STATE OF CONNECTICUT

DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION
PUBLIC UTILITIES REGULATORY AUTHORITY
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-10-03RE04 **APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO IMPLEMENT TIME-OF-USE, INTERRUPTIBLE LOAD RESPONSE, AND SEASONAL RATES - REVIEW OF METER STUDY, DEPLOYMENT PLAN AND RATE PILOT**

August 29, 2011

By the following Directors:

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DRAFT DECISION

This draft Decision is being distributed to the parties in this proceeding for comment. The proposed Decision is not a final Decision of the PURA. The PURA will consider the parties' arguments and exceptions before reaching a final Decision. The final Decision may differ from the proposed Decision. Therefore, this draft Decision does not establish any precedent and does not necessarily represent the PURA's final conclusion.

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DRAFT DECISION

I. INTRODUCTION

This proceeding under the Public Utilities Regulatory Authority, formerly known as the Department of Public Utility Control, began in the Spring of 2010 with hearings and the draft Decision developed under the examination of three Commissioners, of which two are no longer with the Public Utilities Regulatory Authority.

This preliminary draft is presented to provide an outline for discussion for the new Public Utilities Regulatory Authority (PURA) panel of Directors, which became responsible for this Decision after hearings were closed and the Department of Public Utility Control (DPUC) was consolidated under Department of Energy and Environmental Protection (DEEP) resulting in the replacement of the DPUC participating panel.

Due to a significant amount of technical detail and major impacts on ratepayers, the Directors determined that they should discuss the issues related to advance meters, the proposed deployment plan, dynamic pricing and the rate pilot results.

Pursuant to §§1-200(a) and 1-225 of the General Statues of Connecticut, a majority of the PURA Directors and previous DPUC Commissioners can not meet to discuss docket information except at noticed meetings where all parties are afforded the opportunity to be present. Therefore, a noticed technical meeting was scheduled for August 31, 2011, in order for the new PURA panel to discuss information presented in the proceeding. Following the technical meeting a new draft Decision will be issued for written comment and oral argument by all Participants approximately one month after the technical meeting.

A. SUMMARY

The Connecticut Light and Power Company (CL&P or Company) conducted a meter study during the 2009 Summer to evaluate one solution for installing advance metering infrastructure meters for every customer and a Rate Pilot to determine customer interest and response for dynamic pricing rates. The meter study showed that radio frequency AMI meters and radio towers would work well in Connecticut but the associated equipment to control customer household loads and reprogram meters remotely required further development by the manufacturers. Industry standards for AMI meter interchangeability and data security also needs additional development.

The Rate Pilot study indicated that projected capacity savings are significant for residential customers on the most extreme dynamic rate options. Savings are much more modest for residential customers on time-of use rates and small commercial and industrial customers. CL&P's large commercial and industrial customers are already required to be on time-of use (TOU) rates. The Rate Pilot study results did not indicate any energy savings from the TOU or dynamic pricing options studied.

Dynamic pricing rates are new to customers and there is little evidence as to the desire of customers to participate in these types of pricing options. CL&P did not provide any surveys or results from other states to support their estimates of customer interest in dynamic pricing rates. Even if customers decide to try new rate options, it is uncertain as to how long they will participate and whether savings will continue at the same levels over many years.

CL&P proposes to deploy 1.2 million meters to all of its customers over a four year period from 2012 to 2016 at a cost of $863 million. Smart meters have the potential to offer customers new options to control their electric use and reduce their electric bills by providing them with new pricing options and better usage information. This would provide benefits to participating customers as well as to the electric system through lower peak demand and energy usage. The operations of the electric system could also improve from theft detection, mid-cycle meter reading, remote disconnect and reconnect capabilities and other operational efficiencies, reducing costs and providing benefits to all ratepayers. In order to achieve these benefits a significant investment is required.

The Company's analysis totaled the estimated costs and benefits of the meter deployment plan and then discounted these totals to arrive at a net present value (NPV) of the Smart Meter Program. CL&P's cost/benefit analysis concluded that a full deployment of smart meters to all of its customers would result in a net positive benefit of $154 million. Assuming that the Company's forecasted costs and benefits are accurate, the lifetime savings realized by a residential customer in the Base Case is $11.17 or approximately $.05 per month, while a C&I customer would save approximately $96 over the useful life of the meters. Tr. 11/22/10, pp. 1964 and 1965; Response to Interrogatory EL-64. The Authority views this savings benefit to the customer as minor considering the substantial risks that are inherent in a project of this size.

The cost/benefit analysis performed by the Company has numerous instances of costs and benefits that cannot be quantified with actual data, but instead relies on forecasts using many theoretical assumptions. There is a wide range of variability in both the costs and benefits that can be derived from the information provided.

The Authority, through its own analysis and relying on all of the information presented in this docket, concluded that the net benefit of the cost benefit analysis (CBA) totaled negative $142 million. In several cases, the Authority believes that CL&P has overestimated the benefits and significantly impacted the results of the benefit/cost analysis. The most significant adjustments are $149 million for energy reduction. These benefits have nothing to do with dynamic rates or the smart meters. The Authority also excluded $62 million of very speculative benefits associated with the value of reliability improvements to customers and added $41 million for stranded costs that could result if the current meters are replaced before the end of their useful life as planned.

Due to the low benefit-cost ratio, low monthly savings over a 20-year meter life, risks to customers for achieving 20 years of savings, a 14-year payback period, and the uncertainty of customer desire for and use of dynamic pricing rates needed to achieve estimated savings, the PURA hereby denies the full implementation of the AMI meter system as proposed by CL&P at this time. However CL&P should begin installing smart meters at a more moderate pace once industry standards for AMI meters and infrastructure are developed and the Company has determined a specific AMI technology to install.

B. METER SYSTEMS

CL&P currently uses Automatic Meter Reading (AMR) technology. This is one-way, drive-by radio communication (i.e., meter to meter reading vehicle) where CL&P meter reader vehicles drive by the AMR meters, on a monthly basis, to collect scheduled meter reads for billing. These meters were installed between 1992 and 2005 making the average age of the meters 11 years old. The basic meter provides only a one-time, non-time differentiated monthly read. Time-of–Use meters that are compatible with the system can be used. Any changes to the rate parameters such as time periods must be performed manually and require a different meter. The current system is not good for dynamic rates having many price periods or changing rates and peak periods. CL&P has had TOU rates for many years but only 407 residential customers subscribe to them or 0.04% in a total base of 1,100,378 residential customers. Additionally, there are 1,151 small commercial and industrial customers on TOU rates, which is 1% of its 111,406 commercial and industrial (C&I) customers. All customers having an annual maximum demand equal to or greater than 350 kW are currently on TOU rates.

Advanced Metering Infrastructure (AMI) or smart meter technology meters record consumption in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing purposes. Smart meters enable two-way communication between the meter and the central system and allow the use of more sophisticated time-based rates. Since all the meters have this capability, customers can try new rate options without changing meters and the Company can change the rate parameters remotely. The meters are also capable of being remotely turned on or off and can provide information to the utility which can be used to detect theft, and provide other operational efficiencies. Communication occurs using several different technologies. The almost real time readings are available to customers through monitors or the Internet so the customer can make decisions to manage their energy consumption.

C. BACKGROUND OF THE PROCEEDING

Sections 13(a) and 13(c) of Public Act 05-01, An Act Concerning Energy Independence, now codified as General Statues of Connecticut (Conn. Gen. Stat.) §16-243n required CL&P to submit an application to the PURA regarding implementation of time-of-use, interruptible and seasonal rates. CL&P submitted its application on October 1, 2005.

The Authority took steps to use rate design to provide economic incentives to customers to shift demand to off-peak periods to reduce Connecticut's peak demand for electricity. However, at the time, CL&P indicated that its existing metering system and ongoing upgrade to their billing system severely limited the Company's ability to introduce some rate design changes that were directed under Conn Gen. Stat. §16-243n or to move forward with the initiatives being required. Given these restrictions, the Authority required CL&P to do the following:

- Implement redesigned Time-Of-Use rates for large commercial and industrial customers to become effective on January 1, 2008;
- Implement redesigned voluntary Time-Of-Use tariffs for residential Rate 7, and Commercial and Industrial Rates 27, and 37 for January 1, 2008;
- Implement voluntary Real-Time and Variable Peak Pricing for large commercial and industrial customers to become available January 1**,** 2008;
- Implement mandatory seasonal rates for all customers to become effective April 1, 2008;
- Phase-in mandatory residential time-of-use rates beginning January 1, 2009;
- Phase-in mandatory small commercial and industrial time-of-use rates beginning January 1**,** 2009;
- Increase the fixed recovery of residential distribution revenues over the next five years.

As a result of the above mentioned directives, in filings dated December 1, 2009 and March 31, 2010, CL&P submitted its compliance for Order No. 4 to the December 19, 2007Decision in Docket No. 05-10-03RE01 – <u>Application of The Connecticut Light and Power Company to Implement Time-of-Use, Interruptible Load Response, and Seasonal Rates – Review of Metering Plan</u> (CL&P 2007 Decision).

Since that time, CL&P has installed meters and placed all of its commercial and industrial customers above 350 kW on TOU rates. Other aspects of this initiative however, have not progressed. Seasonal rates have not been adopted and there has been no effort to promote TOU rates to residential or small C&I customers. These customers have not been encouraged because it would require the replacement of the current meters with TOU meters. It was thought that this should wait until a new meter system was decided to avoid creating new stranded costs. CL&P has instituted voluntary real time and variable peak pricing rates. To date however, only 14 customers are on these rates.

In CL&P's filing dated April 15, 2008, CL&P submitted a revised meter plan recommending the use of modern radio frequency meters instead of the mesh technology originally contemplated in the CL&P 2007 Decision. CL&P proposed to deploy 4,000 Modern RF meters instead of the 10,000 mesh meters originally contemplated under the Decision. In the Authority's May 2, 2008 response letter to CL&P's revised meter plan, the Authority approved the use of 3,068 meters for the meter study (Meter Study).

In 2009 CL&P applied to the Department of Energy (DOE) for a Smart Grid Investment Grant but was not selected for an award. Late Filed Exhibit No. 6, p. 2. The CL&P application to DOE also included meter deployment costs for Western Massachusetts Electric and Public Service of New Hampshire and funds for smart grid distribution equipment and electric vehicles. Tr. 11/11/10, p. 2069

Order No. 4 of CL&P 2007 Decision requires that on, or before December 1, 2009, CL&P shall file reports regarding a 10,000 Meter Study and the results of a Rate Pilot conducted during the summer of 2009. That report was to include, but not be limited to, a discussion of the technical capabilities of the meters, reliability of the meters, effectiveness in rural areas, a summary regarding customer response to the rate pilot, and cost effectiveness of the meters and rate options. CL&P provided results of the Rate Pilot on December 1, 2009, and a report on the 10,000 Meter Study, a meter deployment plan and its cost effectiveness on March 31, 2010.

On December 1, 2009 and March 31, 2010 CL&P filed the following documents containing information regarding the results of the Rate Pilot and dynamic pricing, the Meter Study and its AMI deployment plan:

1. Results of CL&P Plan-It Wise Energy Pilot, filed 12/1/09 (RPIWEP).
2. RPIWEP Appendix A - CL&P's Plan-it Wise Program Summer 2009 Impact Evaluation, by The Brattle Group, filed 12/1/109. (RPIWEP Appendix A).
3. RPIWEP Appendix B - Load Impact Analysis Methodology, by The Brattle Group, filed 12/1/09. (RPIWEP Appendix B).
4. RPIWEP Appendix C - Plan-it Wise Customer Experience, filed 12/1/09. (RPIWEP Appendix C).
5. RPIWEP Appendix D - AMI Supporting Data and Enabling Technology Results, filed 12/1/09. (RPIWEP Appendix D).

6. CL&P AMI and Dynamic Pricing Deployment Cost Benefit Analysis, filed 3/31/10, (ADPDCBA).
7. ADPDCBA Appendix A - Detailed Cost Benefit Analysis and Assumptions, filed 3/31/10. (ADPDCBA Appendix A).
8. ADPDCBA Appendix B - AMI Technology, Standards and Deployments Update, filed 3/31/10. (ADPDCBA Appendix B).
9. RPIWEP Appendix C Sup - Plan-it Wise Pilot Results - Supplemental Analysis by The Brattle Group, filed 3/31/10. (RPIWEP Appendix C Sup).

The purpose of the Meter Study and the Rate Pilot was to gather more information about how AMI meters could provide cost savings for customers through time-based rates and to provide additional information which would assist the Authority to make a more educated decision about the further deployment of AMI meters.

CL&P claimed it successfully executed the Rate Pilot and the Meter Study from June 1, 2009 through August 31, 2009, and that the Plan-it Wise Energy Program rate pilot achieved its objectives to gain insight into customer interest in, and response to, dynamic pricing rates, while at the same time gathering experience and insight into the capabilities and maturity of certain AMI technologies. RPIWEP, p. 2.

The Company requested conditional approval of its Plan to begin a full AMI deployment replacing all its meters by December 31, 2012. This approval would be subject to Authority review and approval of cost recovery in a proposed July 31, 2012 Company filing. ADPDCBA, p. 12. The Company testified that it is asking for conditional approval now in order to pursue planning, to begin the RFP process, and to know if it will need to pursue additional pilots between now and the end of 2012. Tr. 11/11/10, p. 2163.

The Company anticipates incurring an incremental expense as it plans for the AMI and Dynamic Pricing deployment and proposes continued recovery for incremental costs incurred through Federally Mandated Congestion Charges (FMCCs). The Company proposes applying the existing unused portion of the Plan-it Wise Pilot budget, approximately $1 million, towards this purpose prior to July 31, 2012. AMI project costs may include additional pilots. ADPDCBA, p. 12; Late Filed Exhibit No. 2, p.19.

Prior to commencing full deployment, the Company proposed to submit the following filings to the Authority:

- On or before October 31, 2011, an informational update on key AMI standards, AMI technology, AMI deployments, Smart Controlling Technologies in the industry, any updates to the cost benefit analysis, and any proposed changes to the deployment plan.
- On or before July 31, 2012, a request for approval of AMI & dynamic pricing cost recovery based on AMI vendor responses to the Company's RFP. ADPDCBA, p. 12; Late Filed Exhibit No. 2, p.19.

By Decision dated August 18, 2010, in Docket No. 05-10-03, Application of The Connecticut Light and Power Company to Implement Time-of-Use, Interruptible or Load Response, and Seasonal Rates, the Authority reopened this proceeding for the limited purpose of reviewing the Metering Study, Rate Pilot and Meter Deployment Plan submitted by CL&P.

D. CONDUCT OF THE PROCEEDING

Pursuant to a Notice of Reopened Hearing to review the metering study, rate pilot and cost effectiveness of the associated meters, meter development and rate options submitted by CL&P dated October 14, 2010, public hearings were conducted on November 22, 2010, January 19, 2011, and February 1, 2011, at the offices of the Authority, Ten Franklin Square, New Britain. The matter was closed at the conclusion of the February 1, 2011 hearing.

E. PARTIES

The Authority designated The Connecticut Light and Power Company, 107 Selden Street, Berlin, Connecticut 06037; the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, Connecticut 06051; and the Office of the Attorney General (AG), Ten Franklin Square, New Britain, Connecticut 06051; as Parties to this proceeding.

F. METER STUDY-SUMMER 2009

1. Company Meter Study

The Company submitted its original Meter Plan in March 2007 and proposed to replace all of its meters with an Open Advanced Metering Infrastructure[1] (OpenAMI) over an 18-month period beginning January 1, 2009, at an estimated cost of approximately $264 million. CL&P 2007 Decision, p. 2. The intent of the Meter Plan was to offer Time of Use rates to all CL&P commercial and industrial customers and to phase in over six years large residential customers that use over 2,000 kWh/month.

In CL&P's filing dated April 15, 2008, CL&P submitted a revised meter study recommending the use of Modern RF meters instead of the mesh technology originally contemplated in the CL&P 2007 Decision. Since Modern RF meters do not require the same geographic saturation as the mesh technology, fewer meters would be needed to conduct its Rate Pilot. CL&P proposed to deploy 4,000 Modern RF meters instead of the 10,000 mesh meters originally contemplated under the CL&P 2007 Decision. In the Authority's May 2, 2008 response letter to CL&P's revised meter plan, the Authority approved the use of 3,068 meters for the Meter Study. Tr. 11/11/10, p. 2058.

CL&P conducted the Meter Study from June 1, 2009 through August 31, 2009, to evaluate the technical capabilities and reliability of the Penname Metering System. CL&P also conducted a rate pilot within the Meter Study to determine customer acceptance of and response to time-based rates.

The Company meter test evaluated a two-way fixed radio AMI solution. Sensus FlexNet two-way radio AMI infrastructure and meters were deployed in the Stamford and Hartford areas to read residential customers hourly energy usage. The AMI metering solution read hourly usage consistently and without meter communication failures. Ninety- eight point sixty- eight percent of hourly reads were captured by the first day of each participating customer's billing window and 100 percent of these customers were read and billed on time during the pilot. RPIWEP, p. 10

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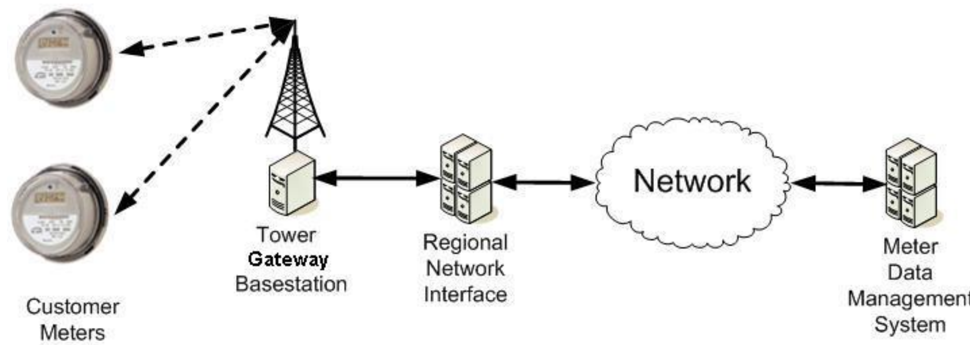
1 OpenAMI, technology is an advanced metering infrastructure that allows for two-way communications between CL&P and the meter using open, non-proprietary standards and a Mesh Network communications system. The Mesh Network communications system is comprised of all the OpenAMI meters within a given geographic area. Each meter not only collects and transmits its own data, but also serves as a relay for the other meters to propagate their meter readings, control signals and rate programs within the network thereby reducing the communications infrastructure required and increasing communication reliability.

2. AMI Infrastructure

Figure 1 below is an illustration of an AMI two-way communication network:

Figure 1. AMI Two-way Communication Network



RPIWEP Appendix D, p. 1.

Tower Generation Base stations (TGBs) are the backbone of the AMI two-way radio solution and they communicate meter data to a Regional Network Interface (RNI). The RNI controls the TGBs and formats meter data information for the Company's Meter Data Management System (MDMS) and ultimately, for customer billing. TGBs are also used to transmit commands such as security updates, meter read requests, from the RNI to the individual customer meters. The means of communication between the RNI and a company's MDMS can vary, depending on the company's preference. RPIWEP Appendix D, pp. 1 and 2.

The Company leased seven TGBs and installed them on four existing communication towers in the Hartford area and three existing communication towers in the Stamford area for the Meter Study. RPIWEP Appendix D, p.2.

3. AMI Meter Technology

CL&P utilized the Sensus fixed 2-way radio AMI metering solution for the residential portion of the pilot. The 2-way radio AMI rate pilot required the installation of AMI meters and integrated meter data collection infrastructure. RPIWEP Appendix D, p. 1. The Company claimed that the AMI technology had solid performance and found that AMI meters worked effectively at capturing and transmitting hourly energy usage. There were no meter failures during the Meter Study. RPIWEP, p. 5.

Electric meters may require reprogramming of their internal programmable read-only memory similar to the way computer software receives regular security and feature updates. While core AMI capabilities have matured since 2007, critical emerging capabilities, like the ability to remotely apply security software patch upgrades, are still maturing. RPIWEP, p 10. Any AMI technology deployed must have the ability to remotely update AMI meters. RPIWEP Appendix D, pp. 2 and 3.

During the pilot, the Company performed one wireless, over the air, programming and successfully reprogrammed 1,265 of the 1,320 (95.8 percent) AMI meters. The remaining 55 meters (4.2 percent), required field visits and were programmed locally by a field technician. The Company found that the capability to perform over the air meter programming is still low on the technology maturity curve. RPIWEP Appendix D, p. 3.

In a broad AMI meter deployment, the fixed 2-way metering solution would be designed to achieve 100 percent communication to a tower. Each meter would be designed to have tower communication redundancy. RPIWEP Appendix D, p. 2.

The Company found that network bandwidth is an area to watch while standards are being developed. During the pilot, the largest peak utilization percentage of any individual tower location's overall capacity was 7 percent. The average percentage utilization for the seven towers was approximately 1 percent. This data does not provide enough information to determine whether there will be enough bandwidth to accommodate future requirements for home area networking (HAN)[2] which is a network of controls and devices located inside the home with their operation controlled by signals from the AMI meter and distribution automation. RPIWEP Appendix D, p. 2.

For a broader deployment, the success rate for wireless programming must be close to 100 percent in order to avoid inefficient and costly field visits. In addition to the capability to perform wireless programming, the Company believes that meter data collection software will require more frequent updates than today's meter data collection software. RPIWEP Appendix D, p. 3.

The core Sensus fixed 2-way radio AMI technology used for the residential customers worked as designed, with no meter accuracy issues or failures identified in the pilot. The Company prefers that some AMI capabilities, such as remote programming, increase in maturity prior to broad deployment. The fixed 2-way radio AMI technology used in the rate pilot would be a technically effective option from a cost perspective in evaluating a broader deployment of AMI meters across CL&P. RPIWEP Appendix D, p. 5.

The Authority recognized that the Meter Study only analyzed the performance of one AMI technology. The Meter Study indicated that that there were no meter failures during the study period and that readings were obtained for every bill during each billing cycle on time.

It would be helpful to the Authority if the Meter Study provided a comparison of AMI technologies that showed the strength and weaknesses of each technology and which technologies would be best suited for the CL&P territory and electric system. The Meter Study should have presented the reasons why some meter readings were not

[2] HAN devices include in-home displays to provide electricity pricing, usage history, and utility messages; thermostats to provide demand response and load control for the home heating or cooling systems; individual load-shedding controls that may be installed on window air conditioners, pool pumps, water heaters, or other devices; and Smart appliances that react to pricing data or demand response messages to reduce their load.

initially obtained during the billing period for reasons due to the meter components or other infrastructure and communication equipment failures and how the rate of meters reads improved during the test period.

The Authority is concerned that wireless reprogramming of AMI meters needs improvement before it reaches an acceptable performance level to be utilized by the Company. The Authority also believes that this AMI technology requires fuller development before CL&P deploys the AMI meters.

4. Industry Standards

The National Institute of Standards and Technology (NIST) is tasked with developing emerging smart grid standards and protocols. CL&P fully supports the development of open standards and is an active and voting participant in NIST's Smart Grid Interoperability Panel (SGIP). SGIP is a membership-based organization created to support its role as defined by the Energy Independence and Security Act (EISA) of 2007 to coordinate the development of standards for the Smart Grid. The mission for SGIP includes ongoing coordination, acceleration and harmonization of standards development and review use cases, identify requirements, coordinate conformance testing, and proposes action plans for achieving these goals. The Company also actively participates in the OpenHAN, OpenAMI, and Open Smart Grid industry user groups. RPlWEP, Appendix D, p. 5.

CL&P reported that the maturity of critical AMI capabilities will be dependent on the development of standards. During 2010, AMI standards' development has gained structure and momentum. The NIST plan is to complete the development of the most critical AMI standards by the end of 2010. CL&P's parent company, Northeast Utilities, (NU) is participating in these key working groups. Once the standards are developed, additional time for the meter manufacturers to implement these structures and more time for the capabilities to achieve stability and maturity will be necessary. RPIWEP, p. 10.

To achieve smart grid interoperability and security, NIST ascertained that many standards will require revision or enhancement before they can be implemented. NIST determined that 75 existing standards are applicable to Smart Grid goals and also found that there were 70 gaps that require new standards or enhancements to existing standards. The most critical gaps have been grouped into 17 priority action plans (PAPs). CL&P is tracking closely the following PAPs that directly impact decisions related to AMI:

- Meter Upgradeability Standard: Standard to ensure CL&P can upgrade meters in the field without replacing it or having to "roll a truck" to manually upgrade the meter. This standard has been defined and implemented.
- Use of Internet Protocol (IP): For interoperable networks NIST is studying whether the IP technology suits smart meter applications. If IP is chosen as a viable alternative, CL&P's decision around an AMI

technology needs to incorporate IP as a critical component in the final solution.

- Use of Wireless Communications: NIST is exploring the strengths, weaknesses, capabilities and constraints of using wireless communications as a solution for smart grid applications, including AMI. Results of the work will be used by CL&P to assess the appropriateness of using wireless communications for smart meter applications.
- Standards from Appliance Communications in the Home: In the future smart appliances will need to communicate to devices in the network, including the meter, in a plug and play manner without requiring manual configuration by homeowners. Currently there are multiple technologies that are not interoperable, and operation in close proximity can cause interference leading to performance degradation or even malfunctions. As CL&P chooses an AMI technology it will need to be sure that it can support interoperability standards that ensure smart appliances can function properly in the future. ADPDCBA Appendix B, pp. 3 and 4.

Standards addressing the 17 identified PAPs were scheduled to be completed by the end of 2010, however an analysis of the current progress identifies several activities already being delayed. It is CL&P's expectation that work will be finalized by mid-2011. ADPDCBA Appendix B, p. 4.

To address cyber-security and privacy issues, NIST developed the Cyber-Security Coordination Task Group (CSCTG). CL&P, through NU, is a member of this group and is actively participating in the discussion around cyber-security and privacy risks. ADPDCBA Appendix B, p. 4. A final report of the Smart Grid Cyber-Security Strategy and Requirements was issued in August 2010.

The development of AMI standards will be a critical milestone to the timing of future broad deployment solutions. The Company is very committed to the development of AMI standards through NIST for this reason. The Authority infers from CL&P's update on industry standards that progress on the development of new AMI standards is being made but the availability of final standards was not completed in 2010 and may not be completed until the end of 2011. This will cause at least a one year delay in the start of the Company's deployment plan. The Authority agrees with the Company that the new AMI standards must be implemented by manufacturers before a deployment plan is commenced.

a. Effects of Radio Frequencies

After the hearing was closed, the AG provided copies of several letters written by customers in New York expressing concerns over health issues that they believe were due to radio frequencies and radiation produced by smart meters installed at their homes. CL&P responded by submitting two industry articles indicating that the level of radiation from smart meters was very low and below the limits set by the Federal Communications Commission.

There was no evidence or complaints filed or presented in hearings related to heath issues caused by AMI meters during the Company's 2009 meter study or the testing of AMI meters in 2008 in Stamford and Hartford.

The Authority is aware of the concerns over health issues related to AMI Meters and continues to monitor this issue and its development in other states and with utility commissions. The Authority is not aware of any tests or records that prove that radiation produced in AMI meters is a safety hazard**.** The Authority will continue to monitor health related events and studies in other states associated with AMI systems. Should the Company decide on an AMI technology and meters and submit an updated deployment plan, the Authority will also review the radiation and health concerns related to the specific AMI equipment at that time.

Due to customer concerns over alleged health affects caused by Smart Meters producing radiation, some states are allowing concerned customers to opt out of having an AMI meter installed at their home but they have to pay a fee to offset extra meter reading costs. In May 2011, the Maine Public Utilities Commission[3] required Central Maine Power to offer customers two opt-out options. The customer can have a Smart Meter with the transmitter turned off and pay an initial charge of $20.00 and a monthly charge of $10.50. The second option is to keep an existing analog meter and pay an initial charge of $40.00 and a monthly charge of $12.00. Low-income customers, those who are eligible for Low Income Heating Assistance will be charged only 50% of the cost of their chosen opt-out option. California is also considering opt out choices.

Until there is evidence that Smart Meters cause health problems, the Authority will not require opt out options because they are expensive and reduce the efficiency of the metering system. Despite the evidence, if some customers continue to demand the use of more conventional meters rather than smart meters for their home then it would be best to identify these customers first so new meters are not installed needlessly. This issue must continue to be monitored and may require CL&P to include educational material to customers prior to the roll out of smart meter deployment.

b. Security and Privacy Risks

Customers are also concerned that the wireless transmission of and large quantity of locally stored electricity data in the meter could be stolen and then analyzed to gain knowledge of their living patterns to determine when no one is home in order for someone to illegally enter the premises.

The Authority is not aware of any instances where electricity data has been hacked or stolen where AMI meters are installed. SGIP issued guidelines in August 2010 for setting up cyber-security protections for electric grid systems including hardware and software components and addressed privacy issues within personal dwellings. The Authority is currently conducting a review[4] of Connecticut utilities'

3 MPUC Decides Smart Meter Investigation, May 17, 2011**,**
http://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=245859&v=article08

4 Docket No. 10-11-08, <u>DPUC Determination of a Public Service Company-Specific Cyber Security Policy</u>

cyber-security principles, policies and practices that they employ in order to protect their infrastructure and computer networks from cyber attacks and company practices employed to protect customer personal information. The Authority will review the Company's methods and standards to ensure that customer electricity data will be protected after the Company proposes to install specific AMI infrastructure.

5. AMI Enabling Technologies

AMI enabling technologies are devices used to control energy usage systems and provide information to help customers use energy more efficiently. Controlling devices tested in the rate Pilot were smart thermostats and smart switches. RPIWEP Appendix D, p. 3.

Smart thermostats can be remotely controlled, have two-way communication and customers can override temperature and control settings directly on the thermostat. A licensed electrician must install the smart thermostat. RPIWEP Appendix D, p. 3.

Smart thermostats are still early in their development cycle and have yet to be widely deployed in smart meter implementations. There were significant technological, installation, and usability issues with the residential smart thermostats in the rate pilot. RPIWEP Appendix D, p. 3.

The Company anticipates that the customer usability design and technical maturity will improve significantly in the years ahead. Currently the smart thermostat solution is not ready for broad deployment. RPIWEP Appendix D, p. 4.

A smart switch is installed on the outside of the house to cycle the central air conditioner on and off at pre-set intervals. It is remotely controlled with one-way communication, but a customer needs to call the Company to override settings. RPIWEP Appendix D, p. 4. There were no problems reported with this technology.

Informational Display technology provides real-time energy pricing or usage information to help customers use energy more efficiently. Informational Displays can not be used to remotely control energy usage. RPIWEP Appendix D, p. 4.

The Rate Pilot Ambient Devices' Energy Orb used one-way paging communication to effectively change colors to indicate peak time. The orb technically performed well and was reliable. In all tests conducted on the orb, the devices changed to the correct color at the correct times indicating that they properly associated on-peak and off-peak rates. RPIWEP Appendix D, p. 4.

The Company identified the following technical constraints with the energy orb:

- one-way communication does not allow validation that the color has changed;
- paging area coverage gaps existed in some areas where the orbs could not receive a signal to change color; and
- there were challenges penetrating physical structures which may prevent receipt of the paging signal. RPIWEP Appendix D, p. 4.

The Company utilized a second informational display device, called the Power Cost Monitor (PCM) made by Blue Line Innovations, for some of the Pilot's Residential TOU customers. PCMs effectively allowed customers to view their approximate real-time energy usage. RPIWEP Appendix D, p. 4.

The PCM solution includes installation of a measurement collar on the outside of the glass on the meter that reads the register. The collar sends the meter reading via radio signal into the customer's home, where the PCM is on display. The PCM must be configured with the pricing, peak times and meter type that the customer is on. Then, the measurement collar with the PCM display must be synchronized at close proximity. Once those steps are completed, the PCM displays the real-time cost and energy usage. RPIWEP, Appendix D, p. 5.

Setting up and programming the PCM correctly is complex and time-consuming. Since the PCM has one-way communicating, it will work with a TOU rate because TOU can be pre-programmed. However, PCMs will not work for true peak-time rates, because peak-time rates cannot be pre-programmed. Adjusting the measurement collar over the meter register is difficult, and if done incorrectly, the device will not read the meter. Once the device is set up successfully, if the distance between the collar and the PCM display is greater than 20 meters, such as in an apartment or a condominium complex, the PCM monitor is unable to receive the meter information. Due to the power requirements of both components, frequent battery replacement was required within the three month pilot. RPIWEP Appendix D, p. 5.

The Company gained experience with enabling technologies and learned that residential smart thermostats are still immature from a technology and a customer usability design perspective. Smart thermostats also are low on the maturity curve, are not compatible with some older HVAC systems and required significant time to schedule the installation inside the customer's home.

Based on the problems customers experienced with smart thermostats, information displays and HAN communications, the Authority is concerned that the interaction between AMI meters and customers requires more technical development of these devices. The Meter Study did not demonstrate a good success for the use of customer controls and coupled with the difficulty monitoring energy consumption in the home, customers could become dissatisfied with AMI meters.

In the enabling technology area, the informational displays used in the pilot provided basic, clear information to customers, but were not effective in all areas and do not allow for true dynamic pricing communication. In addition to technology maturity, the use of enabling technologies in a broader meter deployment must be determined based on the savings from incremental peak load reduction or conservation.

6. Meter Study Summary and Conclusion

CL&P installed 1,320 AMI residential meters during the 2009 summer in the Stamford and Hartford areas to evaluate the technical capability and reliability of AMI two-way radio technology in preparation to replace its current AMR meter system. The

AMI system consisted of meters with control devices and data transmission, data collection and data management infrastructure. The AMI meters were required to provide hourly readings, be capable of remote programming and updates, contain local signal devices to provide real time price signals to the customer, control certain household loads and be reliable.

The Company reported that the AMI meters performed reliably with 100 percent of the customers metered accurately and billed on time and there were no meter or communication module failures. The Authority is satisfied with the Meter Study results that indicate that two-way radio is another AMI technology that can perform well in Connecticut. No participant disputed the Company's meter study results.

Although the meters generally performed well, some enabling control devices did not perform as required. Many smart thermostats were provided by the manufacturer with a defect that caused them to fail. They were fixed by reprogramming the thermostat manually. Newer thermostats were also supplied with the same defect and had to be reprogrammed before being installed. Customers also had difficulty in understanding the meaning of commands indicated on the thermostats such as the Hold and Off-Hold settings. The programming of the power cost monitor was complicated and time-consuming and its battery life was very short.

The Authority is concerned that wireless reprogramming of AMI meters must be improved before it reaches an acceptable performance level. In the one wireless over the air programming test, 4.2% of the AMI meters could not be reprogrammed remotely due to low signal strength caused by the small number of communication towers used in the study.

The development of AMI standards is a critical milestone to the timing of future broad deployment solutions. Progress on the development of new AMI standards is being made, but the availability of final standards was not completed in 2010 and may not be completed until the end of 2011. The Authority believes that the new AMI standards must be implemented by manufacturers before a deployment plan is commenced.

Other technical issues have emerged such as cyber security and health effects from radio frequencies. These issues must be monitored and customer concerns addressed before any deployment begins.

G. RATE PILOT

Order No. 4 of the CL&P 2007 Decision states:

> On or before December 1, 2009, CL&P shall submit a report regarding the 10,000 Meter Study. The report shall include, but not be limited to, a discussion of the technical capabilities of the meters, reliability of the meters, effectiveness in rural areas, a summary regarding customer response to the rate pilot, and cost effectiveness of the meters and rate options.

In compliance with the above Order, CL&P conducted a rate pilot within its Meter Study between June 1, 2009 and August 31, 2009 to examine AMI meter related issues and customer response to TOU rates and other dynamic pricing schemes (Rate Pilot).

1. Customer Selection/Enrollment Process

CL&P stated that it solicited participants for its rate pilot through direct mail and that it designed the enrollment process to minimize self-selection bias[5] and to improve on other similar studies that have been conducted in the United States. To do this CL&P randomly assigned the customers that would be solicited into one of the test rates (i.e., Critical Peak Pricing (CPP) high, CPP low, Peak Time Rebate (PTR) high, PTR low, etc.) and then randomly assigned customers into marketing "waves." The waves were used to minimize a bias that evolves for early versus late customer responsiveness to direct mail of outbound calls. Appendix C - Plan-it Wise Customer Experience, pp. 2 and 3; Tr. 11/22/10, pp. 1944-1948.

Customers were given two weeks to respond to the Rate Pilot invitation. If a customer did not respond within that time their option to participate was closed and the next marketing wave commenced. Responding customers were asked to provide a range of information including whether they had central air conditioning. Customers were then slotted into their test rates as being either with or without enabling technology. To further mitigate self-selection bias and assure valid results, enrolling customers were not allowed to choose among the rate options that were being studied nor were they provided insight into the other rate treatment options. As a result, customers either participated under their assigned rate or chose not to participate. Id.

CL&P stated that the enrollment process included a financial incentive to participate; residential customers who participated to the end of the Meter Pilot were paid $100 while business customers were paid $200. CL&P indicated that it would pay customers these same amounts to enroll in dynamic pricing tariffs going forward. Tr. 11/22/10, pp. 2023-2026.

CL&P indicated that it enrolled 1,500 residential customers in Hartford and Stamford and 1,500 business customers throughout Connecticut. While it began the Rate Pilot with 3,000 participants, only 2,237 remained at the end of the study and were statistically analyzed. The number of customers enrolled at the end of the Rate Pilot included 1,114 residential and 1,123 business customers, plus 200 control group customers. Tr. 11/22/10, p. 1886; Late Filed Exhibit No. 2, p. 7.

CL&P indicated that in the few months dedicated to marketing the Rate Pilot that 3.1% of the residential customers and 4.5% of the business customers that were solicited enrolled. CL&P acknowledged that although these enrollment rates are low, over time it expects voluntary participation in dynamic pricing programs to improve as customers become familiar with them and realize the potential savings and environmental benefits that they offer.

[5] Self-selection bias can occur when individuals select themselves into a group of participants rather than being selected randomly from a population of potential participants.

2. Rates Studied

CL&P stated that it chose to study three rate structures: TOU, PTP and Time PTR. Each rate design was tested with a high and low price differential of peak to off-peak to develop a price elasticity curve. In filings dated December 1, 2009, and March 1, 2010, CL&P provided a summary of and findings associated with the Rate Pilot.[6]

The TOU rate reflected the time periods used under CL&P's current time-of-day tariffs, with an eight-hour peak period (noon to 8 p.m. weekdays) and off-peak being all other hours. Under this structure, there are 128 off-peak hours (76.2% of the 168 total weekly hours) and 40 peak hours (23.8% of the 168 total weekly hours) Customers are assessed higher rates during the peak period and lower rates during the off-peak period. For the Rate Pilot, CL&P established wider TOU price differentials than the differential that exists under their current TOU rates. Appendix A, pp. 1-18; Tr. 11/22/10, p. 1882.

The CPP and PTR rates were in effect for 10 days, from 2 p.m. to 6 p.m., a total of 40 hours, during the Rate Pilot. The CPP rate increased prices up to $1.60/kWh during the peak hours while providing a discount of up to $.05/kWh during the off-peak. The PTR rate retained normal tariff pricing during all hours of the Rate Pilot, but provided customers the opportunity to receive rebates of up to $1.60/kWh during peak hours if the customer reduced their demand during that time. The 10 days on which CL&P notified its customers that CPP and PTR pricing was in effect, are referred to as event days and customers were notified the day before an event day was called.

In addition to being assigned to a rate structure, CL&P testified that some customers were provided a thermostat or switching device (Enabling Technology) that allowed CL&P to control central air conditioning systems. Additional residential customers were provided an ORB to indicate peak and off-peak time periods or a Power Cost Monitor. Id.

3. Impact - Peak Demand and Energy Consumption

Residential customers assigned to the PTP and PTR rates demonstrated significant peak demand reductions ranging from 7% to 23.3% while the customers assigned to the eight-hour TOU rate showed a very low impact of no greater than 3.1%. In addition, Enabling Technologies increased the impact for the residential PTP and PTR groups but had no additional impact under TOU rates. The ORB and Power Cost Monitor also had no measurable impact. Finally, there was very little impact to energy consumption among residential customers.

CL&P also indicated that the reduction in demand among its PTP and PTR business customers ranged from 1.7% to 7.2%. Although these reductions were less than those demonstrated by its residential customers, CL&P finds these results to be statistically significant. Further, business customers assigned to TOU rates did not respond in any statistically significant way. For business customers the ORB and

[6] CL&P chose to name its Rate Pilot "Plan-it Wise."

Power Cost Monitor had no measurable impact, but the thermostat increased the responsive for PTP and PTR, but had no meaningful incremental effect for customers on TOU rates. Finally, overall energy consumption among business customers did not change in response to time varying rates. Tables 1 and 2 below summarize the results presented by CL&P.

Table 1. Results Presented by CL&P - Residential Customers

PTP customers reduced their critical peak period usage by 10.2% to 23.3%
PTR customers reduced their critical peak period usage by 7.0% to 17.8%;
TOU customers reduced their critical peak period usage by 1.6% to 3.1%;
Neither the ORB nor IHD improved customer response under any price plan;
A/C switch or thermostat increased impacts for PTP & PTR but not for the TOU group;
Consumption increased by 0.2% under PTP but decreased by 0.2% under PTR & TOU.

November 11, 2009 Impact Evaluation, p.11.

Table 2. Results Presented by CL&P - Small C&I Customers

PTP customers reduced their critical peak period usage by 1.7% to 7.2%
PTR customers reduced their critical peak period usage by 2.7% to 4.1%;
TOU customers did not reduced their critical peak period usage;
Neither the ORB nor IHD improved customer response under any price plan;
Thermostat increased responsiveness under PTP & PTR but not for the TOU group;
Consumption did not change in response to time-varying rates.

November 11, 2009 Impact Evaluation, p.14.

4. Pre & Post-Pilot Information

CL&P conducted a post-pilot survey to determine, among other things, customer satisfaction with the Rate Pilot. CL&P stated that the results of this survey showed that customers were very satisfied with the program reporting that 92% of residential and 74% of business customers would participate if the Rate Pilot was conducted again. CL&P reported that residential customers rated their overall satisfaction of the program at 5.1 out of 6, while C&I customers rated, their satisfaction at 4.1 out of 6. The PTP rate was the most satisfying rate and the smart switch was the most satisfying Enabling Technology for both residential and business customers. However, residential customers were less satisfied with the PTR and least satisfied with the TOU rate while business customers were less satisfied with the TOU rate and least satisfied with the PTR. CL&P noted that although all participants received the survey, only 205 of the residential participants and 55 of the total business participants who completed the program responded to it. These 260 respondents reflect about 12% of the 2,237 customers who participated to the end of the program. Tr. 11/22/10, pp. 2031-2038.

CL&P also noted that the limited income participants saved an average of $8.07 and that the remaining residential customers on average saved $15.21 over the duration of the study. C&I customers, on average, paid an additional $15.45 over the course of the Rate Pilot. Customers who logged on to the web site saved more, with the average residential customers saving $24.69 and C&I customer saving $0.14. RPIWEP, p. 9.

CL&P indicated that the customers who participated in the pre-pilot focus group and post-pilot survey indicated that the eight-hour TOU duration was too long for them to be able to significantly respond to their consumption patterns. In addition, Brattle identified CL&P's TOU period as being the longest duration to their knowledge. Brattle continued, noting that other utility pilots, including the California Statewide Pricing Pilot (California Pilot) have demonstrated that a shorter TOU period would provide a higher impact. Brattle continues, noting that the California Pilot included rates similar to CL&P's CPP and PTR rates and that the California Pilot showed results similar to CL&P's Rate Pilot for these rate designs. Id.

CL&P indicated that although a four-hour TOU rate was not tested in its Rate Pilot, Brattle was able to provide a reasonable extrapolation of the impact that this rate design would have on consumption. Brattle's results indicate that a four-hour TOU rate would reduce peak load by 6.3% and .8% for residential and business customers, respectively. Id.

Regarding the duration of the Company's current TOU tariffs and seasonal TOU variations, CL&P testified that it had previously opposed seasonal TOU periods (i.e., different peak periods for the summer, winter and shoulder periods), and shorter durations citing the potential for customer confusion and the need to assure that the peak hour would be always be captured within the defined peak period. However, citing the impact that Connecticut's energy policies have had on customer behavior and awareness as well as a cultural shift in society's view toward energy, CL&P now supports four-hour seasonal TOU periods (e.g., summer peak from 2 p.m. to 6 p.m. and winter peak from 4 p.m. to 8 p.m.) to reflect actual peak demand data. Tr. 11/22/10, pp. 1940-1943; Response to Interrogatory EL-81.

CL&P believes that the Rate Pilot achieved its objectives to gain insight into customer interest in, and response to, dynamic pricing rates, while at the same time gathering experience and insight into the capabilities and maturity of certain AMI technologies. Table 3 below summarizes CL&P's conclusions regarding the Rate Pilot.

Table 3. CL&P Conclusions - Residential and Small C&I Customers

All customers responded to dynamic rates despite mild summer conditions; Residential demand response compares favorably to other pilots; Small C&I customers were less price responsive than residential customers; All customers were generally not responsive to the eight-hour TOU rates; The ORB did not increase price responsiveness; A/C switch & thermostat increased responsiveness for PTP & PTR but not for TOU; PTP led to a small increase in residential consumption; PTR and TOU led to a small decrease in residential consumption; Small C&I customers did not change consumption under any dynamic price scheme.

November 11, 2009 Impact Evaluation, p.17.

The OCC expressed concern about the results of the Rate Pilot because CL&P was overly optimistic in its interpretation of the Rate Pilot results. For example, CL&P achieved a low participation rate despite the significant amount of attention that was given to enrolling customers in the study. As a result, CL&P cannot support its base case participation rates of 25% for residential and 50% for commercial and industrial customers. Brief, p. 4.

The OCC stated also that the incentive payment combined with the fact that customers were aware of their participation in a pilot project may have stimulated customers to apply an above average good-faith effort to manage their electric consumption, thus skewing the results of the study. The OCC noted that only 0.02% of customers have enrolled in CL&P's current and voluntary TOU rates. Based on such a low enrollment in the current rate, the OCC concluded that there was not a strong desire among customers to participate in dynamic pricing. Additionally, a targeted approach which provides AMI capabilities to customers who specifically request dynamic pricing and time differentiated rates is less costly than and will achieve the same benefits as full deployment. Id.

The AG argued that the customers who participated in the Rate Pilot were not representative of average CL&P customers. Instead, customers who participated in the Rate Pilot were motivated to try the new technology and associated time-based rates and were paid for their participation. The AG, citing CL&P's testimony, stated that a typical CL&P customer is far less likely to consider TOU rates and the installation of Enabling Technologies than the Rate Pilot participants. According to the AG, despite being motivated to embrace these innovative rates and advanced technologies, the Rate Pilot showed no beneficial impact on energy consumption. Brief, pp. 6 and 7. In addition, while residential customers experienced modest savings, (e.g., $15 for non limited income customers), the costs to business customers actually increased. AG noted that these savings do not reflect the cost of the meters or the stranded costs associated with the current AMR system. Id.

The AG claims that the moderate weather conditions in the summer of 2009 likely skewed the results by making participation in the program much less burdensome on the participants and leaving them with a far more positive impression than they would have had under more typical weather conditions. Mild weather made it easy to curtail load while the financial inducement to participate insulated customers from the financial penalties that would have resulted from their failure to shift electric load or curtail demand during event days. Regarding future voluntary enrollment in dynamic pricing, the AG commented that although CL&P currently offers voluntary TOU rates, very few customers purchase service under these tariffs. Id., p. 8.

The AG concluded that the Rate Pilot failed to provide the evidence necessary to support the large scale investment and deployment of AMI meters. As a result, the AG recommended that the Authority not force customers to purchase expensive AMI meters to facilitate rates that they have shown they do not want and are not likely to use. Id., p. 9.

The Connecticut Industrial Energy Consumers (CIEC) argued that despite CL&P's substantial and dedicated marketing efforts and a significant participant incentive payment, the Rate Pilot only generated modest participation rates of 3.1% and 4.5% respectively, among residential and business customers. Further, despite these tepid participation levels and no history that would allow CL&P to understand how many and how long customers will voluntarily participate in dynamic pricing over the long term, the Company projects participation levels nearly 10 times greater than indicated by the Rate Pilot. The CIEC concluded that CL&P's base case participation levels simply cannot withstand scrutiny and therefore should not be relied on by the Authority. Brief, pp. 15 and 16.

5. Rate Pilot Analysis and Conclusion

CL&P designed the enrollment process to minimize self-selection bias and to assure valid results. The Authority finds that the Rate Pilot enrollment process achieved a demographically diverse representation of CL&P's customers for each of the pricing schemes and technologies tested.

The Rate Pilot demonstrated that residential and business customers are willing to reduce their electric demand for short periods of time on select days (i.e., up to four hours on event days under the PTP and PTR rates) when provided with an economic incentive to do so. For example, residential customers showed peak demand reductions ranging from 7% to 23.3% while business customers reduced their demands by 1.7% to 7.2%. However, neither the residential nor business customers in the Rate Pilot reduced their overall energy consumption.

The Rate Pilot also demonstrated that customers are willing to adjust their peak demand on a more regular basis (i.e., throughout the duration of the Rate Pilot period under an eight-hour TOU rate) when provided an economic incentive to do so. However, as discussed below, the summer of 2009 was unusually mild and customers were paid a relatively large fee to participate in this three-month study.

Table 4 below demonstrates the maximum dry bulb temperature that occurred on the ten event days called in June, July and August 2009. As the table shows, there was only one day in which temperatures exceeded 90º at one of the reporting stations (August 18, 2009, Bradley Station) and that temperatures on the remaining days were in the low-to mid-80's. A heat wave is sometimes defined as three consecutive days of temperatures in excess of 90º, a condition that drives peak demand and increased use of air conditioning. None of the event days occurred during a heat wave or other extended period of extreme temperatures.

Table 4. CCP Day Maximum Dry Bulb Temperatures

CPP Day	CPP Date	Maximum Dry Bulb Temperature Bradley Station	Maximum Dry Bulb Temperature White Plains Station
1	June 25, 2009	80	78
2	July 9, 2009	69	70
3	July 16, 2009	82	83
4	July 17, 2009	84	83
5	July 29, 2009	82	81
6	July 30, 2009	86	85
7	August 4, 2009	85	84
8	August 5, 2009	86	85
9	August 11, 2009	89	85
10	August 18, 2009	92	88

Appendix B Load Impact Analysis Methodology, Tables 1 and 2, p. 6.

CL&P acknowledged that the pilot was conducted during a very mild summer, and as a result, "for purposes of evaluating likely peak period load response" CL&P used the weather conditions from the four event days it called in August 2009 because they more closely represented typical peak type conditions. Response to Interrogatory EL-74. CL&P concluded that because there was enough variation in the underlying load values, weather conditions, and price levels, that it could estimate peak load response for a larger population with statistical precision and certainty. Id.

Customers demonstrated a willingness to reduce electric demand during the ten event days, a total of 40 hours, used in the pilot. However, it is reasonable to conclude that the lack of extreme weather conditions influenced the decision to curtail load for this relatively short period of time making participation in the program much less burdensome than might otherwise have occurred under more extreme conditions.

Customers were paid an incentive to participate and as noted by the AG, combined with mild weather, the financial incentive insulated customers from the financial penalties that would have resulted from their failure to shift electric load or curtail demand during event days. In addition, to receive full payment, customers were required to remain in the study for the full term. As a result, the incentive may have influenced the duration of customer participation. Further, as noted by CL&P, there is no history that would allow it to understand how long customers will voluntarily participate in dynamic pricing over a 20 year period.

CL&P's post-pilot survey revealed that customers were very satisfied with the Rate Pilot and would participate again. However, these results are based on a very limited response to the post-pilot survey. The Authority concludes that it is unreasonable to draw broad conclusions regarding customer satisfaction with the Rate Pilot based on the limited response to the post-pilot survey.

Based on the foregoing the Authority finds that while it is reasonable to conclude that customers will respond to standard TOU rates and dynamic pricing it is difficult to predict with certainty the likely peak load response that customers would provide under extreme weather conditions of high heat and humidity. It is also extremely difficult to predict the level to which customers would voluntarily enroll under these rates and the duration of their participation.

H. AMI SMART METER DEPLOYMENT PLAN

1. Company Proposal

a. Overview

On March 31, 2010, the Company submitted a deployment plan (Plan) to install new AMI smart meters to all of its 1.2 million customers during a four-year period starting in late 2012 through 2016 and implement a dynamic pricing program that would continue for another 20 years to 2035. The infrastructure for receiving and storing data, transmitting information, and creating bills would be installed or upgraded over a five year period ending 2016 and require 51% of the total costs. CL&P estimates that the total cost would be approximately $863 million, or $493 million on a present value basis.

The Company analyzed several deployment options: surgical AMI deployments exclusively for customers who sign up for dynamic pricing, geographic deployment scenarios that were focused on the most cost effective areas, partial deployments based on customer segment and a full deployment. After its analysis of scenarios, CL&P concluded that a full deployment to all customers is the most cost effective scenario due to operational savings that allows dynamic pricing to be offered to all CL&P customers. ADPDCBA, p. 3.

CL&P claims that full deployment is the most cost effective option when compared to alternatives such as a phase in approach. CL&P also states that replacing AMR meters as they reach the end of their useful lives with AMI meters will actually increase stranded costs to approximately $80 million versus the full deployment stranded cost of approximately $40 million. Brief, p. 8.

CL&P's smart meter deployment proposal was based on a variety of analyses, including the Plan-it Wise Pilot results, internal and external subject matter experts, independent studies, review of prior AMI business cases and development of a complex financial model with the ability to analyze numerous scenarios. In addition, the Company hired Bridge Strategy Group to assist with development of the CBA financial model. ADPDCBA, Appendix A, p. 2.

In 2009, the Company began developing a platform to enable AMI with a meter data management (MDM) project. Key AMI cyber-security and interoperability standards are being developed in parallel and are estimated to be near complete by mid-2011. Depending on the progress of AMI standards, the Company will move forward in 2011 with a Request for Proposal for an AMI-technology solution. CL&P plans to select a specific AMI technology and vendor in 2012 once key AMI standards are developed and compliant vendor solutions have the opportunity to mature. Both mesh and two-way radio AMI solutions provide the technical capabilities needed in the Plan. ADPDCBA, p. 11.

CL&P expects to submit a proposed cost recovery plan to the Authority by July 31, 2012. Assuming approval in the third Quarter 2012 by PURA, the Company intends to begin deploying AMI meters by December 31, 2012, with implementation in four years. During the physical AMI deployment, the Company will build the IT capabilities required to provide dynamic pricing and hourly energy usage analytics on customer bills. Dynamic pricing will be available to all customers by 2016. The remaining IT capabilities to deliver outage detection, theft detection, and remote service activation operational efficiencies will be developed through 2017. ADPDCBA, pp. 11 and12.

b. Deployment Options Considered

The Company analyzed five separate partial AMI deployment scenarios and one full AMI deployment scenario described below:

- Scenario 1. Providing AMI and dynamic pricing options to the largest 600,000 customers.
- Scenario 2. Providing AMI and dynamic pricing options to only small C&I customers.
- Scenario 3. Providing AMI and dynamic pricing options to customers in Hartford and Stamford.
- Scenario 4. Providing dynamic pricing options through an opt-in Cel-Tel solution (i.e., a customer that signs up for dynamic pricing receives a Cel-Tel meter).
- Scenario 5. Providing dynamic pricing options through an opt-in AMI solution (i.e., a customer that signs up for dynamic pricing receives an AMI/smart meter).
- Scenario 6. (Base Case) Providing AMI and dynamic pricing options to all customers. The base case was updated in Late Filed Exhibit No. 1.

Late Filed Exhibit No. 9.

Table 5 below provides an overview of the various AMI deployment options. The Company claims that full deployment in Scenario 6 is the most cost effective solution, due to the cost of the minimum infrastructure requirements that are necessary for any of the scenarios. In addition, CL&P states that some benefits can only be achieved under full deployment as it eliminates any discriminatory ratemaking issues. ADPDCB Appendix, p. 2.

Table 5. CL&P AMI Deployment Scenarios
Scenarios arranged Worst to Best based on net benefits.
$ in millions

	Scenario 4 Cel Tel-Opt In Solution	Scenario 3 Hartford / Stamford	Scenario 2 C&I Customers Only	Scenario 5 AMI-Opt In Soultion	Scenario 1 600,000 Customers	Scenario 6 Base Case All Customers	Scenario 6 Base Case All Customers LFE-1
Net Benefits	($179)	($56)	($54)	($15)	($9)	$87	$154
Rank of Net Benefits	7 Worst	6	5	4	3	2	1 Best
Total Costs	($314)	($121)	($135)	($195)	($267)	($493)	($429)
Total Benefits	$136	$65	$81	$180	$258	$580	$583
Customer Participation							
Meter Type	Cel Tel	AMI	AMI	AMI	AMI	AMI	AMI
No. of Res Meters	273,250	67,135	0	273,250	496,000	1,093,000	1,093,000
No. of C&I Meters	26,000	44,757	104,000	26,000	104,000	104,000	104,000
Total Meters	**299,250**	**111,892**	**104,000**	**299,250**	**600,000**	**1,197,000**	**1,197,000**
% of Res Meters	25%	6%	0%	25%	45%	100%	100%
% of C&I Meters	25%	43%	100%	25%	100%	100%	100%
% of Total Meters	25%	9%	9%	25%	50%	100%	100%
Dynamic Pricing Participation							
No. of Res Customers	273,250	16,784	0	273,250	124,000	273,250	273,250
No. of C&I Customers	26,000	11,189	26,000	26,000	26,000	26,000	26,000
Totals	**299,250**	**27,973**	**26,000**	**299,250**	**150,000**	**299,250**	**299,250**
Capital Costs							
Meters & Communications	$42	$36	$44	$70	$129	$273	$234
IT	$16	$21	$21	$21	$21	$21	$21
Rate Program	$2	$2	$2	$2	$2	$2	$2
Total Capital	$60	$59	$67	$93	$152	$296	$257
O&M Costs							
Meters & Communications	$203	$21	$27	$41	$65	$121	$112
IT	$24	$34	$34	$34	$34	$32	$34
Total O&M	$227	$55	$61	$75	$99	$153	$146
Customer Engagement	$27	$6	$7	$27	$16	$44	$27
Total Costs	**$314**	**$121**	**$135**	**$195**	**$267**	**$493**	**$429**
Benefits							
O&M	$0	$13	$5	$45	$85	$211	$224
Capital Avoided	$40	$11	$12	$40	$40	$82	$77
Peak Reduction	$52	$5	$5	$52	$26	$66	$52
Energy	$39	$33	$52	$39	$95	$144	$149
Value of Service	$0	$0	$0	$0	$0	$59	$62
CO_2 Emissions	$5	$4	$7	$5	$12	$18	$19
Total Benefits	**$136**	**$65**	**$81**	**$180**	**$258**	**$580**	**$583**
Net Benefits	**($178)**	**($56)**	**($54)**	**($15)**	**($9)**	**$87**	**$154**

Late Filed Exhibit No. 9, p. 5; ADPDCBA, pp. 8 and 9.

The five partial deployment scenarios in Table 2 used the same assumptions as in the base case but only changed the number of customers included in the scenario, the number of customers participating in dynamic pricing rates, and the capital and O&M costs.

A key characteristic of the deployment plans is that net benefits increase as more customers are added to the deployment. All of the AMI scenarios generate peak and energy reduction benefits enabled through dynamic pricing and AMI, but the partial deployment scenarios lack necessary operation and maintenance (O&M) and reliability benefits only achievable in the full deployment scenario. The most significant benefits enabled through a full deployment scenario, but lost in the partial/targeted scenarios, are the meter reading and outage operations savings and the reliability benefits enabled by shorter customer outage durations during storms. None of these benefits can be assumed in the partial deployment scenarios.

The non-AMI solution, Scenario 4, proposing to use Cel-Tel meters, does not yield a positive Net Present Value (NPV[7]). The main reason is the high cost of reading these meters on a monthly basis at $5 per month, per meter. Also, the opt-in AMI solution, Scenario 5, had negative net benefits due to fixed costs.

The Company claims that Scenario 6, the full deployment scenario, as modeled in the Base Case, is the only scenario that produces a positive NPV and demonstrates a cost effective dynamic pricing solution for CL&P customers. The partial/targeted AMI deployment scenarios all contain similar fixed capital costs for IT and Communications as the full deployment scenario. This highlights the point that the most efficient use of the AMI infrastructure is through a full deployment to all CL&P customers.

The Company also claims that Scenario 6 is the best option in terms of costs, benefits and long-term viability. As such, the Authority has focused on the full deployment scenario and the related costs and benefits associated with a full AMI meter deployment.

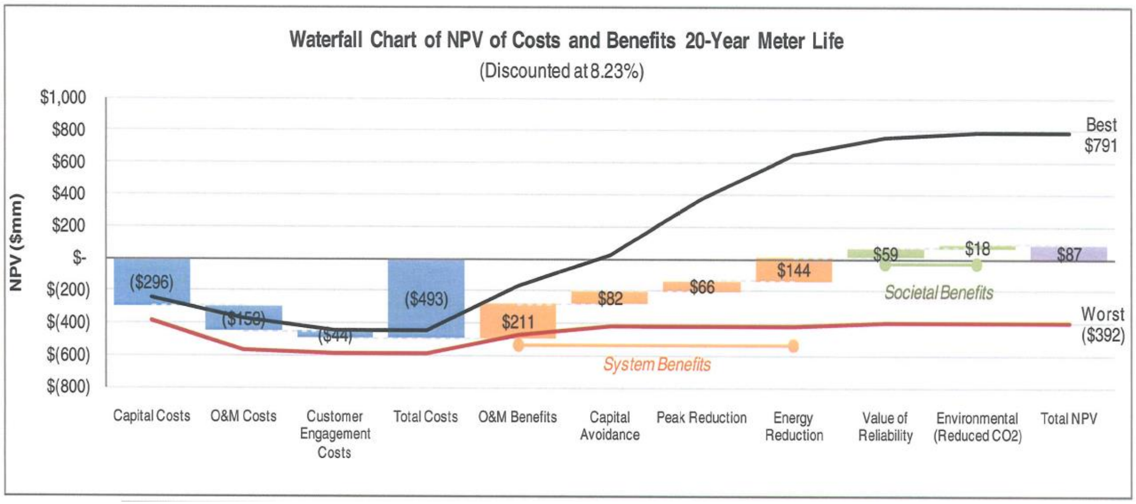
c. Benefit Cost Analysis

CL&P filed a detailed CBA for its deployment plan under three scenarios; a worst case, base case and best case scenario. The results of the worst case and the best case provide a range of net benefits that vary from a low of negative $392 million to a high of $791 million.

The deployment plan for the base case is estimated to cost $493 million with total benefits of $580 million and net benefits of $87 million on a NPV basis. (ADPDCBA, p. 3. Under the base case scenario, CL&P claimed total benefits of $580 million attained from six benefit categories shown in Figure 2 below.

[7] NPV is a standard method for using the time value of money to appraise long-term projects. NPV states the total present value of cost and a benefit stream over a long period of time in present value as the value of dollars in the first year of expenditures. The most critical factor in the NPV methodology is the discount rate which is CL&P's weighted average cost of capital after tax. For example, using a discount rate of 8.23%, today's value of a $1.00 saved 5, 10 or 20 years in the future would only be worth $0.67, $0.45 or $0.21 from that year.

Figure 2. Results of Initial Cost Benefit Analysis



Late Filed Exhibit No.2, Slide 17.

The average cost of the deployment plan and the dynamic pricing program would be $411 per customer ($493 million/1.2million customers). All values are stated in NPV throughout this Decision except where noted differently.

In the base case, the Company determined that the average monthly bill impact to residential and C&I customers would be:

- On a levelized basis, the average residential customer will save $11 over the twenty-year life of the AMI program. ($0.55/year or $046/month);
- On a levelized basis, the average C&I customer will save $96 over the 20 year life of the AMI program. ($4.80/year or $0.40/month); and
- The average customer bill will increase until 2019 and then decrease. ADPDCBA, p. 10.

The Company updated the CBA and the change in result of the base case that was submitted in Late Filed Exhibit No. 1, which became the Company's latest deployment valuation. The net benefits of $154 million in Late Filed Exhibit No. 1 increased over that initially provided in the initial filed base case due to the following changes made by CL&P:

1. A reduction in the discount rate from 8.23% to 7.68% developed in the Company's last rate case which increased savings by $18 million;
2. The Company removed $16 million of Customer Engagement costs for developing an additional sheet for customer bills to support dynamic pricing and conservation objectives;
3. A reduction in capital costs and O&M costs for meters and communications equipment by $59 million due to using the lowest of ten bids received in its RFI for meter costs in place of the average of the middle eight bids used in the initial filing;

4. The Company removed $20 million for TOU peak savings to more accurately reflect the impact of the TOU rate offered in conjunction with the PTP or PTR rates; and
5. The Company removed $4 million of Peak Reduction/Capital Avoidance savings based on recent data from other utility deployments that indicates the base case dynamic participation rate for C&I customers should be 25% and not 50%.

Table 6 below lists the dollar amount of benefits and costs in its original and revised base case.

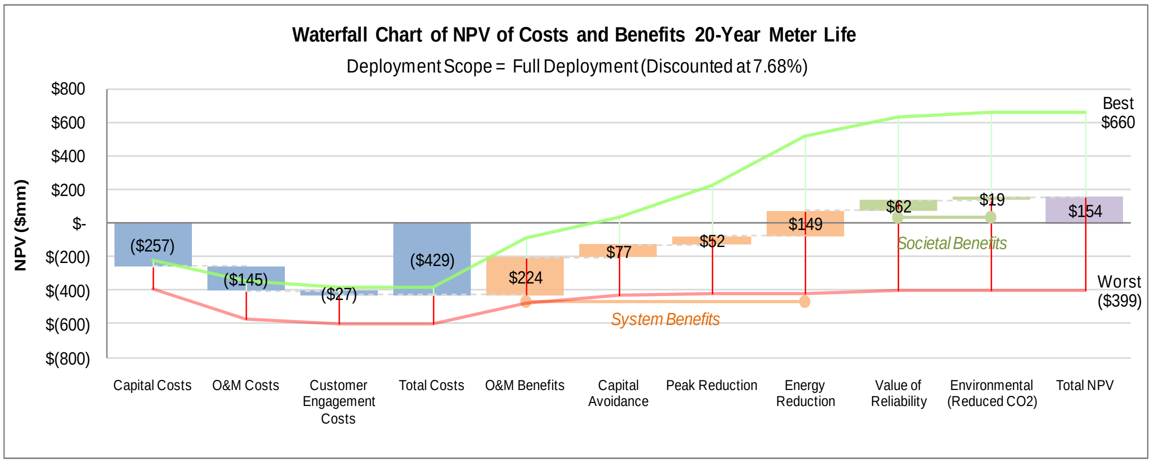
Table 6 CL&P Cost Benefit Analysis Savings
Base Case $ NPV=millions

Benefits	**Original Base Case**		**Revised Base Case**	
O&M Benefits	$	211	$	224
Capital Avoidance	$	82	$	77
Peak-Load reduction	$	66	$	52
Energy reduction	$	144	$	149
Value end-use customers place on reliability	$	59	$	62
Environmental	$	18	$	19
Total Benefits	**$**	**580**	**$**	**583**
Costs				
Capital	$	(296)	$	(257)
O&M	$	(153)	$	(145)
Customer Engagement	$	(44)	$	(27)
Total Costs	**$**	**(493)**	**$**	**(429)**
Overall Net Benefit/Cost	**$**	**87**	**$**	**154**

ADPDCBA, Appendix A, pp. 6 and 10;
Late File Exhibit No. 1.

Figure 3 is the Waterfall Chart for the latest base case revisions for costs and benefits as determined by the Company for a full-scale smart meter deployment.

Figure 3. Results of Revised Base Case Cost Benefit Analysis



Late Filed Exhibit No.1, p. 3.

The Company's CBA is evaluated on a NPV basis, which requires assumptions around future expectations of AMI infrastructure costs and consumer behavior reactions to dynamic pricing as well as forecasted energy prices and Forward Capacity Market (FCM) prices. Since the Company only provided 3 pages of detail in Late Filed Exhibit No. 1 of its revised CBA, the Authority concentrated on the initial CBA then considered the changes in Late Filed Exhibit No. 1 in its evaluation of the proposed deployment plan.

2. Position of Parties

a. Connecticut Industrial Energy Users (CIEC)

The CIEC strongly disagreed with the Company's recommendation for full AMI meter deployment from a cost/benefit perspective for several reasons. The CIEC stated that the lack of demonstrable benefits associated with such a deployment and the substantial economic burden that it would place on the Company's customers as reasons for its opposition. Brief, p. 2. The CIEC also argued that the inclusion of AMR stranded costs would reduce the overall base case benefits of $87 million by $58.9 million, significantly reducing benefits by almost 68 percent to $28.1 million. Id., p. 14. Additionally the CIEC argued that $77 million in societal benefits from reliability and environmental categories artificially inflates the potential benefits derived from AMI. Id., p. 15. According to the CIEC, by eliminating the societal benefit and including the stranded costs results in an overall net benefit of negative $48.9 million. Id.

Additionally the CIEC argues that a full AMI deployment in CL&P's service territory would result in a projected NPV cost increase between $452 million - $581 million with an additional $58 million of stranded costs related to the existing AMR meter system. The CIEC claims that the cost impacts to electricity consumers are stunning given the lack of demonstrable concrete benefits. Brief, p. 9. Alternatively, if AMI meter technology is pursued, the CIEC suggests limiting installations to either a voluntary approach or replacing current AMR meters as they reach the end of their service lives. Id., p. 10.

b. AG

The AG opposes a full scale AMI deployment for various reasons including stranded costs associated with existing AMR meters of $41 - $44 million. Brief, p. 11. The AG also states that a surgical AMI deployment would reduce stranded costs and alleviate some of the costs associated with full AMI deployment such as the inevitable increase in customer inquiries and problems with new meters. Id., p. 12.

Additional the AG maintains that the benefits of CL&P's analysis were much more speculative than the associated costs because they depended on assumptions concerning a variety of critical variables such as, future electric prices, elasticity of demand for electricity and calculating the benefits of peak-time energy usage reductions. Brief, p. 12. The AG further maintains that the participation numbers that CL&P assumed in the full deployment scenario are unrealistic. Id. Finally, the AG asserts that even if CL&P's CBA was accurate, the financial benefits associated with full AMI deployment are small, totaling $11 over a 20 year period for residential customers and $96.35 for C&I customers. Id., pp. 12 and 13.

According the AG proposes that CL&P not be allowed any up-front cost recovery. Instead the AG recommends that the cost recovery for the new meters be considered in a full rate proceeding after the meters are installed and considered "used and useful." Id., p. 17.

c. OCC

The OCC cites numerous risks to full scale AMI deployment including changes in consumer and computer technologies, along with the increasing rates of change in these technologies. Brief, p. 14. The OCC argues that communication standards and protocols to be utilized by CL&P's proposed AMI system are still being developed and will need time for refinement before they operate optimally. Id., p. 15.

The OCC dismissed several of CL&P's claimed benefits including savings associated with OPower studies, revenue protection, outage operations, reliability and environmental savings. The OCC also disagreed with the Company's claimed benefit amounts for reduced theft protection and savings in outage operations as well as the Company's claimed reliability and environmental benefits. Additionally, the OCC dismissed the costs associated with OPower and revenue protection. According to the OCC after making adjustments to CL&P's cost/benefit analysis, the net benefit of $87 million claimed by the Company, materialized into a net ***cost*** of $180 million. Brief, pp. 20–23. Table 7 below details the adjustments OCC made to the Company's cost/benefit analysis. Id., p. 23.

Table 7. OCC Adjustments to Cost-Benefit Analysis
Base Case $-millions

Benefits/Costs of CL&P AMI Plan	**Adjusted Base Case Scenario**
Costs	$493
Less Cost of Opower Study	($16)
Less Revenue Protection Costs	($16)
New Net Costs	**$461**
Benefits	$580
Less Benefits from OPower	($144)
Less Renenue Protection	($68)
Less Environmental	($10)
Less Reliability	($59)
Less Environmental	($18)
New Net Benefits	**$281**
Net Benefits/(Costs)	**($180)**

OCC Brief, pp.20-23.

The OCC proposes utilizing a TOU rate format with existing AMR meters rather than a dynamic pricing rate schedule associated with PTP and PTR. In the opinion of the OCC, that there is potential for significant load shifting in CL&P's service territory using TOU rates coupled with enhanced technologies and other modern load management appliances. Id., p. 29.

I. AUTHORITY ANALYSIS

Smart meters have the potential to offer customers new options to reduce their electric bills and provide benefits to the electric system through lower peak demands and energy usage. The operations of the electric system could also improve from theft detection, remote disconnect and reconnections, lower meter reading expenses and other operational efficiencies, reducing costs and providing benefits to all ratepayers. These benefits require a significant investment. CL&P estimates the cost to be $867 million or $493 million on a NPV basis, half of which would increase rates over the first five years of its plan.

CL&P has conducted a detailed cost benefit analysis of the project. The results indicate net savings of $154 million on a net value basis over a 20 year period. The net savings are relatively small on a per customer basis even if it is assumed that CL&P's analysis is correct. In the base case, the Company determined that the average monthly bill impact to residential and C&I customers would be $11 over the 20 year life of the AMI program. The average C&I customer will save $96 on a levelized basis over the same time period.

CL&P did a very thorough analysis with the information available. However, many assumptions were required since real experience with smart meters and dynamic pricing is very limited. The Authority will examine these assumptions and the costs and benefits presented by CL&P below.

1. Assumptions

As the basis for its CBA, CL&P included five major assumptions to arrive at their conclusions regarding the benefits of a full-deployment of AMI meters. ADPDCBA Appendix A, pp. 2-6. The major assumptions used by CL&P in the CBA are listed and discussed below.

a. Deployment Assumptions
b. AMI Asset Life Assumptions
c. Capacity Savings
    1. Customer Engagement Rates
    2. Peak Load Reduction
    3. Forward Capacity and Energy Prices
d. Discount Rate and Inflation
e. Customer Energy and Demand Growth

These assumptions have a major impact in deriving the majority of the costs and benefits for full AMI meter deployment. Slight changes to any of the assumptions can have a major impact in the final net benefit amounts.

The Authority has carefully reviewed these assumptions to determine their reasonability and has made adjustments where deemed necessary.

a. Deployment Assumptions

The deployment plan proposed by CL&P would involve the total replacement of all 1.2 million meters over a four-year period. The advantages of this deployment plan are that all customers will have a smart meter and access to dynamic and TOU rate options. It also allows the full benefits of operational efficiencies to begin earlier than partial or staged deployment options. The major problem is that it is a large commitment to select a technology at this point given the rapid changes in the industry and the evolving, but yet unfinished standards.

The deployment plan is important in the cost benefit analysis as to the overall costs and benefits since the plan determines the number of customers receiving smart meters and the timing of the deployment.

b. AMI Asset Life Assumptions

CL&P used 20 years as the useful life of the AMI meters in its analysis. In order to arrive at the useful life of meters, the Company relied on its own research of equipment vendors, industry publications and various other inputs from internal and external subject matter experts. CL&P acknowledged the uncertainty within the AMI industry regarding the useful life of the meters and therefore included the asset life as a component of the NPV sensitivity analysis. Based on its analysis, the Company feels that a 20-year meter life is most appropriate in the base case. ADPDCBA Appendix A, p. 3.

The OCC cited the increasing rate of change in technology as a risk to the useful life of AMI meters. The OCC stated that the current AMR meters have a useful remaining life of 13 years but are already considered obsolete by the Company. The OCC also stated that the AMI meters have even more of a chance of early obsolescence than the current AMR meters. Brief, p. 14.

AMI, also known as smart meter technology or AMI technology, is still a relatively new concept with very little “real world” applications and data to make a fully informed decision. CL&P acknowledged that AMI technology is still developing. Late Filed Exhibit No. 2, p. 15. It is conceivable that advanced versions of AMI technology are close and indeed, CL&P acknowledged this fact stating that AMI technology is still maturing. Tr. 11/22/10, p. 1903. The AMI meters that CL&P proposes to install are not guaranteed to be compatible with future AMI standards as technologies change. There is evidenced in Appendix B – AMI Technology, Standards and Deployments Update, to the CL&P 2007 Decision, p. 3, which discusses the interoperability and open standard protocols as not being fully developed.

In the past, meters were generally expected to last 30 to 40 years, but the majority of the current AMR meters have only been in place for approximately 11 years and CL&P is proposing a total replacement. Based on the actual useful life of the current AMR meters if a full-scale deployment of AMI is approved, the Authority is also skeptical of the useful life of 20 years as claimed by CL&P. Fast changing technology for AMI meters and the still developing AMI standards call into question the service life of the AMI meters.

c. Capacity Savings

CL&P estimates that annual peak load reduction savings generated by the proposed dynamic pricing plans to be 126 MW under their original base case analysis. Response to Interrogatory EL-53. These savings are based on customer engagement rates of 25% for residential customers and 50% for small commercial and industrial customers and peak load reductions based on the results of the pilot rate study.

Many of the benefits that are expected from the smart meters result from the savings attributable to the capacity associated with the dynamic pricing and TOU rate options. These benefits include avoided generation, transmission, and distribution capacity benefits and capacity Demand Reduction Induced Price Effect (DRIPE) benefits. The savings are estimated based on the customer participation or engagement rates, the savings per customer and the value of the savings. These assumptions therefore are very important in the determination of the benefits that can be expected from smart meters.

i. Customer Engagement Rates

In its initial CBA, the Company used 25% for residential customers and 50% for small C&I customers as the base case assumption for the number of customers that would participate in dynamic pricing programs. This was changed to 25% for both residential and small C&I customers in their updated filing for the revised CBA.

CL&P acknowledges that there is no history that will allow the Company to predict voluntary participation in dynamic pricing. Over the duration of the Rate Pilot, 3.1% of residential customers and 4.5 % of C&I customers that were solicited by the Company enrolled in dynamic pricing. The Company expects that over a longer period of time, enrollment and participation in dynamic pricing will increase as customers become more familiar with the program. ADPDCBA Appendix, p. 6.

The Company updated its customer engagement rate assumptions in response to Late Filed Exhibit 8, believing that a five-year ramp-up rate was a more appropriate assumption for dynamic pricing sign-ups. Additionally, the engagement rate for C&I customers was reduced from the original assumption of 50% to 25%. The Company stated that these changes did not significantly impact the CBA having a negative NPV benefit effect of $4 million**.** Late Filed Exhibit No. 1, p. 2. Table 8 below shows the Company's predicted ramp-up for dynamic pricing participation.

Table 8. Dynamic Pricing Customer Participation Over Time

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020 and beyond**
Business	0%	0%	0%	5%	10%	15%	20%	25%	25%
Residential	0%	0%	0%	5%	10%	15%	20%	25%	25%

Late Filed Exhibit No. 1, p. 2.

The CIEC claims that the Company's participation rates are overly optimistic and unsupported by the record. Brief, p. 15. In support of that assertion, CIEC points to the dedicated marketing efforts by CL&P and a $100 incentive payment generating participation rates of only 3.1% for residential and 4.5% for C&I customers. Id.

The OCC also suggests that the Company is overly optimistic in its assumption concerning customer engagement rates. Brief, p. 4. In response to OCC cross examination, the Company agreed that the $100 participation award was significant for senior citizens and low-income customers and that the $100 payment was one of the major reasons for them joining the pilot. Tr. 11/19/10, pp. 2022 and 2023.

The updated participation rates proposed by the Company seem reasonable but there is no actual historic data to substantiate their assumptions. Given the relatively low level of participation during the pilot for both residential and C&I customers of 3.1% and 4.5% respectively, the participation levels of 25% claimed by the Company raise considerable uncertainty with these estimates.

Dynamic rates, such as PTP and PTR, are new to customers and there is little evidence as to the desire of customers to participate in these types of pricing options. CL&P did not provide any surveys or results from other states to support their estimate. Even if customers decide to try new rate options, it is uncertain how long they will participate and whether savings will continue at the same levels over many years.

CL&P originally estimated that $44 million would be spent over the first three years to recruit customers and provide outreach including information on how to conserve and save money. This was later reduced to $27 million in CL&P's updated filing of the revised base case. The Company also included costs for a web portal to provide customers access to energy usage reports and analysis. This is a significant amount, but there remains an ongoing educational effort to maintain participation and meaningful savings. It will also require training and commitment from all customer service staff as well as senior executives. CL&P does not have a good track record with its TOU rates. These rates have been available for over 20 years but almost no residential or small C/I customers are on TOU rates. Over the years the Company has done little to modify these rates to make them more attractive or encourage their use. For dynamic pricing and TOU options to provide meaningful benefits, it will require a significant commitment by the Company over the long term.

Additionally the Authority believes that the TOU rates can be used on a larger scale. The United Illuminating Company (UI) currently has 19**%** of its customers on TOU rates. The Authority has mandated TOU rates for all C/I customers above 200 kW and all residential above 2,000 kWh in any month. TOU rates are more common, and likely more acceptable, to the majority of customers but savings have also been shown to be more modest than other dynamic rate options.

ii. Peak Load Reduction

During the Rate Pilot, three rate designs were tested: PTP, PTR and TOU rates. The testing included high and low price differentials of on-peak to off-peak to develop a price elasticity curve. PTP and PTR were in effect for 40 hours on 10 days from 2 p.m. to 6 p.m. Id.

Under PTP, prices were increased up to $1.60 per kWh during peak hours and a discount of up to $.05 per kWh during off-peak hours. The PTR program retained normal tariff pricing during all hours of the Rate Pilot. However, if customers reduced their energy usage during the designated peak hours, rebates of up to $1.60 per kWh could be earned. TOU rates tested the responsiveness of customers to higher rates from noon to 8 p.m. on weekdays, which was the high rate period, and all other hours as the off-peak period. Id.

CL&P stated that the eight-hour TOU rate had a low impact due to the 8-hour duration in which the peak rates were in effect. CL&P determined, using data from the California Statewide Pricing Pilot (CSPP) that a 4-hour TOU period would have had a higher impact in reduction of energy by consumers. Id.

Finally, CL&P assumptions around dynamic pricing response have been adjusted from the actual results of the 2009 Rate Pilot to reflect what a "typical CL&P customer response impact would be." Id. Since the summer of 2009 was unusually cool, CL&P used temperature elasticities to arrive at their final results. CL&P provided these results under each of the pricing programs in the Table 9 below.

Table 9. Pilot Dynamic Pricing Response Adjusted for Typical Summer

Pricing->>	Peak Time Pricing		Peak Time Rebate		8-HR Time of Use	4-HR Time of Use
Customer	Pricing	w/Controlling Technology	Pricing	w/Controlling Technology	Pricing	Pricing
Residential	19.6%	28.5%	13.2%	21.8%	4. 1%	6.3%
Business	3.6%	9.4%	0.0%	5.3%	0.0%	0.8%

ADPDCBA Appendix A, p. 5; Late Filed Exhibit No. 1.

The AG questioned the validity of CL&P's Peak Load Reduction Assumption stating that the pilot results did not support full deployment. The AG cites several reasons as to why the pilot does not support full deployment of AMI. Among the reasons the pilot only consisted of 0.2% of the Company's total customer and that the customers who participated in the Rate Pilot were incented to participate through a monetary payment. Brief, p. 6

The AG also stated that the pilot showed no beneficial impact on total energy usage and cited the following results:

- CPP - total energy usage increased by 0.2% for residential customers and no change for C&I customers.
- PTR - total energy usage decreased by 0.2% for residential customers and no change for C&I customers.
- TOU - total energy usage decreased by 0.1% for residential customers and no change for C&I customers.

Id., p. 7.

Additionally, the AG asserted that residential customers that were enrolled in the CPP and PTR rate pilots reduced peak usage by relatively small amounts; 11% to 16% without controlling technologies and 18% to 23% with controlling technologies. Additionally, the AG points out the fact that the saving amounts mentioned above do not include any of the costs associated with purchasing and installing the new AMI meters as well as the associated stranded costs resulting from replacing the existing AMR meters. Id.

The OCC witnesses stated that the Company could have done more with the TOU rate option to address peak load reductions. Various TOU rate options can be implemented with current AMR meter technology. For example, they cite three other pilot projects in Florida, California and New Jersey that tested an option for TOU rates. The three pilots showed significant demand reductions of 21, 23 and 27 percent respectively. These results were almost ten times the peak energy reduction achieved in the Rate Pilot for TOU rates. Direct Testimony of Frank W. Radigan, Phillip S Teumim, Ronald J. Liberty and Alice Miller, pp. 31 and 32.

The Authority has reviewed Company for Peak Load Reduction assumptions and deems them reasonable based on CL&P's Rate Pilot results. The peak reductions are impressive for the residential customers that participated in the peak time rebate and peak time pricing programs. The Authority; however, is concerned with the low peak savings for small business customers on TOU, PTP and PTR without enabling technologies, and an absence of any overall energy reduction. Additionally, although the Company calculated the consumer response to peak rates during a "typical summer" using temperature elasticities, the results are based on theoretical assumptions rather than actual usage data. Given the projected engagement levels and the low savings from small business customers, it is clear that many of the smart meters deployed will not be used to provide any meaningful capacity or energy benefits.

iii. Forward Capacity and Energy Prices

CL&P used the forecast information provided in the 2010 Integrated Resource Plan for Connecticut (IRP). ADPDCBA Appendix A, p. 4.

The Authority acknowledges that no other parties have commented on the assumptions used by CL&P regarding forward capacity and energy prices. The Authority has no issue with CL&P's assumptions regarding forward capacity and energy prices, but notes that forecasting future energy and capacity prices is inherently difficult. This inexact science of forecasting future energy and capacity prices creates some uncertainty regarding the claimed savings associated with the dynamic pricing and time-of-use benefits from the smart meters.

d. Discount Rate and Inflation

The discount rate used in the initial detailed analysis by CL&P is 8.23% which reflected the Company's after tax weighted average cost of capital at that time. This discount rate was reduced to 7.68% in the revised base case, which is the rate of return that was approved for CL&P in its last rate case. Decision dated June 30, 2010 in Docket No. 09-12-05, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules. According to CL&P, the change in the discount rate increases the NPV net savings in the revised base case by approximately $18 million from $87 million to $105 million. Response to Interrogatory EL-15. In addition to the discount rate, CL&P applied an annual inflation rate of 2.50% to capital costs, operational expenses and forecast energy prices in order to keep all costs and benefits in nominal dollars. ADPDCBA Appendix A, p. 3.

The Authority did not receive any input from other parties relating to the discount rate used by CL&P.

The Authority acknowledges the fact that costs of the Company's AMI implementation are largely front-loaded in the early years of the project while the benefits are mostly back-loaded occurring after implementation is fully achieved. Id., p.

18. The change in the discount rate from 8.23% to 7.68% has a positive impact for the benefit amount in relation to the costs on a present value basis. The effect of the lower discount rate is magnified for the benefits vs. costs due to the fact that the majority of the costs for the project occur during the first five years of the 20-year project, therefore, the reduction in the discount rate has a lesser impact on the costs. As noted above by CL&P, the discount rate change accounts for approximately $18 million, nearly 21% of the original net benefit of $87 million of the increase in the NPV benefit. This example illustrates the sizeable effect a small interest rate change can make in the overall CBA analysis over the 20 year project life.

The Authority agrees with the Company that the appropriate discount rate of 7.68% should be used in the CBA since it is the latest rate approved by the Authority.

e. Customer Energy and Demand Growth

CL&P estimated annual customer growth rates of 0.5% for residential customers and 0.8% for C&I customers over the project period. Additionally, CL&P assumed that the average annual bill for a residential customer was $1,693 per year and was used in calculating certain benefit assumptions. Id.

The Authority acknowledges that no other parties have commented on the assumptions used by CL&P regarding customer energy and demand growth. The Authority accepts CL&P's assumptions concerning customer energy and demand growth.

f. Conclusion on Assumptions

The assumptions presented above formed the basis for CL&P's cost/benefit analysis. In the context of the Company's full AMI deployment CBA, the Authority does not take issue with the aforementioned assumptions but recognizes that uncertainty exists. The Authority is of the opinion that the Company substantiated the reasons for the assumptions used in their analysis. However, the Authority is concerned with the lack of historic data for assumptions concerning participation rates, savings estimates and meter lives which could have a major impact on the potential benefits from smart meters estimated by CL&P. The results of the worst case and best case scenarios provide a range of net benefits that vary from a low of negative $392 million to a high of $791 million.

2. Benefits

The Company estimated the total benefits to be $583 million on a net present value basis in its revised base case over the 24-year plan. Response to Interrogatory EL-14.xls. The Company included six major benefit categories in its analysis. A listing of each benefit along with the associated dollar amount of the benefit is listed below.

Major Benefit Categories

• Capital avoidance	$77 million
• Peak reductions	$52 million
• Energy reduction	$149 million
• O&M benefits	$224 million
• Value of reliability	$62 million
• Environmental	$19 million
Total Benefits	**$583 million**

Late File Exhibit No. 1, p. 3.

The Authority conducted several hearings regarding the smart meter deployment, taking testimony from CL&P, their expert witnesses as well as testimony from expert witnesses for the OCC. In addition to direct cross examination, the Authority continuously requested from CL&P, detailed, historical evidence of the benefits that could be achieved with AMI deployment on a large scale. Responses to Interrogatories EL-44, EL-48, EL-56, EL-61, EL-68, and EL-69. Despite these requests, the Company was unable to provide any such evidence to substantiate their benefit claims other than the theoretical savings based on extrapolating data from its pilot study. ADPDCBA Appendix, pp. 2-6. CL&P claimed that, "the analysis was based on an established analytical framework, sound data and reasonable assumptions." Reply Brief, p. 7. The Company did not include in its statement any reference to benefits achieved by other utilities that have implemented full-scale AMI meter deployments. The Authority will analyze each of the claimed benefits below.

a. Capital Costs

The Company claims it will be able to avoid or delay capital investments in two areas. First, the dynamic pricing programs will reduce peak-load needs and allow for reduction in capacity requirements for the transmission and distribution system. Second, by deploying AMI, CL&P will not incur capital costs associated with the replacement of the current AMR meters and other manual meter-reading equipment that otherwise would be required. CL&P identified $77 million in capital avoidance benefits. Brief, p. 5.

i. Avoided T&D Capacity

CL&P claims a benefit of $77 million in capital avoidance as a result of a full AMI deployment. Brief, p. 5. The Company states that the capital expenditure avoided through a reduction in peak load will be accomplished by leveraging the interval data collected through AMI to more accurately assess electric loading on distribution transformers. The AMI avoided capital assumptions utilized the findings from the avoided transmission and distribution investment study submitted to the PURA, as required by the 2009 C&LM Decision. The avoided capital investment study found less than 1% of transmission capital could be avoided due to peak reduction and 8.55% of distribution capital was estimated to be avoidable due to reductions in peak load. A statistical analysis translated the percentage of avoided capital investment into levelized avoided costs per kilowatt-year (kW-yr). The transmission avoided cost is estimated to be $1.18/kW-yr and the distribution avoided cost is $28.02/kW-yr. These levelized costs per kilowatt year were applied to the kilowatts assumed to be reduced by the adoption of dynamic pricing programs by customers. ADPDCBA Appendix A, p. 14.

In regard to CL&P's claim of a reduction in transmission and distribution capital costs, the AG states that the Company based this assumption on an existing energy conservation study and did not adequately explain why the results of that conservation study would apply in the present case. Brief, p. 13. The OCC made no argument for or against the capital avoidance benefits CL&P proposed in its CBA.

The Authority agrees that the Company's assumed kilowatt reduction due to the adoption of dynamic pricing can be translated to a dollar amount based on the avoided capital cost study results of the 2010 C&LM plan and therefore accepts the estimate of savings as proposed.

ii. Avoided Meter Costs

The Company also claimed a benefit amount of $45.6 million relating to the avoided costs of AMR meter replacement. Response to Interrogatory EL-14. CL&P states that deployment of AMI would avoid the capital costs associated with replacement of AMR meters and other manual meter-reading equipment (e.g., vehicles) that would otherwise have been required. The Company developed an AMR replacement schedule, based on initial AMR installation dates, expected useful lives and projected replacement costs, to calculate the timing of the annual avoided capital costs. Id.

The CIEC states that CL&P failed to include the potential stranded costs associated with the Company's existing AMR system. The CIEC also claimed that the inclusion of the $58.9 million AMR stranded costs immediately reduces the base case benefits by nearly 68 percent to $28.1 million, thereby significantly reducing the estimated benefit to customers. Brief, p. 14. The AG states that the AMR meter replacement benefit is overstated due to stranded costs associated with the existing AMR meters that would be $41 to $44 million. Brief, p. 11

The Authority believes that the benefit CL&P estimated for avoided meter costs is reasonable. However, the Authority notes that the Company failed to include the associated stranded costs of the current AMR meters of $41 million in the claimed benefit amount. Tr. 2/1/11, p. 2311. Therefore the Authority will recognize the stranded cost of current AMR meters of $41 million in its analysis.

b. Peak Load Reduction Benefits

CL&P states that implementation of dynamic pricing and the expected customer response to dynamic rates will enable the shifting of megawatts from peak to off-peak hours. The peak-load reduction benefits quantified by the Company include three sources: avoided generation capacity costs, capacity price mitigation and shifting usage from peak to off-peak hours. CL&P identified $52 million in peak-load reduction benefits. Brief, p. 5.

The Company provided a breakdown in savings between avoided capacity costs of $42 million and capacity price mitigation of $10 million is as follows Tr. 2/1/11, p. 2288.

In deriving savings from avoided capacity costs, CL&P used the 2010 CT IRP as the basis for the forecast FCM pricing. ADPDCBA Appendix A, p. 15. To arrive at the avoided capacity cost savings of $42 million, the avoided peak megawatts were multiplied by the expected value of the forward capacity market. The Company also stated that the shift from peak to off-peak hours also results in a savings benefit and this savings was embedded in the energy price forecast in the 2010 IRP. Id.

Capacity price mitigation is another savings CL&P claims will be achieved due to peak reduction. Id, p. 15. The savings amount is based on the DRIPE concept discussed in the 2009 Synapse study. To determine the capacity price mitigation amount of approximately $10 million, the avoided electric capacity costs are due to a reduction in the price of electric capacity that is acquired to serve remaining load, because that remaining load will be met at prices set by less expensive capacity resources. Id.

CL&P modeled this DRIPE concept based on the discussion in the 2009 Synapse study. The Company states that calculating the DRIPE effect begins by estimating the impact a reduction in load will have upon the overall market price and then estimating the pace at which suppliers participating in that market would respond by taking a different set of action than they would have otherwise taken. According to the Company, the capacity price mitigation effect is generally not persistent over the long term as the market prices adjust upward towards a new equilibrium.

The CIEC expressed concern with the volatility of the Company's claimed benefits due to the uncertainty of the forward capacity and energy markets. Brief, p. 15. The AG stated that CL&P's benefits were very speculative because they depended on assumptions concerning a variety of critical factors including future electric prices and calculating the benefits of peak-time energy usage reductions. Brief, p. 12. The OCC made no argument for or against the peak load reduction benefits CL&P proposed in its CBA.

As with any long-term forecast, the IRP forecast is subject to numerous revisions going forward as conditions in the energy market change. The same can be said for CL&P's savings assumptions for avoided capacity costs, as they are based on the IRP forecast.

The Authority acknowledges CL&P's analysis as being procedurally correct and recognizes that certain assumptions have to be made with any model that tries to predict future energy prices. CL&P acknowledges that "capacity price mitigation effect is generally not persistent over the long term as the market prices adjust upward towards a new equilibrium." Id, p. 15.

The Authority has considered the concerns expressed by other parties relating to benefit amounts being based on long-term forecasts of future electric prices. However, the Company's forecast methodology is widely accepted in the industry and is also procedurally correct. Therefore, the Authority finds that the Company's estimates for peak load reductions are reasonable as presented.

Although the Authority agrees with the estimates for overall capacity savings and associated benefits, they are not particularly impressive. Based on its initial analysis, CL&P estimated the total MW reduction to be approximately 126 MW based on engagement rates of 25% for residential customers and 50% for C&I customers and the savings from the Rate Pilot. Response to Interrogatory EL-53. This equates to a cost of $3,913/kW using the present value cost of $493 million as the total cost of the smart meter deployment as proposed by CL&P. The savings decline to approximately 117 MW and while costs increases to approximately $4214/kW under the updated assumptions in which 25% of C&I customers are expected to participate in the dynamic pricing programs. The estimated cost of CL&P's conservation and load management programs are $2,700 /kW for 2011. The Company is expected to save 30 MW or $82.4 million. 2011 Conservation and Load Management Plan, Table 12. In addition, the C&LM programs will save 2.2 million MWH over the life of the programs while the smart meter program is not anticipated to have any energy savings. Customers also have access to other programs that can save them money. The ISO-NE demand response program is working well with almost no supplemental support from Connecticut ratepayers.

c. Energy Reduction Benefits

CL&P expects to reduce overall energy consumption by providing all customers, including non-participants in dynamic pricing with information about their specific hourly energy information captured through AMI and provided by a redesigned front page of the bill and energy analytics on CL&P's website. CL&P states that customers with hourly consumption data will reduce their energy consumption by 1.25% on average. CL&P identified $149 million in energy reduction benefits. Brief, p. 5.

CL&P claims that total energy consumption for all customers will be reduced by 1.25% in the base case based on studies conducted by OPower. Id. p. 16. According to CL&P, OPower is a firm that provides information to utility customers in a format designed to motivate them to reduce their energy consumption. OPower uses the findings of behavioral research that customers save the most energy when they receive information about how their energy usage compares with their neighbors. In effect, it takes advantage of the human need to avoid being shamed in front of peers. OPower has commercialized this research and turned it into a marketable product, producing reports that use information from various sources to develop a profile of a customer's energy usage. This information is then compared with comparably-sized houses in the neighborhood. OPower has implemented this approach in a number of utility territories throughout the country. Late Filed Exhibit No. 13.

The energy price mitigation savings that CL&P claims is also attributed to the DRIPE concept regarding capacity price mitigation. According to CL&P, resources cleared in the day-ahead energy market or self-scheduled in the real-time energy market will reduce the energy price in these markets. Forward energy prices are the collective expectations of all market participants (buyers and sellers) of what the spot market prices will be in a forward period. Therefore, sustained demand resource participation in the spot markets will ultimately be reflected in the forward energy market prices, which will yield lower term pricing of generation service for all customers. ADPDCBA Appendix A, p. 16.

The OCC argued that savings from OPower do not require AMI meters or dynamic pricing for CL&P to achieve its energy conservation results. Brief, p. 19. The Company stated that it has initiated an OPower pilot program which is not part of the AMI deployment plan. Tr. 2/1/11, p. 2267. Given these facts, the OCC recommends removing the costs and benefits from the overall cost/benefit analysis presented by CL&P. According to the OCC, the benefits are reduced by $144 million and the costs are reduced by $16 million. The elimination of these costs and benefits results in an overall net benefit of negative $41 million. Id.

In support of the OCC's statements, testimony indicated that data relating to energy usage will be available to all customers, not just customers on a dynamic pricing program with an AMI meter. Tr. 2/1/11, p. 2265. The Company also testified that it already initiated an OPower Pilot program which is not part of the AMI deployment plan. Id. The CIEC and the AG made no argument for or against the energy reduction benefits CL&P proposed in its CBA.

The Authority has reviewed the arguments from the parties regarding the energy reduction benefit claimed by the Company as a result of AMI meter deployment. CL&P stated that the energy reduction benefit estimated is directly attributed to the OPower study. Tr. 2/1/11, pp. 2265- 2267. Additionally, benefits of OPower will be available to all customers, not only those with AMI meters. Id.

Based on the fact that OPower benefits can be achieved without AMI meter technology, the Authority will exclude $149 million of the revised benefit amount that CL&P claimed for energy reduction. It is obvious to the Authority that the benefits claimed by the Company for energy reduction can be achieved without full deployment of AMI meters.

One of the most disappointing results of the pilot rate study was the impact on energy usage. The Authority's expectation was that along with a reduction in peak usage, overall energy usage would also decrease. On the contrary, overall energy use actually increased for CPP rate structure by 0.2% and decreased minimally under PTR and TOU pricing. ADPDCBA Appendix C, p. 13.

CL&P states that it primarily concentrated on peak reductions in the pilot study. The Authority believes that much greater savings should be possible with proper education and assistance for customers.

d. O&M Benefits

CL&P claims that the implementation of AMI will allow the Company to improve operations in multiple categories. The most significant areas of O&M benefits are reduced meter reading costs, elimination of off-cycle meter expense, reduction in manual connect and disconnects, reduction in uncollectible expense and improved theft detection. Brief, p. 5.

The Company also states that AMI will enable automated remote meter reading and thereby eliminate current on-cycle AMR mobile meter reading and associated costs. Expected savings include the mobile meter-reading labor expense, supervisory labor expense, meter-reading labor support costs, vehicles/vans, equipment, AMR software maintenance/upgrade expense, AMR meter communication costs, and other miscellaneous materials. ADPDCBA Appendix A, p. 12.

CL&P claims AMI will eliminate off-cycle manual meter reading and associated costs. The ability to capture automated reads on request will eliminate the current need to dispatch field personnel to manually capture off-cycle meter reads. Expected savings include field service labor expense, vehicles, and other miscellaneous materials. Id., p. 11.

The Company further states that remote activation capabilities of AMI meters will allow centralized, automated meter disconnects and reconnects. This automation will eliminate the need to dispatch field service personnel to manually complete the associated 100,000 or so disconnect and reconnect orders that occur annually today. Id.

Moreover, AMI remote activation capabilities will allow remote disconnects. AMI will also improve the ability to adhere to billing path rules on disconnects for non-payment and thereby reduce uncollectible expense. According to the Company, field resource constraints and a relatively high percentage of internal meters (resulting in many "failure to gain access" situations), result in delays in disconnecting customers which increases 90-day receivables and write-offs (i.e., uncollectible expense). However, with AMI, disconnections for non-payment activity will adhere to current billing path rules and significantly reduce disconnect order cycle times, meter access issues and associated 90-day receivables and write-offs. Id., p. 12.

The Company expects that AMI will reduce energy theft in three ways. First, during deployment, CL&P's vendor will be removing every existing meter and replacing each one with a new solid-state meter and the installers will be trained to notice irregularities which can be investigated as potential theft. Second, a tamper-detection capability of new meters will significantly eliminate meter tampering as a source of energy theft, as the meter will provide tamper notification which will be analyzed and potentially investigated for theft. Third, the more sophisticated Meter Data Management

System is expected to allow CL&P to better detect bypass and partial-bypass theft through data mining. Id., p. 11.

The final O&M benefit claimed by the Company is a reduction in operational inefficiency from a lack of meter specific information. Since there is currently no automated way to determine which meters have been restored and which ones remain without power, the Company claims it is necessary to retain contingency staffing and utilize crews to manually confirm customer restorations. AMI provides a clear picture of meter restorations (meters that are restored and meters that remain without power) during each stage (nest) of storm reparation and reduces associated contingent staff requirements as well as manual customer restoration confirmation efforts. ADPDCBA Appendix A, p. 12.

The O&M benefits claimed by CL&P resulted in a NPV benefit of $224 million based on the discount rate of 7.68%. Table 10 shows a dollar benefit breakdown using the original discount rate of 8.23% from the CBA dated 3/31/2010, as well as the updated discount rate of 7.68%.

Table 10. CL&P AMI O&M Benefits

	Initial Filing	LFE No. 1
Discount Rate >>	**8.23%**	**7.68%**
Meter Reading	$ 29,986	$ 32,021
Improved Theft Detection	$ 67,466	$ 71,514
Outage Operations Efficiency	$ 10,462	$ 11,172
Reduce Manual Conn./Disc.	$ 29,789	$ 31,627
Uncollectible Expense	$ 24,420	$ 25,924
Meter Testing	$ 3,424	$ 3,666
Reduced False Outage Calls	$ 2,159	$ 2,305
Eliminate Off-cycle Meters Reads	$ 36,039	$ 38,264
Other O&M Benefits	$ 7,283	$ 7,633
Total O&M Benefits	$ 211,028	$ 224,126

Response to Interrogatory EL-14.

The CIEC made no argument for or against the O&M benefits CL&P proposed in its CBA.

In its Brief to the Authority, the AG questioned the effectiveness of AMI meters in reducing uncollectible bills, stating that the Company has already begun remote shut-offs and that any benefit associated with remote shut-offs cannot be attributed solely to AMI technology. Brief, p. 13.

In regard to service outages, the AG viewed the benefit claimed by CL&P as unsupported by the facts. Specifically, noting that existing AMR meters can also detect outages. The additional benefits claimed by CL&P relating to theft detection were dismissed by the AG, citing the existence of tamper flags in current AMR meters.

According to the AG, the Company did not produce any studies to support the correlation between the AMI meters and theft of service. Id.

The OCC stated that the Company's benefit amount related to theft detection is unreasonable stating that current AMR meters already have tamper flags. The OCC also stated that the Company can already inspect meters and perform data mining on existing data. Brief, p. 6.

In addition the OCC referred to CL&P's outage management benefit claim as illusory, stating that current AMR meters continuously emit meter consumption data. Id. The OCC discounts the Company's claimed increase in reliability due to reduced outage time arguing that it is at odds with CL&P's testimony that it manages its tree trimming efforts to meet but not to exceed reliability targets. As a result, the OCC maintains that any benefit achieved through reduced outage time by CL&P, will end up in a reduction of tree trimming and other O&M expenditures offsetting the purported savings from AMI Id., p. 22.

The Authority has reviewed CL&P's claimed O&M benefits associated with a full-scale AMI deployment. As noted in Table 10, CL&P claimed approximately $11.5 million from meter testing and other O&M benefits. Since the Company already has AMR meters in place, the Authority concludes that manual meter reads by the Company result in far less savings than proposed in the Company's analysis of benefits since the AMR meters are read by drive-by vehicles. The Company testified that the meter test benefit was $526,000. Tr. 11/22/10, 2054. Therefore, the Authority will recognize a benefit of $526,000 rather than the approximate $3.7 million estimated by the Company for meter testing.

Some parties have also questioned the validity of CL&P's claimed O&M benefits. The AG questioned the Uncollectible Expense xxxx?? CL&P has already begun remote shut-offs and that any benefit associated with remote shut-offs cannot be attributed solely to AMI technology. Brief, p. 13. The Company argues that field resource constraints and a relatively high percentage of internal meters have resulted in delays in disconnecting customers thereby increasing 90-day receivables and write-offs (i.e., uncollectible expense). ADPDCBA Appendix, p. 12; Tr. 11/22/10, p. 1908. The Authority finds that the Company's estimated benefit for Uncollectible Expense is acceptable.

The AG also stated that Outage Operations benefits are unsupported by the facts and noting that current AMR meters can also detect outages. Brief, p. 13. However, current AMR meters must be read remotely after the Company has dispatched crews to outage areas. There is currently no automated way for AMR meters to be read. ADPDCBA Appendix, p. 12; Tr. 11/22/10, 1970. Therefore, the Authority finds that the estimated benefit for Outage Operations claimed by CL&P is acceptable.

Both the AG and the OCC questioned the Company's claimed Theft Reduction benefit of over $71 million stating that current AMR meters already have tamper flags and therefore, the additional benefit is overstated. AG Brief, p. 13; OCC Brief, p. 6. The Company responded that AMI technology will capture hourly usage profiles that cannot be produced by CL&P's existing AMR meters and that the information will allow it the opportunity to perform usage analysis in far greater detail in a more timely manner. Reply Brief, p. 8.

The Authority is skeptical regarding the dollar amount of the theft benefit claimed by CL&P. CL&P indicated that the challenges with a lot of data, is turning it into information. Tr. 2/1/11, 2324. In fact, many of the current investigations do not initiate as a result of tamper alerts. The Company stated that field personnel, current customers and many other sources of information help identify possible energy theft. Id. 2321.

The Authority finds it reasonable based on the evidence presented, to make a downward adjustment to the theft benefit claim from approximately $71.5 million to $57.0 million on an NPV basis. Although AMI meters can be more effective than AMR meters in deterring theft of electricity, the Authority finds that the Company's benefit projections are aggressive and therefore warrant a downward adjustment of approximately 20%.

In regard to the "other" O&M benefits, the Authority finds no evidence to substantiate the Company's claimed benefit of over $7.6 million and therefore, will discount this amount from the Company's overall O&M benefit amount of $224 million.

After considering the evidence presented by all parties regarding the validity of CL&P's claimed O&M benefits, the Authority has reduced the NPV benefit by $25.2 million as shown in Table 11 below.

Table 11. Net Benefits Adjusted by Authority
7.68% Discount Rate

	CL&P	Change	DPUC
Meter Reading	$ 32,021	$ -	$ 32,021
Improved Theft Detection	$ 71,514	$ (14,514)	$ 57,000
Outage Operations Efficiency	$ 11,172	$ -	$ 11,172
Reduce Manual Conn./Disc.	$ 31,627	$ -	$ 31,627
Uncollectible Expense	$ 25,924	$ -	$ 25,924
Meter Testing	$ 3,666	$ (3,140)	$ 526
Reduced False Outage Calls	$ 2,305	$ -	$ 2,305
Eliminate Off-cycle Meters Reads	$ 38,264	$ -	$ 38,264
Other O&M Benefits	$ 7,633	$ (7,633)	$ -
Total O&M Benefits	$ 224,126	$ (25,287)	$ 198,839

Response to Interrogatory EL-14.

e. Reliability and Environmental Benefits

CL&P claims a total of $81 million in societal benefits relating to the value of reliability as well as environmental benefits resulting from a reduction in carbon dioxide, CO2, emissions. Id, p. 3. For reliability benefits, the Company stated that AMI is expected to reduce CL&P's storm System Average Interruption Duration Index (SAIDI) by six minutes. This improvement comes from the ability of AMI meters to individually communicate when the customer has power. CL&P claims that this will provide significant value during storms and is estimated to reduce outage restoration efforts. CL&P identified $62 million associated with the value end-use customers place on reliability. Brief, p. 5.

SAIDI is the average outage duration for each customer served by the Company. The outage duration is then converted to a dollar savings amount using a specific methodology. In regard to SAIDI, CL&P states that the AMI technology should reduce storm SAIDI by 5 percent or 6 minutes. See ADPDCBA Appendix A, p. 14. CL&P cited specific studies showing evidence of ten major US electric utilities to substantiate their savings claim and provided an explanation of the calculations to arrive at their numbers. Id. p. 15. The studies were based on surveys of customers conducted between 1989 and 2005. The studies calculated a value of service reliability for the customers based on the survey results. The benefit was then calculated using the "Estimated Average Electric Customer Interruption Costs US 2008 $ Anytime by Duration by Customer." The results from the studies provided a calculated benefit of $0.06 per minute for residential customers and $10.32 per minute for C&I customers. Id., p. 17.

Environmental benefits claimed by the Company included reductions in energy usage due to dynamic pricing and other AMI-enabled conservation capabilities that will result in a net reduction in the tons of carbon emissions emitted in Connecticut. This reduction can be monetized due to the value attributed to a ton of C02 in the marketplace. Based on the supply mix for ISO-NE, it is estimated that the generation of 1 MWh produces 1,004 Ibs. of carbon or 0.50 tons of CO2. The projected market price for CO2 emissions used in the analysis is the "Current Trend Scenario" in the 2010 CT Integrated Resource Plan. CL&P identified $19 million in environmental benefits. Brief, p. 6.

The CIEC stated that the inclusion of reliability and environmental benefits, artificially inflate the potential benefits derived from AMI. The CIEC contends that while the benefits may be worthwhile, their quantification is highly speculative and has no direct impact to the electrical system. CIEC requests that the Authority exclude these benefits from its analysis. Brief, p. 15.

The OCC states that the PURA has steadily ruled that only direct costs and benefits can be considered in the CBA and therefore, the reliability and environmental benefits claimed by CL&P must be excluded from the Authority's analysis. Brief, p. 22.

The AG made no argument for or against the reliability and environmental benefits CL&P proposed in its CBA.

The Company's CBA relies on highly speculative assumptions in an attempt to monetize the value of the reliability savings. The Company admits that the claimed benefits have no direct impact to the electrical system. CL&P AMI and Dynamic Pricing Deployment Cost Benefit Analysis, 3/31/10, p. 7. Six minutes is a very small savings in the SAIDI index without major storms and has ranged from 81 minutes in 2000 to 140 in 2004. Docket No. 11-04-11 DPUC 2011 Annual Report to the General Assembly on Electric Distribution System Reliability June 8, 2011. With this variability, the estimated reduction would not be noticeable for customers, or the Company, to justify a reduction in maintenance expenditures. The Authority has not included such benefits in the analysis of other projects and does not believe they should be included now.

Environmental benefits are generally associated with the reduction in air pollution that results from lower energy consumption due to conservation. The Authority finds that CL&P's estimates for environmental benefits use a more standard and acceptable methodology. Although these are not electric system benefits, they impact all ratepayers and therefore the Authority could consider environmental benefits in the CBA. However, since there are no energy benefits projected from the dynamic pricing options, the Authority can not include these benefits in this case.

3. Costs

In the initial base case CBA filed on March 31, 2010, CL&P estimated the total nominal costs for the AMI full-scale deployment of approximately $862 million. These costs vary from a low of $858 million in the best case scenario to a high of $921 million in the worst case scenario**.** In the first five years of deployment, the nominal costs total over 51% of the overall base case project costs or $442 million. The balance of the nominal costs, $420 million, are spread out over the final 19 years of the deployment. Response to Interrogatory EL-14.

The costs of the full-scale AMI deployment are estimated to be $493 million on a NPV basis in the base case shown in Table 12 below. Costs are estimated to vary from $429 million to $581 million on a net present value basis with an additional $41 million of book value associated with current AMR meter replacement that would have to be charged off as a stranded cost. 2010 AMI Plan, March 31, 2010, p. 3.

A CL&P witness testified that the $493 million of total all-in costs over the 20-year life includes the initial capital costs plus 24 years of ongoing O&M expenses, plus ongoing customer engagement and education expenses. Tr. 11/11/10, p. 2173

In order to construct and support a detailed cost estimate for the CBA, CL&P completed a Request for Information (RFI) with AMI vendors on February 12, 2010. The RFI produced ten comprehensive responses from industry leaders, with cost estimates for each major meter component: AMI meter, HAN capabilities and remote activation capabilities. The base case scenario estimate for AMI metering equipment and communications infrastructure capital costs is based on the average price responses from eight of the vendors excluding the highest and lowest prices received from the RFI. The worst case metering equipment is based on the highest cost vendor and the best case is based on the lowest cost vendor response. CL&P relied on the RFI to build the cost estimates, but the Company has not committed to any specific vendor or technology at this time. ADPDCBA Appendix A, p. 6.

The Company updated the CBA and the change in the results of the base case was submitted in Late Filed Exhibit No. 1, which became the Company's latest deployment valuation. In the revised base case, CL&P reduce the discount rate from 8.23% to 7.68%, removed $16 million of Customer Engagement costs, and reduced capital costs and O&M costs for meters and communications equipment by $59 million due to using the lowest of ten bids received in its RFI for meter costs in place of the average of the middle eight bids used in the initial filing.

Under the updated base case, the estimated cost declined from $493 million on a NPV basis to $429 million. CL&P grouped costs into three major categories; Capital, O&M and Customer Engagement. Total capital costs including metering equipment and communications and IT infrastructure is estimated to be $257 million which represents 60% of the total cost of the base case deployment plan. O&M is estimated to be $145 million or 34% and Customer Engagement costs are estimated to be $27 million or 6% of the total cost of CL&P's base case meter plan. A more detailed breakdown of the estimated costs is described in Appendix A at the end of this Decision.

Table 12 Costs of Each Deployment Case
(NPV $ in millions)

1.2 million customers			Revised		Revised Base Case	
		Initial	Base		% of	
Case:	**Worst**	**Base**	**LFE-1**	**Best**	**Costs**	**$/Cust ****
Capital (Tbl 5)						
AMI Metering Equipment	$351	$256	$219	$223	51%	$183
Communications Infrastructure	$6	$17	$15	$6	3%	$13
IT Systems	$26	$21	$21	$16	5%	$18
Marketing & Education	$2	$2	$2	$2	0%	$2
Capital Total (Tbl 5)	**$385**	**$296**	**$257**	**$247**	**60%**	$214
O&M (Tbl 6)						
Field Srvc, Meter Op	$102	$96	$113	$93	26%	$94
Comm & Cust Srvc O&M	$21	$25		$14	0%	$0
IT Systems	$52	$32	$32	$22	7%	$27
O&M Total (Tbl 6)	**$175**	**$153**	**$145**	**$129**	**34%**	$121
Customer Engagement	**$21**	**$44**	**$27**	**$76**	**6%**	$23
Total Cost	**$581**	**$493**	**$429**	**$452**	100%	$358
Cost/customer (no multiplier)	**$484**	**$411**	**$358**	**$377**		

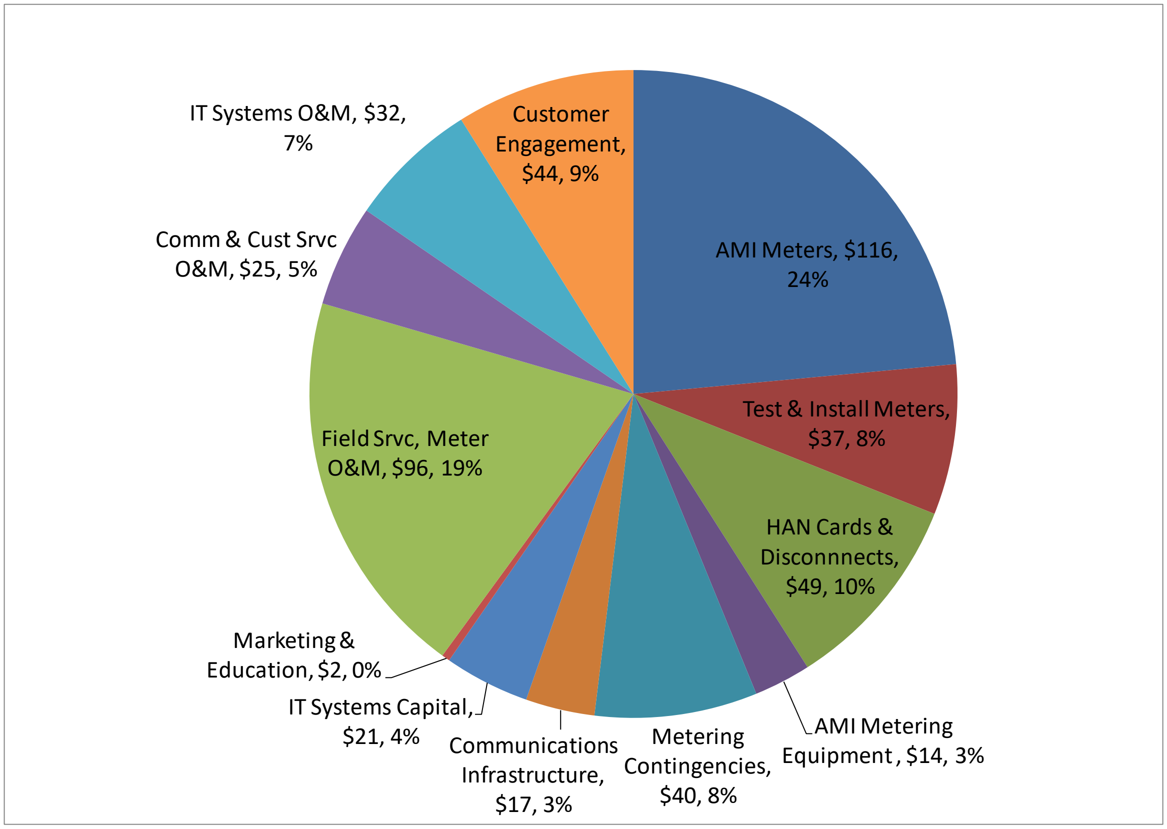
** $/Cust in nominal dollars; no multiplier.

ADPDCBA Appendix A, pp.6-8, Tables 5 and 6;
Response to Interrogatories EL-14 and EL-15;
Late Filed Exhibit No.1.

The total costs represents not only the costs and installation of 1.2 million AMI meters and infrastructure and their 20-year operational expense, but also the costs

CL&P believes are necessary to implement and operate a dynamic pricing program over 24 years. The AMI meter system and a dynamic pricing program are needed to achieve the benefits to cause both programs to be cost effective.

Figure 4. CL&P AMI Deployment Costs and Percent of Total Cost
Base Case, NPV Dollars in millions
Total Cost = $493 million



ADPDCBA Appendix A, pp. 6-10; Response to Interrogatories EL-14; EL-15.

CL&P has not selected the meter system it will deploy. Therefore the costs proposed by CL&P are subject to modification as technologies change or become obsolete. As the OCC witnesses testified, cost estimates for a project of this size are subject to numerous revisions. For example Xcel Energy in Colorado had cost overruns of more than 150% beyond original project estimates. PFT of Frank W. Radigan, Phillip S Teumim, Ronald J. Liberty and Alice Miller. p. 12. Furthermore, the OCC argues that all of the risk in this project is being borne by ratepayers who will fund the project through an increase in rates as per Conn. Gen. Stat. §16-243w(c).

4. Conclusion on Benefit Cost Analysis

The Authority has reviewed the Company's benefit cost analysis and finds that there is considerable risk that the project would not be cost beneficial. The costs of a project are relatively known but still remain uncertain since a final technology has not been selected and continues to evolve. The benefits are much more speculative.

CL&P claimed approximately $583 million of benefits in the base case scenario based on a 20-year meter life net present value basis. CL&P stated that its benefit streams are consistent with the United States Authority of Energy analytical framework for smart grid projects. Id., p. 5.

Looking strictly at the numbers in the Company's analysis, the numbers indicate that a full AMI deployment is the most cost effective method and the most beneficial to ratepayers. However, a more thorough review of the costs and benefits reveals an analysis that contains numerous assumptions and estimates that cannot be supported by any factual historic data or real-world evidence by other utilities using AMI meters. CL&P's omission of this factual data is through no fault of its own, by its own omission, it is due to the lack of real-world experience with new smart meter technologies and dynamic pricing.

CL&P's base, worst and best case scenarios are subject to extreme variability of the net benefits by making minor adjustments to the input assumptions. As shown in Figure 3, there is almost a $1.1 billion difference between the worst case and best case scenarios. Late Filed Exhibit No.1, p. 3.

Small changes in assumptions used in a statistical model can have a major impact on the final output. As proof of the variability in claimed benefit amounts, one only needs to look at the Company's analysis and the revisions that have been made to benefit totals. For instance, changing the discount rate resulted in an increase to the NPV net benefit amount by approximately $17.5 million and the overall benefit number has changed from an NPV of $87 million to $154 million (excluding $41 million of stranded cost). Another example of variability can be seen in the projection of what an average summer weather pattern would be. Trying to extrapolate usage data based on assumptions about average summer weather can become an exercise in futility. As further proof of the variability of the final benefit amounts, the CIEC, the OCC and the AG have developed different versions of what the NPV of the net benefits should amount to.

The Authority reviewed all of the costs and benefits previously shown in Table 5 on a stand-alone basis, evaluating the reasonableness of the assumptions used in order to arrive at the dollar amounts claimed by the Company. In several instances, the Authority believes that CL&P has overestimated the benefits and this had a significant impact on the results of the benefit/cost analysis.

The most significant adjustments are $149 million for energy reduction. These benefits have nothing to do with dynamic rates or the smart meters. The Authority also excluded $62 million of very speculative benefits associated with the value of reliability improvements to customers and also added $41 million for stranded costs that will result if the current meters are replaced before the end of their planned useful life. The Authority excluded $19 million in environmental benefits attributed to air quality improvements since there are no projected energy savings associated with the smart meters. Table 13 below is a reproduction of CL&P's claimed benefits and costs used in its revised analysis with the PURA's adjustments. The amounts determined by the Authority are what it believes are reasonable, achievable benefits for a full AMI deployment based on the evidence presented.

Table 13. Base Case Net Benefits Adjusted by the Authority

Benefits	**CL&P**	**PURA Adjustment**	**DPUC**
O&M Benefits	$ 224	$ (25)	$ 199
Capital Avoidance	$ 77	$ (41)	$ 36
Peak-Load reduction	$ 52	$ -	$ 52
Energy reduction	$ 149	$ (149)	$ -
Value end-use customers place on reliability	$ 62	$ (62)	$ -
Environmental	$ 19	$ (19)	$ -
Total Benefits	**$ 583**	**$ (296)**	**$ 287**
Costs			
Capital	$ (257)	$ -	$ (257)
O&M	$ (145)	$ -	$ (145)
Customer Engagement	$ (27)	$ -	$ (27)
Total Costs	**$ (429)**	**$ -**	**$ (429)**
Overall Net Benefits	**$ 154**	**$ (296)**	**$ (142)**
Overall Benefit/Cost Ratio	**1.36**		**0.67**

Based on the $287 million in NPV benefits that the Authority deems as reasonable along with the adjusted costs of $429 million, the NPV net benefit for a full AMI meter deployment is a ***negative*** $142 million with a benefit/ cost ratio of 0.67.

5. Technical Issues Summary and Conclusion

CL&P installed 1,320 AMI residential meters during the 2009 summer in the Stamford and Hartford areas to evaluate the technical capability and reliability of AMI two-way radio technology in preparation to replace its current AMR meter system. The AMI system consisted of meters with control devices and data transmission, data collection and data management infrastructure. The AMI meters were required to provide hourly readings, be capable of remote programming and updates, contain local signal devices to provide real time price signals to the customer and control certain house-hold loads and be reliable.

The Company reported that the AMI meters performed reliably with 100 percent of the customers metered accurately and billed on-time and there were no meter or communication module failures. The Authority is satisfied with the meter study results that indicate that two-way radio is another AMI technology that can perform well in Connecticut. No participant disputed the Company's meter study results.

Although the meters generally performed well, in the one wireless, over the air programming test, 4.2% of the AMI meters could not be reprogrammed remotely due to low signal strength caused by the small number of communication towers used in the study.

The Company gained experience with enabling technologies and learned that residential smart thermostats are still immature from a technology and a customer usability design perspective. Smart thermostats are low on the maturity curve, are not compatible with some older HVAC systems and required significant time to schedule the installation inside the customer's home. Customers also had issues in understanding the meaning of commands on the thermostats such as the Hold and Off-Hold settings. The programming of the power cost monitor was complicated and time-consuming and its battery life was very short.

The Company has not determined what AMI technology it would install. The Authority is concerned that moving forward at this time with a system wide AMI deployment project is too risky due to the unknown technology that the Company would install, the incompletion of industry standards, and needed improvement in control devices.

The Company has tested both the mesh system and two-way radio AMI systems. While both work, these and other competing technologies continue to evolve. In addition, industry interoperability standards are being developed but are not completed at this time. The Authority would not want to commit to a specific technology then find out in a few years that it was already obsolete or incompatible with other meters or communication systems.

Stranded cost could be significant if the new AMI meters do not last for 20 years as proposed. To minimize future stranded costs that would be caused by early replacement of the new AMI meter system stranded costs, the Company must provide evidence showing that the AMI system would have a 15- to 20-year useful life or agree to accept part of the risk if they do not perform as expected. The Authority would also require that industry standards be further developed and implemented by manufacturers so that AMI meters and associated infrastructure provided by any manufacturer in the future could be installed on the system and would be compatible with the existing AMI infrastructure.

In addition, the Authority required details about the specific AMI equipment that the Company would purchase and test results of the equipments' performance before it would approve an actual deployment plan. The Company must demonstrate that controlling devices have clear, comprehensible commands and would perform their intended functions. Finally, the Company must demonstrate that the AMI system will safe guard customer data and be protected from cyber intrusion.

6. Experience of Other Utilities

Table 14 illustrates the largest AMI deployments as of October 10, 2010 accounting for 13 million smart meters. In addition, CL&P presented data on cost and savings for nine utility deployment plans.

Table 14. Largest Smart Meter Deployments as of 10/21/10

Company	Vendors	Prior AMR	Target Completion Date	Total Electric Meters	Installed AMI Meters	% Installed
Southern California Edison	Itron	No	2012	5,300,000	1,600,000	30%
Pacific Gas & Electric (PG&E)	Aclara (first 50k)- Silver Spring Networks	No	2011	5,250,000	3,515,392	67%
Southern Company	Sensus	No	2012	4,400,000	2,000,000 +	45%
Oncor	Landis+Gyr	No	2012	3,400,000	1,421,131	42%
Center Point Energy	Itron	No	2012	2,000,000	635,000	32%
Duke Energy	Cisco	No	2012	1,500,000	200,000	13%
San Diego Gas & Electric (SDG&E)	Itron	No	2011	1,400,000	867,397	62%
Pennsylvania Power & Light	Aclara	No	Complete	1,350,000	1,350,000	100%
Arizona Public Service (APS)	Elster	No	2013	1,000,000	400,000	40%
Portland General Electric	Sensus	No	2010	835,000	700,000	84%
Austin Energy	Landys+Gyr	No	Complete	400,000	400,000	100%
TOTAL				26,835,000	13,088,920 +	49%

ADPDCBA Appendix B, p. 7; Response to Interrogatory EL-44.

A common characteristic in these utility plans is that most utilities are shifting from a manual meter reading system to an AMI reading system. Only Baltimore Gas & Electric intends to shift from an AMR system to AMI meters. Response to Interrogatory EL-48.

Baltimore Gas & Electric will convert 17% more electricity meters and 700,000 gas meters for essentially the same cost as CL&P, but has 7.5 times more net savings on an NPV basis over a 15-year period as compared to the CL&P savings projected over 24 years. Duke-Indiana will convert 28% fewer meters than CL&P at a 28% higher cost and expects to achieve 370% of the CL&P savings over the same period of years on an NPV basis. Response to Interrogatory EL-48, p. 2.

Due to complaints about meter accuracy and poor customer service, the California Public Utility Commission (CPUC) required PG&E to release progress reports to the public, and ordered an investigation by the Structure Group. The Structure Group found the smart meters to be accurate and that higher customer bills were the result of a hotter than normal summer and two rate increases at the time of deployment. The main problems identified were the result of business process issues and poor customer service. PG&E was slow to transition their business processes for automated meter reading after smart meter installation, resulting in meter reading errors and inadequate billing controls, leading to customer issues and confusion. The Structure Group also found that PG&E did not properly communicate with customers to educate them about smart meters, did not respond adequately to their concerns, and did not satisfactorily resolve customer complaints. In response to Structure Group's analysis, PG&E has established a dedicated smart meter call center and added customer service representatives to answer billing questions. PG&E is also reworking its communications programs to better educate customers in advance of area deployments and post weekly updates on its website, as well as to the CPUC. Response to Interrogatory EL-44, p. 3.

Due to customer concerns about meter accuracy and billing issues the Public Utility Commission of Texas, in conjunction with Oncor, CenterPoint, and AEP Texas, had Navigant Consulting perform an independent investigation into the accuracy of smart meters and customer billing issues at the two utilities. Navigant also analyzed the communication of electricity usage from the meter for billing and whether smart meters record higher energy usage than electromechanical meters. Smart meter testing included new meters, deployed meters that were removed for testing, and meters in service, with 99.96% found to be accurate by American National Standards Institute (ANSI) standards, and consistently more accurate than the meters being replaced. Navigant also found that customer bills were higher due to a colder than normal winter and a longer billing cycle, rather than the installation of smart meters, and that the communications systems were operating properly.

Navigant highlighted the areas that require special attention during deployment including: addressing advanced meter communication issues, monitoring event/error codes communicated by advanced meters, performing root cause analysis on advanced meters, performing root cause analysis on advanced meter failures, evaluating success/failure rates of firmware upgrades and establishing cross-functional teams to evaluate smart meter deployment challenges. Response to Interrogatory EL-44, pp. 3 and 4.

San Diego Gas & Electric (SDG&E) learned from the experience of others and refined its smart meter deployment. SDG&E planned its deployment of smart meters avoiding the warmest summer months so that customers would not associate higher bills with the installation of new meters. It proactively involved community leaders in the development of its plan and engaged customers early with mailings and door hangers. When SDG&E found a problem with 33 meters' it promptly notified customers and the CPUC, and replaced the affected meters as well as 30,000 others from the same generation to avoid future concerns. Response to Interrogatory EL-44, p. 4.

The United Illuminating Company (UI) replaced its manual meter reading system around 1998. UI's current meter system, Cellnet system, is a fixed radio frequency network. The meter transmits energy consumption every 5 minutes to pole top collectors that store the data and then retransmit the data every night to central data collection devices, and thereafter to the UI home office. Docket No. 07-07-02, Application of The United Illuminating Company for Approval of Metering Plan, Decision dated March 19, 2008, p. 2. UI has upgraded its metering network in 2010 to a 2-way mesh system. Docket No. 05-06-04RE06, Response to Interrogatory EL-11.

In 2010 UI began deploying Landis+Gyr Focus Meters which are a solid state, 0.5% accuracy class meter utilizing digital signal multiplication measurement technology as one of its standard meters. The Focus Meter is a true AMI meter and comes standard with an integrated service disconnect device, ZigBee chip for home area networking, net metering functionality in addition to multiple other programming features including time of day and interval data collection, advanced meter events/alarms/diagnostics. With the L+G Gridstream RF radio module, the Focus meter has full two-way mesh communications including over the air firmware and program update capabilities. UI Letter to PURA dated July 6, 2010.

UI's network metering system, when originally installed, was cost neutral to customers, and provided advanced capabilities and information. Recently, UI's metering system has been upgraded to provide full two-way functionality and UI is in the process of deploying 80,000 smart meters to enable the use of emerging technologies to better serve customers. UI's website provides customers with access to information to enable customers to manage their electricity usage, to save money and support state energy policy. Docket No. 10-07-09, Joint Application of UIL Holdings Corporation and Iberdrola USA, Inc. for Approval of a Change of Control of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company, Application, July 16, 2010. pp.17 and 18.

The Authority is not aware of any technical problems or complaints concerning the UI AMI metering system.

At the end of 2010, UI had 18% of its residential customers using 29% of the residential energy on TOU rates. Twenty-eight percent of C&I customers were on TOU rates consuming 87% of the delivered C&I energy. Overall 19% of UI customers are on TOU rates using 63% of delivered energy.

The Authority believes that the best practices in lessons learned from deployment of AMI meters in California, Texas and other states should be incorporated into a CL&P deployment plan particularly company interactions and communications with customers.

7. Compatibility with Electric Choice.

Connecticut is a state that allows retail generation competition. As of March 1, 2011, approximately 40% of CL&P customers and 63% of the total load receives service from competitive suppliers[8].

Retail Choice presents both challenges and opportunities in regards to the use of smart meters.

All customers would benefit from operational efficiencies associated with smart meters. Mid cycle billing would be much quicker and less costly with the remote meter reading capabilities of smart meters. This would allow customers to switch suppliers much faster than today. Smart meters may also be useful by creating more defined pricing options to encourage cogeneration and renewable development. TOU pricing options, which would be readily available with the deployment of smart meters, would also help create the proper pricing incentives for the rollout of electric vehicles.

The largest part of the electricity bill is the generation charge. This is generally the charge that is time differentiated when TOU or other dynamic rates are offered. It is PURA's hope that suppliers embrace smart meters and develop their own innovative pricing options. To date however, there appears to be little interest in time differentiated rates by suppliers in Connecticut. Suppliers have not offered any TOU or any dynamic rates options for residential customers in Connecticut since retail competition began in 2000. Customers therefore may switch to suppliers to avoid mandatory TOU or dynamic rates if the on-off peak differentials appear in the generation charges.

TOU options are possible without differentiating the generation charge. Distribution, transmission and non-bypassable charges could also be broken into on and off peak rates. This has been done with UI's TOU rates. It may however, be difficult to justify a cost basis for large price differentials that are necessary for some dynamic pricing options.

Peak time pricing, peak rebates and hourly pricing, are based on generation costs. It may be possible to offer these types of rates by layering rates over those offered by suppliers. This would complicate rates for customers and may not be acceptable to the suppliers.

Due to Connecticut's electric regulatory paradigm, customer engagement may be more restricted than what the total number of customers suggest if the distribution companies are the only suppliers that offer dynamic pricing options. This market could shrink more in the future if customers continue to move to competitive suppliers

8. Risk to Ratepayers

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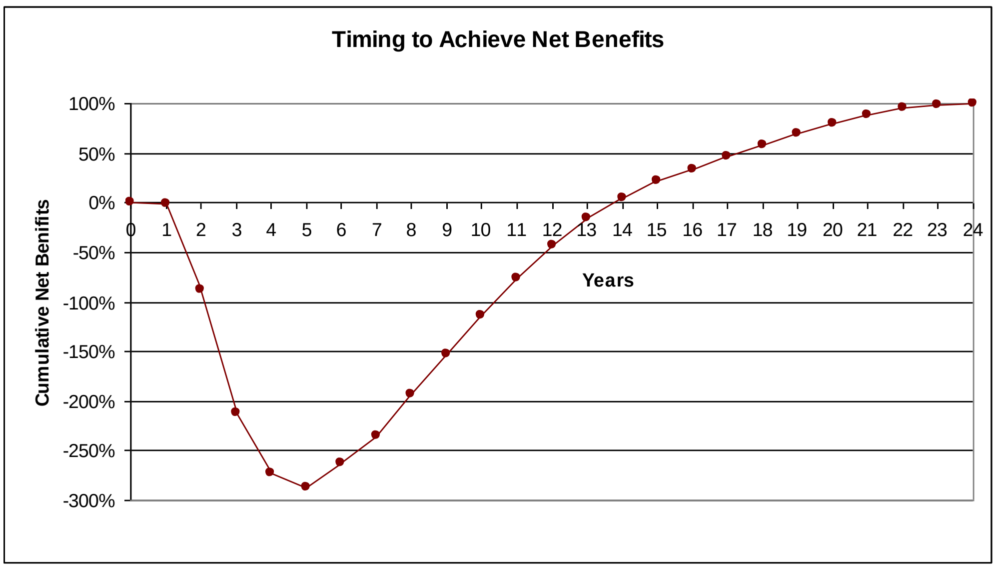
8 Source: http://www.dpuc.state.ct.us/electric.nsf/22bd353cdb8843d985257615005b5bcc/4d19e927ef8972d285257616005c73bf?OpenDocument

CL&P did not submit a cost recovery proposal with its meter deployment plan. Negotiated costs are expected to be submitted in a proposed cost recovery plan to the Authority by July 31, 2012. CL&P would like the approval to move forward without a firm estimate of the cost or benefits of the project at this time. It appears that ratepayers would be responsible for any cost overruns and all costs if the benefits do not develop as planned.

The Authority is very concerned with the time required to achieve sufficient net benefits so that the savings exceed the costs of the AMI deployment and dynamic pricing programs. Using the Company's CBA, the Authority created Figure 5 below which indicates that it will take 14 years before costs are recovered and positive benefits exceed the breakeven point, and 17 years to obtain 50% of the estimated total net benefits assuming the Company's assumptions are correct. The Authority views the 14 years required to achieve positive net benefits and the break even point as extremely risky for ratepayers considering that the average AMR meter to be replaced will only be 15 years old.

Figure 5. Timing to Achieve Net Benefits



Authority Analysis

II. FINDINGS OF FACT

1. CL&P currently uses AMR technology

2. CL&P has 407 residential customers on TOU rates, which is only 0.04% in a total base of 1,100,378 residential customers.

3. CL&P only has 1,151 small commercial and industrial customers on TOU rates, which is 1% of its 111,406 commercial and industrial (C&I) customers.

4. CL&P has 14 customers on voluntary real time and variable peak pricing rates.

5. The Company submitted its original Meter Plan in March 2007 and proposed to replace all of its meters with an Open Advanced Metering Infrastructure over an 18-month period beginning January 1, 2009, at an estimated cost of approximately $264 million.

6. CL&P executed the Rate Pilot and the Meter Study from June 1, 2009 through August 31, 2009.

7. The Company meter test evaluated a two-way fixed radio AMI solution.

8. CL&P utilized the Sensus fixed 2-way radio AMI metering solution for the residential portion of the Rate Pilot.

9. The Company found that the capability to perform over the air meter programming is still low on the technology maturity curve.

10. The Meter Study only analyzed the performance of one AMI technology.

11. The NIST is tasked with developing emerging smart grid standards and protocols.

12. NIST ascertained that many standards will require revision or enhancement before they can be implemented to achieve smart grid interoperability and security.

13. Smart thermostats can be remotely controlled, have two-way communication and customers can override temperature and control settings directly on the thermostat.

14. There were significant technological, installation, and usability issues with the residential smart thermostats in the Rate Pilot.

15. Residential customers who participated to the end of the Meter Pilot were paid $100 while business customers were paid $200.

16. The Rate Pilot began with 3,000 participants.

17. The number of customers enrolled at the end of the Rate Pilot included 1,114 residential and 1,123 business customers, plus 200 control group customers.

18. For the Rate Pilot CL&P established wider TOU price differentials than the differential that currently exists under their current TOU rates.

19. The PTP rate was the most satisfying rate and the smart switch was the most satisfying Enabling Technology for both residential and business customers.

20. Residential customers were less satisfied with the PTR and least satisfied with the TOU rate.

21. Business customers were less satisfied with the TOU rate and least satisfied with the PTR.

22. CL&P supports four-hour seasonal TOU periods (e.g., summer peak of from 2 p.m. to 6 p.m. and winter peak from 4 p.m. to 8 p.m.) to reflect actual peak demand data.

23. The Rate Pilot demonstrated that residential and business customers are willing to reduce their electric demand for short periods of time on select days (i.e., up to four hours on event days under the PTP and PTR rates) when provided with an economic incentive to do so.

24. Neither the residential nor business customers in the Rate Pilot reduced their overall energy consumption.

25. The summer of 2009 was unusually mild.

26. The Company submitted a deployment plan to install new AMI smart meters to all of its 1.2 million customers during a four year period starting in late 2012 to 2016 and implement a dynamic pricing program that would continue for another 20 years to 2035.

27. CL&P estimates that the total cost of its plan would be approximately $863 million, or $493 million on a present value basis.

28. The deployment plan for the base case is estimated to cost $493 million with total benefits of $580 million and net benefits of $87 million on a net present value basis.

29. The average cost of the deployment plan and the dynamic pricing program would be $411 per customer.

30. The Company's last update of the CBA base case submitted in Late Filed Exhibit No. 1 estimated cost of $429 million, total benefits of $583 million and net benefits of $154 million using a 7.68% discount rate.

31. The average age of a CL&P AMR meter is approximately 11 years.

32. Dynamic rates, such as PTP and PTR, are new to customers and there is little evidence as to the desire of customers to participate in these types of pricing options.

33. CL&P has not selected the meter system it will deploy.

34. The base case plan will require 14 years to achieve the breakeven point.

III. CONCLUSION AND ORDERS

A. CONCLUSION

CL&P proposes to deploy 1.2 million meters to all of its customers over a four-year period from 2012 to 2016 at a cost of $863 million. Smart meters have the potential to offer customers new options to control their electric use and reduce their electric bills by providing new pricing options and better usage information. This would provide benefits to participating customers as well as to the electric system through lower peak demand and energy usage. The operations of the electric system could also improve from theft detection, mid-cycle meter reading, remote disconnect and reconnect capabilities and other operational efficiencies, reducing costs and providing benefits to all ratepayers. In order to achieve these benefits requires a significant investment.

To arrive at a Decision that is in the best interest of ratepayers, a thorough review of CL&P's AMI proposal was completed focusing on the major benefit and costs associated with the project, risks to ratepayers and technical issues associated with the smart meter technologies. Not withstanding the immediate impacts, the Authority must also consider the long term ramifications that a project of this magnitude will have on ratepayers and the future of the electric system in the state of Connecticut.

The meter study showed that 2-way radio frequency AMI meters and radio towers would work well in Connecticut but the associated equipment to control customer household loads and reprogram meters remotely requires further development by the manufacturers. AMI meter technology is still evolving and standards are still being developed. This creates Authority uncertainty regarding the Company's cost estimates and the risk that the selected technology may quickly become obsolete or incapable of working with other meters or enabling technologies.

As evidence of this fact, CL&P's current meter system is only 11 years old. CL&P proposed a mesh smart meter system in 2007 but submitted a revised meter study recommending the use of radio frequency smart meters in 2009. CL&P still has not selected the meter technology it would deploy under its plan.

CL&P reported that the maturity of critical AMI capabilities will be dependent on the development of standards. To achieve smart grid interoperability and security, many standards will require revision or enhancement before they can be implemented. The NIST determined that 75 existing standards are applicable to smart grid goals but found 70 gaps which require new standards, or enhancements to existing standards. Current progress in finalizing standards continues to be delayed causing more uncertainty about which technologies will be adopted as the standard for AMI meters.

The Authority views this gap in standards as a risk that is unavoidable at the present time. Under any full deployment scenario, if the meters being deployed are not compatible with the most up-to-date standards, and have no way of being upgraded to meet those standards, they may become obsolete before the end of their useful life.

Beyond the uncertainties of AMI technology and standards, there are several other factors that have been considered by the Authority in assessing the viability of a full-scale smart meter deployment.

The Company's analysis totaled the estimated costs and benefits of the project and then discounted these totals to arrive at a NPV of the Smart Meter program. Assuming that the Company's forecasted costs and benefits are accurate, the lifetime savings realized by a residential customer in the Base Case is $11.17 or approximately $.05 per month, while a C&I customer would save approximately $96 over the useful life of the meters. Tr. 11/22/10, pp. 1964 and 1965; Response to Interrogatory EL-64. The Authority views this savings benefit to the customer as minor considering the substantial risks that are inherent in a project of this size.

CL&P's cost/benefit analysis concluded that a full deployment of smart meters to all of its customers would result in a net positive benefit of $154 million. The cost/benefit analysis preformed by the Company has numerous instances of costs and benefits that cannot be quantified with actual data, but instead relies on forecasts using many theoretical assumptions. There is a wide range of variability in both the costs and benefits that can be derived from the information provided. For instance, the OCC completed its own analysis of the CBA relying on expert witness testimony as well as the information provided by CL&P to arrive at a negative net benefit of $180 million in a full deployment scenario. The conclusions from the Company and the OCC regarding the CBA are at opposite ends of the spectrum, differing by approximately $334 million.

The Authority, through its own analysis and relying on all of the information presented in this docket, concludes that the net benefit of the CBA totaled negative $142 million. In several cases, the Authority believes that CL&P has overestimated the benefits and this has a significant impact on the results of the benefit/cost analysis. The most significant adjustments are $149 million for energy reduction. These benefits have nothing to do with dynamic rates or the smart meters. The Authority also excluded $62 million of very speculative benefits associated with the value of reliability improvements to customers and added $41 million for stranded costs that will result if the current meters are replaced before the end of their useful life as planned.

Capacity savings are projected from the dynamic pricing options, but overall capacity savings and associated benefits are not particularly impressive. Alternative conservation and load management actions could be deployed at lower cost and provide larger environmental benefits.

The capacity savings are estimated to be approximately 117 MW at a cost of $4,214/kW under the updated assumptions in which 25% of residential and C&I customers are expected to participate in dynamic pricing programs. This compares to the estimated cost of CL&P's conservation and load management programs of $2,700/kW for 2011. The Company is expected to save 30 MW or $82.4 million. Table 12, 2011 Conservation and Load Management Plan. In addition, the C&LM programs will save 2.2 million MWH over the life of the programs while the smart meter program is not anticipated to have any energy savings.

Projected capacity savings are significant for residential customers on the most extreme dynamic rate options. Savings are much more modest for residential customers on time-of use rates and small commercial and industrial customers. Larger C&I customers are already required to be on time-of use rates.

Dynamic rates are new to customers and there is little evidence as to the desire of customers to participate in these types of pricing options. CL&P did not provide any surveys or results from other states to support their estimates. Even if customers decide to try new rate options it is uncertain how long they will participate and whether savings will persist at the same levels over many years.

The Authority is concerned with the low level of participation rates by both residential and C&I customers despite the Company offering a monetary incentive to join the Pilot program. The Authority finds that the Company's revised participation rates are very uncertain given the low participation rates of the pilot.

CL&P has not had a great track record for promoting -of- TOU rates or alternative pricing options in the past. For a program of this magnitude to be successful, it will require more than simply installing the meters. It will require a commitment for all areas of the company to educate customers and promote the program over a sustained period. It is obvious to the Authority that a much more vigorous marketing and public awareness effort by the Company would be needed to achieve the customer participation levels and savings over the longer term.

CL&P currently uses AMR technology. This is one-way, drive-by radio communication (i.e., meter to meter reading vehicle) where CL&P meter reader vehicles drive by the AMR meters, on a monthly basis, to collect scheduled meter reads for billing. These meters were installed between 1992 and 2005, making the average meter 11 years old. The meters have many years to go before they reach the end of their estimated useful life. With the deployment of this technology, CL&P has vastly reduced its meter reading staff and captured the associated cost savings which other utilities would receive by moving directly from manual meters to smart meter technologies. CL&P also did not receive any stimulus funding which has helped the economics of some of the other utilities now deploying smart meters.

The Authority concludes that new AMI standards must be implemented by manufacturers before considering any full-scale deployment commencement. Given the risks to ratepayers and the uncertainty of the costs and benefits, the Authority does not see a compelling reason to move forward with the rapid full deployment of smart meters at this time as proposed by CL&P.

Although the Authority does not believe that full deployment should be aggressively pursued at this time, the implementation of smart meter technology by CL&P should not be abandoned. Meters must be installed for new customers and replaced for various reasons every day. Contrary to CL&P's conclusions in the Rate Pilot study, the Authority believes that smart meter deployment does not have to be an all or nothing proposition. Moving forward at a slower but deliberate pace would mitigate the risk associated with quickly changing technology and allow for mid-course corrections if necessary. Voluntary programs for peak pricing and other new rate options could allow for more experimentation and provide valuable insight into customer acceptance. At the same time, mandatory TOU rates could be phased in to most, if not all customers.

Full operational benefits will not be realized as soon as a full deployment scenario, but some O&M benefits should still result, which will grow as more meters are deployed. Full system benefits associated with peak and energy reductions will be realized quickly by first providing meters to those customers most willing to participate and those with the greatest potential savings. Renewable technologies and electric vehicles could also be encouraged by making smart meters quickly available to customers on request.

Costs will be reduced over the next few years and spread out more evenly over a longer deployment period. Changing out meters as they reach the end of their useful lives or as requested by customers would be more expensive than under a mass deployment. The meters, however, would be better utilized and installation costs are relatively small compared to the overall cost of the deployment plan. Meter installation costs can also be minimized by providing meters to all new customers, and taking advantage of other opportunities to replace meters for existing customers when a service representative must go to a home or business for other reasons.

Based on the above, the Authority does not approve the full deployment of the smart meter technology as proposed by CL&P at this time.

B. ORDERS

For the following Orders, submit one original of the required documentation to the Executive Secretary, 10 Franklin Square, New Britain, CT 06051, and file an electronic version through the Authority's website at www.ct.gov/dpuc. Submissions filed in compliance with Authority Orders must be identified by all three of the following: Docket Number, Title and Order Number.

1. The Company shall not proceed with the implementation of its proposed AMI deployment plan.

2. Not later than February 15, 2012 as updated on and August 15, 2012, February 15, 2013 and August 15, 2013, the Company shall provide the Authority with a report describing the latest advancement of AMI technology including meters, infrastructure and HAN devices, the development of AMI industry standards and what the industry is expected to develop during the next 12 months.

3. Should the AMI industry develop to the point where the Company believes an AMI deployment would be cost effective based on the conditions described by PURA in this Decision, the Company shall request a technical meeting to update the Authority on the industry development in order to determine a plan of action to evaluate an updated deployment plan and related cost recovery.

4. CL&P shall include in any revised deployment plan the technical details of the actual meter and communications equipment to be installed after manufacturers are complying with the newly developed AMI industry standards.

APPENDIX A

Table 12 Costs of Each Deployment Case
(NPV $ in millions)

1.2 million customers Case:	Worst	Initial Base	Revised Base LFE-1	Best	Revised Base Case % of Costs	Revised Base Case $/Cust **
Capital (Tbl 5)						
AMI Metering Equipment	$351	$256	$219	$223	51%	$183
Communications Infrastructure	$6	$17	$15	$6	3%	$13
IT Systems	$26	$21	$21	$16	5%	$18
Marketing & Education	$2	$2	$2	$2	0%	$2
Capital Total (Tbl 5)	**$385**	**$296**	**$257**	**$247**	**60%**	$214
O&M (Tbl 6)						
Field Srvc, Meter Op	$102	$96	$113	$93	26%	$94
Comm & Cust Srvc O&M	$21	$25		$14	0%	$0
IT Systems	$52	$32	$32	$22	7%	$27
O&M Total (Tbl 6)	**$175**	**$153**	**$145**	**$129**	**34%**	$121
Customer Engagement	**$21**	**$44**	**$27**	**$76**	**6%**	$23
Total Cost	**$581**	**$493**	**$429**	**$452**	100%	$358
Cost/customer (no multiplier)	**$484**	**$411**	**$358**	**$377**		

** $/Cust in nominal dollars; no multiplier.

ADPDCBA Appendix A, pp.6-8, Tables 5 and 6;
Response to Interrogatories EL-14 and EL-15.
Late Filed Exhibit No.1.

A. CAPITAL COSTS

1. AMI Metering Equipment Capital Costs

Meter capital costs for the Revised Base Case Deployment Plan are $219 million. The $219 million total costs of base case metering equipment represents 51% of the total cost of the revised base case deployment plan of $429 million.

In the CBA, the average cost of a residential meter in the base case was $189, $273 in the worst case and $167 in the best case. Response to Interrogatory EL-15. The average cost of a residential meter in the revised base case was $167, the same as in the initial best case. Tr. 2/1/11, p. 2307.

Meter capital costs include:

- meter hardware;
- meter installation;
- incremental personnel for engineering;

- project and change management;
- pre-deployment quality assurance lab for meter validation and interoperability testing; and
- leasing a facility for meter and other equipment storage.

Each AMI meter includes a remote activation card and a HAN card. ADPDCBA Appendix A, p. 6.

CL&P completed a Request for Information on February 12, 2010, with AMI vendors in order to construct and support a detailed cost estimate for the CBA. The RFI produced ten comprehensive responses from industry leaders, with cost estimates for each major meter component; AMI meter, HAN capabilities and remote activation capabilities. The base case scenario estimate for AMI metering equipment and communications infrastructure capital costs is based on the average price responses from eight of the vendors excluding the highest and lowest prices received from the RFI. The worst case metering equipment is based on the highest cost vendor and the best case is based on the lowest cost vendor response. CL&P relied on the RFI to build the cost estimates, but the Company has not committed to any specific vendor or technology at this time. ADPDCBA Appendix A, p. 6. In the Company's revised base case proposal in Late Filed Exhibit No. 1, CL&P used the best case cost of metering equipment because it is it's policy to use the least cost solution that meets the it's requirements. Tr. 2/1/11, p. 2306.

In the CBA, the average cost of a residential meter in the base case was $189, $273 in the worst case and $167 in the best case. Response to Interrogatory EL-15. The average cost of a residential meter in the revised base case was $167, the same as in the initial best case. Tr. 2/1/11, p. 2307.

The $219 million total costs of base case metering equipment represents 51% of the total cost of the revised base case deployment plan of $429 million.

The Company estimated that it would cost $44 million to replace the current AMR meters with new AMR meters over 17 years, 2013 through 2029. Responses to Interrogatories EL-14 and 50.

2. Communications Infrastructure Capital Costs

AMI communications capital costs for the Revised Base Case Deployment Plan are $15 million. AMI communications capital costs include:

- hardware and installation costs for AMI communications infrastructure;
- hardware and installation of the IP backbone, the head end collection system; and
- contracted engineers.

ADPDCBA Appendix A, p. 6.

IT capital costs for the Revised Base Case are $21 million. IT capital costs include developing the requirements and the design, building, performance acceptance testing and implementation preparation for the various technology requirements related to managing and communicating AMI data throughout CL&P's operations and back to customers. IT Capital investments million will be required to support:

- Web Portal - Website applications to provide customers with access to energy usage reports and analysis to assist customers with making more informed energy usage decisions leading to increased energy conservation;
- IT Infrastructure - Primarily additional hardware needed for increased data storage, additional data processing speed and system interfaces;
- Billing Upgrades - Building system interfaces from the Meter Data Management System into CL&P's customer billing system (C2);
- Customer Notification - Upgrades to the C2 system to enable new communications with customers related to peak energy periods, estimated customer restoration times, and customer self service applications; and
- Real Time Orders - System upgrades utilize AMI enabled capabilities for remote meter connects and disconnects, ad-hoc meter reads, and other remote investigations.

ADPDCBA Appendix A, pp. 6-7.

3. Marketing and Education Capital Costs

Marketing and education capital costs for the Revised Base Case are $2 million. They include the development of marketing and education materials and enabling IT systems to handle a letter mailing campaign to educate customers on new dynamic pricing programs. The marketing and education campaign will begin one year prior to the start of the dynamic rate programs and last through the initial year of dynamic rates. ADPDCBA Appendix A, p. 8.

B. O&M COSTS

The AMI capital investment will cause several changes within CL&P's day-to-day operations impacting annual O&M expense. These operational changes will translate into increased cost in some functions such as increased meter maintenance expenses while other operational areas are projected to experience lower costs such as meter reading expenses. ADPDCBA Appendix A, p. 8.

1. Field Equipment and Field Services O&M

The field services and meter operations group account for $90 million of the O&M incremental cost increases primarily driven by additional meter maintenance, meter implementation related service calls, and more energy theft investigations.

CL&P analyzed existing field service orders and used the lessons learned from the Plan-it-Wise pilot to project changes in the meter maintenance work in a full deployment scenario. Since AMI meters include more technology and communication components than current AMR meters, the CL&P

team concluded that the additional complexity of the AMI meters is expected to increase annual maintenance costs as problems could occur in more places such as base meter, remote activation card, and HAM cards compared with existing AMR meters.

Energy theft detection cases are expected to increase since AMI technology will provide CL&P with meter tamper flag indicators and data analysis to facilitate increased theft detection. The AMI business case includes an important theft reduction benefit, but in order to produce the theft reduction benefit, CL&P will rely heavily on manual investigations at customer sites. The Company will need additional employees to perform these investigations. ADPDCBA Appendix A, p. 9.

2. Communications and Customer Services O&M

Communications and Customer Services O&M costs of $23 million are primarily driven by annual vendor maintenance costs related to meter-to-fiber equipment and Head End Collection Systems, which, together transmit and gather the interval meter data. CL&P also estimated other annual operational costs to maintain equipment covered under warranty and non-labor costs of the new communication systems being deployed, which is estimated at an annual expense of 2% of the cumulative capital for communications capital previously purchased. This figure covers out-of-warranty repair costs for hardware, software maintenance fees, and costs to re-install failed equipment. Estimated changes in communications costs have also been included in the best and worst case scenarios. The best case scenario assumes annual maintenance costs to be 15% lower than the base case, while the worst case scenario assumes annual maintenance costs to be 25% higher than the base case. ADPDCBA Appendix A, p. 9.

CL&P's customer service center is expected to realize increased call volume as customers receive educational materials introducing new dynamic rate programs and for a period of time after the new rate programs are implemented. Customers are also likely to increase their calls and questions related to the accuracy of the new meters, as evidenced by PG&E and the Texas utilities AMI implementations and for more questions regarding new rates and bill inserts. The majority of the increased call volume is projected to be short term in nature with only a small residual increase throughout the life of the project. The overall increased call volume will lead to additional staffing requirements and the associated labor costs. ADPDCBA Appendix A, p. 9.

The O&M cost changes in the best and worst case scenarios were primarily driven by the estimated annual maintenance on the AMI meter equipment. The best case scenario assumes annual maintenance costs will be 15% less than the base case, while the worst case scenario assumes annual maintenance costs will be 15% higher than the base case. ADPDCBA Appendix A, p. 9.

3. IT O&M

IT O&M costs of $32 million are estimated at an annual expense rate of 12.5% of the cumulative IT capital previously purchased. This annual expense rate covers the application maintenance fees for NU IT application support to run the new applications and vendor products.

The best case scenario assumes annual O&M expenses are 10% of the cumulative IT capital costs, while the worst case scenario assumes a 20% annual O&M expense rate. ADPDCBA Appendix A, p. 9.

4. Customer Engagement Costs

CL&P's total customer engagement costs in the Revised Base Case of $27 million include an initial, early stage customer outreach plan. These costs are expected to span over a three year period, starting the first year prior to new dynamic rate programs and extending through the first two years of the new rate programs. The Company would provide all customers with quarterly mailings, separate from monthly bills, and include information about how the new rate programs work along with opportunities and strategies for customers to conserve energy and save money. The customer engagement costs are based on an estimated acquisition cost per customer. The base case scenario assumes the acquisition cost to be $100 for a residential customer and $200 for a C&I customer. The best case scenario assumes a residential customer acquisition cost of $75 and $150 per C&I customer and the worst case scenario assumes acquisition costs of $200 for a residential customer and $500 for a C&I customer. ADPDCBA, Appendix A, pp. 9-10.

Customer engagement costs also include costs related to customers' energy conservation. CL&P's energy conservation assumptions are enabled by ensuring customers are educated about the energy savings opportunities available with dynamic pricing plans and providing customers with hourly energy usage information analysis and feedback once the new meters and rates are in place. Customers are expected to leverage this information to make better energy usage decisions, ultimately leading to energy conservation during peak and off-peak periods. ADPDCBA Appendix A, p. 10.

The Company's ongoing customer feedback plan will provide energy information via the CL&P website and through an additional page in the customer's monthly bill. The cost benefit analysis includes the incremental cost of an additional monthly bill insert for all 1.2 million customers to drive conservation. To further encourage peak time savings, CL&P is also planning to produce television and radio messages that inform customers of peak time events during the summer months. These customer feedback costs are projected to be incurred annually to promote energy conservation and maintain customer engagement. ADPDCBA Appendix A, p. 10.

DOCKET NO. 05-10-03RE04 **APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO IMPLEMENT TIME-OF-USE, INTERRUPTIBLE LOAD RESPONSE, AND SEASONAL RATES - REVIEW OF METER STUDY, DEPLOYMENT PLAN AND RATE PILOT**

This Decision is adopted by the following Directors:

John W. Betkoski, III

Anna M. Ficeto

Kevin M. DelGobbo

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Public Utilities Regulatory Authority, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Kimberley J. Santopietro
Executive Secretary
Department of Energy and Environmental Protection
Public Utilities Regulatory Authority

Date