A REGULAR MEETING

Of The

TRAVERSE CITY LIGHT AND POWER BOARD

Will Be Held On

TUESDAY, August 9, 2016

At

5:15 p.m.

In The

COMMISSION CHAMBERS
(2nd floor, Governmental Center)
400 Boardman Avenue

Traverse City Light and Power will provide necessary reasonable auxiliary aids and services, such as signers for the hearing impaired and audio tapes of printed materials being considered at the meeting, to individuals with disabilities at the meeting/hearing upon notice to Traverse City Light and Power. Individuals with disabilities requiring auxiliary aids or services should contact the Light and Power Department by writing or calling the following.

Jennifer J. St. Amour
Administrative Assistant
1131 Hastings Street
Traverse City, MI 49686
(231) 922-4940 ext. 201

Traverse City Light and Power
1131 Hastings Street
Traverse City, MI 49686
(231) 922-4940

Posting Date: 8-05-16
2:00 p.m.

AGENDA

Pledge of Allegiance

1. Roll Call

2. Consent Calendar

The purpose of the consent calendar is to expedite business by grouping non-controversial items together to be dealt with by one Board motion without discussion. Any member of the Board, staff or the public may ask that any item on the consent calendar be removed therefrom and placed elsewhere on the agenda for full discussion. Such requests will be automatically respected. If an item is not removed from the consent calendar, the action noted in parentheses on the agenda is approved by a single Board action adopting the consent calendar.

a. Consideration of approving minutes of the Regular Meeting of June 28, 2016. (Approval recommended) (p.4)

b. Consideration of appointing Karla Myers-Beman as Officer Delegate and Kelli Schroeder as Officer Alternate Delegate to cast official votes on behalf of TCL&P at the Annual Meeting of the Municipal Employees Retirement Systems. (Approval recommended) (Schroeder) (p.7)

c. Consideration of authorizing a Letter of Agreement with the Utility Workers Union of America, AFL-CIO Local No. 295. (Approval recommended) (Schroeder) (p.9)

d. Consideration of authorizing a purchase order to Power Line Supply in the amount of $47,625.34 for materials for the pole replacements project. (Approval recommended) (Schimpke) (p.13)

Items Removed From Consent Calendar

a.

3. Unfinished Business

None.

4. New Business

a. Consideration of a Project Authorization Request for AMI. (Menhart) (p.14)

5. Appointments

None.

6. Reports and Communications

a. From Legal Counsel.

None.

b. From Staff.

1. Further analysis on the MPPA Purchase Power Commitment. (Myers-Beman) (p.62)

2. System Project Priority Matrix. (Schimpke) (p.64)

c. From Board.

7. Public Comment

/js

TRAVERSE CITY
LIGHT AND POWER BOARD

Minutes of Regular Meeting
Held at 5:15 p.m., Commission Chambers, Governmental Center
Tuesday, June 28, 2016

Board Members -

Present: Pat McGuire, Amy Shamroe, Bob Spence, John Taylor, Tim Werner, Jan Geht, Jeff Palisin

Ex Officio Member -

Present: Marty Colburn, City Manager

Others: Karla Myers-Beman, Pete Schimpke, Kelli Schroeder, Scott Menhart, Rod Solak, Jennifer St. Amour

The meeting was called to order at 5:15 p.m. by Chairman Geht.

Item 2 on the Agenda being Consent Calendar

Moved by McGuire, seconded by Shamroe, that the following actions, as recommended on the Consent Calendar portion of the Agenda, be approved:

a. Minutes of the Regular Meeting of June 7, 2016.
b. Renewing a collection agency contract with Cadillac Accounts Receivable Management, Inc.
c. Authorizing a purchase order to RESCO in the amount of $20,353.73 for materials for the Pole Replacement project.
d. Approving a construction contract in the amount of $109,282.00 with Newkirk Electric for the Pole Replacement project.
e. Approving a Use of Cellular Telephones & Other Electronic Devices policy.

CARRIED unanimously.

Items Removed from the Consent Calendar

None.

Item 3 on the Agenda being Unfinished Business

None.

Item 4 on the Agenda being New Business

1. Consideration of Orchard Heights Project Authorization request.

   5:23 John Taylor joined the meeting.

The following individuals addressed the Board:

Pete Schimpke, Manager of Operations & Engineering
Rod Solak, Line Superintendent

Moved by Shamroe, Seconded by, Palisin, that the Board approve as presented the Orchard Heights Overhead-to-Underground Conversion Phase 1 Project and directs staff to solicit construction bids and material quotes for the Board's consideration of approval.

Roll Call:

Yes- Shamroe, Spence, Taylor, Werner, Palisin
No- McGuire, Geht

Motion carried.

2. *Removed by the Executive Director.*

Item 5 on the Agenda being Appointments

None.

Item 6 on the Agenda being Reports and Communications

a. From Legal Counsel.

None.

b. From Staff.

1. Strategic Plan Update.

The following individuals addressed the Board:

Karla Myers-Beman, Controller
Pete Schimpke, Manager of Operations & Engineering
Scott Menhart, Manager of Telecom & Technology
Kelli Schroeder, Manager of HR & Communications

2. Project Priority Matrix

The following individuals addressed the Board:

Pete Schimpke, Manager of Operations & Engineering

3. Eighth Street Charette Update.

The following individuals addressed the Board:

Pete Schimpke, Manager of Operations & Engineering

c. From Board.

1. Chairman Geht issued a reminder to the Board, in light of receiving their FOIA training, if they were sending emails to the Union president or representatives and not copying the Executive Director, they needed to make arrangements to preserve their emails for FOIA records.

2. Chairman Geht announced that the July 12th Regular Meeting is cancelled.

Item 7 on the Agenda being Public Comment

There being no objection, Chairman Geht declared the meeting adjourned at 6:00 p.m.

Tim Arends, Secretary
LIGHT AND POWER BOARD

/js

TRAVERSE CITY
LIGHT & POWER

To: **Light & Power Board**
From: Kelli Schroeder, Manager of HR & Communications
Date: August 1, 2016
Subject: MERS Annual Meeting - Delegates

The Municipal Employees Retirement System (MERS) holds their Annual Meeting each year in the fall. Their 2016 meeting is set for September 28 - September 29, 2016 at the Grand Traverse Resort, Traverse City, Michigan.

The MERS Plan Document provides that our Employees' Delegate and Alternate Delegate shall be selected by secret ballot of the employees who are members of the Retirement System. This year Patrick Kendziorski was elected as Employee Delegate.

The Employer appoints an Officer Delegate and Officer Alternate Delegate to attend this meeting. Please appoint Karla Myers-Beman, Controller, as Officer Delegate, and Kelli Schroeder, Manager of HR & Communications, as Alternate Delegate.

Attached please find the MERS 2016 Annual Meeting Delegate and Alternate Certification form appointing the Officer Delegate and Alternate. This form also indicates the Employees' selection for Delegate.

This item is appearing on the Consent Calendar as staff deems it to be a non-controversial item. Approval of this item on the Consent Calendar means you agree with staff's recommendation to appoint a MERS delegate and alternate.

If any member of the Board or the public wishes to discuss this matter, other than clarifying questions, it should be placed on the "Items Removed from the Consent Calendar" portion of the agenda for full discussion. If after Board discussion you agree with staff's recommendation, the following motion would be appropriate:

MOVED BY ____________________, SECONDED BY ______________________,

THAT KARLA MYERS-BEMAN, CONTROLLER, AND KELLI SCHROEDER, MANAGER OF HR & COMMUNICATIONS, BE APPOINTED OFFICER DELEGATE AND OFFICER ALTERNATE DELEGATE RESPECTIVELY, FOR THE 2016 ANNUAL MEETING OF THE MUNICIPAL EMPLOYEES RETIREMENT SYSTEM; AND FURTHER THAT THE EXECUTIVE DIRECTOR BE AUTHORIZED TO EXECUTE THE CERTIFICATION OF DELEGATES.

MERS®
Municipal Employees' Retirement System

Municipal Employees' Retirement System of Michigan
1134 Municipal Way • Lansing, MI 48917
800.767.MERS (6377) • Fax: 517.703.9707
www.mersofmich.com

2016 Officer and Employee Delegate Certification Form

MERS 70th Annual Conference | September 28-29, 2016 | Grand Traverse Resort, Acme, MI

Please print clearly • Retain a copy for your records

IMPORTANT: A **voting delegate** registered to attend the **MERS Annual Conference** is ***NOT*** confirmed to have voting rights until this form has been received by MERS.

The voting delegate representative must be a MERS member, defined as an **active employee on payroll** who is enrolled in either a MERS Defined Benefit Plan, Defined Contribution Plan or Hybrid Plan.

If you are not attending MERS Annual Conference, you do not need to submit this form.

1. Officer (and alternate) delegate information

The officer delegate (or alternate) shall be a MERS member who holds a department head position or above, exercises management responsibilities, and is directly responsible to the legislative, executive, or judicial branch of government.

Officer Delegate name
Karla Myers-Beman, Controller

Officer Alternate name
Kelli Schroeder, Manager of HR & Communications

Officer delegate and alternate listed above were appointed to serve at the 2016 MERS Annual Conference by official action of the governing body (or chief judge for a participating court) on ________________, 2016.

2. Employee (and alternate) delegate information

The employee delegate (or alternate) shall be an employee member who is not responsible for management decisions, receives direction from management and, in general, is not directly responsible to the legislative, executive, or judicial branch of government.

Employee Delegate name
Patrick Kendziorski

Employee Alternate name
None Selected

Employee delegate and alternate listed above were elected to serve at the 2016 MERS Annual Conference by secret ballot election conducted by an authorized officer on June 16, 2016, 2016.

3. Certification

NOTE: Certification should be signed by a member of the governing body or chief administrative officer, or the chief judge for a participating court, and municipality number provided in space at the bottom of certification box.

I certify that the officer delegate and alternate selections are true and correct, and the secret ballot election results for employee delegate and alternate are true and correct.

Employer/municipality name*	Municipality number*	Email address
Traverse City Light & Power	2811	jstamour@tclp.org

Employer address	Employer city	Employer state	Employer zip code
1131 Hastings Street	Traverse City	MI	49686

Signature of authorized authority*	Printed name
	Timothy Arends

Title of authorized authority*	Date
Executive Director	

* Required field

Form 7175 20160316

FOR THE LIGHT & POWER BOARD MEETING OF AUGUST 9, 2016

TRAVERSE CITY
LIGHT & POWER

To:	**Light & Power Board**
CC:	**Tim Arends, Executive Director**
From:	Kelli Schroeder, Manager of HR & Communications
Date:	August 1, 2016
Subject:	Letters of Agreement - Meal Allowance

It has been brought to staff's attention that there have been inconsistencies in the application of the meal allowance outlined in Section 54 of the Collective Bargaining Agreement. Past practice granted a meal allowance to an employee when immediately called back into work versus the requirement that work must be continuous beyond the normal quitting time as outlined in the contract language (see attached). Additionally, a meal allowance has been granted to employees who have been called into work on a regularly scheduled off day and who work more than six hours which is not currently addressed in the contract.

In order to ensure consistency going forward, staff recommends that the attached Letter of Agreement be authorized between the Union and the Board. The impact to the budget will be minimal.

This item is appearing on the Consent Calendar as it is deemed by staff to be a non-controversial item. Approval of this item on the Consent Calendar mean's you agree with staff's recommendation.

If any member of the Board or the public wishes to discuss this matter, other than clarifying questions, it should be placed on the "Items Removed from the Consent Calendar" portion of the agenda for full discussion. If after Board discussion you agree with staff's recommendation, the following motion would be appropriate:

MOVED BY ____________________, SECONDED BY _______________________,

THAT THE BOARD AUTHORIZE THE EXECUTIVE DIRECTOR TO SIGN THE LETTER OF AGREEMENT BETWEEN TCL&P AND THE UTILITY WORKERS UNION OF AMERICA LOCAL, NO. 295 THAT DESIGNATES WHEN A MEAL ALLOWANCE SHALL BE GRANTED.

Letter of Agreement
between
Traverse City Light & Power
and
Utility Workers Union of America, AFL-CIO Local No. 295

Meals Allowance

WHEREAS, the undersigned are parties to a Collective Bargaining Agreement expiring on June 30, 2017; and

WHEREAS, the current contract under Section 54, *Meals Allowance*, paragraph two, states that when an employee is required to work beyond his or her scheduled quitting time for more than two (2) hours, he or she will be furnished a meal allowance in the amount of twenty dollars ($20) per meal allowance; and thereafter every six (6) hours.

WHEREAS, there are instances when an employee has left work at the end of the normal worked day but is immediately called back within the first hour; and

WHEREAS, this does not provide enough time to eat prior to returning back to work; and

WHEREAS, there are instances when an employee is called into work on a Saturday, Sunday or holiday and who work longer than six hours; and

WHEREAS, this results in the inability to obtain a meal from home within a reasonable timeframe;

THEREFORE, be it known that the Employer and the Union agree that:

Section 54, paragraph 2, shall be amended to read the following: When an employee is required to work beyond his or her scheduled quitting time or is called back into work within one hour after the scheduled quitting time, and works for more than two (2) hours, he or she will be furnished a meal allowance in the amount of twenty dollars ($20) per meal allowance; and thereafter every six (6) hours.

Employees who are given less than 12 hours advance notice to report to work on a regularly scheduled off day and who work for more than six (6) hours will be furnished a meal allowance in the amount of twenty dollars ($20) per meal allowance; and thereafter every six (6) hours.

This change shall be retroactive to July 1, 2016.

WHEREBY, the parties signify agreement to the above by representative signatures appearing hereon.

Traverse City Light & Power Department

By:________________________________
Timothy Arends, Executive Director

Date:_______________________________

Utility Workers Union of America, AFL-CIO Local No. 295

By:________________________________
Robert Hipp, President Local 295

Date:_______________________________

this Agreement, each had the unlimited right and opportunity to make demands and proposals with respect to any subject or matter not removed by law from the area of collective bargaining and that the understandings and agreements arrived at by the parties, after the exercise of that right and opportunity, are set forth in this Agreement. Therefore, the Employer and the Union, for the life of this Agreement, each voluntarily and unqualifiedly waive the right, and each agree that the other shall not be obligated, to bargain collectively with respect to any subject or matter referred to or covered by this Agreement and with respect to any subject or matter not specifically referred to or covered in this Agreement, even though such subject or matter may not have been within the knowledge and contemplation of either or both of the parties at the time they negotiated or signed this Agreement.

Section 54. Meals Allowance. When an employee is required to report to work two (2) hours or more preceding his or her regular starting time and continues work into his or her regular shift, he or she will be furnished a meal allowance at the Board's expense that will be paid to the employee as an addition to the next payroll.

When an employee is required to work beyond his or her scheduled quitting time for more than two (2) hours, he or she will be furnished a meal allowance; and thereafter every six (6) hours.

The Board will pay twenty dollars ($20) per meal allowance.

When such a meal is furnished by the Board, a meal allowance will not be permitted.

TRAVERSE CITY
LIGHT & POWER
EST. 1912
Investing Our Energy In You

1131 Hastings Street
Traverse City, MI 49686
231.922.4940

To: **Light & Power Board**
From: Pete Schimpke, Manager of Operations & Engineering PS
Date: August 2, 2016
Subject: Pole Replacements Project – Project Materials

At the February 23, 2016 regular meeting, the Board approved the project authorization request for the Pole Replacements Project, which includes the replacement of approximately 300 substandard poles and related material.

Requests for project materials were sent out to three bidders, Power Line Supply, RESCO and WESCO. WESCO did not submit a bid. Below is a summary of the two bids submitted:

Bidder	**Bid Total***
Power Line Supply	$47,625.34
RESCO	$50,903.50

**Bid totals are based on the estimated quantities provided in the RFP, with adjustments made to account for any minimum quantities required*

This item is appearing on the Consent Calendar as it is deemed non-controversial. Staff recommends issuing a purchase order to Power Line Supply in the amount of $47,625.34 for the purchase of materials for the Pole Replacements Project. Approval of this item on the Consent Calendar means you agree with staff's recommendation.

If any member of the Board or the public wishes to discuss this matter, other than clarifying questions, it should be placed on the "Items Removed from the Consent Calendar" portion of the agenda for full discussion. If after Board discussion you agree with staff's recommendation the following motion would be appropriate:

MOVED BY ________________________, SECONDED BY __________________________,

THAT THE BOARD AUTHORIZES THE EXECUTIVE DIRECTOR TO ISSUE A PURCHASE ORDER TO POWER LINE SUPPLY IN THE AMOUNT OF $47,625.34 FOR MATERIALS FOR THE POLE REPLACEMENTS PROJECT.

FOR THE LIGHT & POWER BOARD MEETING OF AUGUST 9, 2016

TRAVERSE CITY
LIGHT & POWER
EST. 1912

To: **Light and Power Board**
From: Scott Menhart, Manager of Telecom & Technology
Date: July 5th, 2016
Subject: Advanced Metering Infrastructure (AMI) Project Authorization

TCL&P Staff has previously presented on advanced metering infrastructure (AMI) to the Board which included a special study session in December 2015 along with a follow-up presentation by staff at a regular board meeting in May 2016. These presentations gave the Board the chance to have Q&A sessions with staff, along with time in between for staff to address any unknown answers.

At the last presentation, the lingering question the Board had was relating to the overall impact that AMI has on influencing residents in a community to participate in possible future utility programs that AMI may create. Without physically rolling AMI out, this question is incredibly difficult to address and answer with absolute accuracy as all communities are different.

It must be emphasized that staff's main foundation for AMI is to utilize the infrastructure and data as an internal tool to drive future internal business. This mainly relates to grid reliability projects and customer rate structures as the utility will finally have meaningful metrics on the electric grid to formulate such future plans and projects.

To answer the main question, staff has attached a whitepaper that focuses on the different types of customer classes and how AMI may influence their behaviors. The whitepaper titled, "The Costs and Benefits of Smart Meters for Residential Customers," breaks down customer segments with varying levels of eco-awareness and value consciousness. It pulls data from multiple sources, including the "State of Consumer Report," which assumes that consumer adoption patterns will align with their energy worldviews. Unless an AMI deployment is physically completed and data is collected for analyzation, this assumption is a reasonable assumption for the TCL&P community as well.

The whitepaper concludes that whether you are a pioneer utility, such as a larger utility, or an exploratory or cautious utility such as TCL&P, the net benefits are positive. It goes on to state that the customer-driven benefits could be much greater with more investment in and focus on customer education and engagement and "most customers migrate from passive engagement in energy management to much more active strategies," which is a large additional benefit in addition to TCL&P staff using AMI as an internal tool.

The cost within the Capital Improvement Project (CIP) is currently at $5,000,000. However, feedback from vendors that were willing to give a very high level preliminary estimate for a full deployment put the cost closer to $3,800,000 for an entire deployment.

As stated, staff views AMI as a primary internal tool for driving the majority of future TCL&P business. This includes a wide range of opportunities that staff is looking to take advantage of, now with adding an optimistic approach to influencing customer use. A full list of these potential uses can be found in the packet labeled "AMI Usage and Benefits." As a result, staff would like to seek Board approval to solicit proposals by method of an RFP. This will identify the true cost of the system for TCL&P.

Staff recommends Board approval of the Project Authorization Request for the Advanced Metering Infrastructure Project.

If after Board discussion you agree with staff's recommendation the following motion would be appropriate:

MOVED BY ______________________, SECONDED BY _________________________,

THAT THE BOARD APPROVES THE ADVANCED METERING INFRASTRUCTURE PROJECT AUTHORIZATION REQUEST AND DIRECTS STAFF TO SOLICIT BIDS FOR THE BOARD'S FUTURE CONSIDERATION OF APPROVAL.

PROJECT AUTHORIZATION REQUEST

TRAVERSE CITY LIGHT & POWER

Project Name: Advanced Metering Infrastructure (AMI)

Budgeted in CIP: Yes

Dollar Amount Budgeted: $5,000,000

Date of Board Presentation: August 9, 2016

Objective: Target Completion date of 2018

Project Description:

The project consists of rolling out advanced meters to TCL&P customers.

Project Purpose and Necessity:

While there will be ancillary benefits to customers, the main reason for AMI is for staff to utilize the data the system will provide as the primary tool to making future CIP, distribution automation, and rate structure decisions.

<u>Assets & Project Prioritization</u>: Currently, Staff receives a single meter read once a month per customer, which results in twelve reads a year per customer. While this identifies the load a customer has used for the month, it does not give any detailed patterns of usage or system trending for customers or segments of the grid. As a result, Staff compiles system-planning recommendations by utilizing an internal matrix that is still in the process of being developed. While the matrix is TCL&P's best effort on prioritizing projects and grid operation and maintenance, it does this without real snapshots, data, and trending of the grid, which results in a lower level of absolute certainty when prioritizing needs. This leads to issues such as unnecessarily replacing assets prior to their full useful life or incorrect prioritization of projects, both of which have a direct impact on customer reliability and rates.

<u>Project Results</u>: Over the years, the Board has asked for metrics that show whether projects are having an impact on areas and/or rates. One such area has been demand response initiatives. The more real-time data that TCL&P has, the better Staff can understand on which initiatives are working and which ones TCL&P should drop. This will give prudent information to the Board to assist with making confident future decisions on demand side management projects.

<u>Engineering Analysis</u>: Prior to construction, engineering calculation are performed for any job to determine the size of wire, transformers, fuses, etc. However, as time moves on, customers change their demand needs and put additional unaccounted for strain on the equipment, resulting in power quality issues. When this happens, Staff has no current way of knowing this unless customers call to report power issues. At this point, irreversible damage to transformers and other equipment may have already resulted. With AMI, Staff would know the second there is overloaded equipment and can address it before it becomes a problem or outage. This would

also result in the potential salvage and re-use of equipment prior to any permanent damage occurring. This would be a paradigm shift in operations, turning TCL&P into a proactive utility reducing overall customer issues or outages.

Outage Response: The number one criticism of customers of electric utilities is communication barriers during the initial stages of large outages. This is a result of Staff waiting to collect enough data to analyze and prioritize outages. Today, Staff has to wait for enough phone calls to come in to get an idea of outage damage before restoration times can be determined. During this time, Staff cannot give customers any insight on restoration times, simply because there is not enough data. This lack of information tends to upset customers very quickly. Essentially, TCL&P is in a reactive state as it waits for customers to report on issues. Again, with AMI, TCL&P can change its entire operating model to a proactive utility and address small issues before customers are even aware, and prioritize and quickly release public statements on large outages. This is because we will instantaneously have all customers that are offline with a very good degree of accuracy. Staff can even update phone messages for when customers call in indicating that TCL&P is already aware of their outage and give an estimated restoration time to each individual caller.

Project Benefits: See attached presentation: AMI Usage and Benefits documentation

Other Alternatives: Do nothing and continue with operations as normal

Timing of Project:

The Board has stated that TCL&P should not be leading edge on innovative technology, nor trailing behind, but somewhere in the middle. At this time, TCL&P is beginning to trail on AMI in comparison to surrounding utilities. TCL&P is also in a cash positive state and can afford such a project without altering current rates. Therefore, staff would like to do this project in the beginning of 2017.

Project Timeline and Expenditures

RFP and selection will happen in the fall of 2016. Anticipated project start dates would be the first quarter of 2017. The expected project completion date is the first quarter of 2018.

Preliminary Engineering Cost Estimate: None

Financing Method:

No bonding or borrowing is required. Current cash reserves are previously been allocated within the Six Year Capital Improvements Plan. It is anticipated to split the funding over two separate fiscal years (2016/17 & 2017/18)

Additional Revenues: None:

Impact on O&M Expenses: See attached presentation: Benefits of AMI TCLP 2016

PROJECT AUTHORIZATION REQUEST

TRAVERSE CITY LIGHT & POWER

Staff Recommendation:

Staff recommends going out for bid and fully deploying AMI.

TRAVERSE CITY
LIGHT & POWER
EST. 1912

AMI Usage and Benefits

Scott Menhart
7/5/2016

High Level

- Advanced Metering Infrastructure (AMI)
- Distribution Optimization (DO)
- Distribution Automation (DA)
- Demand Side Management (DSM)
- Smart Grid Data Analytics – Meter Data Management (MDM)
- Demand Response (DR)
- Carbon Management
- Home Energy Management
- Electric Vehicles

Breakdown Opportunities

- Advanced Metering Infrastructure/Reads (AMI)
    - Reduce/eliminate manual meter reads
    - Complete and Accurate Power Quality Data
        - Voltage Regulation
        - SAIDI, CAIDI, MAIFI statistics
    - Data to support different rate classes of customers
        - Peak customers
        - Time of Use rates (TOU)
    - Distribution Congestion
    - Integration with Outage Management System (OMS);
        - reduce system outage times
        - instant customer notification
            - power outage/power restoration
    - Reliability of Service, Losses, and Loading: Future Tools
        - Historical Statics on over-loading to support new infrastructure (ie: Substations)
        - Feeder and/or Upgrade the Line
    - Avoided Generation
        - Peak Energy Costs

        - Avoiding Capacity Shortfall
        - Planning Reserves
    - Consumer Options
        - Prepayment options
        - Greater Control over Bills
        - Portal for viewing instantaneous energy reads and demand
    - T&D Operations
        - More predictable power flows
        - Lower cost dispatch / power purchases
        - Reduced congestion
    - Carbon Emissions Reduction:
        - Read Meters
        - Remote Connect/Disconnect
        - Outage Restoration
        - Off Cycle Reads
    - Support Data of/and against DR Programs
        - Time of Use (TOU)
        - In-Home Display
        - Critical Peak Pricing (CPP)
        - Programmable Communication Thermostat (PCT)
        - Energy Efficiency

- <u>Distribution Automation (DA)</u>
    - Fault Detection, Isolation, and Recovery (FDIR)
    - Volt/VAR Optimization
    - Automate Switching (Switchgear)
    - Feeder Protection and Control
    - OMS Enhancement
    - Reliability Analysis
    - Operations budget analysis

- <u>Distribution Optimization (DO)</u>
    - Loss Analytics
    - Load Control Optimization
    - Asset Optimization
    - Load Analytics
    - AMI Auditing
        - Put devices on transformers

- <u>Demand Side Management (DSM)</u>

- Customer Portal for monitoring Energy Consumption
  - Remote Functionality to control Appliances (Temperature, etc.)
- Utility Portal for Management of Consumer Demand (Incentive Programs, etc.)
  - Air Conditioners, Hot Water Systems, Pool Pumps, etc.

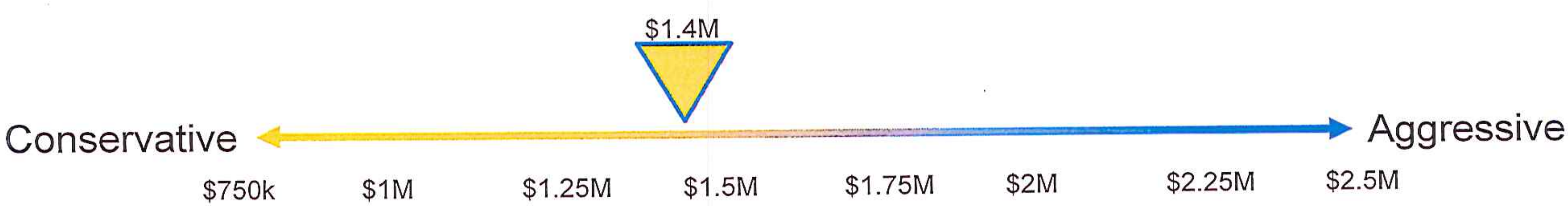
ELECTRIC & WATER AMI

EST. 1912 TRAVERSE CITY LIGHT & POWER 100 YEARS

TRAVERSE CITY LIGHT & POWER

AMI Benefits – Summary (Electric and Water)

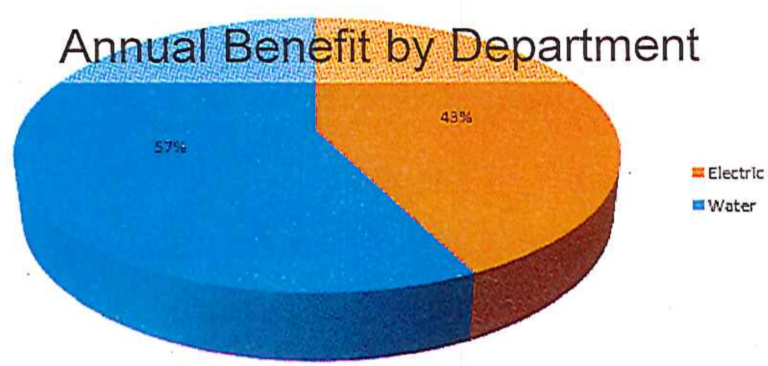
Summary of Annual Estimated Savings		
	Savings	
	Conservative	**Aggressive**
Meter Operations	$220,000	$350,000
Revenue Management	$500,000	$2,000,000
Outage Detection	$20,000	$150,000
Billing/Customer Service	$15,000	$50,000
TOTAL	$755,000	$2,550,000



TRAVERSE CITY LIGHT & POWER

AMI Benefits – Summary (Electric and Water)

Summary of Annual Estimated Savings	
	Savings
Meter Operations	$255,883
Revenue Management	$1,108,791
Outage Detection	$21,178
Billing/Customer Service	$16,250
TOTAL	$1,402,103



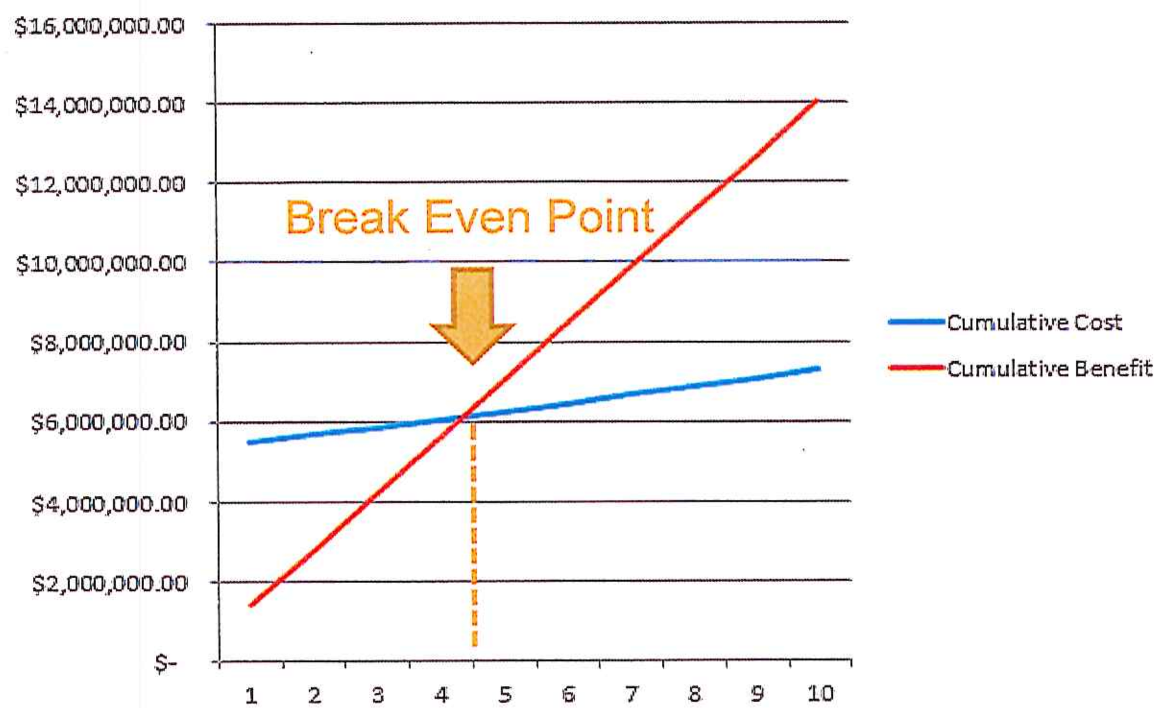
Assumptions Being Made:

- Based on measured results of other utility clients using Traverse City Light & Power data when available.
- Estimated Yearly revenue from electric estimated at $35M.
- Estimated Yearly revenue from water/waste estimated at $7M.
- Estimated number of meter readers is 2 for electric and 2 for water.
- Estimated annual bad debt is $20,000 (elec) $40,000 (water)
- 50% of electric meters are over 20 years old
- 50% of water meters are less than 20 years old.

TRAVERSE CITY LIGHT & POWER

AMI Benefits – Break Even (Electric and Water)

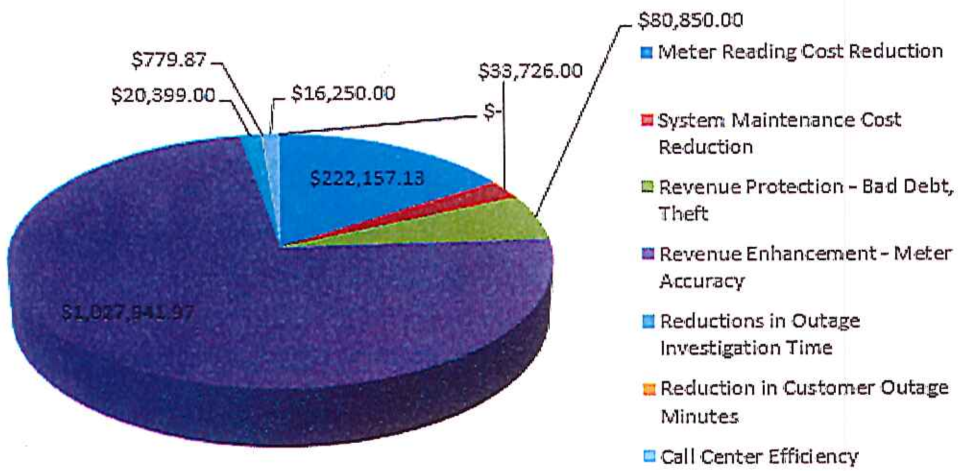
Year	Cumulative Cost	Cumulative Benefit
2017	$ 5,500,000.00	$ 1,402,103.97
2018	$ 5,680,000.00	$ 2,804,207.97
2019	$ 5,864,500.00	$ 4,206,311.97
2020	$ 6,053,612.50	$ 5,608,415.97
2021	$ 6,247,452.81	$ 7,010,519.97
2022	$ 6,446,139.13	$ 8,412,623.97
2023	$ 6,649,792.61	$ 9,814,727.97
2024	$ 6,858,537.43	$ 11,216,831.97
2025	$ 7,072,500.86	$ 12,618,935.97
2026	$ 7,291,813.38	$ 14,021,039.97



Note: Cost estimates include electric and water system, with full installation

TRAVERSE CITY LIGHT & POWER

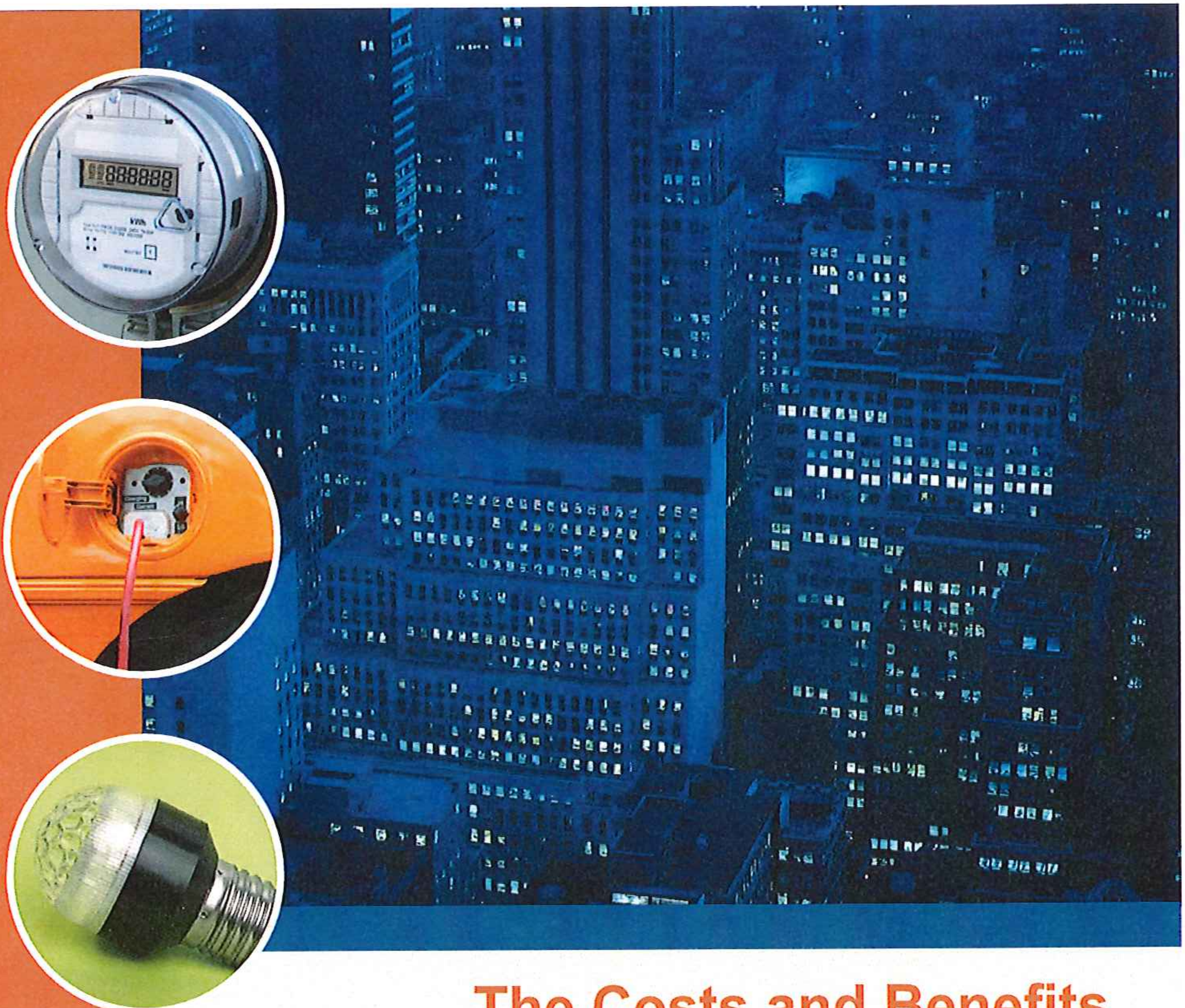
AMI Benefits – Details (Electric and Water)



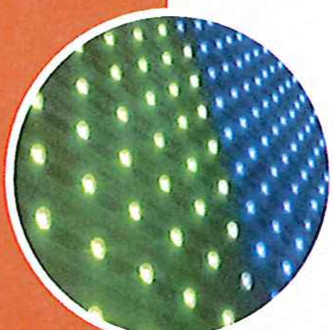
Summary Report - Steady-State Annual Projection

Projected steady-state annual benefits after initial system ramp-up periods.

Item Description	Electric (Annual)	Water (Annual)	Gas (Annual)	$ Annual Benefit
METER OPERATIONS				
Meter Reading Cost Reduction				
On-Cycle Meter Cost Reduction	$ 93,036.67	$ 64,579.79	$ -	$ 157,616.45
Off-Cycle Meter Cost Reduction	$ 36,725.00	$ 25,038.83	$ -	$ 61,763.83
Overtime / Disconnect Cost Reduction	$ 2,776.85			$ 2,776.85
System Maintenance Cost Reduction				
AMR / IT Maintenance Cost Reduction	$ 2,376.00			$ 2,376.00
Meter Maintenance / Testing Cost Reduction	$ 23,750.00	$ 7,600.00	$ -	$ 31,350.00
Total	$ 158,664.52	$ 97,218.62	$ -	$ 255,883.13
REVENUE MANAGEMENT				
Revenue Protection				
Reduction in Bad Debt	$ 17,600.00	$ 15,750.00	$ -	$ 33,350.00
Reduction in Theft	$ 40,000.00	$ 7,500.00	$ -	$ 47,500.00
Reduction in Unbilled Consumption	$ -			$ -
Revenue Enhancement				
Improvement in Meter Accuracy	$ 346,812.27	$ 681,129.70	$ -	$ 1,027,941.97
Total	$ 404,412.27	$ 704,379.70	$ -	$ 1,108,791.97
OUTAGE DETECTION				
Service Dispatch Cost Savings				
Reductions in Outage Investigation Time	$ 20,399.00			$ 20,399.00
Revenue Enhancement				
Reduction in Customer Outage Minutes	$ 779.87			$ 779.87
Total	$ 21,178.87			$ 21,178.87
BILLING-CUSTOMER SERVICE				
Call Center Efficiency				
Reduction in Call Time & Inquiries	$ 16,250.00			$ 16,250.00
Total	$ 16,250.00			16250
TOTAL	$600,505.65	$801,598.32	$ -	$ 1,402,103.97



The Costs and Benefits of Smart Meters for Residential Customers



IEE Whitepaper
July 2011

The EDISON FOUNDATION | INSTITUTE FOR Electric Efficiency

Advancing energy-efficiency and demand response among electric utilities.

The Costs and Benefits of Smart Meters for Residential Customers

IEE Whitepaper

July 2011

Prepared by

Ahmad Faruqui
Doug Mitarotonda

The Brattle Group

Lisa Wood
Adam Cooper

Institute for Electric Efficiency

Judith Schwartz

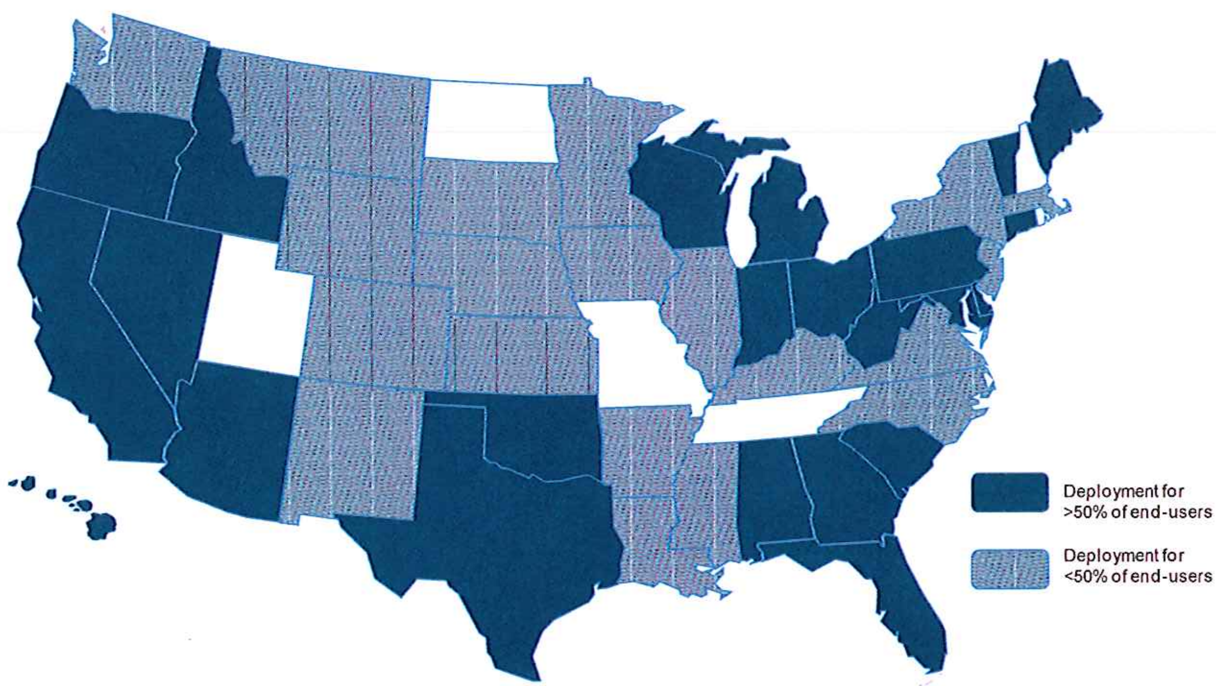
To the Point

TABLE OF CONTENTS

INTRODUCTION

Across the nation, electric utilities are deploying smart meters (technically termed advanced metering infrastructure or AMI) to their residential customers as the basic building block of the Smart Grid. In a few areas of the country, such as California and Texas, smart meters are almost fully deployed. As of June 2011, approximately 20 million smart meters had been deployed in the U.S. and it is likely that the number will rise to approximately 65 million meters by 2015.[1] This would represent approximately 50 percent of all U.S. households. By the end of this decade, smart meters may be deployed to almost all U.S. households. Another noteworthy trend is the growing number of home energy management devices. In a recent report, Greentech Media estimated that approximately 6 million U.S. households will have some type of home energy management device by 2015.[2] This represents about 10 percent of the expected 65 million households with smart meters and, in our view, is a realistic estimate of the size of the home energy management market.

Figure 1: Utility-Scale Smart Meter Deployments, Plans, & Proposals



Source: IEE 2010, www.edisonfoundation.net/IEE

[1] Institute for Electric Efficiency, "Utility Scale Smart Meter Deployments, Plans, & Proposals." (September, 2010). www.edisonfoundation.net/IEE

2 Greentech Media report "Smart Grid HAN Strategy Report 2011: Technologies, Market Forecast, and Leading Players," 2011.

Despite this rapid growth in the home energy management space (almost 100 percent growth is expected over the next 3-4 years according to Greentech Media), and the significant energy management opportunity that is unleashed by the combination of smart meters and smart home energy management devices, concerns about the adverse effects of smart meters continue to dominate conversations among regulators, consumer advocates, and electric utilities.

With an eye toward resolving some of these controversies, this paper presents a framework for quantifying the costs and benefits of smart meters from a wide variety of perspectives across a range of electric utility and customer types. It shows how the magnitude of both costs and benefits might vary across different types of electric utilities and different types of customers. In the paper, we allow utility types to vary in terms of their load shapes; supply mix, including renewable energy and other energy sources; cost structures; current metering technology; and customer base. Furthermore, customers vary in terms of the level of their engagement in energy management.

Smart meters provide two-way digital communications between the utility and the customer, thereby enabling:

- customer energy management and demand response via both information and rate programs;
- utility operational advantages such as outage detection and management, remote meter reading, and remote customer (dis)connections;
- smart charging of plug-in electric vehicles; and
- integration of distributed generation resources.

Our main objective is to provide a framework that is general enough to be adapted by individual utilities and regulators in conducting their own analyses. In places, this whitepaper presents the same data in multiple ways to make the concepts behind the analysis more accessible to the range of stakeholders. Our results demonstrate that the benefits of smart meters exceed the costs under a variety of realistic assumptions. This whitepaper does not claim that AMI and the customer programs measured in this paper would be cost-effective for every utility, and results could vary using different assumptions.

For certain types of utilities, engaging customers in smart energy management programs is not necessary from a benefit perspective. Such utilities show positive net benefits whether or not customers engage in energy management programs. However, we believe that even those utilities that can justify investing in smart meters on operational cost savings alone can further enhance benefits to their customers by engaging with them in ways that are discussed in this whitepaper. Only then will the full power of the Smart Grid be unleashed for the greater good of society and for energy sustainability.

In estimating the consumer-driven benefits of smart meters, we took a very conservative approach by assuming fairly low participation rates by customers in different program offerings and in the use of enabling technologies, even after 20 years. We believe that if customers can choose their preferred rate plans, programs, and enabling technologies, adoption rates will be higher. If significant investment is made in customer engagement, this will enable the realization of more extensive financial benefits to individuals, utilities, and society.

KEY ISSUES NOT ADDRESSED IN THIS STUDY

In some areas of the country, utility customers are "opting out" of smart meters, resulting in a loss of operational savings that could have been realized with full deployment. Such losses in savings are borne by all customers in a utility service area. In addition, it is not clear how allowing small numbers of customers to "opt out" of the basic building block of the Smart Grid will impact the nation's ability to transition to a modernized grid. We do not address this issue in this study.

Given the very low penetration of distributed resources at this time, this paper does not integrate or quantify the incremental value and environmental benefits of integration of distributed renewable generation. However, distributed generation would only increase the benefits of smart meters.

STUDY FRAMEWORK

One question that continually arises in discussions of grid modernization is whether investment in smart meters (AMI) makes economic sense from a benefit and cost perspective. This study quantifies three categories of "benefits" from smart meters.

- **Operational benefits** allow the utility to deliver more reliable service, rapid remote (dis)connection, and better outage detection and recovery to its entire customer base at a lower overall cost.
- **Customer benefits** arise from engagement in energy management driven by information and/or price signals, which leads to electricity usage reduction or load shifting and the opportunity to lower bills or mitigate cost increases.
- **Societal benefits** arise from demand response and direct load control, enabling reduction of peak purchases, thereby applying downward pressure on energy prices in spot markets, offsetting the need for new generation and transmission and distribution (T&D) capacity, and potentially lowering carbon emissions through integration of cleaner distributed generation and household usage reductions.

We estimate these benefits for a range of different utility types using four prototypical "examples" at different stages of deployment of the Smart Grid. We define the profiles for the four utility prototypes based on real world factors that influence the overall business case for smart meters, including the current generation mix, the renewable energy portfolio, the regulatory environment, emphasis on efficiency and conservation, and other factors (see Tables 1 and 2).[3] Also, we include a utility prototype that currently has automated meter reading (AMR) and is therefore likely to have lower operational benefits from smart meters.

1. **Pioneer**: A utility that previously invested in AMR with very high energy prices and that purchases all power.
2. **Committed:** A utility with relatively high energy prices, primarily natural gas-fired generation, and a mandate to aggressively pursue renewable generation.
3. **Exploratory**: A utility with relatively low-cost generation available, high population density, and highest demand in winter months.
4. **Cautious**: A utility with low population density, high annual demand growth, and coal, nuclear, and natural gas dominant in its generation portfolio.

[3] The authors thank Cheryl Hindes of BGE and the AEIC Load Research Committee for making real world load shape data available for this study.

Table 1: Profiles of the Four Utility Prototypes

	Pioneer	Committed	Exploratory	Cautious
Current meter	AMR Operational	AMI in process	All analog	All analog
Direct load control	DLC 1.0 (< 1% customers)	DLC 1.0 (< 1% customers)	DLC 1.0 (< 1% customers)	DLC 1.0 (< 1% customers)
Generation profile	T&D only, all generation purchased (nuclear, gas, hydro)	Mix of generation owned by utility and purchased (hydro, gas, nuclear)	Bulk of generation owned by utility (gas, nuclear, coal)	Bulk of generation owned by utility (coal, nuclear, gas)
Regulatory environment	Approved to proceed	Mandates for SG/RPS	Approved to proceed	Conservative
Climate change attitude	Problem	Serious Problem	Problem	Skepticism
Regional climate	Moderate cold-hot	Fairly temperate	Extreme cold-hot	Temperate-hot
Emphasis on efficiency and conservation	High	High	Low	Low

Another factor included in the study is how customers vary in terms of their energy "worldview." Not only do these patterns vary regionally, households are also likely to exhibit variation in their use of in-home energy management devices, their willingness to engage in smart rate programs, the types of vehicles and appliances they purchase, and their overall engagement in the use of electricity.

Based on multiple studies as cited in the *2011 State of the Consumer Report*[4], we assume that consumer adoption patterns will align with their energy worldviews. We developed energy management participation plans to correspond with four dominant customer segments, described below.

1. **Basic**: For consumers who do not wish to engage at all.
2. **Comfort**: For those with large load homes with air conditioning, pool pumps, smart appliances, minimal interest in energy engagement, and limited concern about their bills.
3. **Saver**: For those primarily motivated by the opportunity to save money on their bills or mitigate potential bill increases.
4. **Green**: For those motivated by environmental concerns and willing to be more engaged.

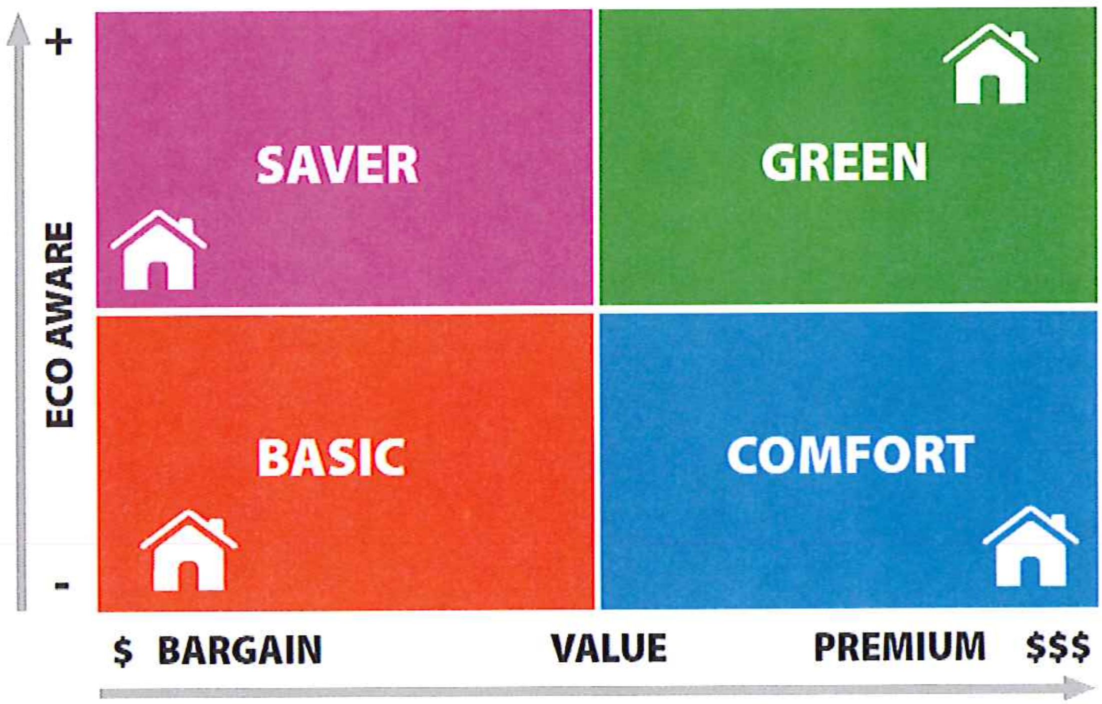
As shown in Figure 2, on the eco-awareness and value axes, the Comfort segment is environmentally and price insensitive when it comes to energy use. The Saver segment is the most bargain-conscious with some degree of eco-awareness. The Green segment has a higher level of eco-awareness and is willing to pay a premium for environmentally friendly energy

[4] *2011 State of the Consumer Report*, Smart Grid Consumer Collaborative (January 31, 2011). http://www.smartgridcc.org

solutions. Finally, the Basic segment is relatively indifferent to environmental concerns and, while wanting low bills, is less willing to take action than the Savers.

Using national studies of current consumer attitudes as a starting point; we assigned specific customer segment mixes to each utility based on the utility profile.

Figure 2: Four Customer Segments with Varying Levels of Eco-Awareness and Value Consciousness



Positive Net Benefits Using Real World Data

By leveraging real world utility load shapes, varied generation mixes, and capacity, T&D, and AMI installation costs based on composites of actual deployments, the study shows that positive net benefits flow to all ratepayers when utilities adopt AMI as part of their Smart Grid modernization plans.

In the analysis, for all of the prototypical "example" utilities, we assume:

- One million customers within the service area;
- AMI is phased in gradually over a five-year time horizon;

- A web portal for feedback, plus the option to add a simple in-home display, are available to everyone that has AMI installed;
- Every customer with a new AMI meter is defaulted to a no risk, peak time rebate rate offered on 12-15 event days per year;
- Customers will choose one of four plans that include pricing options of no risk (i.e., peak time) rebates (the default for everyone), heat wave (i.e., critical peak) pricing, or time of use for households with electric vehicles;
- Direct load control is available and is measurable and verifiable (in contrast to legacy DLC 1.0 programs, which are not measurable and verifiable today);
- A small percentage of customers have electric vehicles with a time of use rate plan applied on a daily basis for the entire household; and
- Energy management automation may be selected by individual consumers.

We based the cost of devices on actual prices and projections provided by manufacturers and assumed that, over the next 20 years, prices will decline significantly as innovations occur, economies of scale take hold, and manufacturing costs decline. We also recognize that technology innovations not known today are likely to appear in the market.

CONSUMER CHOICE

All customers have access to a web portal with simple energy-use feedback information and all customers receive the operational benefits and the avoided costs of AMI whether they choose to engage in energy management or not.

Customers have access to a variety of technologies such as displays, programmable communicating thermostats, and home energy management systems, as well as smart rate and program options including no risk (i.e., peak time) rebates, heat wave (i.e., critical peak) pricing, time of use rates for electric vehicles, and direct load control. We assume customers will choose their own preferred technologies and program options. The model accounts for the technology cost independent of whether it is paid for by the customer, the utility, or a subsidy.

The technology and program/rate options are:

- **Web portal**: An online site the customer can visit to monitor the aggregated electricity usage for the home on a one-day lag basis;
- **Display**: A visual feedback device or application that lets the customer know whether the price of electricity is expensive, moderate, or cheap in real time;

- **Programmable Communicating Thermostat** (PCT): A programmable thermostat that includes an in-home feedback display plus applications that can monitor and control temperature remotely as set by the customer;

- **Home Energy Management System** (HEMS): A device and application that allows the resident to monitor and control a broad range of electrical devices and appliances within the home;

- **Electric Vehicle** (EV): An electric car and charging system that are purchased by the customer;

- **No Risk Rebates**: Peak time rebates (PTR) are the default rate wherever meters have been installed. A customer that reduces usage during event hours will receive a rebate. Otherwise the consumer remains on their current rate;

- **Heat Wave Pricing**: Critical peak pricing (CPP) is available and the percentage of customers that choose it varies by market segment;

- **Direct Load Control 2.0** (DLC 2.0): Customers who choose DLC have a device provided by the utility or a third party that includes monitoring and verification capabilities. Note: load control equipment in use today generally cannot measure and verify usage during a load control event. Hence, we use the term DLC 2.0 to signify a new generation of load control equipment that measures and verifies the change in usage; and

- **Time of Use** (TOU): Time variable pricing on a daily basis is the default rate for EV owners and applies to the entire residence.

Even within a market segment, we anticipate customers will manage their energy usage in a variety of different ways from passive behaviors to active energy management to investing in more elaborate automation. We assume customers will choose different technologies, programs, and rates depending on their style of energy management.

The five customer engagement pathways quantified in the analysis are:

- **Passive**: Unengaged households that benefit indirectly from operational improvements due to smart meters and incrementally if they coincidentally defer usage on demand response event days;

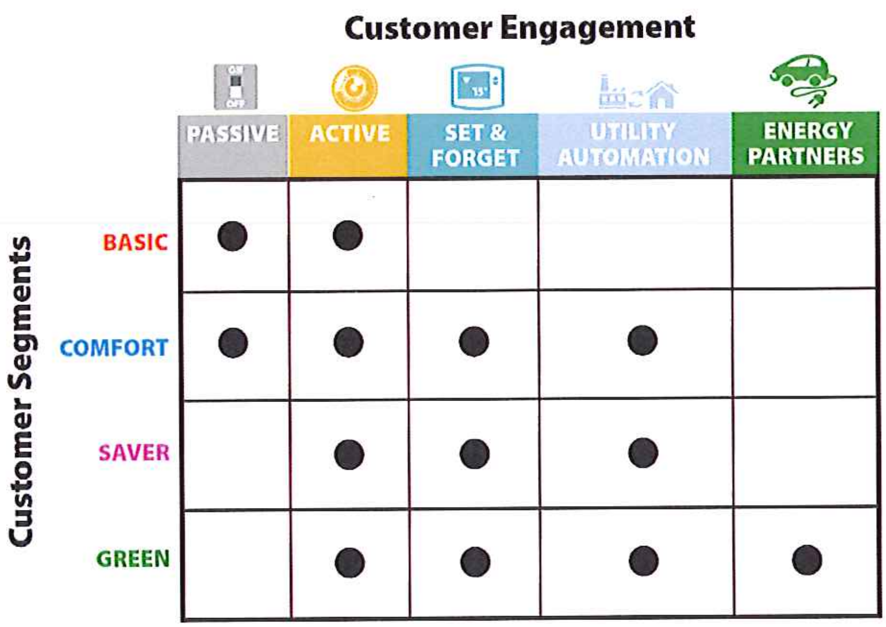
- **Active**: Engaged households that make conscious and manual adjustments to their electricity use based on energy information and price signals from peak rate plans (either no risk PTR or heat wave CPP) obtained via a web portal, a display, or other communications methods (e.g., email, text, or phone);

- **Set and forget**: Engaged households that use automation to adjust their electricity use via technologies such as programmable communicating thermostats (PCT) or home energy management systems (HEMS) based on energy information and price signals from peak rate plans (either no risk PTR or heat wave CPP);

- **Utility automation**: Households that allow the utility or a third party to directly control their central air conditioning via a signal sent to their smart thermostat or to a switch on their air conditioner. Customers retain the ability to override; and
- **Energy partners**: Highly interested and engaged households that have electric vehicles and home energy management systems to automatically control electricity usage. The time of use rate applies to the entire household on a daily basis, not just on event days.

The model assumes, as illustrated in Figure 3, that customers will choose an engagement pathway that resonates with their worldview but will select different technology and rate options based on whether they have central air conditioning, smart appliances, and home energy management systems, or electric vehicles. Attentive customers without automation will be able to save energy, shift tasks, and realize savings, although those with the ability to automate will likely realize the largest customer-driven savings.

Figure 3: The Four Customer Market Segments Choose Different Engagement Pathways



As shown in Figure 4, customers choose different technologies, programs, and rates depending on their energy worldview, willingness to take action, purchase of smart appliances, etc.

Figure 4: The Five Customer Engagement Pathways range from "Passive" to "Energy Partners"

	PASSIVE	ACTIVE	SET & FORGET	UTILITY AUTOMATION	ENERGY PARTNERS
BASIC		Display/no display No risk rebate			
COMFORT		Display/no display No risk rebate	Programmable Communicating Thermostat No risk rebate	Direct load control Programmable Communicating Thermostat or Switch No risk rebate	
SAVER		Display/no display No risk rebate	Programmable Communicating Thermostat No risk rebate or Heat wave pricing	Direct load control Programmable Communicating Thermostat or Switch No risk rebate	
GREEN		Display/no display No risk rebate or Heat wave pricing	Programmable Communicating Thermostat Home Energy Management System Heat wave pricing	Direct load control Programmable Communicating Thermostat or Switch No risk rebate	Electric Vehicle Home Energy Management System Time of use rate

METHODOLOGY

The net benefits of smart meters were calculated using *The Brattle Group*'s *iGrid* numerical simulation model. In addition to the operational costs and benefits of smart meters, the *iGrid* model calculates the costs and benefits of smart meters for the four utility prototypes based on customer programs that vary in terms of customer engagement levels and adoption of enabling technologies and smart rates.

We modeled the net benefits of the following:

- The operational benefits to all customers (including passive customers) that are enabled by smart meters, such as outage detection and restoration, rapid remote connects and disconnects, and automated meter reading;
- Customer response to increased information through web portals, with and without a real time information display;
- Customer response to no risk (i.e., peak time) rebates with a varying mix of enabling technologies, including web portals, displays, home energy management systems, and programmable communicating thermostats;
- Customer response to heat wave (i.e., critical peak) pricing with a varying mix of enabling technologies including: web portals; displays; home energy management systems, and programmable communicating thermostats;
- Customers shifting load via direct load control with measurement and verification (DLC 2.0); and
- Customers with electric vehicles (that substitute electricity for gasoline usage), a home energy management system, and a time of use rate in effect.

COSTS AND BENEFITS

The model includes costs, direct smart meter operational benefits, and customer-driven benefits based upon the mix of technologies and rate plans adopted by the consumer. Table 2 shows model input assumptions for the four utility prototypes.

Costs are associated with the AMI installation as well as the purchase of enabling technologies.

- **AMI costs**: Our review of AMI business cases indicates a range of costs, primarily due to differences between AMI vendors, the features of each AMI installation, and the quantity of AMI meters installed. We chose values that fall within these ranges for each of the utility prototypes.

- **Enabling technology costs**: The costs of enabling technologies are based on conversations with industry experts and device vendors.

For the smart meter benefits, we include three operational benefits:

- **Avoided metering costs**: This is broken into fixed and variable avoided costs. In all years smart meters are installed the fixed cost is calculated as the assumed avoided cost times the fraction of fixed avoided metering cost eliminated by smart meters. The variable cost is calculated as the number of smart meters installed times the variable avoided metering costs times the fraction of variable cost eliminated by smart meters;

- **Value of outage avoidance**: This is calculated by first measuring a customer's value of lost load, which is the number of outage hours per year times the cost per kWh of the outage. Second, the total benefit is calculated as the value of lost load times the customer's average annual demand times the fraction of the outages avoided by smart meters; and

- **Remote connection and disconnection of service**: This is calculated as the number of (dis)connections per year times the avoided cost per (dis)connection due to smart meters times the fraction of (dis)connection costs that are avoided due to smart meters. Based on our review of utility business cases, we assume that 20 percent of customers per year require a connection or disconnection of service.

For the customer related benefits, we calculate five benefits:

- **Avoided generation capacity costs**: This is calculated as the change in peak demand times the avoided cost of generation capacity, and then scaled due to system line losses (assumed to be eight percent) and reserve margin (assumed to be 15 percent). The avoided cost of generation is $50 per kW-year and is based on *Brattle*'s previous experience working on this topic;[5]

- **Avoided transmission and distribution capacity costs**: This is calculated as the change in peak demand times the avoided cost of transmission and distribution, and then scaled due to system line losses and reserve margin. The avoided transmission and distribution capacity cost is assumed to be $10 per kW-year and is based on *Brattle*'s previous experience working on this topic;[6]

- **Avoided energy costs**: This is calculated as the change in energy in each time period (off-peak, peak, and critical peak) times the cost of energy in the respective time period, and then scaled due to system line losses. The avoided energy costs vary by region and are based on reviews of energy market data as well as *Brattle*'s prior experience;

- **Avoided carbon dioxide costs**: This is calculated as the change in energy use in each time period (off-peak, peak, and critical peak) times the carbon dioxide emissions rate in the respective time period times the value of each ton of carbon dioxide emissions. The emissions rate for each utility differs based on the assumed fuel mix. Furthermore, the value

---

[5] Ahmad Faruqui, Ryan Hledik, Sam Newell, and Hannes Pfeifenberger. "The Power of 5 Percent." *The Electricity Journal*. October 2007.

[6] Ibid.

of carbon dioxide emissions is the same for each utility but changes over time with a value of zero until 2016. The value of carbon dioxide emissions is $15 per metric ton in 2017 and increases linearly until 2030 when it reaches a price of $60 per metric ton. This assumes no national carbon legislation will be in place until after the 2016 Presidential election; and

- **Avoided gasoline costs**: This is calculated as the change in gallons of gasoline consumed times the price of gasoline (assumed to be $3 per gallon [2011 dollars], a conservative approximation for the national average gas price). This benefit is only applicable to the customers with electric vehicles. Many conventional vehicle estimates are from a recent EPRI report and electric vehicle assumptions are based on data published by Nissan about the LEAF models.[7]

Table 2: Model Input Assumptions

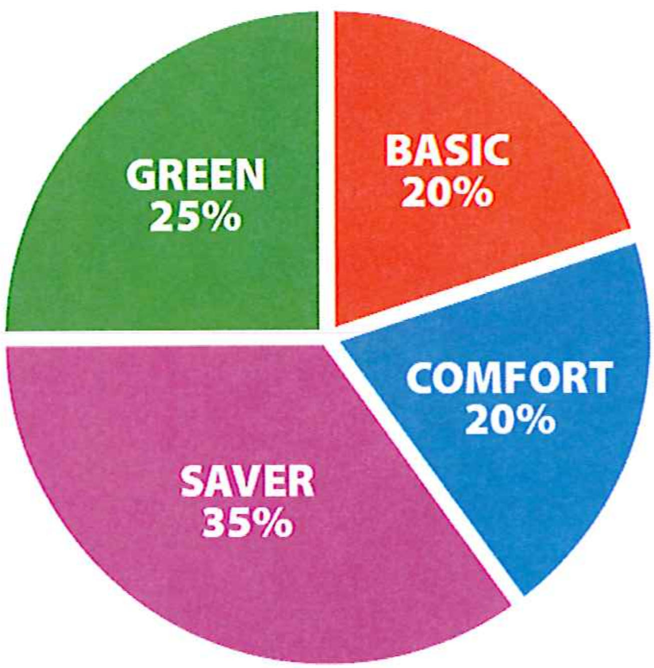
Input	Utility			
	Pioneer	Committed	Exploratory	Cautious
AMI installation cost ($/meter)	150	225	200	250
Avoided meter reading cost ($/meter)	5.00	12.50	10.00	15.00
Cost of generation capacity ($/kW-year)	50	50	50	50
Cost of transmission & distribution capacity ($/kW-year)	10	10	10	10
Energy price: critical peak ($/MWh)	300	240	180	120
Energy price: peak ($/MWh)	90	80	70	60
Energy price: off-peak ($/MWh)	50	40	30	20
Carbon dioxide emissions rate: critical peak (tons/MWh)	0.57	0.57	0.57	0.57
Carbon dioxide emissions rate: peak (tons/MWh)	0.57	0.57	0.57	0.57
Carbon dioxide emissions rate: off-peak (tons/MWh)	0.57	0.57	0.28	1.12
Maximum annual peak demand, per customer (kW) in 2011	2.1	1.8	4.5	3.8
Demand forecast (annual growth rate)	0.6%	0.8%	1.0%	1.2%
Central A/C saturation (% of customers)	15%	40%	71%	80%

[7] Electric Power Research Institute, Natural Resources Defense Council, and Charles Clark Group. "Environmental Assessment of Plug-In Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions." July 2007

PIONEER RESULTS:

For the Pioneer utility, we are assuming a region with a strong social norm of frugality (35 percent of consumers are in the Saver segment) and a general belief that climate change is a problem that needs to be addressed (25 percent in the Green segment). Communities here see the connection between a green mindset and economic vitality. The balance of households less interested in action are divided between those who are indifferent to energy (20 percent Basic) and those who are price insensitive but would be willing to invest in technology if it makes their lives easier and better (20 percent Comfort). Figure 5 shows the Pioneer utility customer segment mix.

Figure 5: Pioneer Utility – Customer Mix

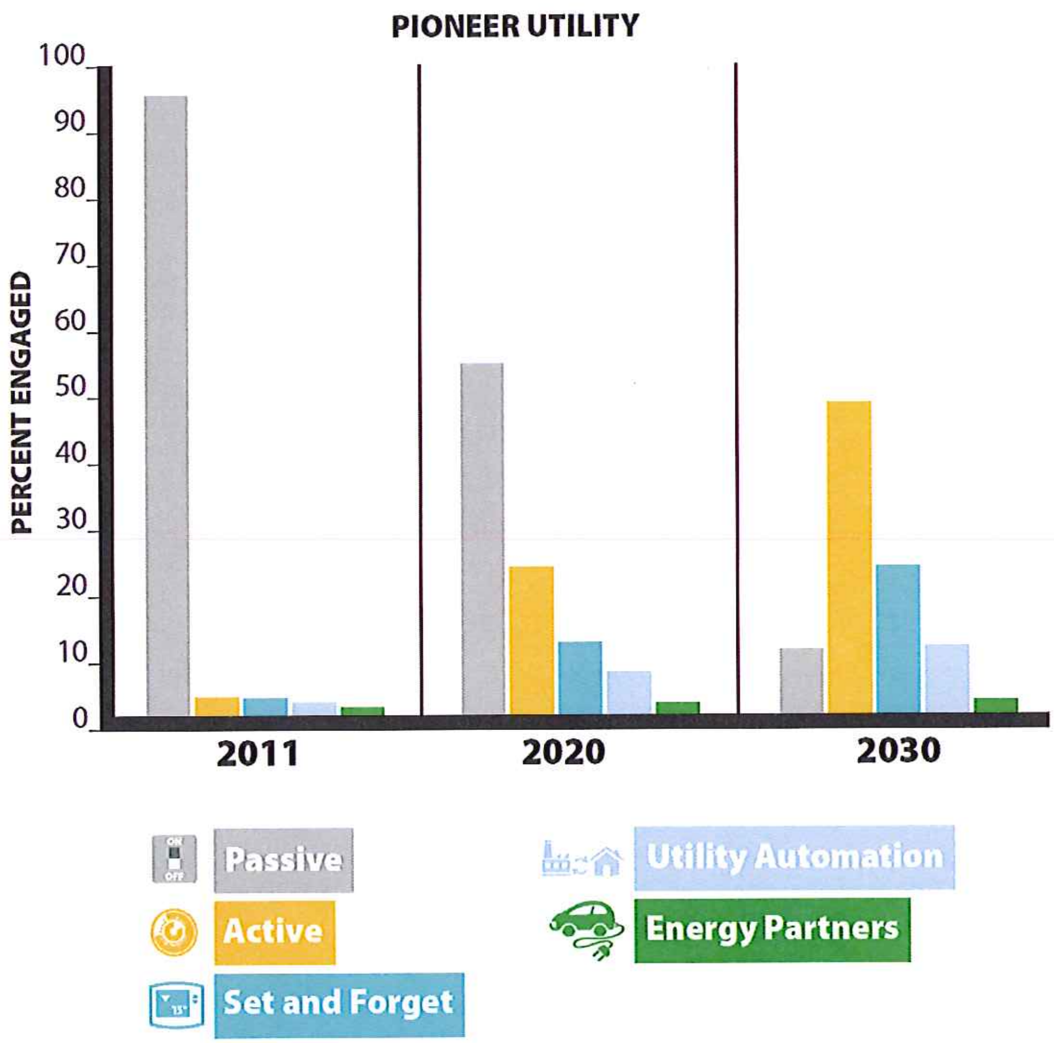


Household characteristics and the path towards energy management are described in Figures 6 and 7. In Figure 6, all four customer market segments begin with minimal engagement in 2011. By 2030, all of the Saver and Green customers are actively engaged. Figure 7 shows the migration of all customers across the five engagement pathways over time; by 2030, most customers have migrated from "passive" to another engagement pathway even among those who are indifferent today. An appropriate analogy is that 50 years ago, most people did not recycle. Today, almost everyone does.

Figure 6: Pioneer Utility – Customer Engagement by Market Segment

Pioneer Utility	Customer Types-2011					Customer Types-2030				
Customer Engagement Pathways	Basic	Comfort	Saver	Green	Total	Basic	Comfort	Saver	Green	Total
Passive	19.70%	19.24%	32.90%	22.88%	94.72%	8.00%	4.00%	0.00%	0.00%	12.00%
Active	0.30%	0.54%	1.40%	0.00%	2.24%	12.00%	11.00%	21.00%	5.00%	49.00%
Set and forget	0.00%	0.02%	0.35%	1.75%	2.12%	0.00%	1.00%	7.00%	16.25%	24.25%
Utility automation	0.00%	0.20%	0.35%	0.25%	0.80%	0.00%	4.00%	7.00%	2.50%	13.50%
Energy partners	0.00%	0.00%	0.00%	0.13%	0.13%	0.00%	0.00%	0.00%	1.25%	1.25%
Total	20%	20%	35%	25%	100%	20%	20%	35%	25%	100%

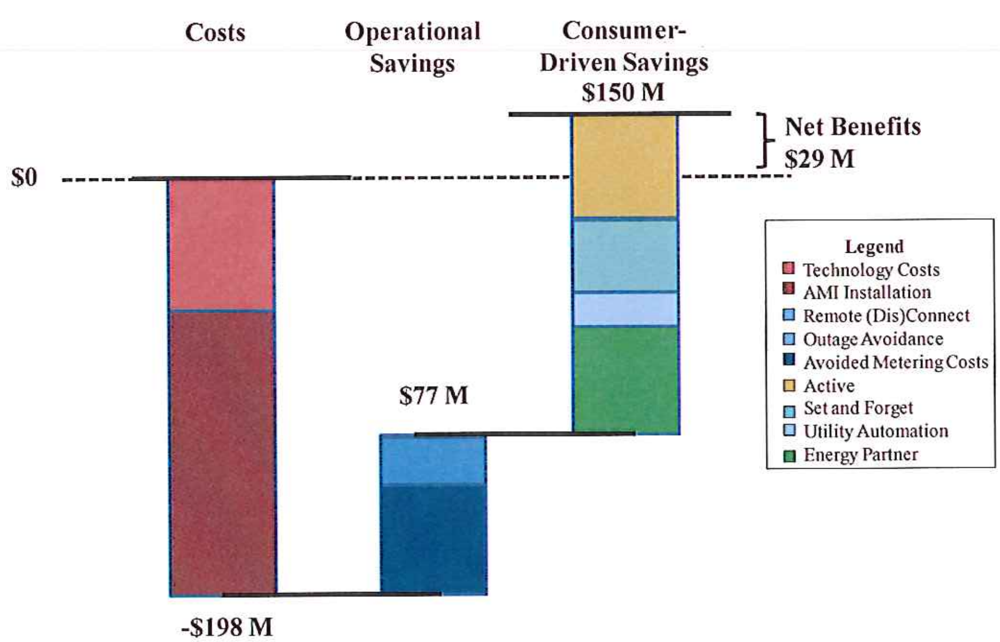
Figure 7: Pioneer Utility – Customer Engagement Pathways over Time (2011-2030)



The Pioneer utility is assumed to have installed AMR prior to the deployment of AMI. For this utility, the total costs associated with meter installation plus any devices/technologies in customer homes are $198 million over the 20 year forecast horizon. The total costs include the costs of meter installation as well as the costs of any devices, equipment, or technologies that customers install (see Figure A-5 in the Appendix for a detailed list of costs and benefits). As shown in Figure 8, the total costs are $198 million and the total operational benefits for this utility are $77 million. The operational benefits are dominated by avoided metering costs ($52 million), followed by improved outage detection and avoidance ($24 million) and remote rapid connections ($1 million).

Due to the customer mix, the regulatory environment, and other factors, this utility has customers that are reasonably engaged (i.e., 60 percent are in the Green or Saver market segments) and high customer benefits totaling $150 million (the largest customer benefits of the four utilities examined). Note the significant contribution of the Energy Partners engagement pathway to consumer-driven savings despite the fact that this pathway includes only 1.25 percent of customers. This demonstrates the large benefit contribution potential of electric vehicles. Total benefits for the Pioneer utility (both operational and customer-driven) are $227 million, indicating a net benefit of approximately $29 million over the 20 year forecast horizon, 2011 to 2030. So, in this case, even with a utility that has already deployed AMR, smart meter deployment still makes economic sense for residential customers.

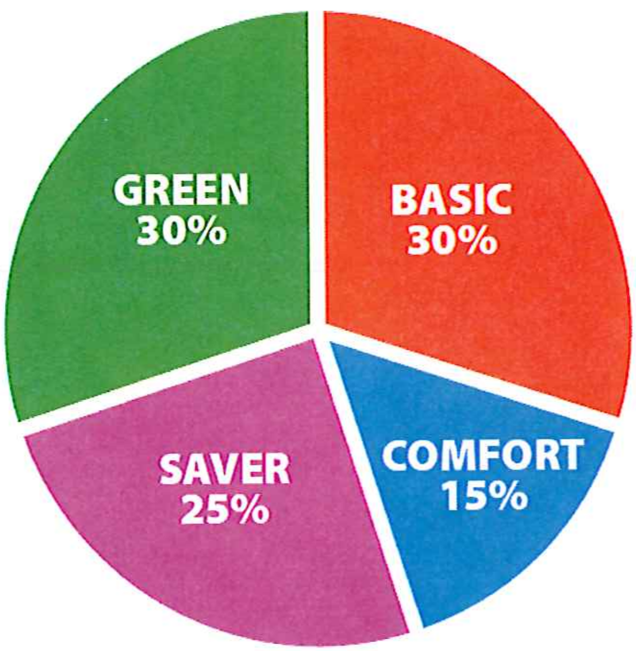
Figure 8: Pioneer Utility – Components of Costs and Benefits



RESULTS: COMMITTED

For the Committed utility, we are assuming a region with relatively high energy prices, a strong social norm of energy awareness, and a widespread belief that climate change is a serious problem that needs to be addressed. Figure 9 shows the Committed utility customer segment mix. The Committed utility services many affluent households willing to invest in green behaviors and technologies (30 percent Green) and a relatively small number of price insensitive customers unconcerned with conserving energy (15 percent Comfort). Savers in this region are likely to be tuned into their energy costs as well as concerned with climate change issues (25 percent). Those customers who are indifferent to environmental issues (30 percent in Basic segment) are likely to become more responsive with financial incentives (see Figure 9).

Figure 9: Committed Utility – Customer Mix

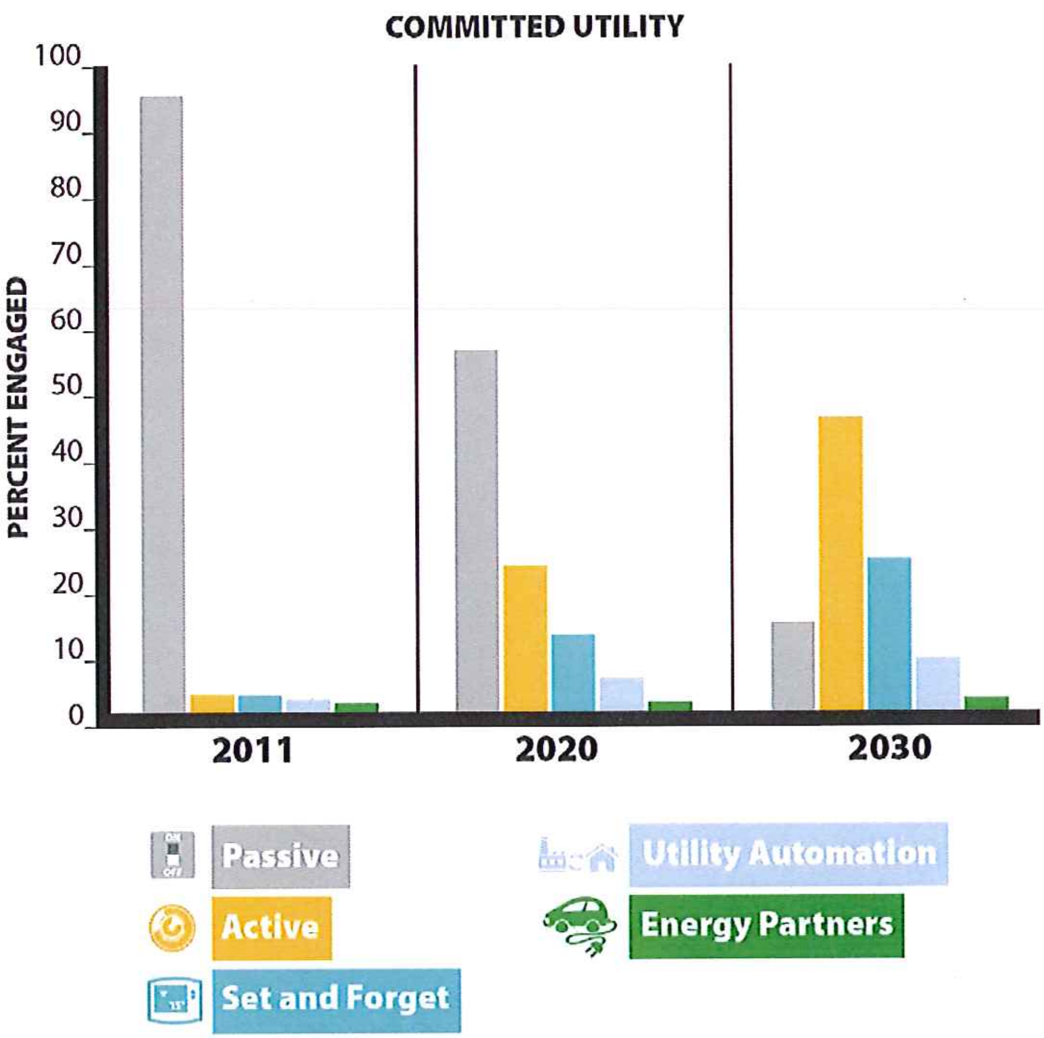


Household characteristics and the path towards energy management are described in Figures 10 and 11. In Figure 10, the four different customer market segments start at different engagement points in 2011. For example, Green and Saver customers are more engaged in energy management than the Comfort customers, while Basic customers are almost totally passive. By 2030, all of the Saver and Green customers are actively engaged in a range of technologies, price signals, and programs. Figure 11 shows the migration of all customers across the five engagement pathways over time; by 2030, most customers have migrated from "passive" to another engagement pathway. For this prototype utility we show very modest penetration of electric vehicles (i.e., 1.5 percent of customers are Energy Partners with EVs), although this type of utility service area is likely to be an epicenter of EV adoption.

Figure 10: Committed Utility – Customer Engagement by Market Segment

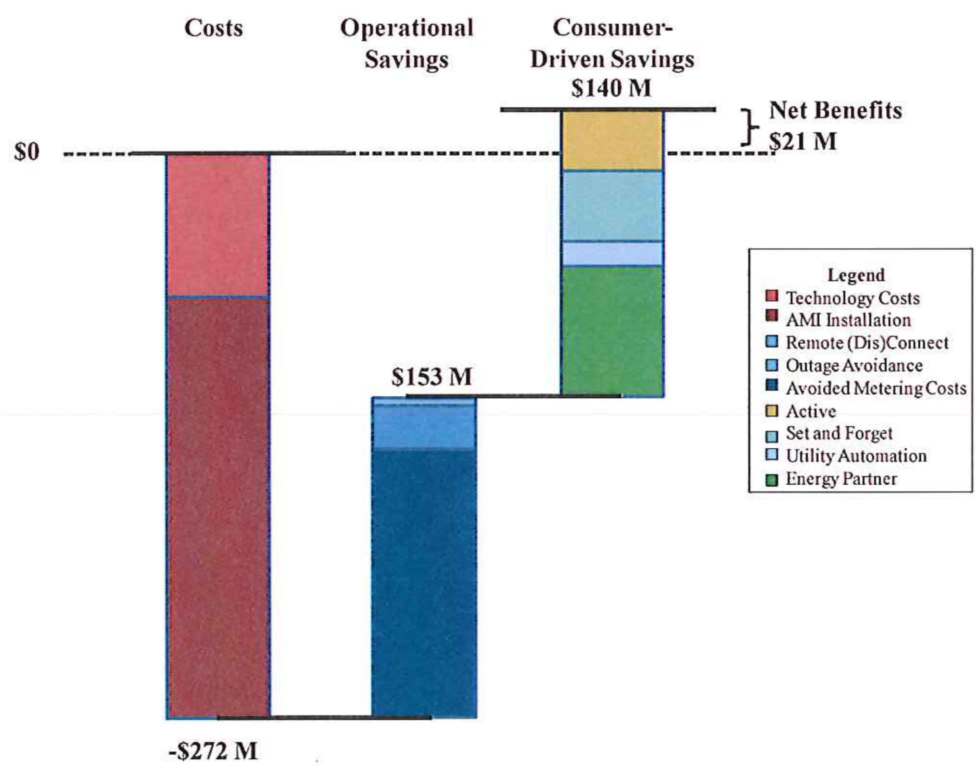
Committed Utility	Customer Types-2011					Customer Types-2030				
Customer Engagement Pathways	**Basic**	**Comfort**	**Saver**	**Green**	**Total**	**Basic**	**Comfort**	**Saver**	**Green**	**Total**
Passive	29.55%	14.43%	23.50%	27.45%	94.93%	12.00%	3.00%	0.00%	0.00%	15.00%
Active	0.45%	0.41%	1.00%	0.00%	1.86%	18.00%	8.25%	15.00%	6.00%	47.25%
Set and forget	0.00%	0.02%	0.25%	2.10%	2.37%	0.00%	0.75%	5.00%	19.50%	25.25%
Utility automation	0.00%	0.15%	0.25%	0.30%	0.70%	0.00%	3.00%	5.00%	3.00%	11.00%
Energy partners	0.00%	0.00%	0.00%	0.15%	0.15%	0.00%	0.00%	0.00%	1.50%	1.50%
Total	30%	15%	25%	30%	100%	30%	15%	25%	30%	100%

Figure 11: Committed Utility – Customer Engagement Pathways over Time (2011-2030)



For the Committed utility, the total costs associated with meter installation plus devices and technologies in the customers' homes are $272 million over the 20 year forecast. The total costs include the costs of the meter installation as well as the costs of any devices, equipment, or technologies that are installed in the home (see Figure A-6 in the Appendix for a detailed list of costs and benefits). As shown in Figure 12, the total operational benefits stemming from the utility investing in smart meters are $153 million. The operational benefits are dominated by avoided metering costs ($128 million), followed by improved outage detection and avoidance ($21 million) and remote rapid connections ($4 million).

Figure 12: Committed Utility – Components of Costs and Benefits

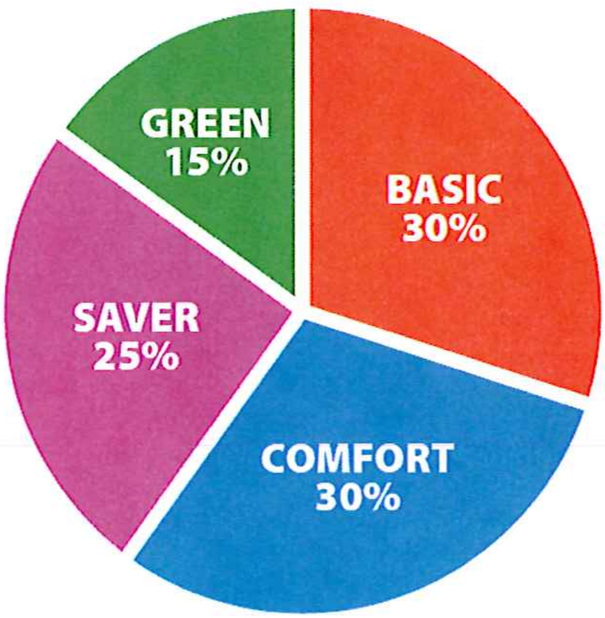


Over a 20 year period (2011-2030), customers migrate towards technology offerings and rate plans that fit their lifestyles and budgets, leading to customer-driven savings totaling $140 million. The consumer-driven savings are dominated by the Energy Partners pathway, demonstrating again the huge benefits contribution of EVs. Total benefits for the Committed utility (both operational and customer-driven) are $293 million, indicating a net benefit of approximately $21 million over the 20 year forecast horizon.

RESULTS: EXPLORATORY

Figure 13 shows the Exploratory utility customer segment mix. For the Exploratory utility, we are assuming a customer base that supports energy use management due to a desire to save money (25 percent Saver) and a concern about energy independence (15 percent Green). The balance of households less interested in action hold a slight majority, and they are divided between those who are indifferent (30 percent Basic) and those who are price insensitive though willing to invest in technology if it makes their lives easier and better (30 percent Comfort).

Figure 13: Exploratory Utility – Customer Mix

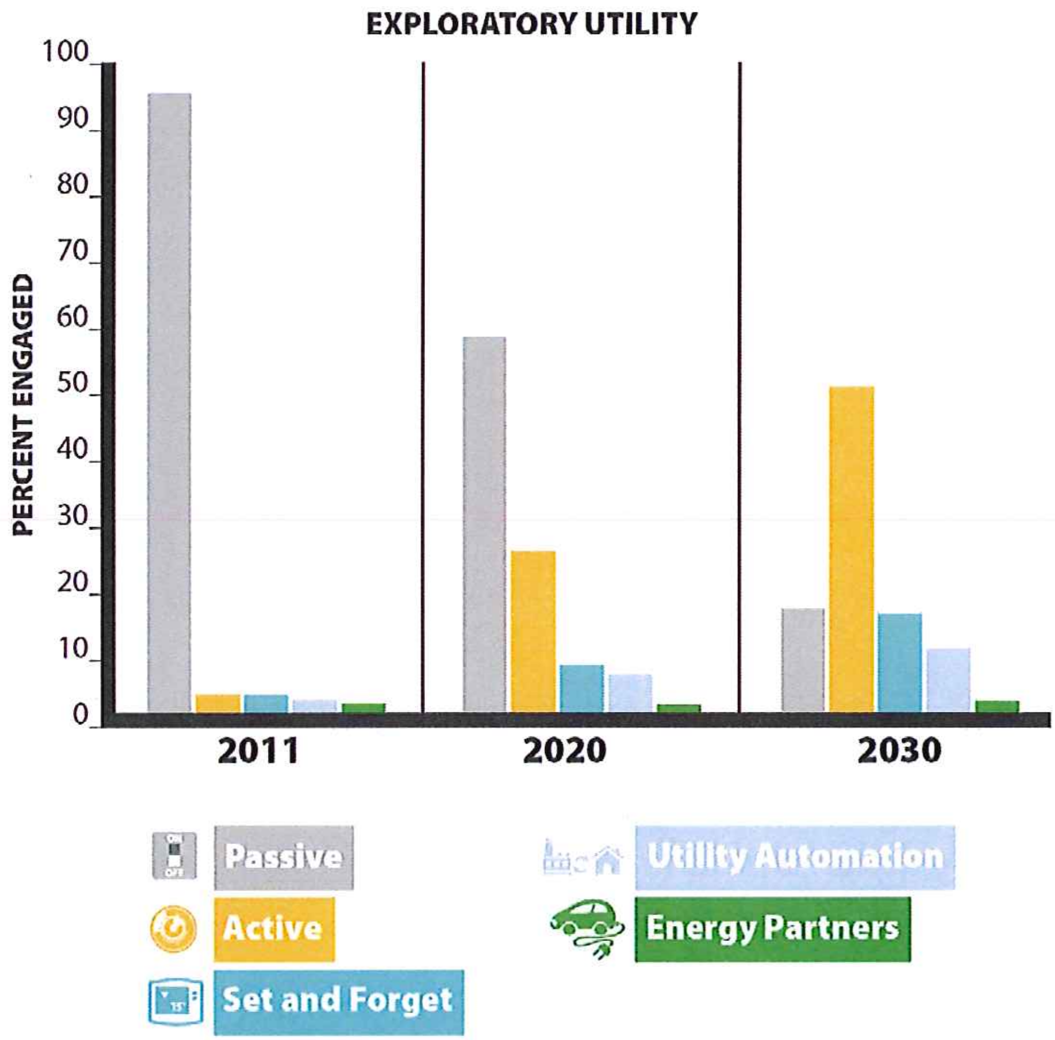


Household characteristics and the path towards energy management are described in Figures 14 and 15. In Figure 14, the four different customer market segments start at different engagement points in 2011. As in the other segments, initially very few customers are actively engaged in energy management. By 2030, all of the Saver and Green customers are either actively engaged or using automation. Figure 15 shows the migration of all customers across the five engagement pathways over time; by 2030, most customers have migrated from "passive" to another engagement pathway.

Figure 14: Exploratory Utility – Customer Engagement by Market Segment

Exploratory Utility	Customer Types-2011					Customer Types-2030				
Customer Engagement Pathways	Basic	Comfort	Saver	Green	Total	Basic	Comfort	Saver	Green	Total
Passive	29.55%	28.86%	23.50%	13.73%	95.64%	12.00%	6.00%	0.00%	0.00%	18.00%
Active	0.45%	0.81%	1.00%	0.00%	2.26%	18.00%	16.50%	15.00%	3.00%	52.50%
Set and forget	0.00%	0.03%	0.25%	1.05%	1.33%	0.00%	1.50%	5.00%	9.75%	16.25%
Utility automation	0.00%	0.30%	0.25%	0.15%	0.70%	0.00%	6.00%	5.00%	1.50%	12.50%
Energy partners	0.00%	0.00%	0.00%	0.08%	0.08%	0.00%	0.00%	0.00%	0.75%	0.75%
Total	30%	30%	25%	15%	100%	30%	30%	25%	15%	100%

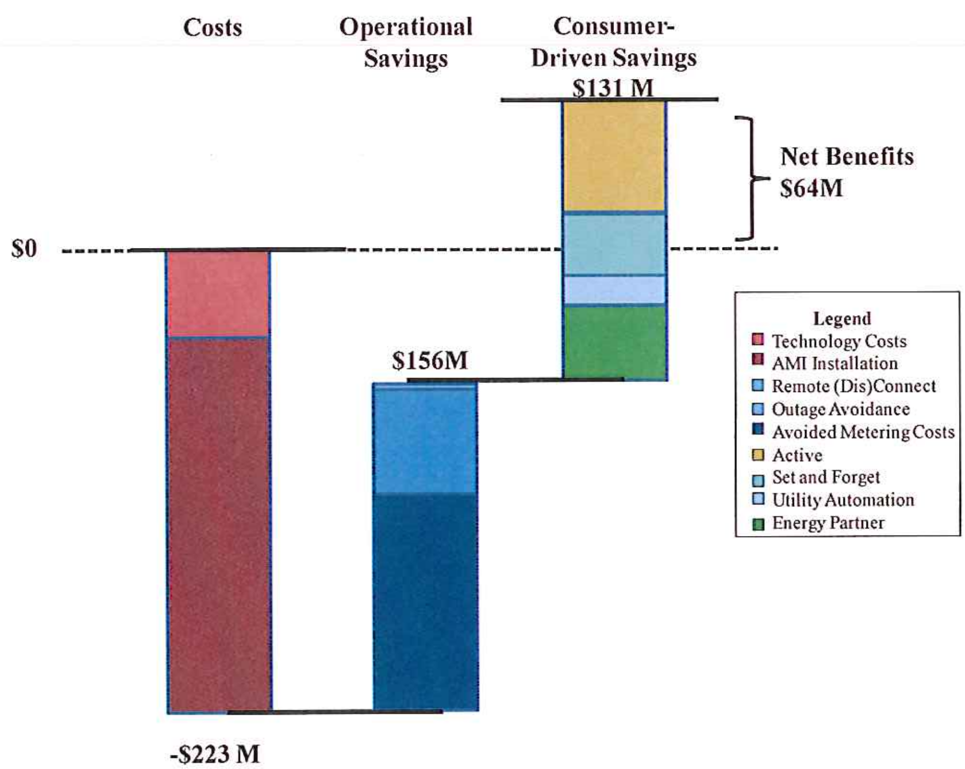
Figure 15: Exploratory Utility – Customer Engagement Pathways over Time (2011-2030)



For the Exploratory utility, the total costs associated with meter installation plus any devices or technologies in customer's homes are $223 million over the 20 year forecast horizon. The total costs include the costs of the meter installation as well as the costs of any devices, equipment, or technologies that are installed in the home (see Figure A-7 in the Appendix for a detailed list of costs and benefits). As shown in Figure 16, the total operational benefits stemming from the utility investing in smart meters are $156 million, which are dominated by avoided metering costs ($103 million), followed by improved outage detection and avoidance ($50 million) and remote rapid connections ($3 million).

Over a 20 year period (2011-2030), customers migrate towards technology offerings and rate plans that fit their lifestyles and budgets leading to customer-driven savings totaling $131 million, dominated by the Active engagement pathway. Total benefits for the Exploratory utility (both operational and customer-driven) are $287 million, indicating a net benefit of approximately $64 million over the 20 year horizon (2011-2030); this profile enjoys the largest net benefit of the four utility prototypes because their operational savings are relatively high relative to costs and their customer engagement is moderate. For the two utility prototypes with higher customer-driven savings (i.e., the Pioneer and Committed utilities), either the costs of installing and operating AMI are much higher (e.g., the Committed utility) or the associated operational savings are much lower (e.g., the Pioneer utility).

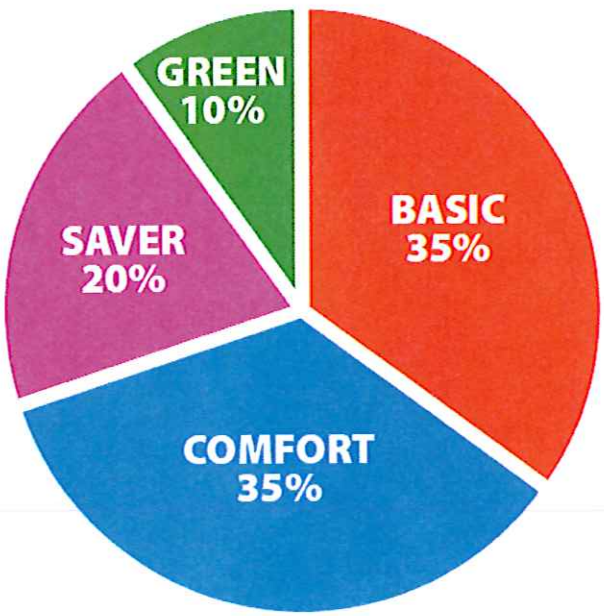
Figure 16: Exploratory Utility – Components of Costs and Benefits



RESULTS: CAUTIOUS

For the Cautious utility, we are assuming a region skeptical about climate change with very low energy costs in the absence of carbon surcharges. Figure 17 shows the Cautious utility's customer segment mix. Most households are uninterested in action and are divided between those who are indifferent (35 percent Basic) and those who are price insensitive though willing to invest in technology if it makes their lives easier and better (35 percent Comfort).

Figure 17: Cautious Utility – Customer Mix

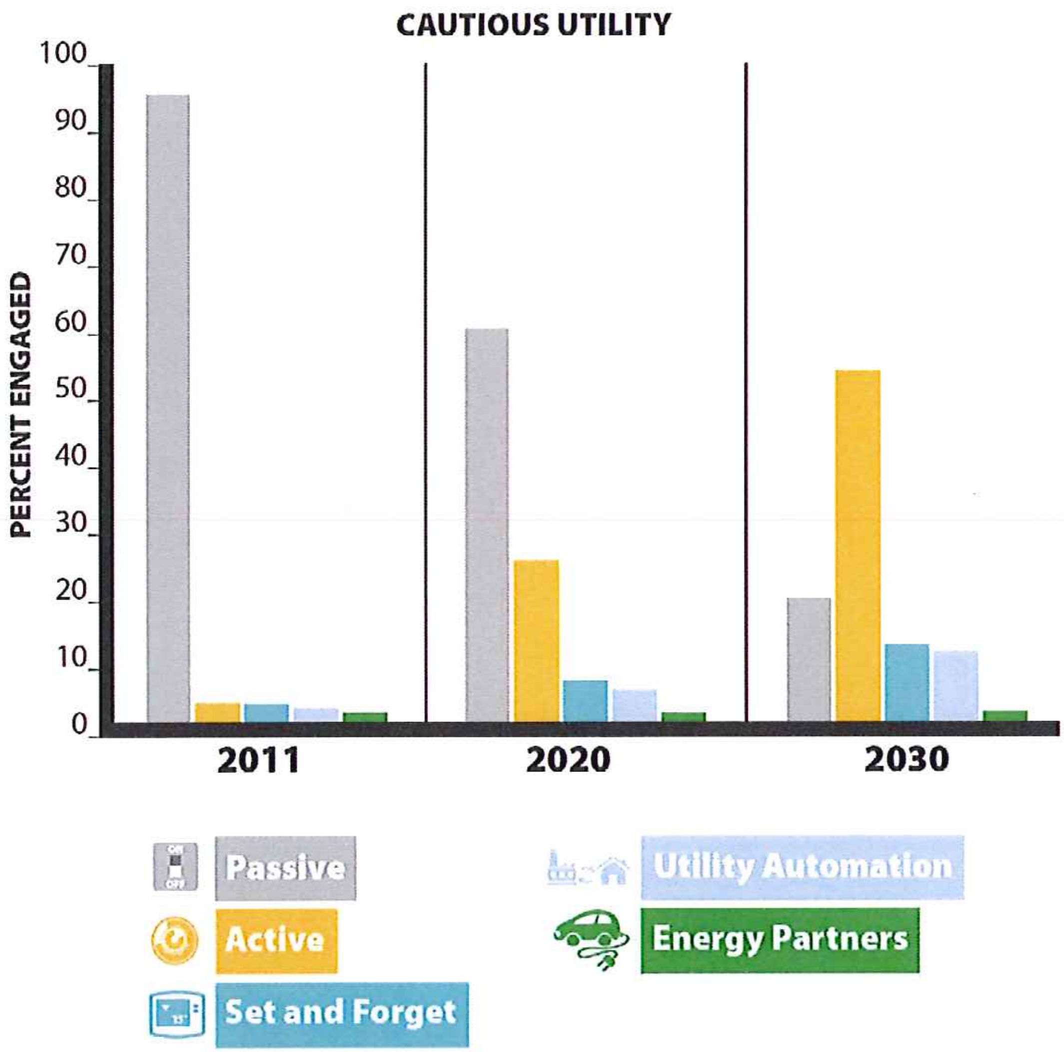


Household characteristics and the path towards energy management are described in Figures 18 and 19. This region has the slowest adoption rate (i.e., the highest percentage of customers in the Passive engagement pathway). Figure 19 shows the migration of all customers across the five engagement pathways over time; by 2030, a sizable number of customers have migrated from "passive" to another engagement pathway, though very few are energy partners. Unless there is a significant price trigger, increase in carbon prices, or emphasis on education and engagement, this region will be slow to change.

Figure 18: Cautious Utility – Customer Engagement by Market Segment

Cautious Utility	Customer Types-2011					Customer Types-2030				
Customer Engagement Pathways	Basic	Comfort	Saver	Green	Total	Basic	Comfort	Saver	Green	Total
Passive	34.48%	33.67%	18.80%	9.15%	96.10%	14.00%	7.00%	0.00%	0.00%	21.00%
Active	0.53%	0.95%	0.80%	0.00%	2.27%	21.00%	19.25%	12.00%	2.00%	54.25%
Set and forget	0.00%	0.04%	0.20%	0.70%	0.94%	0.00%	1.75%	4.00%	6.50%	12.25%
Utility automation	0.00%	0.35%	0.20%	0.10%	0.65%	0.00%	7.00%	4.00%	1.00%	12.00%
Energy partners	0.00%	0.00%	0.00%	0.05%	0.05%	0.00%	0.00%	0.00%	0.50%	0.50%
Total	35%	35%	20%	10%	100%	35%	35%	20%	10%	100%

Figure 19: Cautious Utility – Customer Engagement Pathways (2011-2030)

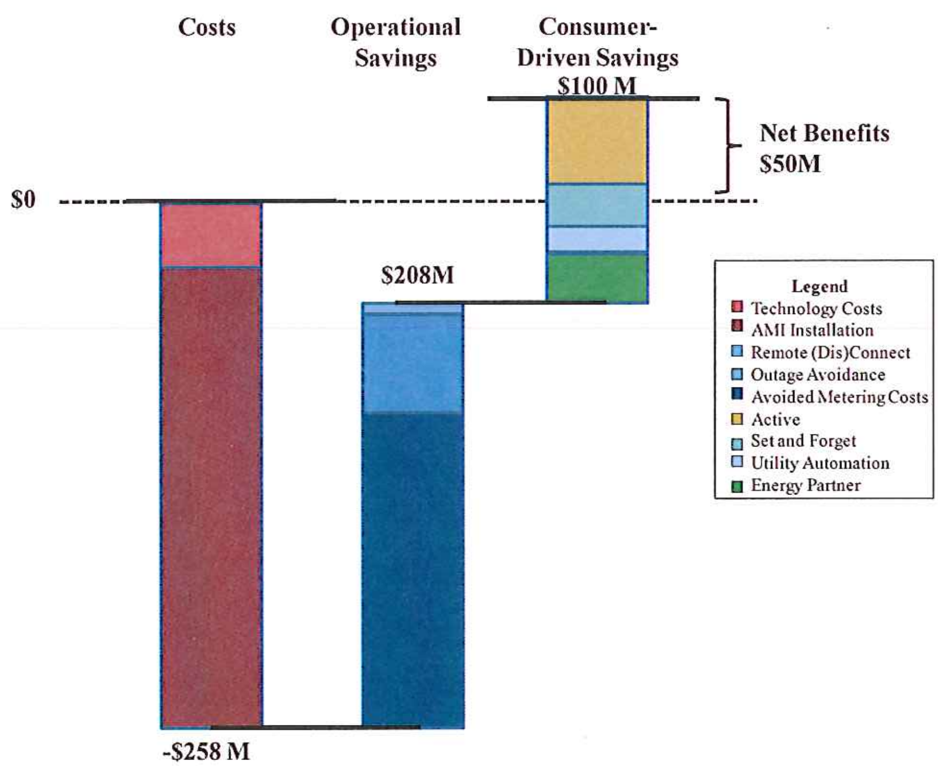


The total costs associated with meter installation plus devices and technologies in customers' homes are $258 million over the 20 year forecast. The total costs include the costs of the meter installation as well as the costs of any devices, equipment, or technologies that are installed in the home (see Figure A-8 in the Appendix for a detailed list of costs and benefits). As shown in

Figure 20, the total operational benefits stemming from the utility investing in smart meters are $208 million, which are dominated by avoided metering costs ($155 million), followed by improved outage detection and avoidance ($48 million) and remote rapid connections ($5 million). These are the largest operational benefits of the four utilities examined, which offsets the slower energy management adoption rates.

Over the time horizon, even minimal migration towards technology offerings and rate plans leads to customer-driven savings totaling $100 million. Total benefits for the Cautious utility (both operational and customer-driven) are $308 million, indicating a net benefit of approximately $50 million over the 20 year horizon (2011-2030).

Figure 20: Cautious Utility – Components of Costs and Benefits



CONCLUSIONS

This paper presents a framework for utilities and regulators to evaluate investments in smart meters and associated enabling technologies from a benefit and cost perspective. Even with conservative assumptions regarding consumer engagement in technology, programs, and rate plans, the results show positive net benefits are possible for all four utility types. Assuming a service territory of one million households, the total costs of investing in AMI and associated technologies for home energy management varies across the four utility prototypes based on the utility and customer characteristics from a low of $198 million for the Pioneer utility to a high of $272 million for the Committed utility.[8] Likewise the benefits vary across the four utility prototypes based on both utility and customer characteristics.

- The operational savings vary from a low of $77 million for the Pioneer utility (who has already deployed AMR) to a high of $208 million for the Cautious utility.
- The consumer-driven savings vary from a low of $100 million for the Cautious utility to a high of $150 million for the Pioneer utility. The benefits contribution from EVs in the Energy Partners pathway is significant given the very small percentage of customers in this engagement pathway (from 0.5 percent of customers to 1.5 percent of customers).
- The net benefits vary from a low of $21 million for the Committed utility to a high of $64 million for the Exploratory utility.

Figure 21: Summary of Costs and Benefits by Utility Type (NPV, $ millions)

	Pioneer	Committed	Exploratory	Cautious
Costs ($ million)	198	272	223	258
Operational savings ($ million)	77	153	156	208
Consumer-driven savings ($ million)	150	140	131	100
Net Benefits ($ million)	29	21	64	50

Although the net benefits are positive for each utility in this analysis, signifying that investments in smart meters make economic sense, we believe that the customer-driven benefits could be much greater with more investment in and focus on customer education and engagement. Over the 20 year horizon in this study, most customers migrate from passive engagement in energy management to much more active strategies. This holds true for all utilities types. Hence, a potential area for further study is how to accelerate this process so that a broad array of customers are ready, willing, and able to engage in energy management soon after smart meters

[8] In developing the four utility prototypes, we used actual utility load shapes and information on utility system characteristics, AMI costs and benefits, technology costs, and consumer engagement benefits based on experience and available sources.

are deployed. Given the high satisfaction ratings of dynamic pricing pilot participants where education is a key component, we believe the combination of program choice based on personal preferences (thereby avoiding opt-in, opt-out arguments) with comprehensive consumer education could yield tremendous financial and societal benefits. This emphasis is consistent with the recent NARUC Board of Directors' Resolution on Smart Grid Principles, approved at the summer meeting in Los Angeles, on July 20, 2011.

This analysis shows that the strategy with the potential to achieve the greatest financial impact is to focus on accelerating EV adoption. The benefits of EVs (as demonstrated by the contribution of the Energy Partners engagement pathway to overall consumer-driven savings) are disproportionately high, indicating that even modest increases in EV adoption will have a large impact on benefits.

APPENDIX

Figures A-1 through A-4 show the customer engagement pathways over time, aggregated across all customer segments for each utility prototype.

Figure A-1: Pioneer Utility: Customer Engagement Pathways over Time (all segments)

Pioneer Utility	Engagement over Time		
Customer Engagement Pathways	**2011**	**2020**	**2030**
Passive	94.7%	55.5%	12.0%
Active	2.2%	24.4%	49.0%
Set and forget	2.1%	12.6%	24.3%
Utility automation	0.8%	6.8%	13.5%
Energy partners	0.1%	0.7%	1.3%
Total	100%	100%	100%

Figure A-2: Committed Utility: Customer Engagement Pathways over Time (all segments)

Committed Utility	Engagement over Time		
Customer Engagement Pathways	**2011**	**2020**	**2030**
Passive	94.9%	57.1%	15.0%
Active	1.9%	23.4%	47.3%
Set and forget	2.4%	13.2%	25.3%
Utility automation	0.7%	5.6%	11.0%
Energy partners	0.2%	0.8%	1.5%
Total	100%	100%	100%

Figure A-3: Exploratory Utility: Customer Engagement Pathways over Time (all segments)

Exploratory Utility	Engagement over Time		
Customer Engagement Pathways	**2011**	**2020**	**2030**
Passive	95.6%	58.9%	18.0%
Active	2.3%	26.1%	52.5%
Set and forget	1.3%	8.4%	16.3%
Utility automation	0.7%	6.3%	12.5%
Energy partners	0.1%	0.4%	0.8%
Total	100%	100%	100%

Figure A-4: Cautious Utility: Customer Engagement Pathways over Time (all segments)

Cautious Utility	Engagement over Time		
Customer Engagement Pathways	**2011**	**2020**	**2030**
Passive	96.1%	60.5%	21.0%
Active	2.3%	26.9%	54.3%
Set and forget	0.9%	6.3%	12.3%
Utility automation	0.7%	6.0%	12.0%
Energy partners	0.1%	0.3%	0.5%
Total	100%	100%	100%

Figures A-5 through A-8 show a detailed breakdown of the benefits, costs, and net benefits for each of the four utility prototypes. These values were used in computing the overall costs, the operational benefits, the consumer-driven savings, and the net benefits presented in the paper. The numbers presented are in net present value (NPV) terms for the 20 year horizon.

Figure A-5: Pioneer Utility: Total NPV Net Benefits (2011-2030)

Technology	Tariff/Program	Responds to...	Benefit	Cost	Net Benefits
AMI + WP (Installation)			0	135,657,187	135,657,187
AMI + WP (Avoided meter reading)			51,453,162	0	51,453,162
AMI + WP (Value of outage avoidance)			24,259,229	0	24,259,229
AMI + WP (Remote connection and disconnection)			1,234,876	0	1,234,876
-	PTR	No response			
-	PTR	Information only	1,775,021	0	1,775,021
Display	PTR	Information only	2,978,698	2,132,046	846,652
-	PTR	PTR	11,916,802	0	11,916,802
-	CPP	CPP	5,335,158	0	5,335,158
Display	PTR	PTR	18,065,332	4,352,581	13,712,751
Display	CPP	CPP	8,365,217	3,535,990	4,829,227
Display + PCT	PTR	PTR	9,657,939	2,898,640	6,759,299
Display + PCT	CPP	CPP	3,829,539	2,286,197	1,543,342
HEMS	PTR	PTR	0	0	0
HEMS	CPP	CPP	13,720,465	10,590,464	3,130,001
HEMS + PCT	PTR	PTR	0	0	0
HEMS + PCT	CPP	CPP	6,640,668	6,575,436	65,232
DLC	-	-	15,908,764	0	15,908,764
HEMS + EV	TOU	TOU	52,136,657	29,746,437	22,390,220
Total			227,277,527	197,774,979	29,502,548

Benefit cost ratio	1.1492

Figure A-6: Committed Utility: Total NPV Net Benefits (2011-2030)

Technology	Tariff/Program	Responds to…	Benefit	Cost	Net Benefits
AMI + WP (Installation)			0	203,485,781	203,485,781
AMI + WP (Avoided meter reading)			128,632,904	0	128,632,904
AMI + WP (Value of outage avoidance)			20,757,821	0	20,757,821
AMI + WP (Remote connection and disconnection)			3,704,628	0	3,704,628
-	PTR	No response			
-	PTR	Information only	1,733,041	0	1,733,041
Display	PTR	Information only	2,664,956	2,544,870	120,085
-	PTR	PTR	5,719,063	0	5,719,063
-	CPP	CPP	3,680,186	0	3,680,186
Display	PTR	PTR	9,052,464	3,375,047	5,677,418
Display	CPP	CPP	6,161,529	2,762,603	3,398,926
Display + PCT	PTR	PTR	6,169,624	2,092,330	4,077,294
Display + PCT	CPP	CPP	3,008,222	1,632,998	1,375,224
HEMS	PTR	PTR	0	0	0
HEMS	CPP	CPP	16,330,345	12,708,557	3,621,788
HEMS + PCT	PTR	PTR	0	0	0
HEMS + PCT	CPP	CPP	8,473,175	7,890,523	582,652
DLC	-	-	12,082,494	0	12,082,494
HEMS + EV	TOU	TOU	64,505,463	35,695,724	28,809,738
Total			292,675,914	272,188,433	20,487,481

Benefit cost ratio	1.0753

Figure A-7: Exploratory Utility: Total NPV Net Benefits (2011-2030)

Technology	Tariff/Program	Responds to...	Benefit	Cost	Net Benefits
AMI + WP (Installation)			0	180,876,249	180,876,249
AMI + WP (Avoided meter reading)			102,906,323	0	102,906,323
AMI + WP (Value of outage avoidance)			50,721,203	0	50,721,203
AMI + WP (Remote connection and disconnection)			2,469,752	0	2,469,752
-	PTR	No response			
-	PTR	Information only	4,145,017	0	4,145,017
Display	PTR	Information only	6,954,702	3,198,069	3,756,633
-	PTR	PTR	12,502,040	0	12,502,040
-	CPP	CPP	4,611,318	0	4,611,318
Display	PTR	PTR	17,569,091	3,694,853	13,874,238
Display	CPP	CPP	7,055,271	2,469,967	4,585,304
Display + PCT	PTR	PTR	10,982,187	2,551,663	8,430,524
Display + PCT	CPP	CPP	3,173,754	1,632,998	1,540,756
HEMS	PTR	PTR	0	0	0
HEMS	CPP	CPP	9,955,737	6,354,279	3,601,459
HEMS + PCT	PTR	PTR	0	0	0
HEMS + PCT	CPP	CPP	4,761,766	3,945,261	816,505
DLC	-	-	13,812,187	0	13,812,187
HEMS + EV	TOU	TOU	35,247,284	17,847,862	17,399,422
Total			286,867,633	222,571,202	64,296,431

Benefit cost ratio	1.2889

Figure A-8: Cautious Utility: Total NPV Net Benefits (2011-2030)

Technology	Tariff/Program	Responds to...	Benefit	Cost	Net Benefits
AMI + WP (Installation)			0	226,095,312	226,095,312
AMI + WP (Avoided meter reading)			154,359,485	0	154,359,485
AMI + WP (Value of outage avoidance)			48,315,562	0	48,315,562
AMI + WP (Remote connection and disconnection)			4,939,504	0	4,939,504
-	PTR	No response			
-	PTR	Information only	3,626,297	0	3,626,297
Display	PTR	Information only	6,083,663	3,731,081	2,352,582
-	PTR	PTR	10,637,651	0	10,637,651
-	CPP	CPP	3,118,121	0	3,118,121
Display	PTR	PTR	12,870,861	3,365,990	9,504,871
Display	CPP	CPP	5,904,086	1,936,955	3,967,130
Display + PCT	PTR	PTR	9,119,479	2,378,174	6,741,305
Display + PCT	CPP	CPP	2,678,743	1,306,398	1,372,344
HEMS	PTR	PTR	0	0	0
HEMS	CPP	CPP	6,842,304	4,236,186	2,606,118
HEMS + PCT	PTR	PTR	0	0	0
HEMS + PCT	CPP	CPP	3,198,136	2,630,174	567,961
DLC	-	-	12,332,227	0	12,332,227
HEMS + EV	TOU	TOU	23,954,677	11,898,575	12,056,102
Total			307,980,795	257,578,845	50,401,950

Benefit cost ratio	1.1957

For more information contact:

Institute for Electric Efficiency
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
1.202.508.5440
www.edisonfoundation.net/iee

The EDISON FOUNDATION | INSTITUTE FOR Electric Efficiency

TRAVERSE CITY
LIGHT & POWER

EST. 1912

To: **Light & Power Board**
From: Karla Myers-Beman, Controller KMB
Date: August 2, 2016
Subject: Further Analysis on MPPA Purchase Power Commitment

At the June 7, 2016 board meeting, Board member Tim Werner requested for staff to provide a range of what the utility is exposed to with accepting the Michigan Public Power Agency's ("MPPA") wind purchase power commitment. To perform this analysis staff obtained 10 years of historical and projected LMP (local marginal pricing) data from MPPA and averaged two years of Stoney Corner's data for amount of wind produced as the MPPA's Beebe project only has one full year of data. The analysis staff performed is what is often referred to as a stress test; it is providing information as to what would occur if the LMP were to fluctuate more or less than what it is projected.

The projected LMP data was provided/calculated by MPPA and based on the latest market indices published for the future four years at the Indiana hub and use the latest basis information from prior transactions to move the pricing into Michigan. The hourly profile is taken from Ventyx data and beyond the four years it is assumed that the implied heat rate in the market is constant and move prices with the Henry Hub natural gas.

Staff reviewed the annual fluctuations of the LMP market for the past 10 years and they fluctuated from a - 34.17% to a maximum of 41.58% when looking at average percentage differences from year to year and over 10 years the average percentage increase was 6.58%. Then staff looked on an hourly basis and out of the 10 years, the majority of the time the hourly rate fluctuated within the range of -25% to 25%. Based on this combined information of the annual average increase over 10 years and the majority fluctuations being within the range of -25% to 25%, staff is providing the effects (premium/discount) on the purchase power commitment if the annual projected LMP (that has projected increases of .33%, 4.44%, 4.81%, 4.58%, 5.09 % and -2.65%, respectively starting in 2020) were to fluctuate on a year to year basis between -25% to 25% over the next 10 years in increments of 5%.

The results of this test show if prices were to increase it reduces the amount of premium (the difference between the wind contract and LMP) or the credit we are receiving in selling the electricity in the market is coming closer to the amount that we are paying for the energy. Conversely, if the prices were to decrease it increases the amount of the premium and the wind energy becomes more costly than purchasing the power off of the market.

This analysis did not include the benefits of capacity and the renewable energy credits to meet the State renewable mandate it only is focused on energy costs.

Traverse City Light and Power
Further Analysis on MPPA Purchase Power Commitment
July 2016

CALCULATED REVENUE

Row Labels	Sum of Wind Revenue	Sum of LMP Revenue	Sum of LMP 5% increase	Sum of LMP 10% increase	Sum of LMP 15% increase	Sum of LMP 20% increase	Sum of LMP 25% increase
2018	$ 466,429.18	$ 368,739.53	$ 387,176.51	$ 405,613.49	$ 424,050.46	$ 442,487.44	$ 460,924.42
2019	$ 1,102,474.10	$ 879,784.09	$ 923,773.30	$ 967,762.50	$ 1,011,751.71	$ 1,055,740.91	$ 1,099,730.11
2020	$ 1,109,435.73	$ 882,673.33	$ 926,806.99	$ 970,940.66	$ 1,015,074.33	$ 1,059,207.99	$ 1,103,341.66
2021	$ 1,126,115.14	$ 921,896.33	$ 967,991.15	$ 1,014,085.96	$ 1,060,180.78	$ 1,106,275.60	$ 1,152,370.41
2022	$ 1,143,100.78	$ 966,218.96	$ 1,014,529.90	$ 1,062,840.85	$ 1,111,151.80	$ 1,159,462.75	$ 1,207,773.69
2023	$ 1,160,198.70	$ 1,010,503.16	$ 1,061,028.32	$ 1,111,553.47	$ 1,162,078.63	$ 1,212,603.79	$ 1,263,128.95
2024	$ 1,177,562.02	$ 1,061,953.77	$ 1,115,051.46	$ 1,168,149.15	$ 1,221,246.83	$ 1,274,344.52	$ 1,327,442.21
2025	$ 1,195,190.75	$ 1,033,856.64	$ 1,085,549.47	$ 1,137,242.31	$ 1,188,935.14	$ 1,240,627.97	$ 1,292,320.80

DISCOUNT/(PREMIUM) CALCULATED

	Discount/ (Premium) - LMP	Discount/ (Premium) - LMP - 5%	Discount/ (Premium) - LMP - 10%	Discount/ (Premium) - LMP - 15%	Discount/ (Premium) - LMP - 20%	Discount/ (Premium) - LMP - 25%
2018	$ (97,689.65)	$ (79,252.67)	$ (60,815.70)	$ (42,378.72)	$ (23,941.74)	$ (5,504.77)
2019	$ (222,690.01)	$ (178,700.81)	$ (134,711.60)	$ (90,722.40)	$ (46,733.19)	$ (2,743.99)
2020	$ (226,762.40)	$ (182,628.74)	$ (138,495.07)	$ (94,361.41)	$ (50,227.74)	$ (6,094.07)
2021	$ (204,218.81)	$ (158,123.99)	$ (112,029.18)	$ (65,934.36)	$ (19,839.54)	$ 26,255.27
2022	$ (176,881.82)	$ (128,570.87)	$ (80,259.93)	$ (31,948.98)	$ 16,361.97	$ 64,672.92
2023	$ (149,695.54)	$ (99,170.38)	$ (48,645.23)	$ 1,879.93	$ 52,405.09	$ 102,930.25
2024	$ (115,608.25)	$ (62,510.57)	$ (9,412.88)	$ 43,684.81	$ 96,782.50	$ 149,880.19
2025	$ (161,334.11)	$ (109,641.27)	$ (57,948.44)	$ (6,255.61)	$ 45,437.22	$ 97,130.06

CALCULATED REVENUE

Row Labels	Sum of Wind Revenue	Sum of LMP Revenue	Sum of LMP -5% decrease	Sum of LMP -10% decrease	Sum of LMP - 15% decrease	Sum of LMP - 20% decrease	Sum of LMP - 25% decrease
2018	$ 466,429.18	$ 368,739.53	$ 350,302.56	$ 331,865.58	$ 313,428.60	$ 294,991.63	$ 276,554.65
2019	$ 1,102,474.10	$ 879,784.09	$ 835,794.89	$ 791,805.68	$ 747,816.48	$ 703,827.27	$ 659,838.07
2020	$ 1,109,435.73	$ 882,673.33	$ 838,539.66	$ 794,406.00	$ 750,272.33	$ 706,138.66	$ 662,005.00
2021	$ 1,126,115.14	$ 921,896.33	$ 875,801.51	$ 829,706.70	$ 783,611.88	$ 737,517.06	$ 691,422.25
2022	$ 1,143,100.78	$ 966,218.96	$ 917,908.01	$ 869,597.06	$ 821,286.11	$ 772,975.16	$ 724,664.22
2023	$ 1,160,198.70	$ 1,010,503.16	$ 959,978.00	$ 909,452.84	$ 858,927.68	$ 808,402.53	$ 757,877.37
2024	$ 1,177,562.02	$ 1,061,953.77	$ 1,008,856.08	$ 955,758.39	$ 902,660.70	$ 849,563.02	$ 796,465.33
2025	$ 1,195,190.75	$ 1,033,856.64	$ 982,163.81	$ 930,470.98	$ 878,778.15	$ 827,085.31	$ 775,392.48

DISCOUNT/(PREMIUM) CALCULATED

	Discount/ (Premium) - LMP	Discount/ (Premium) - LMP - (5%)	Discount/ (Premium) - LMP - (10%)	Discount/ (Premium) - LMP - (15%)	Discount/ (Premium) - LMP - (20%)	Discount/ (Premium) - LMP - (25%)
2018	$ (97,689.65)	$ (116,126.63)	$ (134,563.60)	$ (153,000.58)	$ (171,437.56)	$ (189,874.53)
2019	$ (222,690.01)	$ (266,679.22)	$ (310,668.42)	$ (354,657.62)	$ (398,646.83)	$ (442,636.03)
2020	$ (226,762.40)	$ (270,896.07)	$ (315,029.74)	$ (359,163.40)	$ (403,297.07)	$ (447,430.74)
2021	$ (204,218.81)	$ (250,313.63)	$ (296,408.44)	$ (342,503.26)	$ (388,598.07)	$ (434,692.89)
2022	$ (176,881.82)	$ (225,192.77)	$ (273,503.72)	$ (321,814.66)	$ (370,125.61)	$ (418,436.56)
2023	$ (149,695.54)	$ (200,220.70)	$ (250,745.86)	$ (301,271.02)	$ (351,796.17)	$ (402,321.33)
2024	$ (115,608.25)	$ (168,705.94)	$ (221,803.63)	$ (274,901.32)	$ (327,999.01)	$ (381,096.70)
2025	$ (161,334.11)	$ (213,026.94)	$ (264,719.77)	$ (316,412.60)	$ (368,105.43)	$ (419,798.27)

TRAVERSE CITY
LIGHT & POWER
EST. 1912
Investing Our Energy In You

1131 Hastings Street
Traverse City, MI 49686
231.922.4940

To: **Light & Power Board**
From: Pete Schimpke, Manager of Operations & Engineering PS
Date: August 2, 2016
Subject: System Priority Matrix

The 2016 Traverse City Light & Power Strategic Plan, item 2 under System Reliability & Power Quality, calls for the development of a rating system to prioritize capital system improvements and to annually update this rating system. In addition, this rating system also provides direct support of item 1 in the Plan which pertains to maintaining an ASAI rating of 99.970% or more.

Attached is the Project Priority Matrix (Matrix) that Staff plans to implement. This Matrix provides for the rating of several individual parameters, primarily on a circuit-by-circuit basis, that serves as a mechanism for ranking potential capital projects. In particular, some of the parameters are: system condition (% primary/secondary copper conductor, % delta transformers); pole condition (age and results of pole replacement project); main line conductor capacity; number of customers that benefit from the project, density of customers, and the impact of an outage for this circuit. Details by circuit/project can be found in the pages attached to this cover letter.

Note that since this is the initial Matrix it will likely change somewhat over time as experience using it is acquired and circuit specific details are more available—primarily through TCLP's Milsoft WindMil software program which analyzes distribution systems. Accordingly, the circuits/projects may move up or down in the list from year-to-year.

Staff feels confident that this Matrix, including future derivatives of it, will be a valuable tool to be used to maximize value of dollars allocated to capital improvements.

TCLP Project Priority Matrix (MATRIX)

Notes:

1. The list of circuits is tentative at this time although considered quite accurate. Finalization will occur after receipt of the GRP Distribution System Study scheduled for mid-August.
2. Components for Transmission & Substation Projects will be finalized after receipt of the GRP Distribution Study.
3. The words Circuit and Project have the same meaning.

Highlights:

1. The basic strategy for the development of the Matrix is to be proactive to maintain high system reliability by prioritizing projects to first focus on those that provide the best value to our customers.
2. Consistent with #1 above, the maintaining of the business goal of 99.970% or higher for ASAI (Average Service Availability Index) is the overall target for these projects along with normal system maintenance.
3. The Matrix has initially been developed on a circuit basis to be consistent with past practice to "rebuild one circuit per year". However, Staff recommends modifying this practice to focus more on parts of a circuit and less on the circuit as a whole.
4. "Non-circuit" projects have been inserted in the Matrix in an attempt to provide ratings for most anticipated projects.
5. Higher ratings mean the circuit has more issues than circuits with lower ratings.
6. Based on #3 above, the circuit ratings should be viewed as "pointing" to individual circuits that have problem areas. Correcting these problem areas will result in the entire rating being improved. Note that re-building the entire circuit, as was done with BW-22, is still an option under this Matrix.
7. This initial Matrix includes several components which is the result of Staff's attempt to develop a system that captures the most important components. Staff expects that over time some of the components may be deleted due to limited value or at least modified. New components may be added as time goes on. Below is a summary of the ratings used in the Matrix.

RATINGS COMPONENTS

SYSTEM CONDITION
- % OVERHEAD COPPER CONDUCTOR - PRIMARY
- % OVERHEAD COPPER CONDUCTOR - SECONDARY
- % DELTA TRANSFORMERS

POLE CONDITION
- # OF POLES
- # OF POLES OVER 40 YEARS OLD
- # OF POLES OF FAILED POLES

SAIDI (not used at this time)

CONDUCTOR CAPACITY
- % OF AMPACITY (336.4 ACSR)

CUSTOMERS BENEFITTED
- IF <= 100, THEN RATING IS 10
- IF <= 200, THEN RATING IS 20
- IF <= 300, THEN RATING IS 30
- IF <= 400, THEN RATING IS 40
- IF > 400, THEN RATING IS 50

ACCESSIBILITY

CUSTOMER DENSITY
- IF CUSTOMERS / MILE <= 30, THEN RATING IS 1
- IF CUSTOMERS / MILE <= 60, THEN RATING IS 2
- IF CUSTOMERS / MILE <= 90, THEN RATING IS 3
- IF CUSTOMERS / MILE <= 120, THEN RATING IS 4
- IF CUSTOMERS / MILE > 120, THEN RATING IS 5

IMPACT
- IMPORTANCE OF AN OUTAGE

8. Each of the components above received a ratings and the ratings were then normalized with the circuit receiving the worst rating in a category receiving a rating of 100.
9. Some ratings are necessarily subjective in nature.
10. This Matrix is labor intensive as databases for circuit information is limited. Over time Staff is hopeful that the manual labor can be reduced to improve efficiency in updating the Matrix.
11. How the Matrix should be used:
    a. The Matrix should be viewed as a guide when deciding projects. In other words, if a circuit has a total rating of 50 points higher than another circuit, the two circuits should be viewed as close in their ratings.
    b. A circuit may be chosen, based on its overall rating, and later given a lower rating after detailed Engineering analysis begins.

12. Projects not included:
    a. Improvements to provide more reliability to critical customers unless the improvement is very costly. Most improvements are low cost and considered a project that is required. Examples of critical customers are: Police Department, Waste Water Plant, the Water Department, and 911 Dispatch.
    b. Improvements to provide more reliability to key account customers unless the improvement is very costly. Most improvements are low cost and considered a project that is required. Examples of critical customers are: Tyson Foods and Century Sun.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1																		
2	**NORMALIZED WEIGHTINGS**																	
3												CONTROL	-					
4			WEIGHTS		100.00				100.00				100.00				100.00	
5				SYSTEM	SYSTEM			POLE	POLE							COND	COND	
6			CIRCUIT	CONDITION	CONDITION		CIRCUIT	COND	COND		CIRCUIT	SAIDI	SAIDI		CIRCUIT	CAPACITY	CAPACITY	
7	1		HL20	14.65	100.00		HL21	43.50	100.00		HL33	0.8313994	-		CD22	35.90	100.00	
8	2		PC22	12.98	88.61		PC32	39.50	90.80		SS31	0.7127641	-		HL22	31.79	88.57	
9	3		PC30	10.00	68.25		BW31	36.50	83.91		PC32	0.1253837	-		CD31	31.22	86.96	
10	4		BW23	9.88	67.42		CD21	30.50	70.11		BW31	0.0771013	-		PC30	29.23	81.43	
11	5		HL33	9.72	66.34		HL33	29.50	67.82		CD31	0.0002023	-		PC23	25.13	70.00	
12	6		BW30	9.30	63.47		PC22	28.50	65.52		PC22	0.0001364	-		HL31	23.85	66.43	
13	7		SS20	9.17	62.56		CD30	27.50	63.22		BW23	0.0001337	-		BW31	22.88	63.75	
14	8		BW31	8.15	55.62		CD31	27.50	63.22		BW30	0.0001292	-		PC32	21.86	60.89	
15	9		PC32	7.95	54.29		BW23	23.50	54.02		CD30	0.0000472	-		PC22	20.38	56.79	
16	10		CD21	7.85	53.57		SS30	22.50	51.72		HL21	0.0000446	-		BW30	18.85	52.50	
17	11		PC23	7.70	52.58		BW30	21.50	49.43		CD21	0.0000428	-		HL21	16.86	46.96	
18	12		HL22	7.16	48.86		HL22	19.50	44.83		HL22	0.0000294	-		CD21	13.91	38.75	
19	13		CD30	7.00	47.78		HL32	12.50	28.74		BW22	-	-		HL32	12.50	34.82	
20	14		HL31	6.85	46.76		BW22	7.50	17.24		CD22	-	-		SS31	10.96	30.54	
21	15		HL21	6.78	46.25		HL31	7.50	17.24		CD23	-	-		CD30	10.51	29.29	
22	16		HL30	6.45	44.03		PC23	6.50	14.94		HL20	-	-		HL30	10.38	28.93	
23	17		HL32	6.16	42.04		HL20	5.50	12.64		HL23	-	-		HL20	9.94	27.68	
24	18		CD31	5.31	36.24		SS31	5.50	12.64		HL30	-	-		HL33	9.94	27.68	
25	19		CD23	5.30	36.14		CD23	3.50	8.05		HL31	-	-		SS21	9.81	27.32	
26	20		SS31	3.48	23.75		SS21	3.50	8.05		HL32	-	-		BW23	7.88	21.96	
27	21		SS21	2.90	19.79		CD22	2.50	5.75		PC21	-	-		SS30	7.69	21.43	
28	22		BW22	2.21	15.05		HL23	2.50	5.75		PC23	-	-		CD23	7.05	19.64	
29	23		SS30	2.14	14.62		HL30	2.50	5.75		PC30	-	-		SS20	3.85	10.71	
30	24		CD22	-	-		PC31	2.50	5.75		PC31	-	-		BW22	3.78	10.54	
31	25		HL23	-	-		SS20	2.50	5.75		SS20	-	-		PC31	3.27	9.11	
32	26		PC21	-	-		PC21	-	-		SS21	-	-		HL23	-	-	
33	27		PC31	-	-		PC30	-	-		SS30	-	-		PC21	-	-	
34																		
35				SYSTEM	SYSTEM			POLE	POLE							COND	COND	
36			CIRCUIT	CONDITION	CONDITION		CIRCUIT	COND	COND		CIRCUIT	SAIDI	SAIDI		CIRCUIT	CAPACITY	CAPACITY	
37																		

	S	T	U	V	W	X	Y	Z	AA	AB	AC
1											
2											
3											
4			100.00		CONTROL	1	200.00				100.00
5		CUST	CUST							CUST	CUST
6	CIRCUIT	BENEFITED	BENEFITED		CIRCUIT	ACCESS	ACCESS		CIRCUIT	DENSITY	DENSITY
7	BW22	50	100.00		HL21	5	200.00		BW22	5	100.00
8	BW23	50	100.00		PC32	5	200.00		BW23	5	100.00
9	BW30	50	100.00		PC31	5	200.00		BW31	5	100.00
10	BW31	50	100.00		BW23	4	160.00		CD21	5	100.00
11	CD21	50	100.00		BW31	4	160.00		CD30	5	100.00
12	CD30	50	100.00		HL30	4	160.00		HL20	5	100.00
13	HL22	50	100.00		PC21	4	160.00		HL22	5	100.00
14	HL23	50	100.00		PC30	4	160.00		HL31	5	100.00
15	PC21	50	100.00		BW30	3	120.00		HL32	5	100.00
16	SS20	50	100.00		CD22	3	120.00		HL33	5	100.00
17	SS30	50	100.00		HL22	3	120.00		PC23	5	100.00
18	HL32	40	80.00		HL31	3	120.00		PC31	5	100.00
19	PC23	40	80.00		HL32	3	120.00		SS21	5	100.00
20	HL20	30	60.00		PC22	3	120.00		SS31	5	100.00
21	HL21	30	60.00		CD21	2	80.00		BW30	4	80.00
22	HL33	30	60.00		CD23	2	80.00		HL21	4	80.00
23	PC30	30	60.00		CD30	2	80.00		PC32	4	80.00
24	SS31	30	60.00		CD31	2	80.00		PC22	3	60.00
25	CD23	20	40.00		HL20	2	80.00		CD23	2	40.00
26	CD31	20	40.00		HL23	2	80.00		CD31	2	40.00
27	CD22	10	20.00		HL33	2	80.00		SS20	2	40.00
28	HL30	10	20.00		PC23	2	80.00		CD22	1	20.00
29	HL31	10	20.00		SS20	2	80.00		HL23	1	20.00
30	PC22	10	20.00		SS21	2	80.00		HL30	1	20.00
31	PC31	10	20.00		SS30	2	80.00		PC21	1	20.00
32	PC32	10	20.00		SS31	2	80.00		PC30	1	20.00
33	SS21	10	20.00		BW22	1	40.00		SS30	1	20.00
34											
35		CUST	CUST							CUST	CUST
36	CIRCUIT	BENEFITED	BENEFITED		CIRCUIT	ACCESS	ACCESS		CIRCUIT	DENSITY	DENSITY
37											

	A	C	D	E	G	H	I	K	L	M	N	Q
40	CIRCUIT TOTALS											
41										CONTROL	1	
42			SYSTEM	POLE	SAIDI	COND	CUST		CUST	IMPACT		
43			CONDITION	COND		CAPACITY	BENEFITED	ACCESS	DENSITY	10.00		TOTAL
44	1	BW22	15.05	17.24	-	10.54	100.00	40.00	100.00	10.00		293
45	2	BW23	67.42	54.02	-	21.96	100.00	160.00	100.00	10.00		513
46	3	BW30	63.47	49.43	-	52.50	100.00	120.00	80.00	10.00		475
47	4	BW31	55.62	83.91	-	63.75	100.00	160.00	100.00	10.00		573
48	5	CD21	53.57	70.11	-	38.75	100.00	80.00	100.00	10.00		452
49	6	CD22	-	5.75	-	100.00	20.00	120.00	20.00	10.00		276
50	7	CD23	36.14	8.05	-	19.64	40.00	80.00	40.00	10.00		234
51	8	CD30	47.78	63.22	-	29.29	100.00	80.00	100.00	10.00		430
52	9	CD31	36.24	63.22	-	86.96	40.00	80.00	40.00	10.00		356
53	10	HL20	100.00	12.64	-	27.68	60.00	80.00	100.00	10.00		390
54	11	HL21	46.25	100.00	-	46.96	60.00	200.00	80.00	10.00		543
55	12	HL22	48.86	44.83	-	88.57	100.00	120.00	100.00	10.00		512
56	13	HL23	-	5.75	-	-	100.00	80.00	20.00	10.00		216
57	14	HL30	44.03	5.75	-	28.93	20.00	160.00	20.00	10.00		289
58	15	HL31	46.76	17.24	-	66.43	20.00	120.00	100.00	10.00		380
59	16	HL32	42.04	28.74	-	34.82	80.00	120.00	100.00	10.00		416
60	17	HL33	66.34	67.82	-	27.68	60.00	80.00	100.00	10.00		412
61	18	PC21	-	-	-	-	100.00	160.00	20.00	10.00		290
62	19	PC22	88.61	65.52	-	56.79	20.00	120.00	60.00	10.00		421
63	20	PC23	52.58	14.94	-	70.00	80.00	80.00	100.00	10.00		408
64	21	PC30	68.25	-	-	81.43	60.00	160.00	20.00	10.00		400
65	22	PC31	-	5.75	-	9.11	20.00	200.00	100.00	10.00		345
66	23	PC32	54.29	90.80	-	60.89	20.00	200.00	80.00	10.00		516
67	24	SS20	62.56	5.75	-	10.71	100.00	80.00	40.00	10.00		309
68	25	SS21	19.79	8.05	-	27.32	20.00	80.00	100.00	10.00		265
69	26	SS30	14.62	51.72	-	21.43	100.00	80.00	20.00	10.00		298
70	27	SS31	23.75	12.64	-	30.54	60.00	80.00	100.00	10.00		317

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
73	**FEEDER EXITS**																
74				SYSTEM	POLE		SAIDI	COND	CUST			CUST	IMPACT		T/S/D		
75				CONDITION	COND			CAPACITY	BENEFITED		ACCESS	DENSITY	100.00		50.00		TOTAL
76	1		BW22-EXIT	15.05	17.24	-	-	10.54	100.00	-	40.00	100.00	100.00		-		383
77	2		BW23-EXIT	67.42	54.02	-	-	21.96	100.00	-	160.00	100.00	100.00		-		603
78	3		BW30-EXIT	63.47	49.43	-	-	52.50	100.00	-	120.00	80.00	100.00		-		565
79	4		BW31-EXIT	55.62	83.91	-	-	63.75	100.00	-	160.00	100.00	100.00		-		663
80	5		CD21-EXIT														
81	6		CD22-EXIT	-	5.75	-	-	100.00	20.00	-	120.00	20.00	100.00		-		366
82	7		CD23-EXIT														
83	8		CD30-EXIT	47.78	63.22	-	-	29.29	100.00	-	80.00	100.00	100.00		-		520
84	9		CD31-EXIT	36.24	63.22	-	-	86.96	40.00	-	80.00	40.00	100.00		-		446
85	10		HL20-EXIT														
86	11		HL21-EXIT														
87	12		HL22-EXIT														
88	13		HL23-EXIT														
89	14		HL30-EXIT														
90	15		HL31-EXIT														
91	16		HL32-EXIT														
92	17		HL33-EXIT														
93	18		PC21-EXIT	-	-	-	-	-	100.00	-	160.00	20.00	100.00		-		380
94	19		PC22-EXIT	88.61	65.52	-	-	56.79	20.00	-	120.00	60.00	100.00		-		511
95	20		PC23-EXIT	52.58	14.94	-	-	70.00	80.00	-	80.00	100.00	100.00		-		498
96	21		PC30-EXIT														
97	22		PC31-EXIT														
98	23		PC32-EXIT														
99	24		SS20-EXIT														
100	25		SS21-EXIT														
101	26		SS30-EXIT														
102	27		SS31-EXIT														

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
105	**TRANSMISSION**																
106													200.00		100.00		
107	1		GT1 (BW-TO-PARS)										200.00		-		200
108	2		GT2 (HALL TO-CASS)										200.00		-		200
109	3		GT1/GT2										200.00		-		200
110																	
111																	
112	**SUBSTATION**												100.00		50.00		
113	1		BARLOW SW STATION										100.00		-		100
114	2		BARLOW #1 XMER										100.00		-		100
115	3		BARLOW RECL UPGRADE										100.00		-		100
116	4		CASS RECL UPGRADE										100.00		-		100
117	5		PARSONS SW STATION										100.00		-		100
118	6		PARSONS RECL UPGRADE										100.00		-		100
119																	

	A	B	C	D	E	F
194	**SORTED**					
195	**(COPY THE DATA ABOVE AND PASTE SPECIAL/VALUES FOR BOTH COLUMNS THEN SORT)**					
196			BW31-EXIT	713		
197			BW23-EXIT	653		
198			BW30-EXIT	615		
199			BW31	583		
200			CD30-EXIT	570		
201			PC22-EXIT	561		
202			HL21	553		
203			PC23-EXIT	548		
204			PC32	526		
205			BW23	523		
206			HL22	522		
207			CD31-EXIT	496		
208			BW30	485		
209			CD21	462		
210			CD30	440		
211			BW22-EXIT	433		
212			PC22	431		
213			PC21-EXIT	430		
214			HL32	426		
215			HL33	422		
216			PC23	418		
217			CD22-EXIT	416		
218			PC30	410		
219			HL20	400		
220			HL31	390		
221			CD31	366		
222			PC31	355		
223			SS31	327		
224			SS20	319		
225			SS30	308		
226			BW22	303		
227			PC21	300		
231			HL30	299		
232			CD22	286		
233			SS21	275		
234			CD23	244		
235			HL23	226		