CES indicated that a critical element of the energy efficiency proposals centers on a shift from a reliance on ratepayer funding to one that has a much greater focus on private capital leveraged by limited government funding.[11] The Authority endorses the concept of this shift, especially in light of an estimated 262% increase in spending that the CES endorsed. More private capital included in financing energy efficiency will lessen the effect on public utility rates. Over time, this initiative should allow ratepayer funding to be scaled back. The CES also advocated regulatory changes in the PGA credit sharing. Specifically, the allocation of PGA credits would be for an interest rate buy-down to bring customer financing rates to 1% instead of being used to reduce rates generally.[12]

Presently small business owners can receive loans for efficiency upgrades from the utilities at ratepayer-subsidized interest rates. The loans are then paid back on utility bills with no enforcement mechanisms, such as the ability to shut off service to

[11] CES, p. 13.

[12] CES, p. 139; Response to DR-31.

customers who default on the loans.[13] Alternative financing, and the concurrent decrease in ratepayer funding should be included in the planning horizon.[14] Failure to specify the amount and sources of future financing will not allow market players to plan effectively and may create a market expectation of continuous ratepayer funding that will prove difficult to reverse later. The best way to ensure consistent funding for energy efficiency is to diversify the revenue sources that support them. Further, the CES stated that ratepayers cannot indefinitely support the bulk of energy efficiency program budgets.[15]

C. HOME ENERGY SOLUTIONS PROGRAM

The CES stated that of the 951,000 customers eligible for the Home Energy Solutions Program (HES Program), only 74,000 residents have participated since 2007.[16] There is a need to review the goals, incentives, and ratepayer benefits of efficiency programs prior to expansion of the HES Program to ensure efficient use of current ratepayer funding. Any type of program should ensure that customers are not being oversold on the benefits of conversion and understand all of the ramifications and costs of a changeover.

The CES indicated that the HES program has over-rewarded companies that can perform the initial audits en masse. The CES recommended that a scorecard be developed to evaluate contractor performance, tested and refined to make it as effective as possible.[17] The PURA is concerned that financial rewards to contractors are linked to the number of customer conversions that are achieved. Any over-rewarding of contractors would result in an increase in conservation expenses, impact the cost benefit analysis, and ultimately ratepayers through higher rates.

D. UPFRONT CAPITAL OUTLAY

The CES concluded that the major barrier to customers seeking deeper efficiency measures is the upfront capital outlay. For residents who heat with oil, converting to more energy-efficient less expensive natural gas has an average residential cost of $7,500. Conn. Gen. Stat. §16a-40l directs the DEEP to establish residential heating equipment financing through on-bill financing or by other means. The CES stated that bill financing must have enforcement mechanisms that lower lenders' risks.[18] This suggestion questions the effectiveness of utility company enforcement mechanisms. With or without enforcement mechanisms, on-bill financing may have the potential to increase uncollectible accounts that would affect the general ratepayer rates. The OCC disagrees, for consumer protection reasons, with allowing utility shut-offs for nonpayment of loans.[19] The PURA believes that service termination,

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[13] CES, p. 25.
[14] OCC Comments, p. 7.
[15] CES, p. 6.
[16] CES, p. 21.
[17] CES, pp. 21 and 29.
[18] CES, p. 30.
[19] OCC Comments, p. 2.

as a part of these programs, should be limited to what is contained in current statutes related to non-payment.

The CES suggested that landlords may be reluctant to participate in the state's energy efficiency programs if their properties have health and safety related code violations, such as asbestos, mold, or "knob-and-tube" electric wiring. These code violations would have to be remedied before a home energy audit could be performed.[20] Although the details of any such program are not stated in the CES, the PURA is concerned with the potential of ratepayer funds being used to remedy landlord code violations.

II. ELECTRICITY SECTOR STRATEGY

A. DECREASED ELECTRIC PRICES

The CES noted that a number of factors have decreased prices for electric consumers.[21] One is a large decline in the price of natural gas coupled with the fact that 45% of the generation mix in Connecticut is gas-fired. A smaller portion of the decrease is due to the expiration of the recovery of stranded costs by the Competitive Transition Adjustment/System Benefit Charge. The reduction in current electric prices should not be seen as a permanent reduction.

The largest factor in the current electricity price decrease in natural gas commodity price subject to volatility. The cost of gas is projected to increase by 2017.[22] Therefore, the current electric price decrease should not be treated as "found money" for other programs. This cushion should be preserved, as any other approach would have a significant impact on consumers when commodity prices increase as expected. The OCC argued that the "all-in" price for electricity paid by customers may have already ebbed, even adjusting for inflation.[23]

B. RENEWABLE POWER

Connecticut has the lowest amount of renewable resources of any New England state and the highest RPS standards. Under the current structure, entities serving Connecticut's load routinely fail to meet the current RPS goal. The CES called for a rapid expansion of in-state renewable power while also supporting a regional collaboration to procure the most cost-effective out-of-state renewable resources.[24] Additional renewables sources of energy are likely to raise costs and ultimately ratepayer rates and bills as a result of the subsidies given to renewables. The process of rapidly expanding in-state renewable power is costly given Connecticut's limited renewable resources. A comprehensive and impartial cost-benefit analysis should precede any further ratepayer commitment to renewable energy projects to ensure that the estimated impact on customers is understood prior to investment in a strategy.[25]

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20 CES, p. 32.
21 CES, p. 74.
22 CES, p. 81.
23 OCC Comments, p. 26.
24 CES, p. 82.
25 UI Response to DR-62.

Based on the potential availability of renewable resources in Connecticut, the fact that consideration is being given to raising the RPS target above the current 20% target by 2020 is of concern.

The potential cost impact that pursuing wind and solar resources would have on ratepayers needs to be assessed. The potential for in-state wind generation is limited since Connecticut lacks the geographic characteristics of Northern Maine, New Hampshire, and Cape Cod. In 2012, the Authority established a $1 billion zero emissions REC (ZREC) and a low emissions REC (LREC) program.[26] Concerning the ZREC portion of that program, solar only has a load factor in the 15% to 17% range. The CES stated that "[u]nless regional development of renewable resources and enabling transmission accelerates, Connecticut customers could face Alternative Compliance Payment (ACP)[27] obligations of more than $250 million (in 2012 dollars) annually by 2022 under the structure of the existing RPS."[28] All else being equal, increasing the RPS would only increase these obligations.

C. Nuclear and Natural Gas Generation

The CES pointed to Connecticut's reliance on nuclear (47%) and natural gas (45%) generation, which accounts for 92% of the current electric generation. While these sources meet current needs, this limited diversification in generation exposes the state to both price and reliability risks.[29] The CES called for an electricity sector that has greater flexibility, more diverse sources of supply, a higher use of renewable energy and a commitment to capacity increases in step with demand growth. Connecticut is part of a regional wholesale market, so diversity is viewed as a regional and state issue. There is no dispute that these are worthy goals; however, achieving these goals in unison may prove to be difficult and costly. Increased flexibility, diversity of resources and a higher use of renewables will likely not lead to reduced electricity costs.

The CES pointed to potential price spikes in natural gas as being problematic.[30] Potential price spikes have implications for the natural gas build-out and customer conversion program that the CES contemplates. Additionally, potential price spikes and the effect that they may have on the projected customer savings are of major concern from a ratepayer perspective. Natural gas price volatility has the potential to be the single largest factor affecting ratepayers due to its significant impact on customers' bills.

D. Clean Energy Resources

The CES stated that regional coordination and federal regulation to phase out dirty power plants within and beyond the state's borders are needed to address

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[26] See, Decision dated April 4, 2012 in Docket No. 11-12-06, Joint Petition by The Connecticut Light and Power Company and The United Illuminating Company for Approval of the Solicitation Plan for the Low and Zero Emissions Renewable Energy Credit Program.

[27] The ACP is a penalty to be paid by ratepayers in the event that the 2020 goal is not met.

[28] CES, p. 82.

[29] CES, p. 82.

[30] CES, p. 115.

Connecticut's air quality issues effectively.[31] They will, however, come at a price of higher rates to ratepayers. Matching the benefits with the costs is critical.

1. Landlord Generation and Sale of Electricity

The CES recommended that the state allow "submetering" of electricity produced on site by a landlord in a multi-tenant building. The arrangement described in the CES is a limited case of submetering.[32] More generally, submetering is the practice of a landlord individually metering the electric usage in a multi-tenant building, regardless of who supplies the electricity, with a master meter installed by the electric utility. A master meter measures the electric usage of the entire premises. Billing of each tenant is based on the billing rate for the electricity consumed, and a landlord may not charge more for electricity than the utility rate applied to all consumption metered at the main meter. Unless safeguards are put in place, electric submetering could be harmful to tenants of buildings. It sets up a monopoly arrangement, whereby landlords may charge tenants excessive rates for electricity, subject to minimal protection or intervention from a regulatory authority. The tenants cannot opt out of such an arrangement, choose an alternate electric supplier, or participate in utility-sponsored conservation programs, since they are not utility customers.

2. Financial Implications of CES on EDC Ratepayers

The cost of equity was an important consideration in the CES because it affects the utility service rates paid by all customers. One of the risks affecting equity costs and typically faced by EDCs is the volatility of sales revenues. The EDCs' sales revenues are negatively affected through lost revenues resulting from conservation and load management measures. To mitigate the loss of revenues by the EDCs due to expanded conservation and load management, the CES advocates decoupling. Decoupling is a regulatory mechanism that enables a utility to recover its allowed costs even as sales decline due to efficiency gains.

In 2009, the Authority established a decoupling mechanism for UI on a pilot basis that provides for the difference between the actual revenue collected as compared to the allowed revenue set by the Authority to be trued up in an adjustment mechanism.[33] For CL&P, the Authority implemented decoupling through rate design in 2007 and then denied full decoupling in 2010.[34] The unanticipated loss of revenues from increased conservation reduces expected returns and may be perceived by investors as an increase in risk. UI and CL&P argued that their ROEs should reflect this increase in risk and called for higher allowed ROEs in their respective rate cases, all other factors held constant. However, all other factors are usually not held constant. The key considerations are whether energy efficiency investments increase or lessen revenue volatility, whether the expected loss in revenues is accounted for in setting rates, and

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[31] Id.

[32] CES, p. 107.

[33] Decision dated February 4, 2009, in Docket No. 08-07-04, Application of The United Illuminating Company to Increase Its Rates and Charges.

[34] Decision dated January 28, 2008, in Docket No. 07-07-01, Application of The Connecticut Light and Power Company to Amend Rate Schedules, and Decision dated June 30, 2010, in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules.

whether revenue volatility is mitigated through rate design or true-up mechanisms. Increases in required ROEs should be avoided, as they equate to higher rates for customers.

III. NATURAL GAS EXPANSION PLAN

The CES proposed an expansion of an estimated 900 miles of new gas mains to the LDCs' distribution systems and the addition of 305,000 new firm customers consisting of on-main customers (Segment A, 216,000) and off-main customers (Segment B, 89,000).[35] The proposed expansion represents a 53% increase in customers over the LDCs' December 31, 2011 578,890[36] existing meter/customer base. That growth is in contrast to the LDCs' addition of 57 miles of main in 2012 and the average growth rate over the past seven years of approximately 1.1% per year. Given its size, the proposed expansion could have a significant impact on all gas ratepayers depending on how much of the expansion needs to be subsidized by existing ratepayers. It is estimated that 250,000 dekatherms of incremental capacity will be needed to provide service to these new customers.[37] Existing ratepayers may end up being responsible for the cost of this capacity before new customers are connected to the system. The cost of the incremental capacity is currently unknown. Adequate gas pipeline capacity is both a short- and long-term issue and may not be available in quantities to support the scope of the proposed expansion plan.

After the CES plan is approved, the LDCs plan to file a joint plan that proposes to expand natural gas conversion activities over the next seven years targeting cost-effective potential on- and off-main customers. The plan would be developed in consultation with the DEEP and submitted to the Authority for approval.[38]

A ON-MAIN CAPITAL INVESTMENT – SEGMENT A

The CES stated that the LDCs estimated that there are about 177,000 homes and businesses in Connecticut located on-main that currently have no gas service. In addition, that there are 39,000 non-heating gas customers that have the potential to convert to heating. The non-heating customers will have the same overall conversion costs as the "on main" customers (e.g., for equipment replacement); however, the gas companies incur little to no distribution infrastructure costs when the customer converts. It appears that the CES used for purposes of its analysis, 216,000 (177,000 + 39,000) new Segment A customers, 89,000 Segment B customers for a total of 305,000. In reading this portion of the CES plan, the Authority used the plan's assumption of 305,000 new customers. These numbers do not match the customer numbers presented by the LDCs. The CES calculated the estimated cost to convert 216,000 Segment A customers to be approximately $815 million.[39]

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[35] CES, pp. 5, 124-126;

[36] The LDCs' latest meter count was 578,890 (CNG, 173,217; Southern, 193,362; and Yankee, 212,311) as of December 31, 2011. CNG, Southern, Yankee FERC Form 2. While some customers have more than one meter, the billing is the same as if each meter was another customer.

[37] Response to DR-15.

[38] CES, p. 138.

[39] CES, pp. 123-126; Response to DEEP Questions, dated August 17, 2012, p. 1, Table.

The Authority analyzed the potential rate impact on existing ratepayers associated with the 216,000 on-main Segment A customers. The CES defined a new firm residential on-main customer as one that is located within 150 feet from an existing natural gas main. Under this assumption, no main extension would be needed to convert these customers to natural gas. The CES further estimated that the average cost for service and meter installations would be $4,283 for a new residential customer, $7,669 for a commercial customer and $11,504 for an industrial customer.[40]

Under the LDCs' proposal, any residential customer within 150 feet of an existing main would be considered an average customer. The Hurdle Rate[41] would not be used for that customer even if a short extension of new main were required to connect them to the existing system.[42] It is unclear how the LDCs define this distance. One interpretation is that the length of pipe put in the ground to serve the customer must be no longer than 150 feet. Another is that the 150 feet is the linear distance in a straight line from the main to the home across a customer's property. In the latter case, the actual length of new main plus the service could be greater than 150 feet, while the wording of the definition is still met. The definition of whether an average new customer is within 150 feet of an existing main must be clear and unambiguous. It specifically should indicate whether 150 feet from an existing main is for the length of a service or new main plus the service length. Depending on how the 150 feet is defined, the total cost to provide service to a customer would be higher or lower ultimately affecting the capital cost of serving that customer.

B OFF-SYSTEM CAPITAL INVESTMENT - SEGMENT B

The CES cited a Department of Economic and Community Development (DECD) study that indicated there was a potential of 89,000 new off-main customers (Segment B) within Connecticut.[43] The DECD study stated that the LDCs would have to add almost 900 miles of new natural gas mains during two, five-year periods.[44] The Authority developed the analysis below showing the potential impact to ratepayers associated with the expansion plan for the off-main customers cited in Segment B.

For the cost per mile of off-main, the CES used different numbers than those provided by the LDCs. The CES estimated the capital cost to add 89,000 customers to be approximately $1.44 billion. This number includes $926 million for the 900 miles of new distribution mains over a seven-year period and $512 million for services and meters.[45] Based on the Segment B total capital investment of $1.44 billion, the Authority calculated the average cost per new off-main customer of $16,180 ($1.44 billion / 89,000 new customers). This cost is approximately four times higher than the

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40 CES, pp. 121 and 124.

41 The Hurdle Rate is a calculation whereby the gas company would invest (and then recover from existing ratepayers) the costs of expanding the distribution system to add a new customer if the expected increase in revenues from supplying natural gas to the new customer is sufficient to recover both the costs and the associated utility rate of return over a specific period of time.

42 Tr. 1/29/13, pp. 459-465.

43 In 2011, Connecticut's LDCs commissioned the DECD to produce a study of The Economic Impact of Expanding Natural Gas Use in Connecticut.

44 CES, p. 128.

45 CES, pp. 122, 126; Response to DEEP Questions, dated August 17, 2012, p. 2.

CES estimated cost of $4,283 for a new on-main customer. As with all capital investments, the LDCs' shareholders initially fund those costs in excess of the contribution-in-aid-of-construction (CIAC). Subsequently, each LDC could request, in a future rate case, recovery from ratepayers for such items as their capital investment through the rate of return (ROR) on rate base, depreciation, and taxes on the $1.44 billion associated with the addition of 89,000 customers.

C. IMPACT OF THE EXPANSION ON RATEPAYERS

1. Rate Base

The CES estimated the total proposed cost for Segments A and B customers to be $2.26 billion ($815 million for on-main new customers + $1.44 billion for off-main new customers). This amount does not include any expansion costs upstream of the new customers or peaking facilities that may be necessary to support the addition of the new customers. CNG and Southern have preliminary information concerning the expansion of the LNG facilities; however, neither company has issued bidding documents for the project. CNG and Southern believe the expansion is economical but will not have a reasonable cost estimate until bids have been received from contractors.[46]

As of December 31, 2011, the LDC total rate base numbers for Mains, Services, Meters, and Meter Installations accounts was $2.08 billion as stated in their annual reports.[47] Acceptance of the CES' proposed expansion plan would result in an additional increase of $2.26 billion in rate base. This increase would more than double the LDCs' latest rate base of $2.08 billion for a total plant investment in those accounts of $4.34 billion at the end of seven years. The $4.34 billion does not include any other plant additions occurring during the seven–year period. Finally, the CES did not provide a breakdown of the capital investment cost between services and meters. Therefore, it is unclear if the capital investment associated with meter installations was included in the CES capital investment for Segments A and B. If it was not included, the capital investment amount would be higher, increasing the revenue requirement and consequently increasing rates.

As part of the expansion plan, the CES recommended that the Hurdle Rate payback period be increased to 25 years for the three LDCs. Expanding the Hurdle Rate payback period would increase the rate base funded by the gas companies and ultimately their general ratepayers by approximately $339 million.[48] Any increase in the payback period for the Hurdle Rate needs to be fully analyzed to determine whether it is cost effective and the potential impact to the new customer and existing ratepayers.

2. Revenue Requirements

a. LDCs' Analysis of Potential Impacts on Ratepayers

[46] Tr. 1/29/13, p. 407.

[47] 2011 CNG; Southern and Yankee Federal Energy Regulatory Commission Forms No. 2, p. 209.

[48] CES, p. 143.

The LDCs stated that it was premature to provide a full revenue requirement calculation for the estimated $813 million cost to provide services to 177,000 potential new on-main customers and for the estimated $1.4 billion cost to provide services to 89,000 potential new off-main customers. Currently, they do not have detailed costs, such as depreciation, related O&M, property taxes, uncollectible expense and the tax treatment associated with this potential expansion plans. However, the LDCs estimated that the additional annual revenue requirement associated with the proposed on-main expansion is approximately 20% of the additional annual rate base amount. Hence, the LDCs calculated an estimated peak annual revenue requirement of approximately $163 ($813 x 20%) million for the on-main expansion and approximately $288 ($1,400 x 20%) million for the off-main expansion. Additionally, the LDCs are unable to determine the level of subsidization required from existing customers because they have not determined the overall revenue requirement and corresponding rate design. Nevertheless, they indicated that the substantial expansion of the natural gas system envisioned in the CES may not occur without some funding from all gas ratepayers and potentially all state residents through taxes and bonding. The LDCs stated that they agree with the CES that the recovery of the revenue requirements, the returns of and on capital investment, depreciation expense, associated incremental O&M costs, uncollectible expense, income and property taxes, associated with the expansion plan should be done in a timely manner and set via a fully reconcilable annual tracker.[49]

To recover the estimated $1.4 billion for the off-main expansion, the LDCs recommended a new rate design with two different rate components. First, a Shared Savings Rate (SSR) for new customers in the form of either current distribution rates increased by a pre-determined percentage, or an increased monthly customer charge, an increase on the volumetric charge or a combination of the two. Second, any revenue requirement dollars not collected through the SSR would be collected monthly from all existing customers through a new System Expansion Rate (SER). The proposed SER would be reviewed annually, trued up at the end of the expansion program, and have a duration linked to the size of the program.[50]

The allocation of the revenue requirement between the new and existing gas customers would depend on factors such as the size and cost of the program, the level of SSR revenues from the new customers, the potential impact on existing ratepayers and the price differentials between gas and fuel oil. The LDCs plan to submit their detailed proposal as part of the expansion plan filing subsequent to the issuance of the final CES.[51] The LDCs stated that the implementation of the gas expansion plan could not be done without increasing customer rates or charges. The significant expansion required by the CES plan is different from that allowed under normal rate regulations. For this reason, the LDCs are proposing the SSR and SER to help fund the Segment B expansion.[52]

The LDCs provided the calculations depicted in the table below to show the potential impacts of the natural gas pipeline expansions proposed in the CES on

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[49] Response to DR-26, pp. 1 and 2.
[50] Response to DR-35.
[51] Response to DR-35.
[52] PURA's Technical Meeting, Tr. 01/29/2013, pp. 492 and 493.

existing ratepayers.[53] The gas companies emphasized that these calculations represent a high-level estimate and are based on highlighted assumptions. Thus, changes to those assumptions will change the results. Furthermore, the LDCs noted the rate impact represents the peak revenue requirements during the expansion period.

As the expansion is executed, it will take several years before reaching this peak level, and once the peak level is reached, rates will start to decline. For example, under the seven-year expansion program, the revenue requirement will grow in each of the first years, reach its maximum level in the final seventh year of the capital expansion and then decrease over the remaining life of the expansion investments. The reason that the revenue requirement will decline beyond the peak year is that depreciation reduces the net plant value and related required return. Additionally, the potential ratepayer impact will wane over time as additional expansion volume and revenue make an increasing contribution toward the declining revenue requirement beyond the peak year. Thus, over the life of the assets, on a levelized basis, the impact on existing ratepayers will be substantially lower than for the peak year period.[54] The following is the table provided by the LDCs where "Res" stands for residential customers, "Comm" commercial customers, and "Ind" industrial customers.

[53] Response to DR-68, p. 3.

[54] Id., pp. 1 and 2.

Main Expansion Costs - Rate Impact

ITEM	Res		Comm		Ind		Total	
Gross capital investment - meter & services ($ in millions)							$	1,323
Services adjustment								90%
Net capital investment - meter & services ($ in millions)							$	1,191
Gross off-main capital investment - mains ($ in millions)							$	926
Economies of scale assumption								5%
Net off-main capital investment - mains ($ in millions)							$	880
Total off-main capital investment ($ in millions)							$	2,070
Peak annual revenue requirements assumption								20%
Peak annual revenue requirements ($ in millions)							$	414
Off-main customer additions (by end of expansion plan)		51,506		37,333		539		89,378
On-main customer additions (by end of expansion plan)		160,852		15,585		569		177,006
New customer additions (on-main and off-main)		212,358		52,918		1,108		266,384
Average annual usage per customer (MCF)		100		300		500		
Distribution charge unit rate ($/MCF)	$	8.00	$	7.50	$	7.00		
Average annual distribution margin per customer per year	$	800	$	2,250	$	3,500		
Customer annual distribution margins ($ in millions)	$	170	$	119	$	4	$	293
Shortfall revenue requirements ($ millions)							$	121
Shared Savings Rate for new customers		30%		30%		30%		
"Shared Savings Rate" margin per customer per year	$	240	$	675	$	1,050		
Shared Savings Rate annual revenues ($ in millions)	$	51	$	36	$	1	$	88
Shortfall revenue requirements ($ millions)							$	33
Allocation across customer class		76%		22%		2%		100%
Allocated revenue requirements to recover (in millions)	$	25	$	7	$	1	$	33
Existing number of customers		498,665		48,726		2,592		549,983
"System Expansion Rate" annual customer impact	$	51	$	151	$	258		
"System Expansion Rate" monthly customer impact	$	4.24	$	12.57	$	21.48		
Supply, CAM and other non-distribution unit rates ($/MCF)	$	6.50	$	6.50	$	6.50		
Total annual bill estimate	$	1,450	$	4,200	$	6,750		
"System Expansion Rate" % impact on total bill		3.5%		3.6%		3.8%		

The LDCs' calculations of the potential ratepayer impact of the proposed expansion of the natural gas distribution pipelines are noticeably skewed towards the assumption that all 266,384 new customers are added by the end of the expansion period and that the average usage per customer is achievable. Any changes to the number of potential customers and estimated average consumption will drastically change the amounts to be contributed by existing customers. During the earlier years of the expansion, existing customers are likely to be responsible for a significant portion of the revenue requirement. For example, under the assumption that the total cost of the expansions is equally prorated over seven years, the annual revenue requirement in year one under the LDCs' total return of 20% is approximately $59 million ($414 / 7). If only 5% of the potential new customers were added in year one, the estimated total distribution revenue recoverable from these new customers would be approximately $19 million [($293 + $88) x 5%]. Under this scenario, existing ratepayers would be responsible for approximately $40 million.

Similarly, in year three, the annual revenue requirement is approximately $177 million ($59 x 3). If only 25% of the potential new customers were added by year three, the estimated total distribution revenue recoverable from these new customers would be approximately $95 million [($293 + $88) x 25%]. Under this scenario, existing ratepayers would be responsible for approximately $82 million ($177 - $95). Changes to the assumptions underlying the calculations of the estimated revenue requirement and new customer growth level will have profound impact on the level of the additional revenue requirement recoverable from existing ratepayers.

In the past, the Authority has made every effort to prevent subsidies between customers and customer classes and existing ratepayers have not been responsible for reducing the cost to connect new customers. The substantial proposed expansion of the natural gas system could result in an additional increase of $2.26 billion in rate base and may not occur without funding from all natural gas ratepayers and potentially all state residents. Historically, the Authority has taken steps toward assigning costs to the customers that cause the cost to be incurred and designing rates to reflect this position.

b. Authority Analysis of Potential Impacts on Ratepayers

The CES did not indicate the rate at which the Segments A and B expansions would occur over the seven-year period. The LDCs' exhibits did not indicate how the projected growth would occur over the seven-year period.[55] Therefore, the Authority assumed the expansion would be linear and equally weighted each year. This assumption simplifies the analysis of the issues associated with the expansion and on the potential impact on customer rates. The Attachment A analysis presents its assumptions and two options, each with a different cost of equity.

The CES recommended that the Authority consider authorizing a ROE based in part on performance for both the electric and gas companies.[56] While the PURA cannot predict the extent to which the utilities will perform, assuming different levels of performance and corresponding levels of ROE, it can provide an example of what the impact would be on ratepayers of varying RORs. The annual capital investment for each year is assumed to be $322 million ($2.26 billion expansion plan / 7 years). In Option 1, the Authority calculated the ratepayers' impact using the numbers provided in the CES and an average ROR of 9.13%, which represents the average of the three LDCs' approved RORs (CNG 9.31%, Southern 9.26%, and Yankee 8.83%). This calculation results in a revenue requirement for the first year of $19 million assuming that, on average, one-half of the $322 million rate base is in-service during year one.

The Cumulative Revenue Requirement for the expansion over seven years would be $939 million. In Option 2, the PURA calculated the potential effect of raising the ROE to 12%. This results in a first-year revenue requirement of $24 million and a cumulative revenue requirement of $1.168 billion in year seven. The impact on ratepayers with a higher 12% ROR is a cumulative revenue requirement increase of $229 million ($1.168 billion - $939 million) over the seven-year expansion period. Any

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55 Response to Data Request No. 68 Supplemental.

56 CES, p. 102.

increase in a company's ROR would be included in the revenue requirements of its next rate case and could result in an increase in rates charged to ratepayers.

If the LDCs effectively increase their customers by an additional 305,000, they may need to expand their liquefied natural gas (LNG) peaking facilities to meet a much higher design peak day capacity requirement. This cost is unknown. An example of the cost to Yankee when it built a new LNG facility several years ago was an initial capital investment of $108 million. The facility added an annual revenue requirement of approximately $21.6 million. This amount was based on the assumption that a revenue requirement is 20% of a capital investment / rate base.

Neither the CES nor the PURA's revenue requirement analysis included the following items: costs associated with any future LDC increases to the cast iron steel replacement programs; LDC revenue increases associated with normal capital investment; and any other typical capital investment or expense increase that occurs in a rate case. Additionally, the revenue requirement shown above does not include any cost increases associated with the supply of materials to build the expansion; the potential cost increase that may occur to obtain qualified contractors to build the expansion; and / or any other costs that may result from the proposed 900-mile expansion in the LDCs' distribution systems. If a revenue shortfall occurs, all ratepayers could be responsible for the capital investment associated with the expansion.

3. Increase to Average Distribution-Only Bill

The Authority conducted its own analysis and compared today's average distribution-only bill for all three LDCs combined with the average bill that would exist for all 883,890 customers in year seven. The increase in the average distribution-only bill would be 37% as discussed below. The companies submitted a high-level rate impact calculation that included many assumptions that they expect to change. The Authority's analysis presented here demonstrates the increase in the average distribution-only bill for year seven. It also makes assumptions that will require revising as more detailed and reliable information becomes available.

The current average distribution-only bill for all three utilities combined is presently $5.63/Mcf. This represents the combined revenue requirement awarded to the three LDCs in their respective latest rate case decisions divided by pro forma firm sales that existed in those cases.[57] This average distribution bill does not include gas costs. Adding $451 million[58] to the existing distribution revenue requirement and increasing total sales to 133,540,000 Mcf to reflect the new customer count of 883,890[59] results in a new average distribution bill of $7.26/Mcf. This average bill was then increased to $7.73 to reflect the increase in pipeline demand charges.[60] The overall increase reached in year seven is $2.10, or 37%.

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57 Response to OR-7.

58 Response to DR-26

59 See Table: CES Cost to 883,890 Customers for $3.672 Billion Expansion, p. 46.

60 Represents $0.16 new capacity charge mitigated by 50% sold back stated on a per MCF basis.

The new bill of $7.73 in year seven does not include gas costs, which all parties expect to increase within the seven-year time horizon. If the ROE is increased by 300 basis points as a proxy for the incentive ROE, which the utilities believe will be required to attract capital, the revenue requirement will increase by an additional $60 million. This would result in an average bill of $8.18, an increase of $2.55 or 45%.

Additionally, the new bill does not include any increment in customer bills to cover such events as: normal rate increases, safety related cast iron to bare steel distribution main replacement, nor the myriad of other subsidies gas customers would be required to contribute to through their gas bill for the programs discussed in the CES. Finally, the forecasted increase developed here assumes that all 305,000 customers are fully connected in year seven as planned. Any slippage in forecasted sales would increase the average distribution bill as the level of sales available to contribute to costs decreases. For example, a 15% reduction in forecasted new sales growth could increase the projected average distribution bill of $8.18 to $8.55, an overall increase of 52% over today's average bill.

4. Construction Crews

The LDCs provided an exhibit that demonstrated how many miles of mains and number of services a single crew can install per year. A single crew can install 6 miles of mains or 200 services per year based on a 166-day construction season. The exhibit also showed that the three LDCs installed a total of 57 miles of mains for new business and 6,250 services during 2012.[61] Using the data cited above along with the goals set forth in the CES, the Authority estimates that the LDCs would need to add 12 new crews to install 72 additional miles of mains each year [(CES goal of 900 miles / 7) years – 57 miles of main installed in 2012] over and above the amount installed in 2012. Assuming each new customer has an individual service, the LDCs would also need to add 187 new crews to install 37,371 services a year [(305,000 services / 7 years) – 6,250 services installed in 2012]. Based on the above, the total number of new crews needed to complete the proposed expansion plan would be 200 to install the 900 miles of new main and 305,000 services. This would increase the cost of the expansion and increase the cost to existing ratepayers. This analysis assumes that the expansion occurs equally over each year, the number of mains installed during 2012 for new business remains constant, and is included in the 900 miles of new mains to be installed under the expansion plan.

D. Gas Supply

The three LDCs expect to submit a proposed plan regarding the CES proposed expansion plan to the Authority three to four months after the CES has been finalized. The off-main portion of the expansion is expected to begin in 2014 and end by 2020.[62] If the LDCs begin their expansions in 2014, it would be in the middle of the five-year supply and demand forecast period. The LDCs already have made commitments to meet the normal load growth shown in the five-year forecast. Therefore, within the next

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[61] Response to DR-24

[62] CNG, SCG and Yankee Responses to Interrogatory EN-9 in Docket No. 12-10-06, PURA Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2013-2017.

18 months, the LDCs would have to find significant peak day capacity to serve any of the customers proposed in the CES.

1. Incremental Capacity

The 305,000 increase in new customers would require the addition of a large increment of design peak day capacity because there is not sufficient capacity in the pipelines or within the LDCs' distribution systems or current peaking facilities to add these new customers. The CES acknowledged that the interstate pipeline systems are constrained and that there is not enough interstate pipeline, storage or LDC peaking capacity to serve a large-scale addition of new customers.[63]

The only known potential capacity expansion project into Connecticut is the Algonquin Incremental Market (AIM) project with a targeted service commencement date of November 1, 2016. It is currently unknown if this project will be built, how much capacity the LDCs ultimately will purchase or the cost of this incremental capacity. The Open Season[64] ended on November 2, 2012, and the PURA does not know how much pipeline capacity in total the LDCs will ultimately receive as part of the project. The LDCs only included a 1.2% normal annual growth rate as shown in its five-year Supply and Demand Forecast that may be related to the above cited project or a combination of projects.[65] They did not include capacity additions to support the 305,000 new on-main and off-main customers projected in the CES.[66] As the Algonquin project will not directly bring supply to Connecticut, the LDCs would need to acquire additional capacity back to a supply source.

2. Impact on Demand Charges from CES

While the CES proposed to add up to 305,000 new customers to the three LDCs' gas systems, it does not estimate how much design peak day capacity would be necessary to serve these additional customers.[67] The entire body of ratepayers is responsible for the capacity requirements demand charges. The Authority analyzed the peak day capacity requirements with the addition of the 305,000 new customers to the LDCs' distribution systems and determined the potential impact on ratepayers for such items as gas costs and demand charges. Any incremental capacity needs estimated by either the LDCs or the PURA at this time can only be calculated by using assumptions. The Authority is well aware that its analysis will not be the final peak day needs of the LDCs. It is only a logical attempt to show the scope of the required capacity additions that could be necessary.

One logical assumption is to estimate the peak day requirements for the new customers and utilize the residential and C&I customers' peak day use as the potential

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[63] CES, p. 136.

[64] An Open Season is a process by which the interstate pipelines send out official requests to potential customers regarding the need for incremental capacity before a project is built to assess interest.

[65] See Docket No. 12-10-06, PURA Review of the Connecticut Gas Utilities Forecasts of Demand and Supply 2013-2017.

[66] LDCs Responses to Interrogatory EN-2, Docket No. 12-10-06.

[67] CES, p. 117.

incremental peak day capacity necessary to support the proposed expansion plan. The average firm residential peak day demand for both CNG and Southern is 1 Mcf and for Yankee 0.75 Mcf. This results in an estimated average peak day demand for a firm residential customer of 0.92 Mcf [(1 Mcf + 1 Mcf + 0.75 Mcf) / 3]. Only Yankee provided the average firm commercial (12.08 Mcf) and industrial (10.74 Mcf) peak day demand for 2012.[68] The LDCs agreed it was reasonable to assume that the customers under the expansion plan would have a design peak day demand that is greater than a single family home.[69] The LDCs have accepted the above assumptions.

The Authority used as a proxy for the LDCs the average of Yankee's C&I peak day demand of 11.41 Mcf [(12.08 + 10.74) / 2]. To determine the percentage of residential and C&I customers from total customers, the PURA averaged the LDCs' customer numbers presented in their last rate cases.[70] For CNG, there were 90.84% residential customers and 9.16% C&I customers; for Southern, 89.63% residential and 10.37% C&I; and for Yankee, 87.99% residential and 12.01% C&I. This resulted in an average of 89.49% for residential and 10.51% for C&I customers. For this analysis, the Authority assumed that the 305,000 customers would consist of 272,944 (89.49% * 305,000) residential customers using 0.92 Mcf on the peak day and 32,056 (10.51% * 305,000) C&I customers using 11.41 Mcf. This calculation resulted in an estimated design peak day demand increase of 616,867 Mcf or MMBtus[71] per day [(0.92 Mcf * 272,944 new residential customers) + (11.41 Mcf * 32,056 new C&I customers)]. The 616,867 MMBtus represents estimated incremental peak day capacity requirements as it is based on the above cited averages for both residential and C&I customer use.

The actual peak day capacity number would be higher than the combined LDCs' current design peak day capacity. For the winter of 2012/2013, the LDCs had a combined design peak day firm load of 998,661 MMBtus.[72] Based on the above, the addition of the CES's proposed expansion of 305,000 new customers compared to the LDCs' current design peak day load for the winter of 2012/2013 results in an estimated increase of 61.77% (616,867 MMBtus / 998,661 MMBtus) to their existing design peak day firm load. Consequently, the total demand charges for the LDCs would increase. Currently, the demand charges for the 578,890 meters/customers as of the November 2012 PGA filing is $184,514,704.[73] The Authority calculated the design peak day capacity of 47,443 MMBtus[74] that the LDCs have available in their gas supply portfolios

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68 CNG, SCG and Yankee Responses to Interrogatory EN-1, in Docket No. 12-10-06.

69 Tr. 1/29/13, pp. 417 and 418.

70 Schedules 3.4 in Docket Nos. 08-12-06, Application of Connecticut Natural Gas Corporation for a Rate Increase; 08-12-06, Application of The Southern Connecticut Gas Company for a Rate Increase; and 10-12-02, Application of Yankee Gas Services Company for Amended Rate Schedules.

71 While billing is in Mcf, the LDCs' peak day requirements are based on MMBtus. One Mcf of gas is equal to 1.023 MMBtus of gas according to the U.S. Energy Information Administration.

72 The 998,661 MMBtus represents (CNG 320,912 MMBtus + Southern 281,255 MMBtus + Yankee 396,494 MMBtus). Docket No. 12-10-06, CNG/Southern, Exhibit S-4; and Yankee, Exhibit IV-4.

73 The $184,514,704 represents ($53,424,461 for CNG + $53,056,750 for Southern + $78,033,493 for Yankee). CNG, Southern and Yankee November 2012 PGA filings in Docket No. 13-04-01, PURA Semi-Annual Investigation of the Purchased Gas Adjustment Clause Charges or Credits Filed by: Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company and Yankee Gas Services Company.

74 The 47,443 MMBtus was calculated by subtracting the peak day customer load of 998,661 MMBtus from the total peak day resources of 1,046,104 MMBtus (332,818 MMBtus for CNG + 299,196

as of the winter of 2012/2013 to support the estimated normal firm customer growth of 1.2%.

3. Reliability of Natural Gas

The CES stated that underestimating and purchasing too little capacity can lead to reliability issues (e.g., a shortfall in supply during peak winter season), or might require the gas companies to turn away new customers who want to convert.[75] Regarding the first part of the statement, the Authority also notes the following. If the LDCs do not have or cannot obtain the capacity to serve the new 305,000 customers, they would be unable to provide these customers with firm service. Reliability is defined as the ability of an LDC to serve its existing firm customers on a design peak day and is not based on the LDC's ability to provide firm service for a large expansion of customers in the future. The CES's statement leaves the impression that reliability issues could potentially occur as a result of the CES proposed expansion, which is not accurate. Only the ability to serve new and future customers would be affected. Reliability only becomes an issue when the LDC does not have enough peak day supply to meet existing firm demand or uses interruptible supply to meet firm load. The use of interruptible supply would not occur because of the 100% supplier of last resort obligation that the LDCs must maintain to continuously provide reliability 365 days a year.

To the Authority's knowledge, the LDCs have not had any reliability issues in the recent past because of their 100% supplier of last resort obligation. The Authority is also aware that reliability issues related to large gas-fired generators in New England have occurred in the recent past. Specifically, these reliability issues were due to the fact that interruptible gas supply was used by a number of generators instead of firm supply to produce electricity. These issues currently are being discussed in the Federal Energy Regulatory Commission's Docket AD12-12-00, Coordination between Natural Gas and Electric Markets.

In addition, it appears that the CES is developing a policy regarding natural gas fracking[76] that the gas utilities could only be able to purchase gas from states or regions that have the appropriate environmental and safety laws.[77] If this policy were enacted, the LDCs' ability to purchase gas from certain states or regions might be limited. There would be difficulty in differentiating between acceptable and non-acceptable gas. This difficulty would affect the procurement of natural gas supply for Connecticut at a time when a significant expansion of the distribution systems and the addition of 305,000 customers would be underway. Such a policy could also increase the price of gas when the intent was to increase the number of customers using gas as a fuel source.

MMBtus for Southern + 414,090 MMBtus for Yankee). Supply and Demand Forecasts, Docket No. 12-10-06.

75 CES, p. 136

76 Fracking is the propagation of Hydraulic fracturing is in a rock layer by a pressurized fluid to release petroleum, natural gas, or other substances for extraction.

77 CES, p. 129.

If the above proposed fracking policy was implemented and it reduced supply options, the LDCs might have to purchase gas at a higher cost. In addition, the LDCs may need to hire more staff, depending on the documentation requirements that would be associated with a fracking discrimination policy. Therefore, the higher commodity cost of gas and the potential increase in the staffing levels of new employees could increase each company's revenue requirement and ultimately impact ratepayers.

4. Impact of Certain Items on All Natural Gas Ratepayers

The impact of the CES expansion plan on existing customers will be a function of the total capital and cost of providing service to new customers, the level of customer participation, CIAC[78] from participating customers as a result of any Hurdle Rate model analysis and rate design changes that may be made to both participating and non-participating customers to help fund the necessary investments.[79]

The LDCs stated that all existing customers not participating in the expansion plan for Segment B would have to subsidize these new conversions.[80] As a result, existing customers' bills are expected to increase. The Authority analyzed the: (1) costs associated with the increased peak day demand resulting from the proposed expansion plan; and (2) use of non-firm margins (NFMs) to reduce the cost of conversions for the new customers. In its analysis, the PURA used the numbers provided by the LDCs' in its response to DR-10 and information obtained during the January 29, 2013 Technical Meeting. Subsequently, the PURA determined the potential impact from these two items on a typical residential customer's bill as discussed below.

a. Impact of Segment B Distribution Charges to All Ratepayers

The LDCs indicated that there would be additional distribution charges with the addition of the estimated 89,000 customers in Segment B, and all of the ratepayers would be subsidizing these new customers. For example, a typical residential customer using 100.3 Mcf of gas a year would realize a distribution-related bill increase of $5 a month or $60 a year.[81] There will be additional increases resulting from the new peak day demand to all existing customers' bills resulting from the proposed expansion plan.

b. Impact of New Peak Day Demand to All Ratepayers

To meet the increased demand for the new Segments A and B customers, the LDCs will have to procure additional peak day capacity of approximately 250,000 Mcfs for which all ratepayers would be responsible. The LDCs did not provide the cost for the 250,000 Mcfs of peak day capacity. However, they estimated the cost to ratepayers of procuring an additional 100,000 Mcf of peak day capacity at 100% load factor, which

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[78] A CIAC is a surcharge that is applied to new customers' bills when the revenues associated with that customer are insufficient to recover the connection costs over the allowed payback period. The new customer must pay these costs up-front through a CIAC surcharge on their respective bills.

[79] CNG & Southern Response to DR-7.

[80] Tr. 1/29/13, p. 486.

[81] Tr. 1/29/13, pp. 279 and 280.

results in a cost of approximately $36.5 million in additional demand charges. The corresponding unit rate of $0.16 per Mcf is used to calculate the total demand charges customers would pay in their bills.[82] The unit rate for the 250,000 Mcf incremental capacity addition cited by the LDCs would be $0.40 Mcf [$0.16 * (250,000 Mcf / 100,000 Mcf)]. Based on the above analysis, an average residential customer using 100 Mcf per year would pay an additional $40 just related to demand charges. Using the same calculation without any mitigation of the demand charges, a residential customer would pay an additional $80 a year just related to demand charges.

c. Non-Firm Margins and PGA Credits

The non-firm margins consist of interruptible on-systems margins and off-system sales and capacity release margins. PGA credits include non-firm margins and pipeline refunds.[83] The CES recommended using a portion of the non-firm margin credit to offset rate base or other costs incurred for the proposed expansion plan. Another approach would be to use a portion of the non-firm margin credit to reduce the CIAC costs for off-main customers converting to gas. Another approach would be that PURA allow 50% of the PGA credit to support system expansion.[84]

In the past, the Authority has not used either the non-firm margin credits or the PGA credit to subsidize the system expansion and/or reduce the CIAC costs. Both actions would raise all existing customers' gas costs. Historically, these credits have been used to reduce the cost of gas to customers. Using a ratepayer's credit to reduce an individual customer's CIAC would be discriminatory and favor new customers.

In response to the CES, the LDCs proposed a gas conversion financing program to fund customer equipment, installation and labor costs for items such as furnaces. The LDCs used an example for an annual fund of $15 million supported by NFMs. A fund of this size would enable the LDCs to support interest buy down rates associated with loans for conversions for approximately 15,000 new customers. The key feature of the program would be an interest rate buy-down to bring customer financing rates to 1%.[85]

Had the CIAC and the interest buy-down programs been in effect during 2012, 87% [($20,498,778 + $15,000,000) / $40,997,556] of the 2012 NFMs would have been allocated to subsidize the addition of new customers.[86] This would have resulted in all customers paying $35,498,778 more for natural gas. The table below shows the results of allocating 87% of the NFMs to new customers to subsidize their conversion to natural gas. The Authority used the latest PGA factors for its calculation, which were filed by each LDC for February 2013. The increases range from $7.03 to $15.30 to a customer in just the month of February 2013.

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82 Response to DR-10.

83 Responses to DR-31 and DR-47.

84 CES, p. 145.

85 Response to DR-31.

86 Response to DR-47.

Impact on an Average Residential Customer Due to Proposed Reduction in NFMs

Company	February 2013 bill no change to NFMs	February 2013 bill with a 87% reduction in NFMs	Increase in February bill due to proposed reduction in NFMs
CNG	$221.89	$228.92	$ 7.03
Southern	$232.10	$247.40	$15.30
Yankee	$251.00	$256.86	$ 5.86

These increases result only from the proposed change to the allocations of the NFMs and do not include the bill impact from any other aspect of the proposed expansion plan.

d. Summary

The following table shows the total potential impact on a typical residential customer's bill during the month of February 2013 from: increased demand charges, reduction in NFMs, and the $5 month additional distribution charge. The increases range from $18.18 to $27.62 for the month of February 2013 for an average residential customer using 183 ccf.

Summary of Residential Customer Bill Increase from 3 Components

	Original February 2013 bill	Change to bill NFM reduction	Incremental capacity costs	Additional $5 charge	Total Increase in bill	New February bill
CNG	$221.89	$ 7.03	$7.32	$5	$19.35	$241.24
Southern	$232.10	$15.30	$7.32	$5	$27.62	$259.72
Yankee	$251.00	$5.86	$7.32	$5	$18.18	$269.18

E. Segments A and B Cost Per Customer By Class

The CES proposed converting 216,000 on-main or low-use customer prospects (Segment A) and building 900 miles of new distribution mains over a seven-year period to provide service to 89,000 new off-main customers (Segment B).[87] For Segment A, the CES stated that a cost of approximately $815 million to connect the 216,000 firm gas customers would be initially funded by the gas companies and their existing ratepayers, if the customer(s) passes the Hurdle Rate calculation. Any capital requirement greater than the revenue amount would be received from the individual customer as a CIAC. The CES expected that the $815 million capital investment would not require a CIAC surcharge.[88] For Segment B, the CES estimated that the gas companies would incur capital costs of approximately $1.438 billion.

The Authority's analyses detailed below assume the completion in year seven of the CES's proposed expansion plan. The PURA estimated the costs to connect one on-main or off-main customer in each class. The calculation included the CES's estimated

[87] CES, p. 126.
[88] CES, pp. 123-125.

total average capital costs plus an estimated revenue requirement less depreciation as detailed in Attachment A. The Authority notes that the costs listed above do not include any other costs such as system costs, operation and maintenance costs, gas costs, and administrative costs.

1. Description of Analysis

There was no analysis in the CES regarding the existing ratepayers subsidizing the new customers in Segments A and B for their respective expansions. The CES cited estimated expansion costs, the combined LDCs' capital costs, and the number of residential and C&I customers in each segment. However, LDC-specific information was not provided for the additional 305,000 customers. Consequently, the Authority conducted its own analysis showing the total combined impact on the LDCs and not on each LDC or its respective customers.

To determine the impact of the expansion on gas customers, the PURA used historical information from the LDCs' last rate cases and their respective annual reports. The Authority calculated each class and individual customer costs over the seven-year period for their respective segment without any subsidization by other ratepayers. The PURA calculated the cost per class and individual customer for the addition of the 216,000 customers in Segment A, the 89,000 customers in Segment B, and the total 305,000 customers. The Authority's goal was to determine the cost to one customer in each class under several different scenarios without subsidization from existing gas customers. Also, calculated was the cost to all of the existing 578,890 meter/customer base as of December 31, 2011. To allocate the costs to both the classes and individual customers, the Authority used consumption as a proxy to determine a dollar amount to represent a customer's share of the expansion cost.

For these analyses, the Authority used the CES estimated capital costs. The seven-year expansion program was used as recommended in the CES. In addition, the LDCs' total firm customer count and corresponding Mcfs from their last rate cases were used.[69] Using this data, the Authority calculated the natural gas customer percentage for each rate class: Residential General: 12.98%; Residential Heating: 76.52%, Residential Multifamily: 0.46%; Small C&I: 8.41%; General C&I: 1.24%; and Large C&I: 0.40%. These percentages were then applied to the total customer count to estimate the number of customers in each rate class. The Authority calculated the average annual use per customer by dividing the LDCs total Mcf per class by the average number of customers in that class: Residential General: 20 Mcf; Residential Heating: 90 Mcf; Residential Multifamily: 1,183 Mcf; Small C&I: 173 Mcf; General C&I: 983 Mcf; and Large C&I: 8,221 Mcf. For each rate class, the average number of natural gas customers was then multiplied by the average Mcf usage per customer to determine a total Mcf in year seven. Then the expansion costs were divided by the total Mcf to determine a unit cost per Mcf. The Authority then multiplied the total rate class customer usage in year seven by the Mcf unit cost to determine the cost per class. The total class cost was then divided by the number of natural gas customers in each class to determine the individual annual average customer cost for usage.

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69 Schedules 8.4 in Docket Nos. 08-12-06, 08-12-07, and 10-12-02.

2. Segment A – 216,000 Customers

The total estimated cost for the connection of the Segment A customers consists of capital costs of $815 million and a cumulative revenue requirement of $339 million for a total of $1.154 billion. The PURA calculated a unit cost of $39.29 per Mcf by dividing $1.154 billion by the total customer class usage of 29,373,290 Mcf. The calculation for the addition of one on-main customer out of the 216,000 Segment A customers is illustrated below.

CES COST TO 216,000 CUSTOMERS FOR $1.154 BILLION EXPANSION

Rate Class	Breakdown 216,000 Customers	Average Customer Use per Mcf	216,000 Total Cus. Class Usage Mcf	Cost per Class for Expansion of $1.154 billion	Cost per Cus. for Expansion of $1.154 billion
Res. General	28,037	20	570,117	$22,398,425	$799
Res. Heat	165,275	90	14,831,638	$582,696,401	$3,526
Multifamily - Res.	995	1,183	1,177,594	$46,264,611	$46,486
C&I - Small	18,169	173	3,147,206	$123,645,530	$6,805
C&I - General	2,669	983	2,624,384	$103,105,193	$38,630
C&I - Large	854	8,221	7,022,350	$275,889,840	$322,998
	216,000		29,373,290	$1,154,000,000	

The analysis in this scenario resulted in an estimated cost to connect a new residential non-heating customer at $799; a heating customer, $3,526; a multifamily customer, $46,486; a small C&I customer, $6,805; a general C&I customer, $38,630; and a large C&I customer, $322,998. The usage for a large C&I 75 kW co-generator would be almost double the 8,221 Mcf average shown above and the estimated cost to connect them would be $645,996 ($322,998 * 2).

3. Segment B – 89,000 Customers

The total estimated cost for the connection of the Segment B customers consists of capital costs of $1.44 billion and a cumulative revenue requirement of $599 million for a total of $2.04 billion. The PURA calculated a unit cost of $168.55 per Mcf by dividing $2.04 billion by the total customer class usage of 12,102,883 Mcf. The calculation for the addition of one off-main customer out of the 89,000 Segment B customers is illustrated below.

CES COST OF 89,000 CUSTOMERS FOR $2.04 BILLION EXPANSION

Rate Class	Breakdown 89,000 Customers	Average Customer Use per Mcf	89,000 Total Cus. Class Usage Mcf	Cost per Class for Expansion of $2.04 billion	Cost per Cus. for Expansion of $2.04 billion
Res. General	11,552	20	234,909	$39,595,137	$3,428
Res. Heat	68,100	90	6,111,184	$1,030,069,894	$15,126
Multifamily - Res.	410	1,183	485,212	$81,784,927	$199,441
C&I - Small	7,487	173	1,296,766	$218,576,154	$29,196
C&I - General	1,100	983	1,081,343	$182,265,680	$165,733
C&I - Large	352	8,221	2,893,468	$487,708,209	$1,385,761
	89,000		12,102,883	$2,040,000,000	

The analysis in this scenario resulted in an estimated cost to connect a new residential non-heating customer at $3,428; a heating customer, $15,126; a multifamily customer, $199,441; a small C&I customer, $29,196; a general C&I customer, $165,733; and a large C&I customer, $1,385,761. The usage for a large C&I 75 kW co-generator would be almost double the 8,221 Mcf average shown above and the estimated cost to connect them would be $2,771,522 ($1,385,761 * 2).

4. Total Expansion of 305,000 Customers

The total estimated cost for the connection of the total expansion of 305,000 customers consists of capital costs of $2.26 billion and a cumulative revenue requirement of $939 million for a total of $3.20 billion. The PURA calculated a unit cost of $77.15 per Mcf by dividing $3.20 billion by the total customer class usage of 41,476,173 Mcf. The calculation for the addition of one customer from the combined 305,000 customers in the proposed expansion plan is illustrated below.

CES COST TO 305,000 CUSTOMERS FOR $3.20 BILLION EXPANSION

Rate Class	Breakdown 305,000 Customers	Average Customer Use per Mcf	305,000 Total Cus. Class Usage Mcf	Cost per Class for Expansion of $3.20 billion	Cost per Cus. for Expansion of $3.20 billion
Res. General	39,589	20	805,027	$62,110,018	$1,569
Res. Heat	233,375	90	20,942,822	$1,615,795,912	$6,924
Multifamily - Res.	1,405	1,183	1,662,807	$128,290,081	$91,290
C&I - Small	25,656	173	4,443,972	$342,864,556	$13,364
C&I - General	3,769	983	3,705,727	$285,906,949	$75,861
C&I - Large	1,206	8,221	9,915,819	$765,032,484	$634,305
	305,000		41,476,173	$3,200,000,000	

The analysis in this scenario resulted in an estimated cost to connect a new residential non-heating customer at $1,569; a heating customer, $6,924; a multifamily customer, $91,290; a small C&I customer, $13,364; a general C&I customer, $75,861; and a large C&I customer, $634,305. The usage for a large C&I 75 kW co-generator would be almost double the 8,221 Mcf average shown above and the estimated cost to connect them would be $1,268,610 ($634,305 * 2).

5. Total Expansion Cost Impact on 578,890 Existing Customers

The Authority calculated the estimated cost to the combined LDCs' firm gas customer count if the expansion cost for the addition of 305,000 heating customers were spread across all of the 578,890 existing meter/customer base. The total estimated cost for the connection of the total expansion of 305,000 customers consists of capital costs of $2.26 billion and a cumulative revenue requirement of $939 million for a total of $3.20 billion. The PURA calculated a unit cost of $40.65 per Mcf by dividing $3.20 billion by the total customer class usage of 78,721,777 Mcf. The calculation for the addition of one customer from the combined 305,000 customers in the proposed expansion plan spread across all of the 578,890 customers is illustrated below.

CES COST TO 578,890 CUSTOMERS FOR $3.20 BILLION EXPANSION

Rate Class	Breakdown 578,890 Customers	Average Customer Use per Mcf	578,890 Total Cus. Class Usage Mcf	Cost per Class for Expansion of $3.20 billion	Cost per Cus. for Expansion of $3.20 billion
Res. General	75,139	20	1,527,941	$62,110,018	$827
Res. Heat	442,946	90	39,749,477	$1,615,795,912	$3,648
Multifamily - Res.	2,667	1,183	3,156,007	$128,290,081	$48,098
C&I - Small	48,695	173	8,434,658	$342,864,556	$7,041
C&I - General	7,153	983	7,033,470	$285,906,949	$39,969
C&I - Large	2,289	8,221	18,820,224	$765,032,484	$334,197
	578,890		78,721,777	$3,200,000,000	

As a result of spreading the cost of the expansion over the entire body of existing ratepayers of 578,890, the estimated cost to connect a new residential non-heating customer would be $827; a heating customer, $3,648; a multifamily customer, $48,098; a small C&I customer, $7,041; a general C&I customer, $39,969; and a large C&I customer, $334,197. The usage for a large C&I 75 kW co-generator would be almost double the 8,221 Mcf average shown above and the estimated cost to connect them would be $668,394 ($334,197 * 2). This scenario shows the subsidy that existing ratepayers would have to pay to provide service to one customer out of the 305,000 new customers.

6. Equipment Replacement Costs

The CES stated that a new gas customer would have to replace its existing oil-burning furnace or boiler and hot water heater with a high-efficiency gas furnace or boiler and, often, gas water heater. The cost to a residential customer for this type of furnace or boiler would be approximately $3,000-$4,000. A high-efficiency gas furnace or boiler can be used with existing radiators/ductwork, plus a natural gas water heater. Further, the customer may also be responsible for the cost to have his/her oil tank removed, depending on whether it is located underground or inside the home.

The CES also stated that the cost for equipment replacement for new Segment A customers would be approximately $1.84 billion and Segment B customers approximately $1.16 billion. Service and meter installations will cost on average, roughly $4,283 for a residential customer, $7,669 for a commercial customer and $11,504 for an industrial customer. The CES referenced the DECD study and stated that equipment replacement for off-main customers is estimated to be $7,500 for a residential customer, $20,300 for a commercial customer and $40,600 for an industrial customer.[90] The CES does not contain supporting information as to how these amounts were calculated.

The DECD study and CES have conflicting information. The CES referenced the cost of equipment replacement while the DECD study discussed the cost to retrofit existing heating equipment. According to the DECD study, if the cost to retrofit existing oil heating equipment with high-efficiency natural gas heating equipment and standard AC in a 2,000 square foot (typical) residence is $7,500, the break-even period is six years assuming the conversion is completed in 2011. The CES cited that the DECD

[90] CES, pp. 120-126.

study used 40,600 industrial customers. However, the DECD study actually cited the same number, $20,300, for commercial customers and also for industrial customers. Finally, the DECD study stated that if the cost to retrofit existing oil heating equipment with high-efficiency natural gas heating equipment is $20,300, the break-even period would be 7.4 years for commercial and 0.47 for industrial assuming the conversion is completed in 2011.[91]

7. Financial Implications on Ratepayers

The CES calls for the Connecticut LDCs to establish a planning process for natural gas expansion. The CES also calls for the LDCs jointly to file a plan to expand natural gas conversions, lowering the costs of conversion, and ensuring the reliability of gas supply. It should also include a customer conversion plan and schedule, feasibility analysis, outreach and marketing analysis, cost reduction strategy, capacity procurement, financing mechanisms, and regulatory proposals.[92]

The CES advocates setting an allowed ROE in rate cases that would include a performance component as discussed below:

> . . . that PURA consider authorizing a variable return on equity tied to quantitatively-tracked results in achieving public policy goals related to storm response, global efficiency goals, grid reliability, electricity costs, and perhaps other factors. This system would allow each company to earn a performance-based rate of return based on defined performance targets. Performance-based returns will create substantial incentives to perform. In fairness to ratepayers, poor performance should result in a reduction in basis points.[93]

The LDCs could face greater investor perceived risk due to the very large increase in gas customers as called for in the CES. The CES proposed an expansion plan that would increase the share of Connecticut homes and businesses heating with natural gas to 50% penetration for residential customers and 75% for firm C&I customers.[94] The LDCs asserted that to effectively carry out the CES proposed expansion plan, it would be necessary that the expansion program ROE be sufficient to attract incremental capital and be based on the gas LDCs' existing ROE with an additional variable ROE component based on certain pre-defined performance goals to be agreed upon with DEEP.[95]

The CES proposed that approximately $1.4 billion would be needed for the construction of new gas mains that would be spread across some combination of new gas customers, all gas ratepayers and bond funding. In addition, approximately $815 million of the $1.4 billion would be required to connect customers on or near gas mains

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91 DECD, pp. 8-13.
92 CES, pp. 138 and 139.
93 CES, p. 102.
94 CES, pp. 125-126.
95 LDCs Response to DR-52.

to be financed by the LDCs.[96] The LDCs believe that this financing would be carried on in a similar manner to the process that exists at present. The LDCs would use a combination of debt and equity to finance the expansion. This is the normal method of financing conducted by the LDCs, although the $815 million is well in excess of the LDCs' historical needs to fund the CES gas expansion goals. The LDCs stated that a regulatory framework that includes reasonable assurance of investment recovery together with an attractive return would be viewed favorably by the investment community.[97] Recovery of the revenue requirements associated with the expansion plan on the capital investment and its return, depreciation expense, associated incremental O&M expense, uncollectibles, income and property taxes should be done on a timely manner and effectuated through an annual tracker that is fully reconcilable.[98]

An aggressive expansion program may be viewed by investors as greater risk for the LDCs and, therefore, all else being equal, an increase in the ROE would be necessary to equal this increase in risk. Such a larger ROE would translate to higher rates for the customers of the LDCs. The LDCs testified that "[i]f anyone thinks we are going to implement this plan without increasing rates or having to charge more, then, you know, let's just kind of all leave, because that ain't happening."[99] To attract capital, the ROE must be sufficient for investors to risk their money. As such and unless risk mitigating measures are used (e.g., annual trackers), the LDCs will require an increase in rates in order to increase ROE to attract investors. Therefore, LDC customers' monthly bills could increase under the CES proposal.

The Authority cannot estimate an exact dollar amount increase needed related to an increase in required ROEs. However, at a minimum, and all else being equal, due to the increase in risk from the unprecedented expansion program, an increase of some amount in the allowed ROE would need to be considered. As an indication of the impact of such an increase on revenue requirements, for every 10 basis point increase in the allowed ROE based on the LDCs last rate cases, CNG's annual revenue requirement would increase by $382,451, Southern's by $521,864, and Yankee's by $654,000.

F. Summary of CES's Impact on Gas Ratepayers

The CES proposed expansion plan will have an impact on all of the natural gas ratepayers who would pay for the expansion through increases to their bills. The LDCs provided existing and estimated numbers for the major components associated with the CES proposed expansion, which are summarized below.[100]

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96 CES, pp. 5 and 6.

97 LDCs Response to DR-34.

98 LDCs Response to DR-35; Tr. 1/29/13, pp. 258-260.

99 Tr. 1/29/13, pp. 492-498.

100 Response to DR-15.

ITEM	CNG	Southern	Yankee	Total
Expansion Cost for 305,000 Customers				
Off-System				
Capital Investment – Services & Meters				$510M
Capital Investment – Mains				$926M
Total Off-System Investment Capital at Year 7				$1,436M
On-System				
Capital Investment – Services & Meters				$813M
Capital Investment – Mains				$0M
Impact of Adjustment to Hurdle Rate				(1)
Total On-System Investment Capital at Year 7				$813M
Total Investment Capital at 7-Year (total all lines above)				$2,249M
Cumulative Revenue Requirement at year 7 for Segments A and B				$450M
Cost to ratepayers in year 7				(2)
Minimum Demand Charges to add 305,000 new customers				(3)
Total Design Peak Day Demand for 305,000 new customers in MMBtus				(3)
OTHER EXPANSION COMPONENTS				
Average cost for one new off-main residential customer (main costs only)				$10,383
Average cost for one new off-main com. customer (main costs only)				$10,383
Average cost for one new off-main industrial customer (main costs only)				$10,383
Average cost for one new off-main res. customer (service & meter costs only)				$4,283
Average cost for one new off-main com. customer (service & meter costs only)				$7,669
Average cost for one new off-main industrial customer (service & meter costs only)				$7,669
Average cost for one new on-main customer (service & meter costs)				$4,283
Average cost for one new on-main com. customer (service & meter costs)				$7,669
Average cost for one new on-main industrial customer (service & meter costs)				$7,669
Percent increase in customer base compared to the end of 2011				56%
ACTUAL LDCs DATA AS OF 2011				
Customer count	161,083	179,229	209,671	549,983
Total Demand Charges for 2011 customer Count	$53,373,244	$54,267,622	$70,017,451	$177,658,317
Design Peak Day Demand for winter 2011/2012 in MMBtus	320,912	281,255	396,494	998,661
Total miles of mains for all three LDCs' entire				

distribution systems	2,022	2,281	3,256	7,559
Total miles of mains installed during 2011	14.5	18.0	17.0	49.5
Total rate base for mains, services, meters & meter installations including depreciation	$331,510,228	$329,380,509	$660,187,248	$1,321,077,985
Total rate base for all three LDCs including Depreciation	$368,637,845	$440,455,476	$877,419,509	$1,686,512,830

(1) An assessment of the impact of the adjustment to the hurdle rate is premature as the LDCs have not estimated the proportion of customers impacted by the change. See also response to DR-42.
(2) See DR-7e.
(3) See responses to DR-10, DR-15 and DR-17.

This table shows the impact of the proposed expansion plan on the natural gas ratepayers and includes paying a rate of return on rate base for the capital investment through increased rates. For the customer count in the exhibit, the LDCs used their actual data as of 2011. The LDCs' exhibit shows the average cost of $14,666 for a new off-main gas customer, which is 342% higher than the average cost of $4,283 for a new on-main gas customer. The seven-year capital investment costs or rate base for the expansion would be $2.249 billion. As stated earlier, the addition of the new natural gas customers will require an additional 616,867 MMBtus of design peak day capacity. When combined with the LDCs' combined current design peak day firm load of 998,661 MMBtus, it totals 1,615,528 MMBtus.

The addition of 305,000 new natural gas customers results in an estimated minimum annual demand charges of $279,487,020 at the end of seven years as compared to the 2012 demand charges of $184,514,704 for the current 578,890 meters/customers. Based on an average LDC ROR of 9.13%, the cumulative revenue requirement for the expansion would be $939 million[101] by year seven.

G. Proposed Expansion Plan Conclusion

The expansion plan has the potential to generate uneconomic investments that would ultimately cost ratepayers, causing them to pay more for service than they currently pay. The natural gas expansion plan relies on assumptions that need to be carefully analyzed to avoid uneconomic investments. In some instances, the PURA has concerns that not all costs are being considered when evaluating the appropriateness of investment, and that details are not provided to support conclusions arrived at in the CES. Depending on the number of customers converting, the impact of the proposed expansion on existing ratepayer is unknown.

It is unclear who would pay for the $2.26 billion of capital investment associated with the expansion plan. The CES has used a number of possible funding sources including ratepayers, bonding through the State of Connecticut, third party private capital investment and funding through the utilities shareholders. Additional issues that need to be fully examined include:

- whether a shortfall between the revenue requirement and the collected revenues may occur;

101 See, Attachment A.

- whether existing ratepayers should subsidize the addition of the new customers through increased rates;
- how much of an upfront rate increase may be necessary to complete the expansion;
- the costs associated with the additional peak day capacity on the interstate pipeline systems and when capacity would become available;
- whether capacity credits currently included in the PGA should be used to off set the conversion cost for new customers and the corresponding impact on all other ratepayers bills;
- how to quantify additional costs such as those associated with the expansion of the liquefied natural gas facilities to meet the increased peak day demand; and
- whether it would be necessary to expand the existing system through reliability projects to meet the new peak day demand increase along with the cost.

IV. GAS PIPELINE SAFETY

The United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) has recently implemented integrity management regulations for natural gas distribution systems (DIMP) that are intended to help ensure pipeline integrity and improve pipeline safety. The purpose of the DIMP regulations is to require that pipeline operators analyze their particular pipeline systems, circumstances and programs to identify potential threats that could result in high consequence accidents and to subsequently address those threats before accidents occur. If accidents occur, rate payers are potentially impacted on several fronts including loss of life, injury, lawsuits against the LDC, higher insurance premiums, and lower investor interest. All of these would serve to drive up borrowing costs and lower interest from the public for conversions to natural gas.

One of the greatest threats to the Connecticut LDCs' system integrity is old distribution infrastructure, such as cast iron and bare steel piping. The only way to reduce the threat of cast iron and bare steel pipe leaks is replacement. In addition, another one of the key elements of DIMP is the need to demonstrate improvement in the safety of the LDCs' systems. For the Connecticut LDCs to demonstrate the required safety improvement, it will be necessary to remove a significant portion of the cast iron and bare steel piping from their systems.

The expansion of the natural gas infrastructure contemplated in the CES will necessitate an increase in the workforce that is involved with designing and constructing said infrastructure. This is the same workforce that is involved with replacement of leak-prone piping as well as other requirements stemming from DIMP. It is imperative that the safety of the natural gas system be given the highest priority. If the natural gas companies are to embark on this substantial expansion program, it must not impact their replacement programs or related DIMP requirements.

V. TRANSPORTATION

The CES focused on the development of sustainable funding sources to maintain existing vehicular transportation infrastructure and to develop additional mobility options within the state.[102] One of the challenges to expanding this arena is the cost of these vehicles to customers. For example, plug-in hybrid and electric cars cost customers at least $3,000 more than comparable conventional vehicles, after a $7,500 federal credit. If the federal tax credit expires as anticipated in 2015, the incremental cost of plug-in hybrid electric vehicles increases to greater than $10,000. To help facilitate the adoption of alternative fuel vehicles, the CES proposed that the PURA adopt the use of firm rates for the basis of pricing natural gas vehicle fuel rather than linking the price to gasoline. The CES proposed to increase the number of stations that can refuel electric cars and natural gas vehicles.[103]

CL&P stated that one element of the electric vehicle infrastructure could be to file a trial tariff, on a trial basis, to collect the cost of energy associated with those charging stations, but not for the infrastructure. There is a 2006 PURA Decision that prohibited the LDCs from using ratepayers to fund additional NGV filling stations infrastructure.[104] The OCC argued that increasing the usage of alternative fuel vehicles in Connecticut does not warrant cross-subsidization from electric or natural gas ratepayers to fund alternative vehicle fueling station infrastructure.[105]

NU does not believe that local utilities should be building stations, but they could help facilitate investment and attract more private capital. One way for that to happen is by having NGV customers subscribe to an existing commercial rate. Currently, these customers are on the Natural Gas Vehicle Rate (Rate NGV), which is an interruptible rate and priced to the alternative fuel market.[106] The non-firm margins obtained from this interruptible service is minimal and flows back to firm ratepayers through the PGA. If these entities are switched over to a firm service, the reduction in the non-firm margin will increase the overall cost of gas to customers.

VI. CONCLUSION

The draft CES is a positive first step toward a comprehensive energy policy for the State of Connecticut. As with any document that attempts to address such an expansive topic as energy policy, there needs to be flexibility both in design and execution, both drawing on constructive stakeholder input that takes into consideration the views and recommendations from all affected parties.

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[102] CES, pp. 151-154.

[103] CES, pp. 157-177.

[104] See, Decision dated December 21, 2006 in Docket No. 04-03-03, DPUC Review of the Local Distribution Companies' Provision of Natural Gas for Motor Vehicles.

[105] OCC Comments, p. 3.

[106] Tr. 1/29/13, pp. 324-328.

Calculation of Annual Revenue Requirements

Assumptions:		Other Assumptions:	Option 1	Option 2
Additional off main extension miles	900	GRCF	1.86311	1.86311
Main length in feet (5,280 ft per mile)	4,752,000	Debt Ratio	50%	50%
Capital Cost per foot	$195	Equity Ratio	50%	50%
	(million)	Cost of Debt	6.79%	7.25%
Off-System Capital Investment -Mains	$ 927	Cost of Equity (ROE)	9.13%	12.00%
Off-System Capital Investment-Services/Meters	$ 512	Weighted Cost of Debt	3.40%	3.63%
On-System Capital Investment	$ 815	Weighted Cost of Equity	4.57%	6.00%
Total 7-Year Investment Capital	$ 2,254	Weighted Cost of Capital (ROR)	7.96%	9.63%
		After Tax Cost of Capital	6.39%	7.95%

Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Option 1				($ million)			
Annual Investment	322	322	322	322	322	322	322
Cumulative Annual Investment	322	644	966	1,288	1,610	1,932	2,254
Average Annual Rate Base	161	483	805	1,127	1,449	1,771	2,093
Annual Debt Cost	5	16	27	38	49	60	71
Annual Equity Cost	7	22	37	51	66	81	96
Grossed Equity Cost	14	41	68	96	123	151	178
Total Annual Revenue Requirement*	19	57	96	134	172	211	249
Cummulative Revenue Requirement	19	77	172	306	479	690	939

*Calculation does not reflect the impact of deferred taxes and interest synchronization

Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Option 2				($ million)			
Annual Investment	322	322	322	322	322	322	322
Cumulative Annual Investment	322	644	966	1,288	1,610	1,932	2,254
Average Annual Rate Base	161	483	805	1,127	1,449	1,771	2,093
Annual Debt Cost	6	18	29	41	53	64	76
Annual Equity Cost	10	29	48	68	87	106	126
Grossed Equity Cost	18	54	90	126	162	198	234
Total Annual Revenue Requirement*	24	71	119	167	214	262	310
Cummulative Revenue Requirement	24	95	214	381	596	858	1,168

*Calculation does not reflect the impact of deferred taxes and interest synchronization