COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS RATES AND FOR	**)**	**2016-00371**
CERTIFICATES OF PUBLIC CONVENIENCE	**)**	
AND NECESSITY	**)**	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
FIRST REQUEST FOR INFORMATION OF ASSOCIATION OF COMMUNITY MINISTRIES
DATED JANUARY 11, 2017

FILED: JANUARY 25, 2017

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President – State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robt M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of January 2017.

Susan M Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY	**)**	
	)	**SS:**
COUNTY OF JEFFERSON	**)**	

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Director – Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15th day of January 2017.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John P. Malloy**, being duly sworn, deposes and says that he is Vice President – Gas Distribution for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 1

Responding Witness: Christopher M. Garrett

Q-1. Please provide the calculations used to derive the average percentage and dollar increases in monthly residential electric and gas bills as stated by Robert M. Conroy in his Testimony (hereafter referred to as Conroy Testimony) at page 4, lines 13 through 17, including the calculations for the usages of 957 kWh of electricity and 55 Ccf of gas.

A-1. See the response to PSC 1-53. See Schedule M-2.2-G for the forecast data used to calculate the 5.0% increase in a residential monthly gas bill. The number of customers, total gas consumption, and annual revenue at proposed rates is detailed on Schedule M-2.3-G, page 2 of 9. See Schedule M-2.2-E for the forecast data used to calculate the 9.5% increase in a residential monthly electric bill. The number of customers, electricity usages, and annual revenue at proposed rates are detailed on Schedule M-2.3-E, page 3 of 24. These schedules can be found at Tab 66 of the Filing Requirements.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 2

Responding Witness: John P. Malloy

Q-2. Please provide in Excel format the average annual usage for LG&E residential customers for each of the following years, 2015 and 2016, and provide the supporting calculations for these figures. Please provide this information for:

a) residential electric customers

b) residential gas customers

A-2. a) See the attachment being provided in Excel format.

b) See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 3

Responding Witness: John P. Malloy

Q-3. Please provide in Excel format the average annual usage for LG&E residential customers for each of the following years, 2015 and 2016, who received assistance from a third party agency during the calendar year in question. Please provide the supporting calculations for these figures. Please provide this information for:

a) residential electric customers

b) residential gas customers

A-3. a) See the attachment being provided in Excel format.

b) See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 4

Responding Witness: John P. Malloy

Q-4. Please provide in Excel format the average annual usage for LG&E residential customers by zip code for each of the following years, 2015 and 2016, and provide the supporting calculations. Please provide this information for:

a) residential electric customers

b) residential gas customers

A-4. a-b) See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 5

Responding Witness: Christopher M. Garrett

Q-5. Utilizing the format in Attachment A to this First Request For Information, taken from Case No. 2014-00372 (Attachment to Response to LGE ACM-1 Question No. 5), please provide the average residential gas bill for each month starting January 1, 2015 through December 31, 2016 generated by the average residential gas volume consumed broken down into its component parts (Customer Charge, Distribution Cost Component and Gas Supply Cost Component). Please specify the applicable rate of each component for each month. Please also provide the data in Excel format.

A-5. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 6

Responding Witness: Christopher M. Garrett

Q-6. Utilizing the format in Attachment B to this First Request For Information, taken from Case No. 2014-00372 (Attachment to Response to LGE ACM-1 Question No. 6), please provide the average residential electric bill for each month starting January 1, 2015 through December 31, 2016 generated by the average residential electric usage broken down into its component parts (Customer Charge and Energy Charge). Please specify the applicable rate of each component for each month. Please also provide the data in Excel format.

A-6. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 7

Responding Witness: Christopher M. Garrett

Q-7. Please provide the projected average residential electric and gas bills, respectively, for each month of the forecast period that would be incurred by the average residential customer, broken down into the requested customer and energy charges and projected environmental, DSM and gas line tracker charges. Please provide the supporting calculations. Please provide this information by using the format in Attachment C to this First Request For Information, taken from Case No. 2014-00372 (Attachments 1 and 2 to Response to LGE ACM-2 Question No. 4).

A-7. See attached. Attachment 1 provides the residential electric information, and Attachment 2 provides the residential gas information. LG&E calculated monthly average residential electric and gas usage by dividing the monthly forecasted kWh or MCF by the monthly forecasted number of electric or gas customers. The billing factors used to calculate the average monthly residential electric and gas bills were calculated as a charge per kWh or MCF (except for GLT, which was calculated as a per customer charge) based on the forecast period revenues and volumes on an annual basis and not monthly. These billing factors may be different than the actual billing factors calculated in the detailed filings for the mechanisms during the forecasted test year. The Billing Factor revenues calculated on Schedule N were calculated by multiplying the imputed billing factors by the average usage (except for GLT, which was applied as a per customer charge). The data used to calculate the average residential electric and gas bills can be found in the Excel versions of Schedule N provided as attachments to PSC 1-54.

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2016-00371
Typical Electric Bill Comparison under Present & Proposed Rates
FORECAST PERIOD FOR THE 12 MONTHS ENDED JUNE 30, 2018

DATA: ____BASE PERIOD__X___FORECASTED PERIOD — **SCHEDULE N (Electric)**
TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED — **PAGE 1 of 1**
WORKPAPER REFERENCE NO(S):________ — **WITNESS: C. M. GARRETT**

Residential (Rate RS) / Volunteer Fire Dept (Rate VFD)

	kWh	A Base Rate Current Bill	B Base Rate Proposed Bill	C Increase ($) [B - A]	D Increase (%) [C / A]	E Billing Factors FAC+OSS	F Billing Factors DSM	G Billing Factors ECR	H Total Current Bill ($) [A+E+F+G]	I Total Proposed Bill ($) [B+E+F+G]	J Increase (%) [(I - H)/H]
July-17	1,378	$ 129.77	$ 138.70	$ 8.94	6.9%	$ (5.15)	$ 4.54	$ 11.63	$ 140.79	$ 149.72	6.4%
August-17	1,374	$ 129.42	$ 138.36	$ 8.94	6.9%	$ (5.13)	$ 4.53	$ 11.59	$ 140.41	$ 149.35	6.4%
September-17	958	$ 93.49	$ 103.13	$ 9.64	10.3%	$ (3.58)	$ 3.16	$ 8.08	$ 101.15	$ 110.79	9.5%
October-17	689	$ 70.30	$ 80.39	$ 10.09	14.4%	$ (2.58)	$ 2.27	$ 5.82	$ 75.81	$ 85.90	13.3%
November-17	721	$ 73.02	$ 83.05	$ 10.04	13.8%	$ (2.69)	$ 2.37	$ 6.08	$ 78.78	$ 88.81	12.7%
December-17	1,003	$ 97.41	$ 106.97	$ 9.56	9.8%	$ (3.75)	$ 3.30	$ 8.47	$ 105.43	$ 114.99	9.1%
January-18	1,050	$ 101.47	$ 110.96	$ 9.49	9.4%	$ (3.92)	$ 3.46	$ 8.86	$ 109.87	$ 119.36	8.6%
February-18	840	$ 83.33	$ 93.17	$ 9.84	11.8%	$ (3.14)	$ 2.77	$ 7.09	$ 90.05	$ 99.89	10.9%
March-18	809	$ 80.60	$ 90.49	$ 9.89	12.3%	$ (3.02)	$ 2.66	$ 6.82	$ 87.06	$ 96.95	11.4%
April-18	662	$ 67.95	$ 78.09	$ 10.14	14.9%	$ (2.47)	$ 2.18	$ 5.59	$ 73.25	$ 83.39	13.8%
May-18	857	$ 84.80	$ 94.61	$ 9.81	11.6%	$ (3.20)	$ 2.82	$ 7.23	$ 91.65	$ 101.46	10.7%
June-18	1,140	$ 109.20	$ 118.53	$ 9.34	8.6%	$ (4.26)	$ 3.75	$ 9.62	$ 118.31	$ 127.64	7.9%
Annual Avg	957	$ 93.43	$ 103.07	$ 9.64	10.3%	$ (3.58)	$ 3.15	$ 8.08	$ 101.08	$ 110.72	9.5%

Assumptions:
- Average usage = 957 kWh per month
- Billing Factors calculated as a unit charge based on forecast period revenues and volumes
- Calculations may vary from other schedules due to rounding

Source: Schedule M2.2; M-2.3

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Revenue as Billed	FAC Billing	DSM Billing	ECR Billing	Energy (kWh)	FAC / kWh [(2)/(5)]	DSM / kwh [(3)/(5)]	ECR / kWh [(4)/(5)]
Residential/VFD	441,462,416	(15,615,418)	13,769,784	35,275,380	4,179,523,067	($0.00374)	$0.00329	$0.00844

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2016-00371
Typical Gas Bill Comparison under Present & Proposed Rates
FORECAST PERIOD FOR THE 12 MONTHS ENDED JUNE 30, 2018

DATA: ____BASE PERIOD__X___FORECASTED PERIOD — **SCHEDULE N (Gas)**
TYPE OF FILING: __X__ ORIGINAL _____ UPDATED _____ REVISED — **PAGE 1 OF 1**
WORKPAPER REFERENCE NO(S):________ — **WITNESS: C. M. GARRETT**

Residential (Rate RGS) / Volunteer Fire Dept (Rate VFD)

	MCF	A Base Rate Current Bill	B Base Rate Proposed Bill	C GLT Base Roll In	D Increase ($) [B + C - A]	E Increase (%) [D / A]	F Billing Factors GSC	G Billing Factors DSM	H Billing Factors GLT	I Total Current Bill ($) [A-C+F+G+H]	J Total Proposed Bill ($) [B+F+G+H]	K Increase (%) [(J - I) / I]
Jul-17	1.1	$ 16.72	$ 26.85	$ (5.70)	$ 4.43	26.5%	$ 4.88	$ 0.12	$ 0.83	$ 28.25	$ 32.68	15.7%
Aug-17	1.1	$ 16.66	$ 26.80	$ (5.70)	$ 4.44	26.7%	$ 4.79	$ 0.11	$ 0.83	$ 28.09	$ 32.53	15.8%
Sep-17	1.2	$ 16.98	$ 27.08	$ (5.70)	$ 4.40	25.9%	$ 5.28	$ 0.13	$ 0.83	$ 28.91	$ 33.32	15.2%
Oct-17	2.4	$ 20.29	$ 30.01	$ (5.70)	$ 4.02	19.8%	$ 10.30	$ 0.24	$ 0.83	$ 37.36	$ 41.38	10.8%
Nov-17	6.2	$ 31.17	$ 39.63	$ (5.70)	$ 2.76	8.9%	$ 26.79	$ 0.64	$ 0.83	$ 65.13	$ 67.89	4.2%
Dec-17	11.4	$ 46.22	$ 52.95	$ (5.70)	$ 1.03	2.2%	$ 49.62	$ 1.18	$ 0.83	$ 103.55	$ 104.58	1.0%
Jan-18	14.4	$ 54.74	$ 60.49	$ (5.70)	$ 0.05	0.1%	$ 62.54	$ 1.48	$ 0.83	$ 125.29	$ 125.34	0.0%
Feb-18	12.2	$ 48.43	$ 54.90	$ (5.70)	$ 0.77	1.6%	$ 52.96	$ 1.26	$ 0.83	$ 109.18	$ 109.95	0.7%
Mar-18	8.5	$ 38.00	$ 45.68	$ (5.70)	$ 1.98	5.2%	$ 37.15	$ 0.88	$ 0.83	$ 82.56	$ 84.54	2.4%
Apr-18	3.8	$ 24.38	$ 33.62	$ (5.70)	$ 3.54	14.5%	$ 16.49	$ 0.39	$ 0.83	$ 47.79	$ 51.33	7.4%
May-18	2.2	$ 19.82	$ 29.59	$ (5.70)	$ 4.07	20.6%	$ 9.59	$ 0.23	$ 0.83	$ 36.17	$ 40.24	11.3%
Jun-18	1.3	$ 17.22	$ 27.29	$ (5.70)	$ 4.37	25.4%	$ 5.64	$ 0.13	$ 0.83	$ 29.52	$ 33.89	14.8%
Annual Avg	5.487	$ 29.24	$ 37.93	$ (5.70)	$ 2.99	10.2%	$ 23.87	$ 0.57	$ 0.83	$ 60.21	$ 63.20	5.0%

Assumptions:
Average usage = 5.487 Mcf per month
Billing Factors calculated as a unit charge based on forecast period revenues and volumes
Calculations may vary from other schedules due to rounding

ce: Schedule M2.2; M-2.3

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Revenue as Billed	GSC	DSM	GLT	Volume MCF	GSC / MCF [(2)/(5)]	DSM / MCF [(3)/(5)]	GLT / MCF [(4)/(5)]	# of Customers	GLT / Customer [(4)/(9)]
Residential/VFD	214,163,791	$84,917,418	$2,013,224	$2,965,728	$19,516,322	$4.35	$0.10	$0.15	3,556,511	$0.83

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 8

Responding Witness: Christopher M. Garrett

Q-8. Please provide the average residential electric and gas bills, respectively, for each month starting January 1, 2015 through December 31, 2016 incurred by the average residential customer, broken down into the actual customer and energy charges and environmental, DSM and gas line tracker charges. Please provide the supporting calculations. Please provide this in Excel format.

A-8. See the responses to Question No. 5 and Question No. 6.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 9

Responding Witness: John P. Malloy

Q-9. Please provide the following information pertaining to non-payment disconnection/reconnection reports filed with the Public Service Commission.

a) Please provide copies of the non-payment disconnection/reconnection reports filed by LG&E with the Public Service Commission for the July 1, 2014 through June 30, 2015 period and the July 1, 2015 through June 30, 2016 period.

b) Please confirm that numbers of terminations and reinstatements on the electric customers reports consist of terminations and reinstatements of residential electric only and combined gas and electric customers, and that the corresponding numbers on the gas customers reports consist of terminations and reinstatements of residential gas only customers. If not confirmed, please provide an explanation of what information is included on each.

c) If LG&E has made any changes to the information provided or manner of reporting on the reports requested in part (a) above, as compared to reports for previous reporting periods, please explain the reasons for such changes.

d) For each of the reports requested in part (a) above pertaining to electric customers, please break down the numbers of customers terminated and numbers of customers reinstated into electric only and combined gas and numbers of customers reinstated into electric only and combined gas and electric customers.

A-9. a) See attached.

b) Confirmed.

c) LG&E compiled the 7/1/14 - 6/30/15 and 7/1/15 – 6/30/16 periods in the same manner.

d) The information is not retained in that format and is not otherwise readily available.

LOUISVILLE GAS AND ELECTRIC COMPANY
NON-PAYMENT DISCONNECTION/RECONNECTION REPORT
JULY 1, 2015 THROUGH June 30, 2016
ELECTRIC CUSTOMERS

807 KAR 5:006, SECTION 4(5)

COMPANY: **LOUISVILLE GAS AND ELECTRIC COMPANY**
220 WEST MAIN STREET
LOUISVILLE, KY 40202

Month	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Number Terminated	4,775	5,613	6,179	5,482	4,861	4,721	4,008	5,649	6,690	4,813	3,431	7,990
Highest $ Amount Terminated	$2,404.48	$3,438.24	$2,055.26	$2,010.07	$2,484.98	$1,627.85	$2,040.40	$1,732.66	$6,602.57	$2,074.58	$2,074.24	$1,165.47
Lowest $ Amount Terminated	$75.09	$75.01	$75.02	$75.12	$75.28	$75.01	$75.25	$75.13	$75.09	$75.01	$75.75	$75.15
Median $ Amount Terminated	$142.69	$174.73	$173.36	$171.46	$158.07	$135.42	$155.59	$172.63	$198.82	$195.43	$173.71	$156.98
Average $ Amount Terminated	$182.85	$210.02	$203.92	$207.89	$194.85	$176.70	$189.23	$205.20	$233.32	$242.29	$235.92	$204.95
Number Reinstated	4,244	4,861	5,441	4,975	4,459	4,231	3,576	5,123	5,966	4,438	2,952	3,700

Note: Data includes all residential disconnections excluding returned checks, diversion and others which may skew the results

For information regarding this report contact: Marty Reinert
(502) 627-4173

LOUISVILLE GAS AND ELECTRIC COMPANY
NON-PAYMENT DISCONNECTION/RECONNECTION REPORT
JULY 1, 2014 THROUGH June 30, 2015
ELECTRIC CUSTOMERS

807 KAR 5:006, SECTION 4(5)

COMPANY: **LOUISVILLE GAS AND ELECTRIC COMPANY**
220 WEST MAIN STREET
LOUISVILLE, KY 40202

Month	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Number Terminated	4,813	5,683	5,190	5,940	3,479	4,713	4,329	1,675	6,842	6,883	6,449	5,646
Highest $ Amount Terminated	$2,483.64	$1,868.16	$2,288.99	$1,394.55	$2,050.53	$4,495.74	$2,372.01	$1,772.86	$3,091.66	$4,244.09	$2,575.65	$2,509.09
Lowest $ Amount Terminated	$75.13	$75.10	$75.07	$75.06	$75.04	$75.02	$75.18	$75.92	$75.15	$75.07	$75.01	$75.07
Median $ Amount Terminated	$147.92	$163.18	$157.87	$159.18	$143.47	$133.69	$178.41	$202.62	$217.73	$217.52	$161.59	$135.43
Average $ Amount Terminated	$197.91	$203.39	$195.63	$189.46	$178.67	$170.43	$214.28	$240.48	$265.48	$266.15	$219.21	$180.27
Number Reinstated	2,984	5,054	4,504	5,344	3,291	4,148	3,699	1,798	5,589	5,842	5,820	5,093

Note: Data includes residential disconnections for non-payment. Other types of disconnections are not included.

For information regarding this report contact: Marty Reinert
(502) 627-4173

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 10

Responding Witness: John P. Malloy

Q-10. Please provide in Excel format a breakdown by zip code of (1) the number of residential accounts in the LG&E service territory disconnected for nonpayment and (2) the number of those accounts for which service was reinstated for each of the years 7/1/2014 through 6/30/2015 and 7/1/2015 through 6/30/2016. Please provide this information for:

a) residential electric only customers

b) residential combined electric and gas customers

c) residential gas only customers

A-10. a-c) See the attachments being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 11

Responding Witness: John P. Malloy

Q-11. Please provide the number of LG&E residential customers that received assistance from a third party agency for each month from January 1, 2015 through December 31, 2016. Please state the monthly amount of such funds.

A-11. See below the number of LG&E residential customers that received assistance and the amount from a third party agency for each month from January 1, 2015 through December 31, 2016.

Year	Month	LG&E Residential Customers that Received Assistance from a Third Party	Monthly Amount of Third Party Assistance Funds
2015	January	5,166	$922,262
2015	February	6,580	$1,370,848
2015	March	8,496	$1,587,818
2015	April	3,964	$520,161
2015	May	3,685	$496,313
2015	June	3,631	$401,759
2015	July	3,353	$244,297
2015	August	3,412	$269,964
2015	September	3,163	$258,571
2015	October	4,178	$384,188
2015	November	6,529	$734,868
2015	December	5,433	$536,863
2016	January	4,402	$743,284
2016	February	6,187	$1,079,212
2016	March	6,586	$1,084,645
2016	April	4,815	$699,687
2016	May	3,299	$398,151
2016	June	3,488	$384,468
2016	July	3,015	$242,576
2016	August	3,232	$269,877
2016	September	3,031	$258,280
2016	October	5,349	$551,853
2016	November	7,376	$557,586
2016	December	3,658	$185,307

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 12

Responding Witness: John P. Malloy

Q-12. Please provide in Excel format a breakdown by zip code of the number of residential customers in the LG&E territory who had at least one bill paid by a third party agency and the amount of assistance paid. Please provide this information for the following years:

a) 2015

b) 2016

A-12. a-b) See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 13

Responding Witness: John P. Malloy

Q-13. Please provide in Excel format (1) the number of residential accounts receiving third-party assistance in the LG&E service territory disconnected for nonpayment and (2) the number of those accounts for which service was reinstated for each of the years 7/1/2014 through 6/30/2015 and 7/1/2015 through 6/30/2016. Please provide this information for:

a) residential electric only customers

b) residential combined electric and gas customers

c) residential gas only customers

A-13. a-c) See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 14

Responding Witness: John P. Malloy

Q-14. Please provide the number of Winter Hardship reconnections in LG&E territory for each of the years 7/1/2014 through 6/30/2015 and 7/1/2015 through 6/30/2016 broken down by zip code.

A-14. See attached.

LG&E

Winter Hardship Reconnections

7/1/2014 through 6/30/2015

Postal Code	Number Reconnections	Postal Code	Number Reconnections	Postal Code	Number Reconnections
24273	1	40258	11	42330	1
24277	2	40272	13	42408	1
24283	1	40291	2	42420	1
24293	1	40299	2	42445	1
40004	2	40324	2	42461	1
40006	1	40330	1	42501	1
40014	2	40336	2	42539	1
40019	1	40342	1	42718	1
40047	2	40353	1	42728	1
40050	1	40356	1	42743	1
40059	1	40361	2		
40108	1	40383	3		
40109	1	40390	2		
40118	7	40391	2		
40160	1	40422	1		
40165	7	40437	1		
40202	6	40456	1		
40203	63	40475	4		
40204	7	40503	2		
40205	8	40505	3		
40206	7	40508	3		
40207	6	40509	2		
40208	12	40511	5		
40210	48	40514	3		
40211	96	40515	2		
40212	80	40517	7		
40213	12	40819	1		
40214	39	40828	1		
40215	40	40906	1		
40216	34	40930	1		
40217	4	40965	1		
40218	29	40977	2		
40219	20	40997	1		
40220	8	41003	1		
40222	2	41044	1		
40223	3	42031	1		
40228	6	42032	1		
40229	16	42055	1		
40243	1	42078	1		
40245	3	42320	1		

LG&E

Winter Hardship Reconnections

7/1/2015 through 6/30/2016

Postal Code	Number Reconnections	Postal Code	Number Reconnections	Postal Code	Number Reconnections
24219	2	40245	5	42501	1
24273	1	40258	17	42503	1
24277	1	40272	19	42629	1
24283	1	40291	11	42701	3
24293	3	40299	7	42718	2
40014	2	40336	1	42724	1
40026	1	40342	2	42754	1
40031	2	40347	1		
40059	1	40351	2		
40065	2	40353	1		
40108	1	40370	1		
40109	1	40383	1		
40118	7	40391	3		
40160	1	40422	1		
40165	3	40456	1		
40177	1	40475	1		
40202	3	40502	1		
40203	52	40504	1		
40204	4	40505	1		
40205	2	40509	2		
40206	3	40511	2		
40207	3	40517	2		
40208	23	40701	1		
40209	1	40741	2		
40210	45	40769	1		
40211	93	40806	1		
40212	66	40823	1		
40213	12	40935	1		
40214	33	40965	2		
40215	42	41008	1		
40216	37	41031	2		
40217	7	42038	1		
40218	35	42328	1		
40219	19	42330	2		
40220	7	42345	1		
40222	3	42404	1		
40223	2	42408	1		
40228	2	42437	2		
40229	14	42441	1		
40241	3	42459	1		

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 15

Responding Witness: John P. Malloy

Q-15. Please refer to the Conroy Testimony at page 29, lines 12 through 18 and at page 53, lines 11 through 18.

a) How many electric meters are currently subject to the HEA charge?

b) How many electric meters would be subject to the HEA charge under the proposed deletion of “per meter” from the tariff?

c) How many gas meters are currently subject to the HEA charge?

d) How many gas meters would be subject to the HEA charge under the proposed deletion of “per meter” from the tariff?

e) For each month of the test period, please provide a comparison of what projected revenue from the HEA charges would be under the current tariff language and the proposed tariff language. Please provide the supporting calculations. Please provide this information separately for electric and gas.

f) Assuming an HEA charge of 25 cents, under LG&E’s proposal to delete the “per meter” language, would a residential customer who has both gas and electric service continue to pay the HEA charge on each meter, for a monthly total of 50 cents? If not, please explain.

A-15. a-d) See the table below for a breakdown of the meters subject to the HEA charge.

Meters Subject to the HEA Charge

	Current Tariff	After Deletion of “per meter”
Electric Meters	360,777	360,777
Gas Meters	295,780	295,780

e. The revenue under both the current tariff language and the proposed tariff language will be the same. There will be no change in the way that the HEA charge is included in customers' bills.

f. Yes, residential customers with both gas and electric service will continue to pay the HEA charge on each meter, for a monthly total of 50 cents.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 16

Responding Witness: John P. Malloy

Q-16. Please refer to the testimony of John P. Malloy (hereinafter "Malloy Testimony") at page 24, line 17 through page 25, line 2 and page 25, lines 8 through 12, where some of the purported benefits to customers of full AMS deployment are discussed.

a) Has LG&E investigated the extent to which its low income customers have reasonable access to the technology needed to take full advantage of these benefits? If so, please provide all documents related to that investigation. If not, please explain why not.

b) Have the Companies investigated the extent to which low-income utility customers in other jurisdictions deploying smart meters have participated in these or similar benefits, where available? If so, please provide all documents related to that investigation. If not, please explain why not.

A-16.

a) LG&E has not investigated the extent to which its low income customers have reasonable access to the technology needed to take full advantage of the benefits mentioned because the AMS deployment was evaluated across all customers and found to be net positive over the expected service life of the meters; representing a cost savings to all customers. There are many benefits which accrue to customers, without a need to access their information, such as outage notification to the Companies for system restoration and individual premise restoration, off-cycle reads for customer service inquires, and customer safety.

b) LG&E has not investigated the extent to which low income utility customers in other jurisdictions deploying smart meters have participated in these or similar benefits because the AMS deployment was evaluated across all customers and found to be net positive over the expected service life of the meters; representing a cost savings to all customers. There are many benefits which accrue to customers, without a need to access their information, such as outage notification to the Companies for system restoration and individual premise restoration, off-cycle reads for customer service inquires, and customer safety.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 17

Responding Witness: Robert M. Conroy

Q-17. Please refer to the Malloy Testimony at page 25, lines 2 through 3, where it is stated that "full AMS deployment will enable the Companies to develop time-of-day or more dynamic rate structures…"

a) Do the Companies in fact intend to develop such rate structures for residential service in the LG&E service territory?

b) If so, (i) what is the projected time frame for their development and (ii) are they anticipated to be voluntary?

A-17.

a) See the response to AG 1-383.

b) See the response to AG 1-383.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 18

Responding Witness: John P. Malloy

Q-18. Please refer to page 8 of the Advanced Metering Systems Business Case, Exhibit JHM-1, where it is stated "PPL Electric Utilities (PPLEU), a utility serving customers in Pennsylvania…is currently preparing to deploy… advanced meters in its service territory. The Company is leveraging lessons learned and best practices from PPLEU for successful deployment in Kentucky."

a) Has PPLEU yet obtained regulatory approval for the referenced deployment? Please provide the name of the regulatory body, caption and docket number for the pertinent regulatory proceeding(s).

b) Will PPLEU utilize remote disconnection for nonpayment by residential customers? If so, what policies, procedures and safeguards has PPLEU developed?

c) Have the Companies examined the extent to which state laws, regulations and regulatory precedent relevant to disconnection of residential customers for nonpayment may differ between Pennsylvania and Kentucky? If so, please provide all analyses, reports and related documents.

A-18.

a) Yes, PPLEU has obtained regulatory approval for the referenced deployment. The name of the regulatory body is the Pennsylvania Public Utility Commission; docket number M-2014-2430781.

b) Yes, PPLEU will utilize remote disconnection for nonpayment by residential customers. PPLEU operates under a different regulatory environment and therefore their operational procedures may not be applicable to LG&E.

c) The Companies will comply with all applicable regulations for disconnection of residential customers in Kentucky. The Companies are aware that remote disconnection is being used across Kentucky by other utilities.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 19

Responding Witness: John P. Malloy

Q-19. Please provide an update on the Companies' investigation of "Predictive Usage Alerts" and "Pick Your Own Due Date," as referenced on pages 26 - 27 of the Advanced Metering Systems Business Case, Exhibit JHM-1, including plans and timetables for offering these programs to residential LG&E customers.

A-19. The Companies have not developed plans or timetables at this time for offering these programs to residential customers. The foundation to consider offering these types of services is the full deployment of advanced meters.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 20

Responding Witness: John P. Malloy

Q-20. Please refer to section 7.1.1.1, entitled "Customer Empowerment via ePortal," on page 32 of the Advanced Metering Systems Business Case, Exhibit JHM-1, which states "[p]reliminary opt-in program results show that active users…draw insights from their consumption patterns and adjust their behavior to save energy. The Company conservatively projects a 3% energy savings for those making proactive changes… This represents savings of approximately $166.3 million over 20 years."

a) Please explain in detail how the Companies arrived at the 3% figure.

b) Please describe in detail the particular "proactive changes" an average LG&E residential customer would need to make in order to attain the projected 3% energy savings.

c) Please provide the energy savings, expressed as a percentage, attained by participants in the AMS opt-in program to date, broken out for the LG&E and KU service territories.

d) Please provide the number of AMS opt-in program participants in the LG&E service territory who attained energy savings, broken down by zip code, in Excel format.

e) Of the participants included in the response to (d), how many had a bill paid by a third party assistance provider during either 2015 or 2016?

f) Please provide a copy of the 2013 Smart Grid Consumer Collaborative Report referenced in section 7.1.1.1, footnote 20.

A-20.

a) The Companies arrived at the 3% figure after referencing the Smart Grid Consumer Collaborative (SGCC) report "Smart Grid Economic and Environmental Benefits" which showed active users demonstrated energy savings between 5% and 15%. The Companies desired to remain conservative in their approach and used an estimate that actively engaged participants will achieve an average of 3% energy savings.

b) There is not a prescribed set of changes resulting in 3% of energy savings for any "average" residential customer.

c) In October 2016, the Companies partnered with Tetra Tech, a third-party evaluator, to examine AMS opt-in program participant energy savings. Tetra Tech's analysis indicated average household energy savings of approximately 6%. Tetra Tech analysis was program wide and not broken out by Company.

d) The Company has not performed said analysis.

e) See the response to d. above.

f) See attached.

Smart Grid Economic and Environmental Benefits

A Review and Synthesis of Research on Smart Grid Benefits and Costs

SmartGrid consumer collaborative

October 8, 2013

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FOREWORD

About This Review

Many researchers have forecast the likely costs and benefits of a Smart Grid using macroeconomic analysis. In 2011 the Electric Power Research Institute forecast that the cost to upgrade the U.S. grid to "smart" status would be between $338 billion and $476 billion, and would generate benefits of between $1,294 billion and $2,028 billion,[1] for an anticipated benefit-to-cost ratio of between 2.8 and 6.0 to 1. U.S. utility Smart Grid business cases typically forecast benefit-to-cost ratios of between 1.1 and 3.0 to 1.

Because real-world experience with the Smart Grid is growing, the Smart Grid Consumer Collaborative (SGCC) completed a review of available research quantifying the actual – rather than forecast – benefits and costs to help stakeholders analyze and maximize the value of various capabilities. This report summarizes available research in terms consumers can understand and synthesizes findings in a "per customer" context whenever possible.

Smart Grid planning and investment is undertaken in a complex environment with numerous stakeholders, including, among others:

- Consumer advocates
- Environmental advocates
- Regulators
- Consumers
- Legislators
- Utilities
- Hardware, software, and service suppliers to the utility industry

This review aims to help these stakeholders determine what U.S. consumers can realistically expect to receive relative to Smart Grid investment for their money based on demonstrated experience. It has been specifically developed to help stakeholders understand:

- Exactly how Smart Grid capabilities create value relative to a traditional grid
- The size of the various benefits (economic, reliability, environmental, and customer choice) as supported by available research, expressed "per customer per year" whenever possible
- The key drivers of these benefits
- The costs typically incurred to create those benefits, expressed "per customer" whenever possible

1 Electric Power Research Institute, Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid, March 2011, 1–4.

"Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers"

We have created "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," a separate guide detailing certain technical and economic concepts discussed in this review. The guide is available from the SGCC, and we encourage readers interested in additional details to consult the guide.

About the Smart Grid Consumer Collaborative

SGCC is a consumer-focused nonprofit organization formed to promote an understanding of the benefits of modernized electrical systems among all stakeholders in the United States. Membership is open to all consumer and environmental advocates, technology vendors, research scientists, and electric utilities for sharing research, best practices, and collaborative efforts of the group. Learn more at smartgridcc.org.

About the Wired Group

This research was conducted by the Wired Group, a consultancy helping clients unleash the latent value in distribution utility businesses. Learn more at wiredgroup.net.

Acknowledgements

The SGCC would like to thank the many individuals, companies, and organizations that helped formulate insights from the research reviewed and provided feedback on the content, themes, and layout of this review. Only by continuing to collaborate on consumer issues will we be able to fully realize the promise of Smart Grid. If you are not a member, we invite you to join us as we continue to listen, collaborate, and educate going forward.

October 8, 2013

Patty Durand, Executive Director
Smart Grid Consumer Collaborative

Smart Grid Consumer Collaborative Members

The following organizations support the Smart Grid Consumer Collaborative and its mission:

- Accenture
- ACEEE
- Aclara Technologies
- Alameda Municipal Power
- Alliance to Save Energy
- Ameren Illinois
- Arizona Public Service Company
- Association for Demand Response & Smart Grid
- Avista Utilities
- Baltimore Gas and Electric Company
- BC Hydro
- Benton PUD
- Bonneville Power Administration
- Brookhaven National Laboratory
- C3 Energy
- California Center for Sustainable Energy
- California Public Utilities Commission
- CenterPoint Energy
- Climate + Energy Project
- CNT Energy
- Cobb EMC
- Colorado Public Utilities Commission
- ComEd
- Comverge
- Consumers Energy
- CPS Energy
- DNV KEMA
- Dominion
- DTE Energy
- Duke Energy
- Duquesne Light Company
- Electric Power Research Institute
- Energy Providers Coalition for Education
- Environmental Defense Fund
- Fayetteville Public Works Commission
- FirstEnergy
- Florida Power & Light
- Future of Privacy Forum
- Gainesville Regional Utilities
- Galvin Electricity Initiative
- GE Energy
- Georgia Institute for Technology
- Green DMV
- The Greenlining Institute
- GridWise Alliance
- IBM
- Illinois Citizens Utility Board
- Institute for Energy & Environment at Vermont Law
- Idaho Falls Power
- Intelligent Energy Solutions LLC
- Itron
- Landis + Gyr
- Lawrence Berkeley National Laboratory
- Market Strategies International
- Michigan Public Service Commission
- Middle Tennessee EMC
- Minnesota Valley Electric Cooperative
- Montana State University
- National Institute of Standards and Technology
- National Renewable Energy Laboratory
- Natural Resources Defense Council
- NC Department of Commerce – Energy Office
- NETL – Smart Grid Implementation Task Force
- New Brunswick Power Corporation
- North Carolina Sustainable Energy Association
- Office of People's Counsel DC
- Office of the Ohio Consumers' Counsel
- Oklahoma Gas & Electric
- Oncor
- Opower
- Oracle
- Oregon Citizens Utility Board
- Pacific Gas and Electric Company
- Pacific Northwest National Laboratory
- PayGo
- Peak Load Management Alliance
- Pepco Holdings, Inc.
- Portland General Electric
- Power Systems Consultants, Inc.
- Public Utility Commission of Texas
- Research Triangle Cleantech Cluster
- Sempra Utilities / San Diego Gas & Electric
- Siemens AG
- Silver Spring Networks
- Simple Energy
- Smart Grid Oregon
- Southeast Energy Efficiency Alliance
- Southern California Edison
- Southern Company
- Southface Energy Institute
- Southwest Research Institute
- Stoel Rives LLP
- TechAmerica
- Tendril
- Tennessee Valley Authority
- Texas Office of Public Utility Counsel
- Tri-County Electric Cooperative
- TVPPA
- Utility Consumers' Action Network
- Vermont Energy Investment Corporation

1. EXECUTIVE SUMMARY

The SGCC completed this review to help stakeholders better understand the benefits – economic, environmental, reliability, and customer choice – associated with Smart Grid investments. We present controlled studies from actual Smart Grid deployments whenever possible, synthesizing research results into a "per customer per year" context using assumptions based on actual Smart Grid deployments. In order to reflect variability across different utility operating environments, we present a set of conservative assumptions that we refer to as the "Reference Case," along with more aggressive assumptions reflecting "the state of the possible" that we refer to as the "Ideal Case." We also describe the benefit drivers for each Smart Grid capability.

Findings

We believe readers of this report are likely to reach the conclusion that Smart Grid investments offer economic benefits in excess of costs, and likewise offer significant reductions in environmental impact.

Smart Grid Investment Offers Economic Benefits in Excess of Costs

The Smart Grid appears to offer both direct benefits (those which could affect consumers' bills) and indirect economic benefits to customers. Direct benefits are delivered through four primary mechanisms:

- Increasing electric distribution efficiency, primarily through Integrated Volt/VAr Control (IVVC).
- Facilitating changes in customer behavior, either by shifting usage away from high-demand periods or by reducing usage. These capabilities include offering customers more choices including time-varying rates, prepayment programs, and customer energy management systems.
- Reducing operating costs from capabilities such as remote meter reading and remote service disconnect/reconnect.
- Improving revenue capture through improved Smart Meter accuracy and theft detection capabilities.

The Smart Grid also appears to offer significant indirect benefits to communities through economic productivity increases associated with improved grid reliability. Capabilities such as fault location help repair crews find faults faster, while fault isolation limits the number of customers impacted by any particular service outage.

Smart Grid Investment Offers Significant Reductions in Environmental Impact

The Smart Grid offers significant reductions in environmental impact through two sources: conservation and greater renewable generation integration. Greenhouse gas[2] emission reductions can be traced directly to Smart Grid capabilities – such as time-varying rates and customer energy management systems – offering a conservation effect. We find that the Smart Grid increases the level of customer-sited generation that the distribution grid can reliably and efficiently accommodate. To the extent this generation is renewable, Smart Grid capabilities designed to accommodate it offer even more significant environmental benefits.

Direct and Indirect Benefits by Capability per Customer per Year

Reference Case and Ideal Case Benefits

Table 1 summarizes the available benefits from various Smart Grid capabilities found in the research. In many cases, we have made assumptions about key benefit drivers such as customer participation rates to convert the research findings into a “per customer per year” metric. Where a range is presented, the low end represents the Reference Case, which embodies assumptions typical of the current average capability deployment. The high end represents the Ideal Case, which is based on assumptions that, though the research indicates are achievable, may not be reached unless the benefit drivers are carefully and thoughtfully optimized by Smart Grid stakeholders.

Not all Smart Grid capabilities are subject to large variation. For example, capabilities designed to improve reliability are not driven by customer participation rates. In other cases, insufficient research for a particular capability is available on which to base differences between a Reference Case and Ideal Case, rendering any such distinctions arbitrary. A summary of Reference Case and Ideal Case assumptions is presented in the appendices. Sources are footnoted throughout this review.

Direct and Indirect Benefits

Direct benefits are those that could affect customers’ bills, whereas the indirect benefit calculations represent our attempt to translate reliability and environmental performance improvements from Smart Grid capabilities into economic terms.

2 Referred to throughout this report as “carbon dioxide equivalent emissions,” “CO_2 equivalent,” or “CO_2e” emissions.

Table 1. Benefits by Smart Grid capability per customer per year

Capability	Direct Economic Benefits	Reliability Improvement	CO_2 Equivalent Reduction[3]	Indirect Economic Benefits[4]	Customer Choice Benefits
Integrated Volt/ VAr Control	\$11.24–32.01	Improved power quality (value not quantified)	Likely – 372 lbs.	Likely – \$2.59	
Remote Meter Reading	\$13.68–23.92		Possible	Possible	
Time-Varying Rates	\$2.00–19.98		11–110 lbs.	\$0.08–0.76	Yes
Prepayment and Remote Dis-/ Reconnect	\$7.82–19.56		30–76 lbs.	\$0.21-0.53	Yes
Revenue Assurance	\$3.00				
Customer Energy Mgmt.	\$0.77–1.92		14–34 lbs.	\$0.10–0.24	Yes
Service Outage Management	\$1.18	4.5% 4.9 minutes		\$8.82	
Fault Location and Isolation		20.5% 22.3 minutes		\$40.14	
Renewable Generation Integration	Possible	Likely	Likely		Yes
TOTALS	\$39.69–101.57	25% 27.2 minutes	55–592 lbs.	\$49.35-53.08	Yes

It is important to note that no single utility necessarily has all of these capabilities and each utility's results could vary significantly from these estimates. The most significant drivers of benefits and opportunities for improvement are described for each capability in this review.

3 Carbon dioxide reductions are estimated at 1.22 lbs. per kWh, per U.S. Environmental Protection Agency, "eGRID 2012 Subregion GHG Output Emission Rates for Year 2009." Table 1, column = Total Output Emissions Rate (lb/MWh), April 2012. http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf.

4 The value of carbon emissions reductions is estimated at \$14.00 per metric ton (the price for a CO_2 emissions permit in the May, 2013 California auction). The value of an avoided minute of service outage is estimated at \$1.80 based on a recent Lawrence Berkeley National Laboratory study; see "Estimating the Economic Productivity Impact of Service Outages" in the appendices for more information.

Benefit Drivers

Our analysis indicates that four drivers explain most of the variation in the available benefits.

Table 2. Drivers of Smart Grid capability benefits

Capability	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Integrated Volt/VAr Control	X			X
Remote Meter Reading	X		X	
Time-Varying Rates		X		X
Prepayment and Remote Dis-/Reconnect	X	X		X
Revenue Assurance				X
Customer Energy Management		X		X
Service Outage Management	X			
Fault Location and Isolation	X			
Renewable Generation Integration	X	X		X

There appear to be some opportunities available to increase the benefits of Smart Grid capabilities through policy. As one example, traditional ratemaking practices may not encourage utilities to reduce sales volumes between rate cases. Once electric rates are set in a rate case, reductions in sales volume below anticipated levels reduce the likelihood that a utility will be able to cover its costs. Several Smart Grid capabilities discussed in this review, including Integrated Volt/VAr Control and time-varying rates, derive a significant proportion of available economic benefits via reductions in sales volumes. Other regulatory rules and norms may require revisions to enable some customer economic benefits, for instance billing and payment program innovations. The SGCC hopes this review will help stakeholders work together in pursuit of policy solutions that enable customer equity, provide customers with choices, and encourage utility investment, while maximizing available benefits for all customers.

Costs by Smart Grid Component

The average Smart Grid cost per customer, based on budget information from U.S. utilities' applications for the U.S. Department of Energy's Smart Grid Investment Grant (SGIG) program funds, is presented in Table 3 by component.

Table 3. Average cost per customer by Smart Grid component

Smart Grid Component	Sample Size	Average Cost per Customer
Smart Meter	24 projects	$291.54
Distribution Automation	12 projects	$63.64

In addition to these costs, we assume utilities will make annual expenditures equal to 4 percent of initial Smart Grid investments to operate and maintain hardware, software, and communications networks.[5]

Benefit-Cost Summary

Figure 1 summarizes the Net Present Value (NPV)[6] of benefits and costs for the Reference Case, while Figure 2 does so for the Ideal Case. We assumed a 13-year project life, incorporating 3 years of implementation and 10 years of operation. Based on available research and incorporating the Reference Case and Ideal Case assumptions detailed in this report, we find the ratio of benefits to costs range from 1.5–2.6 to 1 in the Reference Case and Ideal Case, respectively.[7] Subtracting the NPV of total costs from total benefits (direct and indirect) yields net benefits of approximately $247 per customer in the Reference Case and $713 per customer in the Ideal Case.

5 Harvey Kaiser, "Capital Renewal and Deferred Maintenance Programs," APPA Body of Knowledge, 2009, 9.

6 Net Present Value (NPV) is an analytical technique for converting future benefits and costs into present-day dollars for comparative purposes. Please see Section 5, "Costs of the Smart Grid," for more information.

7 Reference Case benefit to cost ratio = ($306.95 + $390.27)/$449.82 = 1.5 (to 1); Ideal Case benefit to cost ratio = ($772.75 + $390.27)/$449.82 = 2.6 (to 1).

Figure 1. Smart Grid costs and benefits by capability: Reference Case

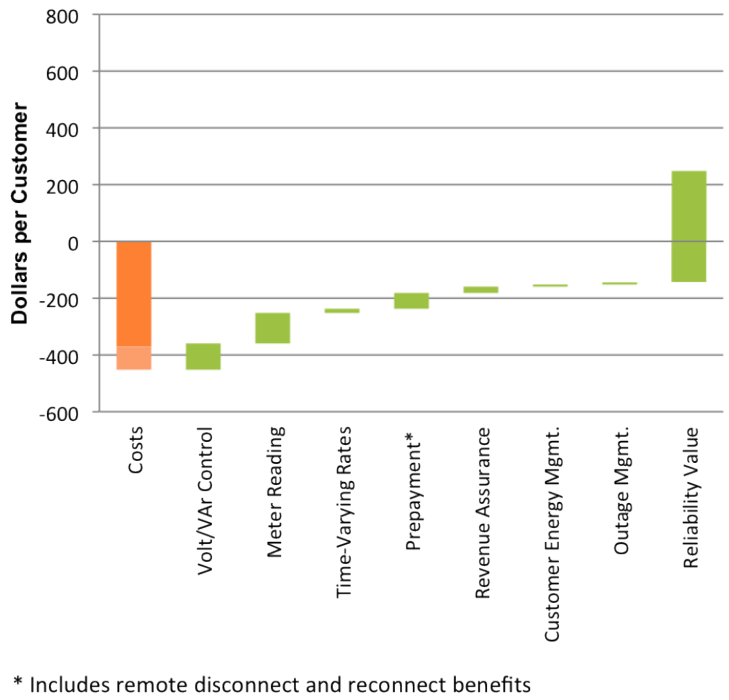
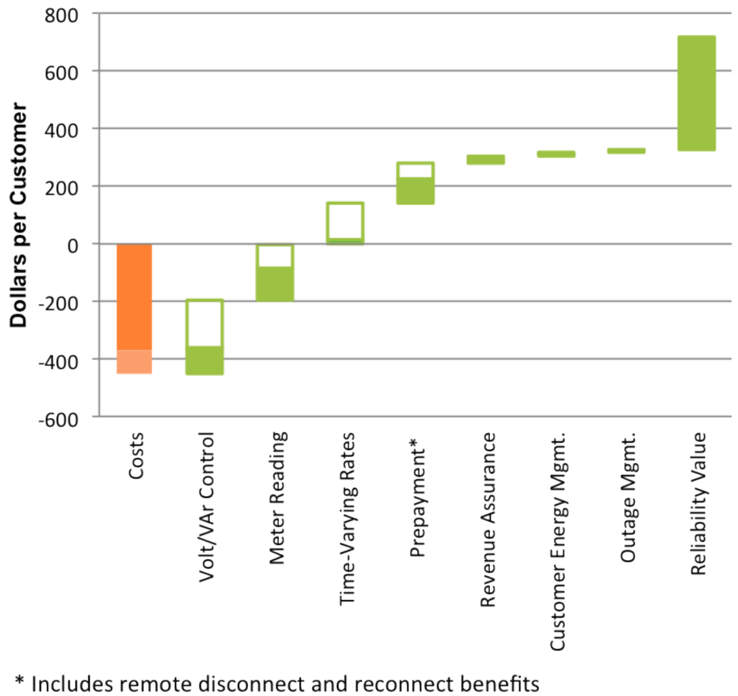


Figure 2. Smart Grid costs and benefits by capability: Ideal Case



Open boxes represent the difference in benefit between the Reference Case and the Ideal Case.

Conclusions and Recommendations

The research presented in this review indicates that grid modernization creates direct and indirect economic benefits for customers in excess of costs. The research also indicates that the Smart Grid delivers significant environmental benefits through conservation and renewable generation integration. Opportunities to optimize these benefits are available through a holistic approach involving customer engagement, utility operations, and regulatory/governance systems. The SGCC encourages all stakeholders (utilities, regulators, advocates, and customers) to collaborate in pursuit of optimizing these benefits.

Looking forward, candid conversations among stakeholders about the critical role that the electric distribution grid plays in a community and the kind of grid a community wants to have are essential. Grid upgrades require long lead times; flexibility and reliability must be designed and built well in advance of when they will be needed. The grid we use today was not designed for the demands society seems poised to place on it in the future. Communities need to be asking key questions about the kind of grid they want, the costs required to build it, and priorities and trade-offs they can agree upon.

As the role electric distribution plays in communities' economic vitality and sustainability increases, a new dynamic is needed in the nature of relations among distribution utility stakeholders. This review can serve as a reasonable starting point for the evolution of a new dynamic, and the SGCC hopes stakeholders embrace it and its message in the spirit of objectivity and collaboration in which it has been researched and developed.

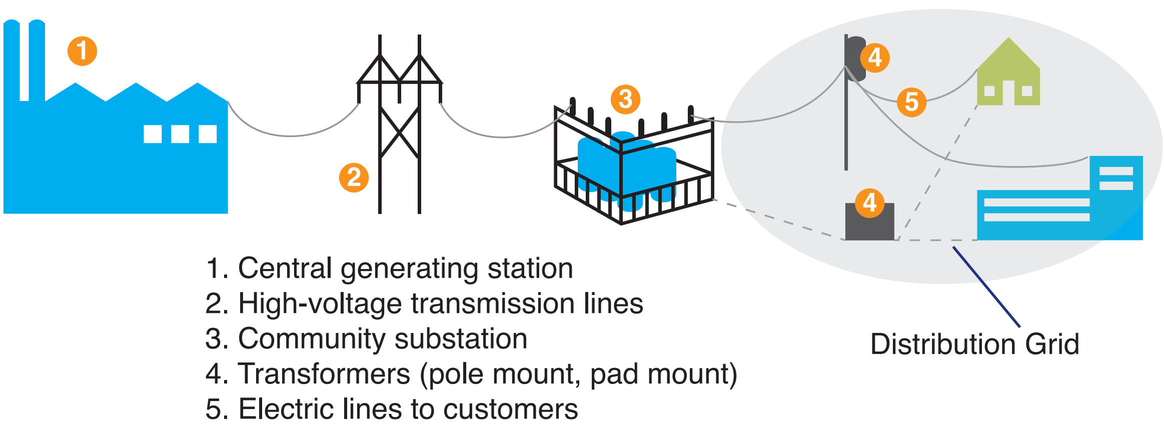
2. INTRODUCTION

What Is a Smart Grid?

The definition of the Smart Grid is presented here only to establish a foundation. What the Smart Grid actually accomplishes – and why stakeholders might want one – is addressed throughout this review.

In recent decades, many industries have grown or perished from the advances made in information and communication technology. However, electric utility systems are still largely operated today in much the same way they were in the early 20th century. Central generating stations produce electric power that is transmitted via high-voltage transmission lines to local community substations. Several primary distribution lines typically extend from each substation, feeding a network of wires and equipment – the distribution grid, or simply "the grid"– that carry electricity to homes and businesses. The distribution grid is the section of the system between the substations and the customers and is the focus of this review.

Figure 3. The distribution grid and its role in the electric utility system



The term "Smart Grid" refers to the computerization of the traditional distribution grid. Until recently, the need to computerize the grid and the communication and information technologies required to do so in a cost-effective manner did not exist. This review will show that the increasing demands society is placing on the grid make computerization more valuable than ever, while advances in technology have made computerization more cost-effective than ever.

How can the traditional grid be computerized? Consider how moving from a traditional grid to a Smart Grid is like moving from a pen and paper to a computer. A computer consists of sensors – such as a keyboard and mouse – that translate and communicate a user's inputs to the computer for information processing and storage. Programs on the computer convert user inputs into spreadsheets or other valuable documents, helping people share information and make decisions. As the inputs change, the shared information and decisions change readily with little or no additional effort. The benefits of using a home computer over pen and paper are fairly clear.

A Smart Grid resembles the computer. Sensors in various locations on the grid collect information on grid operating conditions – including electricity volumes, strengths, and other characteristics – and transmit that information (in some instances continuously and/or instantaneously) to utility computers. These computers can automatically make changes to grid equipment settings without human intervention, continuously and/or instantaneously if needed. In many cases these changes can proactively address issues before they create problems for customers. Information can also be stored for future use, analysis, and decision making by people; for example, in deciding which infrastructure to upgrade based on detailed grid operating data.

In a traditional grid, real-time operating data are not generally available beyond the community substation. To obtain data from the distribution grid, service investigation teams place temporary data-recording devices in select locations, typically only after customer complaints are received. Traditional grid information is limited in timeliness, because it is collected and analyzed long after it has been recorded. Additionally, traditional grid equipment is adjusted only periodically, with many utilities using default “winter” and “summer” settings that suboptimize grid efficiency. Most traditional grid equipment cannot be controlled remotely, so any adjustments generally require the dispatch of service crews.

Why Might Customers Want a Smart Grid?

What does grid computerization offer to utility customers? The computerization of the telephone grid in the late 1980s and early 1990s offers some useful analogies that electric utility customers may be able to appreciate. When the telephone grid was computerized, many new services were suddenly made available to customers, including call forwarding, call waiting, and voice mail. The computerization of the electric grid also offers new capabilities to customers and to utilities, as well. Customers can access electric usage details and money-saving new rate options. Many other new capabilities not immediately apparent to customers are employed by utilities to customers’ benefit – reducing operating costs, improving grid efficiency, reducing service outages, and reliably accommodating customer-owned generation such as photovoltaic (PV) solar and demanding new loads such as electric vehicles. In this review we identify and summarize research completed to quantify the benefits of these capabilities and present it in the context of associated costs.

What Are the Components of a Smart Grid?

There are two primary components of a Smart Grid, which can be implemented more or less independently of one another, although there can be advantages to implementing them together. Each component can be implemented in a number of ways, though the details have been intentionally simplified in this review to facilitate presentation and analysis. These two components are Smart Meters (also known as Advanced Metering Infrastructure, or AMI[8]) and Distribution Automation.

Smart Meters

Smart Meters are digital electric meters that take the place of traditional mechanical meters. Traditional mechanical meters use magnets to measure the electric current flowing through the wires leading into a customer's home; the interaction between the magnets causes a metal disk to spin at a rate proportional to the flow of electric current. The disk revolutions are simply counted by the meter, which is read monthly by a utility employee for billing purposes.

Like a traditional meter, a Smart Meter measures electric current. It also stores information and receives and responds to commands and status inquiries from the utility. Smart Meters are much more accurate than mechanical meters, can detect tampering, and can alert the utility when they lose power. Specific Smart Meter capabilities examined in this report include remote meter reading, time-varying rates, prepayment and remote service disconnect and reconnect, revenue assurance, customer energy management, and service outage management.

Distribution Automation

Distribution Automation involves the section of the Smart Grid between the Smart Meter and the local community substation. Although some parts of many utilities' traditional grids have been automated to a limited degree for some time, Distribution Automation is a much more intensive and focused effort to computerize and/or automate grid operations. Distribution Automation capabilities are largely imperceptible by customers, but research indicates their aggregated benefits are potentially significant. These benefits are presented in this review and include improvements in grid efficiency, grid reliability, and the amount of renewable generation (such as PV solar) the grid can reliably accommodate. Specific Distribution Automation capabilities examined in this report include Integrated Volt/VAr Control (IVVC), fault location and isolation, and renewable generation integration.

8 "AMI" generally refers to the Smart Meters as well as associated communications networks, data storage, and data processing systems; we include all of this when use the term "Smart Meter."

Secondary Research Methods Employed in This Review

The SGCC employed a systematic secondary research method to identify and incorporate reference sources included in this review. We considered two types of research for each Smart Grid capability:

- Controlled studies, which we refer to as "studies"
- Surveys and informed analyses, which we refer to as "estimates"

We gave priority to controlled studies wherever available.

Characterization of Benefits in This Review

We have noted a tendency for many researchers, regulators, and utilities to distinguish between "economic benefits to utility operations" and "economic benefits to customers." In cost-based ratemaking, any and all economic benefits to utility operations eventually flow through to customers in future rate cases. Though the timing of these future rate cases is critical if customers are to promptly receive utility operating benefits in the form of lower rates, this distinction is beyond the scope of this review. Accordingly, we simplify all economic benefits found in available research to gross "per customer per year" benefits in this review (unless otherwise noted).[9]

This "per customer per year" metric is different than "per participant per year," in that some Smart Grid benefits accrue disproportionally to customers who participate in certain programs. For example, customers who participate in time-varying rates receive greater benefits than those who do not. Though we note these where appropriate, we average such benefits across all customers (participants and nonparticipants) to facilitate the comparisons to costs.

In order to capture the variation in actual experience with Smart Grid, we present a range of benefits for many capabilities. Where a range is presented, the low end represents what we refer to as the "Reference Case," and the high end represents what we refer to as the "Ideal Case." The Reference Case is based upon conservative assumptions typical of the average capability deployment today. The Ideal Case, on the other hand, represents "the state of the possible" if benefit drivers are thoughtfully optimized.

With this brief introduction to the Smart Grid as it is typically deployed and how it is organized and presented in this review, let's proceed to examine the customer benefits of Smart Meters and Distribution Automation as found in research completed to date.

9 For a more thorough discussion of this topic, see the discussion on traditional ratemaking in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.

3. DIRECT BENEFITS TO CUSTOMERS

In this section, we will review the research findings available to date on the direct benefits that Smart Grid capabilities can deliver to customers. We will examine the Smart Grid capabilities individually, beginning with those which research indicates offer the greatest potential rate relief or conservation benefits realized on customer bills, including:

- Integrated Volt/VAr Control
- Remote meter reading
- Time-varying rates
- Prepayment programs and remote disconnect/reconnect
- Revenue assurance
- Customer energy management
- Service outage management

Integrated Volt/VAr Control

One of the biggest potential Smart Grid benefits is created by a capability called Integrated Volt/VAr Control (IVVC), which helps utilities optimize the power delivered to customers.

	Economic	Reliability	Environmental	Customer Choice
Integrated Volt/ VAr Control Benefits	\$11.24–32.01 per year	Yes but unquantified	Likely – 372 lbs. CO_2e/year	

Description and Value Propositions of Integrated Volt/VAr Control (IVVC)

Integrated Volt/VAr Control helps utilities more effectively manage voltage and power factor[10] on their distribution lines. IVVC can help lower average voltage on a distribution line while ensuring adherence to minimum voltage standards. By lowering the average voltage, utilities can reduce the energy used by customers without any adverse impact on those customers.

For a more detailed understanding of voltage, power factor (or VAr), and how IVVC works to create economic, reliability, and environmental benefits, readers are encouraged to consult the companion report "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.

10 Power factor is a measure of the productive component of energy in a unit of electricity. A distribution grid power factor of 98 percent or 99 percent is considered excellent performance.

Economic Benefits of Integrated Volt/VAr Control

IVVC can help utilities reduce required capacity during peak demand periods and, if used on a continual basis, reduce overall energy use. We find the economic benefits range from $11.24 to $32.01 per customer per year, depending on how a utility uses IVVC.

The typical IVVC implementation is used by utilities during periods of peak demand. An Xcel Energy Smart Grid study found that IVVC helped reduce distribution line voltage from an average of 121 volts to 116 volts, yielding a 3.25 percent reduction in peak demand.[11]

Utilities can also use IVVC on a continuous basis to reduce the energy used by customer loads throughout the year. A study by Ameren Illinois of its continuous voltage reduction test on two distribution lines found reduced energy use in all seasons of the year regardless of distribution line characteristics.[12]

Table 4. Percent reduction in electricity used for each 1 percent reduction in voltage

Distribution Line Type	Summer	Fall
Urban	0.78%	1.24%
Rural/Urban	0.97%	0.44%

Likewise, the aforementioned Xcel Energy Smart Grid study found that IVVC used on a continuous basis helped reduce customer electricity use by 2.7 percent.[13]

Please see the appendices for details on how we calculated the annual economic benefit from the results of these studies. The Ideal Case benefit is reasonably consistent with the Ohio Public Utility Commission's evaluation of Duke Energy Ohio's deployment, which estimated an annual benefit of $35.87 per customer per year with continuous application of IVVC.[14]

11 Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 62.

12 Electric Power Research Institute, *The Smart Grid Demonstration Initiative 5-Year Update,* August 1, 2013, 5.

13 Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 61.

14 $24.6 million in savings divided by 685,859 customers. U.S. Energy Information Administration, *2011 Annual Electric Power Industry Report,* File 2 (retail revenue, sales, and customer counts by state and class of service). Note: includes bundled (electricity and distribution service) and distribution only customers, Duke Energy Ohio.

Reliability Benefits of Integrated Volt/VAr Control

Although less obvious than service outages, power quality events can cause customer disruptions including flickering lights, tripped circuit breakers, and issues with computers and motors.[15] Although we found no specific research quantifying the degree to which IVVC improved power quality, some anecdotal evidence is available. Xcel Energy's study of its Boulder, Colorado Smart Grid deployment (of 46,000 customers) found that customer power quality complaints fell from an average of 30 annually pre-implementation to zero post-implementation.[16]

Environmental Benefits of Integrated Volt/VAr Control

IVVC offers carbon dioxide emissions reduction benefits in direct relation to electricity usage reductions. Applying U.S. Environmental Protection Agency estimates on carbon dioxide equivalent emissions per kilowatt hour,[17] we estimate IVVC can reduce carbon dioxide emissions by 372 pounds per customer per year when used continuously.

There are also likely environmental benefits from peak load reduction, as the use of less efficient peaking plants (generally single-cycle natural gas plants) can be replaced with more efficient plants designed for intermediate use (generally combined-cycle natural gas plants). We found no research to quantify the size of this environmental benefit.

Drivers of Integrated Volt/VAr Control Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Integrated Volt/VAr Control	X			X

Utilities that perform relatively poorly on optimizing power factor and average voltage will likely experience greater improvements by employing IVVC than utilities that perform relatively well on these measures. Additionally, the marginal cost of generation and cost of "peaker" generation plant construction impact the economic benefit available; those areas that have higher costs will experience higher benefits.

As noted above, using IVVC on a continual basis – rather than only during periods of peak demand – can drive substantial economic and environmental benefits.

15 Electric Power Research Institute, *The Cost of Power Disturbances to Industrial and Digital Economy Companies* (study conducted by Primen for the EPRI), June 29, 2001, 4-3.

16 Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 85.

17 1.22 lbs. CO_2e/kWh.

Remote Meter Reading

Among other capabilities, Smart Meters offer utilities the ability to implement remote meter reading. Remote meter reading offers significant reductions in utility operations costs, particularly for those utilities that have not already implemented remote meter reading through other means prior to Smart Meter installation.

	Economic	Reliability	Environmental	Customer Choice
Remote Meter Reading Benefits	$13.68–23.92 per year		Possible	

Remote Meter Reading Description and Value Creation

Remote meter reading enables a utility to obtain electric usage data from meters for billing purposes without sending personnel to read each meter. This avoids the expense, traffic, and potential safety issues (for example, from slips, dog bites, or auto accidents) of sending meter readers to manually read electric meters every month or for "special" meter reads, such as when a customer moves.

In addition to benefits related to labor and vehicle savings, Smart Meter installations can significantly reduce the amount utilities spend on replacing worn traditional meters, at least until those meters begin to age.

Economic Benefits of Remote Meter Reading

We find the economic benefits of remote meter reading to vary between $13.68 and $23.92 per customer per year, depending chiefly on utility operating characteristics prior to implementation. For the Reference Case, we assume that a utility has already automated monthly meter reads via a capability called Automated Meter Reading (AMR), and therefore include only reductions in special meter reads and non-labor cost savings. The Ideal Case assumes that all meter reads – including routine monthly reads – were previously completed manually.

A study by the Ohio PUC of the benefits of Duke Energy's Ohio Smart Grid deployment found a savings of $10.18 per customer per year in special meter reads.[18] The same study also found that reductions in non-labor expenses related to reductions in meter testing, repair, and replacement amounted to $3.50 per customer per year,[19] bringing the total Reference Case economic benefits to $13.68 per customer per year.

18 $6.98 million annual savings divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 80.

19 $2.4 million annual savings divided by 685,859 customers. Ibid., 83–84.

The Ohio PUC study indicated savings of $10.24 per customer per year in routine monthly meter reads.[20] Hence, in the Ideal Case – a utility moving from fully manual to fully automated meter reading – customer economic benefits total $23.92 per customer per year.

Drivers of Remote Meter Reading Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Remote Meter Reading	X		X	

In addition to whether a utility has previously implemented AMR, other operating characteristics serve as drivers of potential benefits. For example, a rural utility with low customer density will have higher pre-implementation meter reading costs than an urban utility with a high customer density. Duke Energy Ohio's service territory, which includes Cincinnati, its suburbs, and surrounding rural areas, is fairly typical with respect to customer density.

Additionally, rules surrounding customer move outs and move ins impact the available benefits. When responsibility for a particular premises' electric bill passes from one occupant to another, some utilities read the meter on the move-out date, while others simply prorate a month's usage based on the move-out date. Those utilities reading the meter on customers' move-out and move-in dates have much higher meter-reading costs than utilities avoiding such reads through proration, and therefore experience greater savings from remote meter reading.

Finally, rules around how customers who opt out of Smart Meter installation are treated can impact the available benefits. Every customer who opts out of Smart Meter installation increases a utility's meter-reading costs. In some cases, whether by policy or by regulation, utilities do not charge the full incremental costs of manual meter reading to those customers who refuse Smart Meters or associated remote communications capabilities.

When the full incremental cost of manual meter reading is not charged to those customers who opt for it, the remaining customers must pick up the difference. Several issues contribute:

- The fixed costs of operating and maintaining two meter-reading systems is significantly higher than maintaining a single meter-reading system.
- The variable incremental cost of manually reading the meters of a limited number of customers spread out over a wide service territory is likely much higher on a "per manual read customer" basis than the meter-reading costs per customer prior to Smart Meter installation.

20 $7.02 million annual savings divided by 685,859 customers. Ibid., 78.

Those utilities that do charge a fee for manual meter reading generally charge a one-time set-up fee (generally \$20–\$75) and an ongoing monthly charge (generally \$10–\$25).[21] The District of Columbia PSC has ordered an estimate, not yet completed as of this review's publication, of PEPCO's manual meter-reading costs post-AMI deployment (Formal Case 1056).

Time-Varying Rates

By recording both a customer's electric consumption and the day and time when it is consumed, Smart Meters facilitate time-varying rate offerings. However, the drivers of available benefits of time-varying rates are among the most complex of the Smart Grid capabilities discussed in this report, and require strong collaboration between utilities, regulators, and customers to optimize.

	Economic	Reliability	Environmental	Customer Choice
Time-Varying Rates Benefits	\$2.00–19.98 per year		11–110 lbs. CO_2e/year	YES

Time-Varying Rate Description and Value Creation

Because most utility customers have only experienced flat-rate pricing, they do not realize that the cost of electricity varies by the time of day or day of the year. Electricity is, however, subject to the same laws of supply and demand that drive the pricing of other goods and services. Utilities pay more for electricity during periods of peak demand – such as a hot summer afternoon with a high demand for air conditioning – and less during off-peak periods, such as a cool fall night.

The flat-rate pricing for electricity that most consumers are familiar with is a blended average of the actual cost of electricity, and it obscures the variance in electricity costs from consumers. This causes what economists call "inefficiency," because customers have no incentive to shift their usage from peak to non-peak times.

Time-varying rates reduce or eliminate this inefficiency by providing customers with an opportunity to reduce their electric bills by shifting their usage from peak to non-peak times. This usage shifting can even create benefits for customers who do not participate in time-varying rates because utility investments in new generation plants – for which all customers pay – can be delayed or avoided.

21 Will McNamara, *AMI Opt Out: Policies, Programs, and Impact on Business Cases* (white paper), West Monroe Partners, 2012, 11.

Economic Benefits of Time-Varying Rates

The economic benefits of time-varying rates consist of two components. The first is a result of the shift in when customers participating in time-varying rates consume electricity. The second is a result of participating customers reducing their overall electricity use. In total, and depending on the variables described in the next section, these benefits range from $2.00 to $19.98 per customer per year.

There are many types of time-varying rates, each with its own pros, cons, and potential benefits.[22] Controlled studies indicate 10 percent to 30 percent reductions in electricity demand at a given point in time for most types of time-varying rates, with certain types generating point-in-time reductions as high as 40 percent or even more.[23]

Research also indicates that most customers participating in time-varying rates not only shift usage from high-priced to low-priced periods, they also reduce electric use overall. This is due in part to the fact that customers participating in time-varying rates are more aware of their overall energy usage, and in part because reductions in use do not always require a commensurate increase. For example, a customer who turns off lights during a peak period has no need to turn on more lights than they otherwise would during a nonpeak period. A survey of available research on the conservation impact of time-varying rates indicates a 4 percent reduction in overall electric use is likely among customers participating in such rates.[24]

Table 5 summarizes economic benefits from time-varying rates for the Reference Case and Ideal Case. Please see the appendices for more detail on the assumptions and calculations.

Table 5. Summary of economic benefits from time-varying rates

	Reference Case	Ideal Case
Customer Participation	2%	20%
Peak Demand Reduction	$1.38	$13.83
Energy Conservation	$0.62	$6.15
Total	$2.00	$19.98

22 For more information, see the discussion on time-varying rates in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from SGCC.

23 Ahmad Faruqui and Jenny Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity." March 12, 2012.

24 Chris King and Dan Delurey, "Efficiency and Demand Response: Twins, Siblings, or Cousins?" *Public Utilities Fortnightly,* March 2005, 55.

It is important to note these are the total benefits to an entire customer base for a utility offering time-varying rates under these assumptions. Depending on the details of specific time-varying rate designs, these benefits are split in some manner between the customers who participate in the rate (who obtain direct rewards by participating) and those who do not (and simply enjoy the lower costs associated with delayed or avoided investments in the form of lower overall rates). This means customers who participate in these rates and shift their usage are likely to receive much more than $2.00–$19.98 in benefits annually, and customers who do not will receive much less.

Environmental Benefits of Time-Varying Rates

Time-varying rates offer carbon dioxide emissions reduction benefits in direct relation to the conservation effect. Applying U.S. Environmental Protection Agency estimates on carbon dioxide equivalent emissions per kilowatt hour, we estimate time-varying rates can reduce carbon dioxide emissions by between 11 pounds and 110 pounds per customer per year.[25]

Customer Option Benefits from Time-Varying Rates

As described in this section, time-varying rates certainly offer customers an opportunity to reduce their electric bills. Lower electric bills and/or increased control over them are likely to increase the satisfaction of participating customers.

Drivers of Time-Varying Rate Benefits

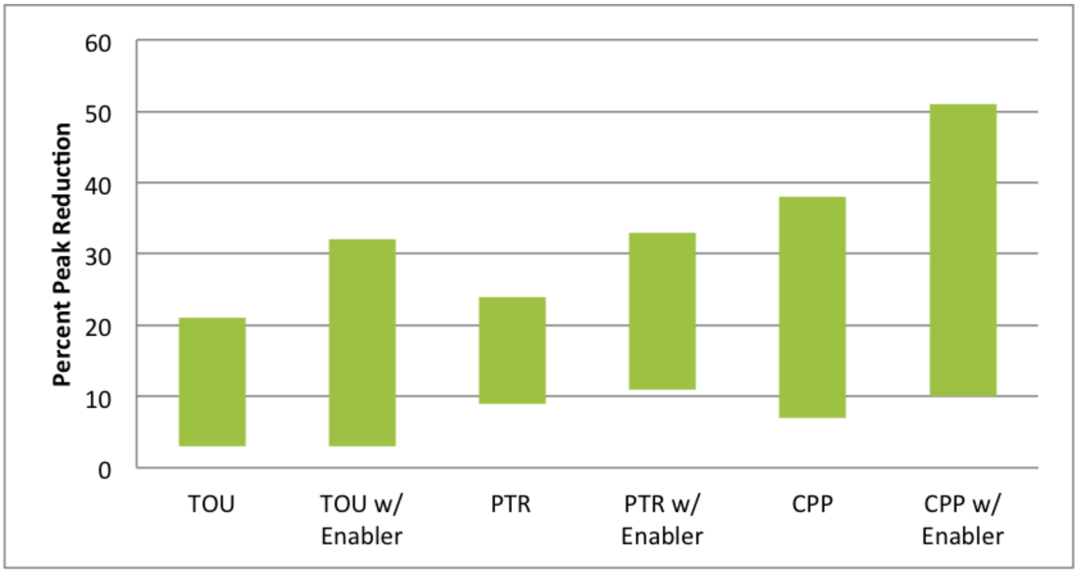
	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Time-Varying Rates		X		X

The single biggest driver of the available benefits of time-varying rates is customer participation rates. There are a number of actions stakeholders can take to increase customer participation rates, though many of them – including changing misperceptions that customers may hold and addressing structural winners and losers – can be challenging. For more detail, please refer to the “Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers,” available from SGCC.

The second biggest driver is the extent to which customers shift and/or reduce their electric usage. Higher variations between off-peak and on-peak pricing lead to higher shifting behaviors. Enabling technologies such as programmable thermostats can also drive greater shifting. See Figure 4 for a summary of different rate designs and the range of usage shifting for each.

25 See calculations in the appendices.

Figure 4. Summary of time-varying rate impact study results[26]



Notes to Figure 4 (highest and lowest results removed from each study type):
TOU: Standard Time-Of-Use rate design; *n* = 37 studies.
TOU w/Enabler: TOU with enabling technology; *n* = 14 studies
PTR: Peak-Time Rebate rate design; *n* = 12 studies
PTR w/Enabler: PTR with enabling technology; *n* = 17 studies
CPP: Critical Peak Price rate design; *n* = 23 studies
CPP w/Enabler: CPP with enabling technology; *n* = 21 studies

Prepayment Programs and Remote Disconnect/Reconnect

Although a few utilities have offered prepayment programs using traditional meters, Smart Meters make such programs significantly easier to implement. Smart Meters' real-time, two-way communications and remote service disconnect/reconnect capabilities enable more cost-effective administration of such programs by utilities and simplify participation for customers.

	Economic	Reliability	Environmental	Customer Choice
Prepayment Program Benefits	\$7.82–19.56 per year		30–76 lbs. CO_2e/year	YES

26 Ahmad Faruqui and Jenny Palmer, "The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity." March 12, 2012.

Prepayment Program Description and Value Creation

Most customers are billed and pay for electricity after they use it. However, some utility customers appear to prefer to pay as they go. Smart Meters enable utilities to more easily offer such programs, which drive reductions in energy use, increases in customer satisfaction, and decreases in utility operating costs.

Research indicates that customers who participate in prepayment programs use less electricity after signing up for the program than they did before. Almost all prepayment programs involve some sort of display informing participants of their account balance, generally expressed in days of electricity left based on current usage rates. These displays serve as a continuous feedback mechanism, making customers constantly aware of the rate at which they are using electricity. As discussed in the "Customer Energy Management" section, feedback is a critical component of energy conservation.

Electric rates are set at a level sufficient to cover utility operating expenses, including those related to billing and collection. Prepayment programs theoretically should reduce several types of billing and collection expenses, including the cost of printing and mailing bills, bad debt write-offs, service visits, and interest expense. Of these, the reduction in service visit costs is by far the most significant, as Smart Meters' remotely controlled disconnect/reconnect switches alleviate the need for service visits to collect or prompt payment on past-due accounts, post notices, disconnect service, or reconnect service.[27] Utility interest expenses are reduced with prepayment, as utilities need not borrow money to fund the difference between the time traditional billing customers use electricity and the time they pay for it.

Economic Benefits

The economic benefits from prepayment programs stem from the conservation effect of program participants – which accrue directly to participants – and in the reduced billing, collection, and interest expense such programs produce. We find a total benefit of $7.82–19.56 per customer per year from these two factors.

A controlled study conducted upon the introduction of a prepayment program by the Oklahoma Electrical Cooperative finds a weather-adjusted 11 percent reduction in electric usage by prepayment customers after joining the program.[28] Additionally, the utility operating one of the most extensive and longest-running prepayment programs in the U.S., the Salt River Project in Arizona, estimates its prepayment customers reduce electric use by 12 percent after joining.[29]

27 This is a particularly expensive proposition, as two or three truck rolls with a variable cost of $35–$50 each can be required to post notices, disconnect service, and reconnect service to collect a single $100 payment (for example) on a past-due account.

28 Michael Ozog, *The Effect of Prepayment on Energy Use* (Integral Analytics, Inc. research project commissioned by the DEFG Prepay Energy Working Group), March 2013, 2.

29 Institute for Energy and the Environment, Vermont Law School, *Salt River Project: Delivering Leadership on Smarter Technology & Rates,* June 2012, 18.

Long-standing programs, such as those in the United Kingdom and at the Salt River Project in the U.S., indicate participation rates as high as 13 percent[30] and 12.5 percent,[31] respectively. Because it can take decades for a prepayment program to reach these participation levels, we use a 2 percent participation rate to calculate economic benefits in the Reference Case and a more aggressive 5 percent participation rate for the Ideal Case. The conservation effect using these assumptions ranges from $1.69 to $4.23 per customer per year. Recall that these are benefits spread across the entire customer base for the purposes of comparison to costs. In reality, only participating customers receive the conservation benefit, and it can be significant. Given these assumptions, the average benefit per participant indicated is $84.62 annually. Please see the calculations in the appendices for more detail.

We find no controlled studies quantifying billing, bad debt, collection, and interest expense reductions from prepayment programs. A leading vendor of prepayment program software estimates reductions of $357 to $377 in bad debt, billing, and collection expenses (particularly service truck rolls) per participant per year,[32] while the Salt River Project estimated these savings at $300 per participant per year in 2006.[33] Using industry averages, we estimate an additional annual benefit of $6.65 per participant in reduced interest expense. These savings equate to $6.13 to $15.33 per customer per year for the Reference Case and Ideal Case, respectively. Please see the appendices for additional detail on these calculations.

Environmental Benefits

The environmental benefits associated with prepay programs are primary due to the conservation effect demonstrated by program participants. We calculate 30 pounds annual carbon dioxide equivalent reduction per customer in the Reference Case and 76 pounds annual carbon dioxide equivalent reduction per customer in the Ideal Case.[34]

We find no research quantifying the environmental impact of reductions in service calls avoided through Smart Meter–enabled remote disconnect and reconnect capabilities. As these service calls are made in vehicles, there are likely reduced emissions associated with mileage reductions. However, these reductions are likely to be small relative to the conservation effect.

30 Department of Energy and Climate Change, *U.K., Smart Metering Implementation Programme: Data Access and Privacy,* April 2012, 25.

31 Chris Villarreal, *A Review of Prepay Programs for Electric Service,* (policy paper of the California Public Utilities Commission, Policy and Planning Division), July 26, 2012, 4.

32 John Howatt and Jillian McLaughlin, *Rethinking Prepaid Utility Service: Customers At Risk* (white paper by the National Consumer Law Center), June 2012, 14.

33 R.W. Beck, *Prepaid Electric Service* (white paper), March 2009, 10.

34 Please see calculations in the appendices.

Customer Choice Benefits

In some cases, consumers may be signing up for prepay due to an inability to qualify for post-pay; however, research indicates that customers who participate in prepayment programs prefer them to post-use billing and payment. Forty-six percent of prepayment program participants give the Salt River Project a 9 or 10 rating on a 10-point "value received considering the amount you pay" score, compared to 37 percent of non-participating customers.[35] A survey of prepayment program participants in Arizona and Texas finds more than half (62 percent) indicate being "very satisfied" with their programs, while an additional 29 percent are "somewhat satisfied" – totaling 91 percent.[36] Asked if they are likely to recommend prepay electric service to family and friends, the same survey finds that 63 percent were "very likely" to recommend doing so, while an additional 25 percent were "somewhat likely."

These results are likely due to the assistance these programs provide in helping customers manage electricity costs. "Control over energy costs and budget" is the reason most respondents in the Arizona/Texas survey cited for participating in prepayment programs.[37]

Drivers of Prepayment Program Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Prepayment Program	X	X		X

The largest drivers of prepayment program benefits are the customer participation rate and the size of a utility's spending on bad debt, billing, collection, and interest expenses.

35 Bernie Neenan, *Paying Upfront: A Review of Salt River Project's M-Power Prepaid Program* (Technical Update 1020260), Electric Power Research Institute, October 2010, 4-3.

36 EcoAlign, *Prepay Energy's Pathway to Customer Satisfaction and Benefits* (results of consumer research), February 2012, 4.

37 Ibid., 3.

Revenue Assurance

Smart Meters help utilities reduce what they call "unaccounted-for losses." "Lost" electricity is electricity generated and distributed, but not billed, to customers. Traditional cost-based ratemaking includes such losses in customer rates. (To understand the mechanics, interested readers are encouraged to review the discussion on traditional ratemaking in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.)

Lost revenues result from three primary sources: metering errors, theft, and line losses. Here we will address how Smart Meters defend against metering errors and theft.

	Economic	Reliability	Environmental	Customer Choice
Revenue Assurance Benefits (Reference Case and Ideal Case)	$3.00 per year			

Revenue Assurance Description and Value Creation

Smart Meters are both much more accurate than traditional mechanical meters and offer theft detection capabilities unavailable in traditional meters. We will address these capabilities individually.

Meter Accuracy

State regulators generally prescribe the minimum accuracy standards for meters for the investor-owned utilities they regulate, typically within 2 percent (high or low) of actual electric current flow. A study by the Ohio Public Utilities Commission of Duke Energy's Ohio Smart Meter deployment found that the analog meters being replaced were accurate to within 0.53 percent of actual use.[38] Manufacturers of most Smart Meters warrant accuracy to within 0.5 percent of actual use, a four-fold increase in accuracy over most states' regulatory rules. The Ohio PUC study found Smart Meters to be accurate to within 0.167 percent,[39] a threefold increase in accuracy over the old analog meters. Additionally, this study found that traditional meters were much more likely to be slow than Smart Meters. A customer with a slow meter is charged for less electricity than he or she is actually using. All other customers make up for these customers' underpayments in the form of slightly higher rates.

38 "Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 21.

39 Ibid.

Theft Detection

All customers pay the price for electricity theft in the form of higher rates. Smart Meters can help utilities identify electricity theft and catch it earlier, to the benefit of all customers. Each Smart Meter is equipped with sensors alerting the utility to meter removal – even if it is only momentary – or to the presence of magnets, both of which are not detected by traditional meters. However, the sensors do not help in cases in which a meter is completely bypassed. This is where Smart Meters' capability to measure when power is used can help.

Most customers who steal electricity through meter bypass (literally, with wires) do so on a temporary basis. For example, they might only bypass the meter for three weeks out of every four, allowing some usage to register so as not to raise utility suspicion. These customers simply repeat the on-off bypass pattern each month. Traditional meters, which only count the spins of the dial since the last meter read, cannot catch this type of activity. However, utilities with Smart Meters are developing and applying review algorithms to detect such patterns in the detailed usage data Smart Meters offer.

Economic Benefits of Revenue Assurance

The total revenue assurance economic benefit amounts to $3.00 per customer per year, consisting of $1.56 in meter accuracy[40] and $1.44 in theft detection benefits.[41] Of note, the theft detection benefit is net of detection and prosecution costs.

Drivers of Revenue Assurance Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Revenue Assurance	X			X

It is likely that the greater the average age of the traditional meters that are replaced, the greater the improvement in accuracy and the greater the resultant benefit. In addition, electric rates have an impact. The higher the price per unit of use, the greater the resulting underbillings for a given level of meter error will be. Ohio electric rates are about average compared to the rest of the U.S.[42]

We make no distinction between the Reference Case and the Ideal Case for the revenue assurance benefit, as clear drivers such as customer participation rates are not available to use as a basis for distinguishing between them.

40 $1.07 million in annual revenue divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 85.

41 $990,000 annual benefit divided by 685,859 customers. Ibid, 82.

42 Ohio is in the middle quintile, with 40 percent of states reporting higher rates, and 40 percent reporting lower rates. U.S. Energy Information Administration, "Table 5A. Residential Average Monthly Bill by Census Division, and State 2011," Line 66 (U.S. Total), Column D ("Price").

Customer Energy Management

A traditional electric bill indicates how much electricity a customer uses over a month. Smart Meters record how much electricity a customer uses every 10 or 15 minutes, information that many utilities make available to customers so that they can better manage and reduce their electric use.

	Economic	Reliability	Environmental	Customer Choice
Customer Energy Management Benefits	\$0.77–1.92 per year		14–34 lbs. CO_2e/year	YES

Customer Energy Management Description and Value Creation

Many customers have had access to electric bill histories via a secure utility web page for some time. Some utilities even provide comparisons to anonymous neighbors' historical usage data to help customers benchmark their usage. However, the detailed information from Smart Meters takes the concept of energy usage feedback to a whole new level.

Smart Meters enable utilities to provide access to detailed historical usage data (in 10- or 15-minute intervals) and/or real-time usage data. Most utilities installing Smart Meters offer customers access to detailed historical usage data via a secure Internet website or a smartphone application, generally on a one-day lag. Some utilities also offer their customers access to real-time data via an in-home display, web portal, or smartphone app. This latter capability, in particular, has a demonstrated impact on electricity consumption by providing customers with immediate feedback on their usage and the impact of changes they make to their usage.

Economic Benefits of Customer Energy Management

A survey of electric usage display impact research in Canada found an average 7 percent conservation effect.[43] A similar survey covering several decades of research worldwide found a range of 5 percent to 15 percent in conservation effect from direct, real-time usage feedback.[44] Although these are significant decreases in usage, adoption of real-time energy usage displays is likely to be limited for some time.[45] As a result, and using adoption rates of 2 percent to 5 percent for the Reference Case and Ideal Case, respectively, we find the economic benefits from customer energy management to range from $0.77 to $1.92 per customer per year. As with many other participation-dependent Smart Grid capabilities, these economic benefits are typically much higher for customers using real-time data, and minimal or nonexistent for customers not using them.

Environmental Benefits of Customer Energy Management

Environmental benefits accrue directly from the conservation effect of customer energy management. We calculate 14 to 34 pounds per customer per year in carbon dioxide equivalent emissions reduction.[46]

Drivers of Customer Energy Management Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Customer Energy Management		X		X

The number of customers using real-time usage data is a critical driver of energy management benefits. Research indicates that coupling this information with incentives such as those offered in time-varying rate or prepayment programs can drive greater benefits than either incentives or feedback on their own.[47] Figure 4 summarizes the results of multiple studies, which collectively indicate a greater impact when an incentive program is paired with an enabling technology, such as a real-time energy usage display device.

43 Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence" (meta-analysis), *Energy* 35, 2010, 1.

44 Sarah Darby, "The Effectiveness of Feedback on Energy Consumption" (literature review), University of Oxford Environmental Change Institute, April 2006, 3.

45 Janelle LaMarche, et al, "Home Energy Management: Products and Trends" (white paper), Fraunhofer Center for Sustainable Energy Systems, 1.

46 Please see calculations in the appendices.

47 Ahmad Faruqui, Sanem Sergici, and Ahmed Sharif, "The Impact of Informational Feedback on Energy Consumption – A Survey of the Experimental Evidence" (meta-analysis), *Energy* 35, 2010, 5.

Service Outage Management

Smart Meters' instantaneous communications capabilities change the way utilities learn of and respond to service outages, reducing service restoration time and cost. Economic benefits are realized when utilities use this capability to avoid unnecessary investigations of outages reported by customers in error.

	Economic	Reliability	Environmental	Customer Choice
Service Outage Management Benefits (Reference Case and Ideal Case)	$1.18 per year	4.5% outage duration reduction		

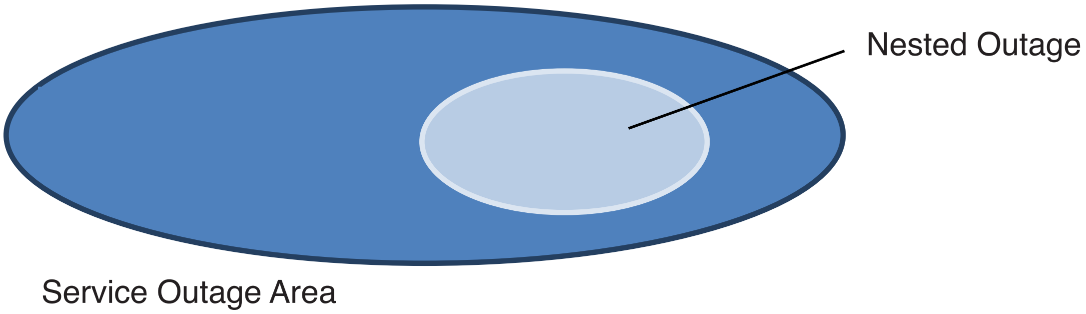
Service Outage Management Description and Value Creation

Utilities have traditionally learned of all but the largest service outages through reports from customers. In fact, an entire software industry segment – outage management systems – has arisen to help utilities log customer outage reports and analyze them in an attempt to determine the extent, nature, and general location of service outages. Unfortunately, customer reports are inherently unreliable; only a small percentage of customers impacted by an outage report it to their utility. Small outages (of one to five homes) can go on for hours before being reported – there is a higher likelihood that no customer is home to detect them – as can outages occurring from midnight to 5 a.m., when most customers are sleeping.

Most Smart Meter models offer a "last gasp" capability, which reports to the utility when the supply of power to the meter is lost. This eliminates or greatly reduces a utility's reliance on customer reports to identify and assess outages. Used in combination with an outage management system, "last gasp" helps utilities learn of outages more quickly and more accurately determine their extent, nature, and general location.

Smart Meters can also respond to utilities' status inquiries. Generally called meter "pinging," a utility can query any Smart Meter to see if it has power. This capability is particularly useful to manage "nested outages" where one outage masks the presence of another, as shown graphically in Figure 5.

Figure 5. Representation of "nested outages"



In a traditional grid, restoration personnel can be unaware of the existence of the nested outage. They repair the larger fault and mistakenly assume that power has been restored to the entire area. Only when customers complain does the utility operating a traditional grid recognize the nested outage. Utilities have traditionally managed this phenomenon by phoning customers to inquire if their power has been restored – a time-consuming, costly, and increasingly ineffective process. With Smart Meter pinging, utilities quickly and accurately verify power restoration and identify nested outages without relying on inbound or outbound telephone calls.

There are concomitant operational benefits that save money. Utilities spend dramatically less manpower (generally overtime and contract labor) understanding the extent and nature of an outage and virtually eliminate the use of resources to verify power restoration.

Additional operational benefits are available from Smart Meter pinging capabilities through reductions in "OK on arrival" service visits. Utilities receive large numbers of outage reports that are not their responsibility to fix, such as when a home's circuit breaker has tripped. With Smart Meter pinging, a utility can instantly and remotely determine if an individual meter has power and help the customer restore power without having to send an employee to investigate.

Service Outage Management Economic Benefits

We find a total expense reduction of $1.18 per customer per year from Smart Meter enhancements to outage restoration and reductions in "OK on arrival" service visits. An evaluation of Duke Energy's Ohio Smart Meter deployment by that state's public utilities commission found that Smart Meters reduce labor costs for power restoration by $1.06 per customer per year.[48] An Xcel Energy study finds the ability to avoid unnecessary "OK on arrival" service visits via meter pinging saves $0.12 per customer per year in operating expenses.[49]

48 $730,000 annual savings divided by 685,859 customers. Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment,* June 30, 2011, 87–90.

49 $2,700 annually divided by 23,000 customers with Smart Meters. Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 63.

In addition to these direct cost savings, increased electric service reliability can deliver productivity benefits to local economies. In this review we calculate an indirect economic productivity benefit of $1.80 per customer per minute, and therefore $8.82 in indirect benefits annually from improved service outage management.[50] For more information, see "Estimating the Economic Productivity Impact of Service Outages" in the appendices.

Service Outage Management Reliability Benefits

In a study of the reliability benefits of Smart Meters, Xcel Energy found that outages are reported more quickly, and that the nature and extent of outages – including nested outages – are estimated more accurately. These capabilities produced an average reduction in service outage durations of 4.9 minutes per customer per year,[51] a 4.5 percent decrease in customer minutes per year versus the baseline of 109 minutes per year.[52]

Drivers of Service Outage Management Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Service Outage Management	X			

Not all utilities have designed their Smart Grids to take advantage of Smart Meters' last gasp capabilities. These utilities typically use sensors located throughout the distribution grid in place of Smart Meters to detect outages. These sensors are not as effective as individual Smart Meters at detecting small (one- to five-home) outages, though utilities employing such an approach point out that sensors can be cheaper than Smart Meters to install (due to smaller quantities) and that large outages are a greater priority than small outages.

We make no distinction between the Reference Case and the Ideal Case for the service outage management benefit, as clear drivers such as customer participation rates are not available to use as a basis for distinguishing between the Reference Case and Ideal Case.

50 Indirect benefit per customer/yr = minutes per customer/yr x value/minute = 4.9 x $1.80 = $8.82.

51 224,000 minutes annually divided by 46,000 customers. Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 81–83.

52 "Xcel Energy, *Xcel Energy Quality of Service Monitoring and Reporting Plan* (Boulder region, 2008 CAIDI total, including ordinary distribution interruptions only), April 18, 2013.

4. INDIRECT BENEFITS TO CUSTOMERS AND COMMUNITIES

In Section 3 we examined the direct benefits available from Smart Grid capabilities offering potential rate relief or conservation benefits on customers' bills. In this section we will turn our attention toward Smart Grid capabilities offering indirect benefits to customers and communities, focusing on electric distribution reliability and renewable generation integration.

Fault Location and Isolation

In the section on service outage management we discussed how the Smart Grid, and in particular Smart Meters, help utilities learn of outages faster, estimate the scope of outages more quickly and with less labor, and reduce the cost of false outage reports. Distribution Automation capabilities – specifically, fault location and isolation – help utilities find and fix faults more quickly and isolate fault impacts to fewer customers.

	Economic	Reliability	Environmental	Customer Choice
Fault Location and Isolation Benefits		22.3 minutes/ year		

Description and Value Propositions of Fault Location and Isolation

Fault Location

Whereas Smart Meters can provide general information on the nature and extent of service outages, fault location capabilities provide repair crews with exact fault locations. In a traditional grid situation, distribution control centers will analyze the locations of customers calling about outages to try to narrow down the location of a fault to a particular distribution line for repair crews. Repair crews will then drive along the distribution line until a sign of trouble is encountered (for example, a downed line or power pole, tripped pole-mounted fault indicator, or blown fuse). Underground lines present a particular challenge because no physical damage is apparent, and repairs crews must physically examine multiple equipment vaults or cabinets to identify locations by a process of elimination. All of these efforts take a lot of time.

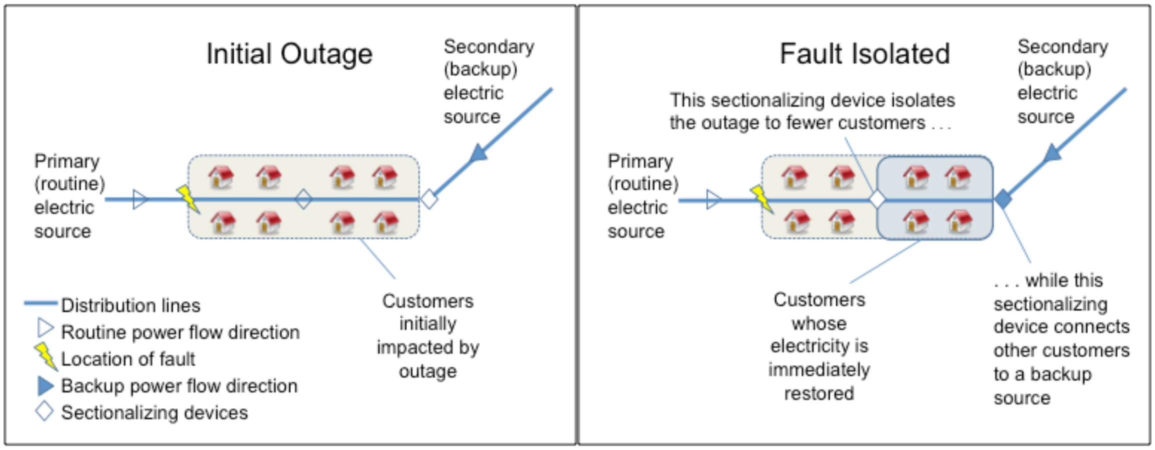
With fault location capabilities, line sensors on either side of the fault measure the time it takes for a pulse sent toward the fault to be reflected back from the fault. Software combines the timing of the reflection with information on other distribution line characteristics to calculate the distance of the fault from each sensor. The distribution control center can then direct a repair crew to within about one hundred feet of a fault.

Fault Isolation

Another type of Distribution Automation capability aimed at improving reliability is called fault isolation. Many people refer to this capability as "self healing," though this is a bit of a misnomer. Faults must still be repaired ("healed"); fault isolation simply reduces the number of customers impacted by any given fault. Although utilities manually execute fault isolation where the hardware is in place today, Distribution Automation significantly increases the geographic extent and level of automation for fault isolation.

In a Smart Grid, several types of devices on a distribution line can serve to isolate a section of distribution line on which a fault has occurred. These devices, generally called sectionalizing devices, operate automatically by sensing a reduction in electric current. Electric service for customers located within the isolated section will not be restored until the fault is repaired. However, once the section is cordoned off, Distribution Automation reroutes power from a nearby distribution line to customers who lie on the other side of isolated section. Figure 6 shows an initial outage, outage isolation, and immediate service restoration to customers beyond the isolated section.

Figure 6. Representation of fault isolation



Reliability Benefits of Fault Location and Isolation

In Xcel Energy's study of its Boulder, Colorado Smart Grid implementation, findings indicate a total reliability improvement of 22.3 minutes per customer per year from fault location and isolation. Xcel Energy found that fault location reduced the duration of outages by 3.5 minutes per customer per year.[53] The same study finds fault isolation to deliver 28,125 customer minutes of outage reductions annually on each of the two distribution lines with the capability. Assuming an average customer count of 1,500 per distribution line, this capability delivers an additional 18.8 minutes of outage reduction per customer per year.[54]

Translating Reliability Improvements into Indirect Economic Benefits

We estimate the economic productivity impact of outages at $1.80 per minute. (See "Estimating the Economic Productivity Impact of Service Outages" in the appendices for more information.) By multiplying the 22.3-minute outage reduction by avoided economic productivity impact of $1.80 per minute, we estimate $40.14 in indirect economic benefits per customer per year.

Drivers of Fault Location and Isolation Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Fault Location and Isolation	X			

The more outages a utility has prior to Smart Grid deployment, the greater the reliability improvement that fault location and isolation capabilities are likely to deliver. Reliability benefits are also likely to increase as the number of sensors and sectionalizing devices placed on a distribution line grows.

53 160,000 customer minutes divided by 46,000 customers. Xcel Energy, *SmartGridCity™ Demonstration Project Evaluation Summary* (report to the Colorado Public Utilities Commission), December 14, 2011, 80.

54 Customer counts per distribution line vary widely by utility and within a utility. Anything between 500 and 2,500 customers per distribution line can be considered typical. We chose 1,500 as an estimate. Ibid., 78

Renewable Generation Integration

The degree to which the traditional distribution grid can integrate renewable generation without harm to reliability and efficiency is finite. In this section we will discuss the primary challenges renewable generation presents to grid operators. We will also describe how Smart Meter and Distribution Automation capabilities can help manage the challenges, thereby increasing the amount of renewable generation that can be reliably and efficiently integrated.

	Economic	Reliability	Environmental	Customer Choice
Renewable Generation Integration Benefits	Possible	Likely	Likely	YES

Description and Value Propositions of Renewable Generation Integration

Renewable generation presents two challenges to grid operators. One is the intermittent nature of the most popular types of renewable generation (wind and solar), as they are only productive when the wind is blowing or the sun is shining. Intermittency is an issue with which grid operators must contend regardless of whether renewable generation is centrally located (typically in massive wind farms or solar generating stations that cover thousands or acres) or connected to the distribution grid (for example, PV solar panels mounted on homes). The other challenge relates to the interaction of renewable generation with the distribution grid to which it is attached. The Smart Grid can help address both challenges, with Smart Meters playing a role in intermittency and Distribution Automation helping to reliably and efficiently accommodate customer-sited renewables. We will examine each individually.

Intermittency Challenges

By enabling time-varying rates and customer energy management, Smart Meters allow utilities to engage customers in helping to balance the supply and demand of electricity. When wind and solar generation make up a large portion of a region's generation portfolio, unanticipated changes in wind speed or cloud cover can unexpectedly change electricity supply. Time-varying rates, and particularly dynamic rates that change hourly based on supply and demand, serve to send a price signal to customers about supply and demand.

With dynamic pricing, rates rise in concert with supply reductions or increases in demand and fall in concert with excess supply. Smart Meter–enabled customer energy management systems can work along with dynamic pricing, automatically managing air conditioning and appliance operation within a customer's prespecified instructions as rates rise and fall. This helps provide the flexibility required to reliably accommodate greater levels of renewable generation.

Customer-Sited Generation Technical Challenges

Customer-sited generation, including renewable generation, presents specific technical challenges to distribution grid operators. These issues are readily manageable at low levels relative to a grid's local capacity, but increase in complexity as customer-sited renewable generation levels grow. Customer-sited generation introduces variability that the distribution grid was not designed to handle, reducing grid efficiency and reliability in the process. At higher levels of customer-sited generation saturation, the associated issues include:

- Upstream protective devices (circuit breakers) can trip, causing outages
- Increased variation in voltage and harmonics can degrade power quality
- Increased load and phase variability can make the grid less efficient

Distribution Automation, and a specific set of software and hardware applications generally labeled DERMS (Distributed Energy Resource Management Systems), can help manage the challenges introduced by customer-sited generation. Distribution Automation and DERMS are essential grid investments if high levels of customer-sited renewables are to be accommodated without reductions in grid reliability and efficiency. For more information on these subjects, readers are encouraged to review the section on the challenges of customer-sited generation (renewable and other) in "Technical and Economic Concepts Related to the Smart Grid – A Guide for Consumers," available from the SGCC.

Economic Benefits of Renewable Generation Integration

The economic benefit of accommodating increasing levels of renewable generation is unknown. There are increased costs associated with renewable generation in the short term, including the investments required to accommodate it and the higher capital investment required to build it (per kWh of production relative to natural gas–fired generation[55]). On the other hand, there are economic advantages to renewable generation over the long term, including the avoidance of fuel costs and the potential economic consequences associated with rapid climate disruption.[56] Many researchers have tackled this complex issue and have reached a wide variety of conclusions. As a result, we elect not to quantify the economic benefits of the Smart Grid's capability to integrate greater amounts of renewable generation, but qualify such benefits as "possible."

55 U.S. Energy Information Administration, *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013,* January, 28, 2013, 4.

56 Electric generation accounts for 33 percent of the carbon dioxide equivalent emissions annually produced in the U.S. U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990–2011,* Table 2-12, April 12, 2013, 2–21.

Reliability Benefits of Renewable Generation Integration

Smart Grid investments are likely needed if significant levels of renewable generation are to be reliably and efficiently integrated into the distribution grid. However, experience with customer-sited renewables at a level which impacts reliability is limited, and we found no research predicting the levels at which customer-sited generation will cause reliability issues. The answer is "it depends," based on a host of variables:[57]

- The strength (impedance) of the distribution line at the point of generation connection
- The specifics of a particular distribution grid's design, operations, and customer loads
- The characteristics of the renewable generation asset (relative size, harmonic output, generation profile, etc.)
- The density/locations/characteristics of other local renewable generation installations

IEEE Standard 1547.2, which governs the connection of customer-sited generation to the distribution grid, suggests that such generation amount to no more than 15 percent of a distribution line's maximum capacity. Utilities in California and Hawaii, the states where customer-sited photovoltaic solar installations are arguably the most common, have moved to a slightly more aggressive standard, allowing up to 100 percent of the minimum load recorded for customers on a distribution line in aggregate.[58] Smart Grid Distribution Automation and DERMS capabilities are likely to improve the amount of renewable generation that can be reliably accommodated on the distribution grid.

Environmental Benefits of Renewable Generation Integration

The greater the level of renewable generation the Smart Grid can reliably and efficiently accommodate, the larger the environmental benefits will be. However, it is difficult to quantify the size of the environmental benefits from Smart Grid capabilities designed to integrate renewable generation due to a host of factors:

- The limits of renewable generation saturation that can be reliably and efficiently accommodated by Smart Grid capabilities have not yet been reached and are unknown.
- The speed with which renewable generation levels will grow varies widely by geography and cannot be accurately predicted.
- The level of investment utilities (and ultimately customers) wish to make in order to reliably and efficiently integrate renewable generation is unknown.

As a result, we elect not to quantify the environmental benefits of the Smart Grid's capability to integrate greater amounts of renewable generation, but qualify such benefits as "likely."

57 Electric Power Research Institute, *Integrating Distributed Resources into Electric Utility Distribution System* (white paper), December 2001, 1–3.

58 Interstate Renewable Energy Council, *Integrated Distribution Planning* (white paper), May 2013, 1.

Customer Choice Benefits of Renewable Generation Integration

As previously discussed, some utilities limit the amount of customer-sited generation on their distribution lines. For example, a 15 percent limit means that the utility will allow up to 750 kilowatts of customer-sited generation to be connected to a distribution line with a peak capacity of 5,000 kilowatts. In 2009, the average size of a residential photovoltaic system was 4 kilowatts.[59] That works out to a limit of 187 systems on this hypothetical distribution line. However, a single photovoltaic solar installation on a large retail store can be as large as 300 kilowatts, significantly restricting the ability of other customers to install their own generation.

By increasing the amount of customer-sited generation the distribution grid can reliably accommodate, Distribution Automation and DERMS enable customers (collectively and individually) to connect greater quantities of renewable generation to a Smart Grid than to a traditional grid. For these reasons, we conclude that these Smart Grid capabilities increase customer choice. It should also be pointed out that the Distribution Automation capabilities that enable greater customer-owned renewable generation also enable greater integration of other types of customer-sited resources tied to the grid, from batteries and fuel cells to combined heat and power plants and microgrids.

Drivers of Renewable Generation Integration Benefits

	Utility Operating Characteristics	Customer Participation and Behavior	Speed of Cost Reduction and Recognition	Market Prices for Electricity and Capacity
Renewable Generation Integration	X	X		X

The largest driver of renewable generation integration benefits is likely to be the willingness of stakeholders to invest today in reliability and efficiency capabilities that, depending on current grid design and customer adoption of renewables, may not be needed until tomorrow. Grid upgrades require long lead times due to size and scale.

Stakeholder conversations on this topic will likely need to address the issue of cost allocation. When Distribution Automation investments are made to accommodate customer-sited renewables, all customers pay for those investments in the form of higher electric rates over time. Similarly, if renewable generation owners avoid paying for their share of the distribution grid, all other customers pay more in the form of higher electric rates over time. These issues are the subject of vigorous debate among distribution utility stakeholders and are outside the scope of this review.

59 Interstate Renewable Energy Council, *2010 Updates and Trends* (annual industry status report), October 11, 2010, 25. (77 percent DC to AC conversion factor applied to 5.2 kW DC figure cited.)

5. COSTS OF THE SMART GRID (AND RELATIONSHIP TO BENEFITS)

Investments must be made to generate the benefits described in this review, and ongoing expenditures must be made to operate and maintain Smart Grid capabilities over time. In this section we describe the likely costs of the Smart Grid.

This section is organized to help readers understand the manner in which we estimated costs as well as the techniques we used to facilitate comparisons of costs to benefits. This section includes:

- Capital investments
- Ongoing expenditures
- Analysis of cost and benefit data

Capital Investments

The U.S. Department of Energy required utilities to submit project budgets for proposed Smart Grid projects to qualify for its Smart Grid Investment Grant (SGIG) matching grant program. These project budgets, including proposed funding from both utilities and SGIG grants, serve as the basis for our Smart Grid cost estimates.[60]

We reviewed summary grant application data to categorize Smart Grid projects as Smart Meter projects or Distribution Automation projects. The total budgeted costs and counts of customers covered by each project were identified and used to calculate a "cost per customer" for each project.[61] We then calculated an average cost per customer for Smart Meter and Distribution Automation projects.

Table 6. Average cost per customer by Smart Grid component

Project Type	Sample Size	Average Cost per Customer
Smart Meter	24 projects	$291.54
Distribution Automation	12 projects	$63.64

There are, of course, some limitations to this analysis. Utilities sometimes exceed their budgets, and changes to project designs and customer counts likely occurred as projects proceeded from planning through design and implementation. However, for the type of secondary research undertaken for this review, this approach is likely the most accurate available to calculate average Smart Grid cost per customer for the most typical Smart Grid deployments.

60 U.S. Department of Energy, "Project Information" and subsequent web pages. Includes summary information on utility projects awarded Smart Grid Investment Grants funded by the American Recovery and Reinvestment Act of 2009. Accessed August 19, 2013.

61 Clear data on customer counts covered by a particular Smart Grid project were not readily available for all projects. Any projects for which customer counts were ambiguous were removed from the analysis. See the appendices for lists of SGIG projects included in the average cost calculations.

Ongoing Expenditures

Ongoing expenditures for asset operation and maintenance are a requirement for large capital investments. After installation, hardware and software must be maintained, repaired, or replaced as needed and operated on a day-to-day basis.

Experience with these sorts of ongoing expenditures in the Smart Grid space is limited as few deployments are fully in place. Once Smart Grid capabilities are fully deployed, no utilities that we know of track associated Smart Grid operations and maintenance expenditures separately; these ongoing costs become part of routine corporate and local operations and maintenance function responsibilities. The U.S. Department of Energy does not track ongoing Smart Grid operations and maintenance expenditures as part of its SGIG program.

To estimate the ongoing expenditures associated with Smart Grid spending, we turn to "rules of thumb" offered by the operations management discipline. Commonly accepted estimates of annual operations and maintenance (O&M) costs range from 2 percent to 4 percent of capital investment.[62] In this review, 4 percent is used as a conservative estimate.

Analysis of Cost and Benefit Data

This review has presented annual economic benefits on a per customer basis. In this section, we present costs for up-front capital investments and ongoing annual operations and maintenance expenditures, again on a per customer basis. Whereas benefits and O&M expenditures are realized over time, capital investments are made up front. To provide an accurate comparison of costs to benefits, we use an analytical framework called "Net Present Value" (NPV).

NPV translates up-front spending, ongoing spending, and ongoing benefits into today's dollars for comparison purposes, adjusting for the time value of money – the idea that a dollar today is worth more than a dollar 10 years from now due to inflation. The time value of money is reflected by the "discount rate," or the rate at which future costs and future benefits are "discounted" to today's dollar values. NPV is an extremely commonplace practice in the business world, and companies – including utilities – regularly use it to help them decide which of many potential investments they are contemplating offers the best economic rewards.

We chose a discount rate reflecting a customer's perspective. In essence, the discount rate represents the interest a customer could earn by purchasing a low-risk investment, such as a government bond, instead of Smart Grid capabilities. Because we are using a 13-year horizon for our cost-benefit analysis, we use the interest rate from a 10-year U.S. government bond (2.74 percent) for the NPV analysis.[63]

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62 Harvey Kaiser, *Capital Renewal and Deferred Maintenance Programs,* APPA Body of Knowledge, 2009, 9.

63 U.S. Department of the Treasury Resource Center, "Daily Treasury Yield Curve Rates (Long Term)." Accessed on August 21, 2013.

Tables 7 and 8 indicate how the NPV is calculated for the Reference Case and Ideal Case. Assumptions include:

- Capital costs are evenly split over the first three years of a deployment.
- A three-year ramp-up period is assumed for capabilities requiring customer participation.
- A 10-year post-implementation evaluation period is used to reflect the likely useful life of Smart Grid components.
- Indirect benefits from reliability improvements (service outage management and fault location and isolation) are included, but indirect environmental benefits (that is, the value of carbon emission reductions) are not.

Table 7. Net Present Value calculation for Smart Grid benefits and costs: Reference Case

		Deployment Year												
Cost or Benefit Category	**NPV**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
IVVC	89.60				11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24	11.24
Meter Reading	109.05				13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68	13.68
Time-Varying Rates	14.16				0.66	1.34	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Prepayment	55.38				2.58	5.24	7.82	7.82	7.82	7.82	7.82	7.82	7.82	7.82
Revenue Assurance	23.91				3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Customer Energy Mgmt.	5.45				0.25	0.52	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Outage Mgmt (direct)	9.41				1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Total Direct Benefits	**306.95**													
Outage Mgmt (indirect)	70.31				8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82
Fault Location & Isolation	319.96				40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14
Total Indirect Benefits	**390.27**													
Smart Meter Costs	-369.22	-97.18	-97.18	-97.18	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66
Distribution Automation Costs	-80.60	-21.21	-21.21	-21.21	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55
Total Costs	**-449.82**													

Table 8. Net Present Value calculation for Smart Grid benefits and costs: Ideal Case

		Deployment Year												
Cost or Benefit Category	**NPV**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
IVVC	255.16				32.01	32.01	32.01	32.01	32.01	32.01	32.01	32.01	32.01	32.01
Meter Reading	190.67				23.92	23.92	23.92	23.92	23.92	23.92	23.92	23.92	23.92	23.92
Time-Varying Rates	141.49				6.59	13.39	19.98	19.98	19.98	19.98	19.98	19.98	19.98	19.98
Prepayment	138.52				6.45	13.11	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56
Revenue Assurance	23.91				3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Customer Energy Mgmt.	13.60				0.63	1.29	1.92	1.92	1.92	1.92	1.92	1.92	1.92	1.92
Outage Mgmt (direct)	9.41				1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
Total Direct Benefits	**772.75**													
Outage Mgmt (indirect)	70.31				8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82	8.82
Fault Location & Isolation	319.96				40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14	40.14
Total Indirect Benefits	**390.27**													
Smart Meter Costs	-369.22	-97.18	-97.18	-97.18	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66	-11.66
Distribution Automation Costs	-80.60	-21.21	-21.21	-21.21	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55	-2.55
Total Costs	**-449.82**													

The ratio of benefits (both direct and indirect) to costs is 1.5 to 1 in the Reference Case[64] and 2.6 to 1 in the Ideal Case.[65] These results are depicted graphically by Smart Grid capability in the following figures.

Figure 7. Smart Grid costs and benefits per customer: Reference Case

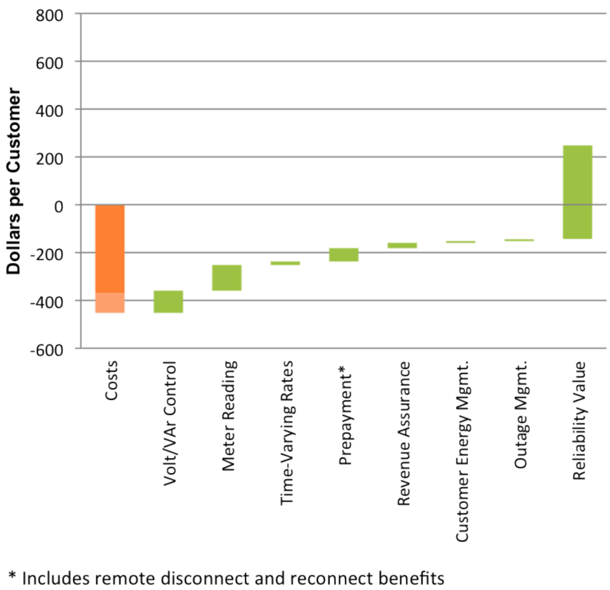
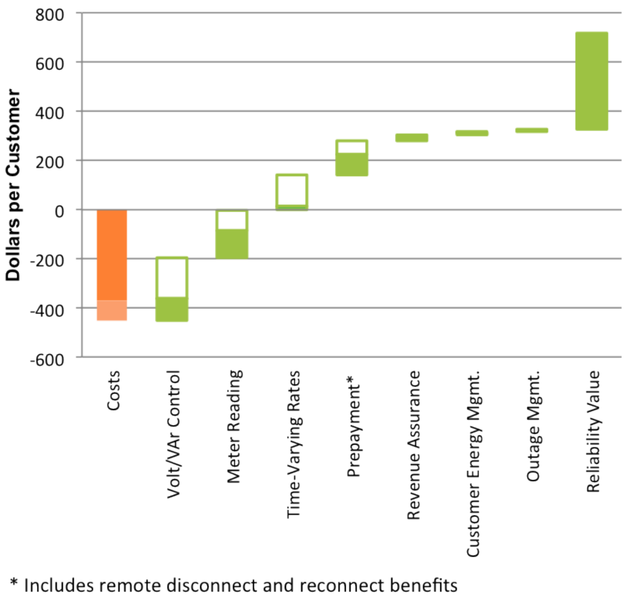


Figure 8. Smart Grid costs and benefits per customer: Ideal Case



Open boxes represent the difference in benefit from the Reference Case to the Ideal Case.

64 Reference Case benefits to cost ratio = ($306.95 + $390.27)/$449.82 = 1.5 (to 1).
65 Ideal Case benefits to cost ratio = ($772.75+$390.27)/$449.82 = 2.6 (to 1).

6. CONCLUSIONS AND RECOMMENDATIONS

In reviewing and synthesizing research on the actual benefits and costs of Smart Grid capabilities and investments, the SGCC intended to provide stakeholders with new insights into the current and potential value of grid modernization and identify associated drivers of that value. While we believe this review has accomplished these objectives, we are struck by the increasingly critical role electric distribution grids will play in the future economic vitality, productivity, and sustainability of the communities they serve. As a result, we have come to see this work as an opportunity to chart a new course in the manner in which stakeholders collaborate to establish and execute a common vision for the distribution grids that serve them. In addition to summarizing our findings, drivers, and opportunities, this section also includes recommendations for researchers and stakeholders.

Findings

We find that the Smart Grid offers a favorable benefit-to-cost ratio when considering both direct and indirect economic benefits. Based on available research and incorporating the conservative Reference Case assumptions detailed in this report, the ratio of direct and indirect benefits to costs is 1.5 to 1.[66] Using the Ideal Case assumptions detailed in this report, the ratio of direct and indirect benefits to costs is 2.6 to 1.[67] In both cases, the indirect benefit from service reliability improvements is significant – and significantly reduces customer inconvenience, as well.

We also find that the Smart Grid offers significant reductions in environmental impact, including both quantifiable and nonquantifiable benefits. Quantified environmental impact reductions of almost 600 pounds of carbon dioxide equivalent emissions per customer per year are available in the Ideal Case from the conservation impact offered by Smart Grid capabilities such as Integrated Volt/VAr Control and time-varying rates. Smart Grid capabilities also appear to enable greater amounts of renewable generation to be integrated by addressing associated intermittency and technical challenges. Although difficult to quantify, the environmental impact reductions from greater amounts of renewable generation are likely many multiples higher than the quantified amounts from Smart Grid capability conservation effects.

Finally, by enabling adoption of new products and services, Smart Grid investments can serve to greatly increase customer choice.

These findings are based on critical assumptions about customer participation levels, utility operating and market characteristics pre- and post-investment, and the speed with which operating cost reductions are effected and recognized.

66 Reference Case benefits to cost ratio = ($306.95 + $390.27)/$449.82 = 1.5 (to 1).
67 Ideal Case benefits to cost ratio = ($772.75+$390.27)/$449.82 = 2.6 (to 1).

Benefit Drivers

Although utilities execute many Smart Grid capabilities "behind the scenes," many other capabilities require extensive and active customer engagement in order to maximize benefits. Customer participation level is the single largest benefit driver for many capabilities that Smart Meters facilitate, including time-varying rates, prepayment programs, and customer energy management. The SGCC encourages utilities to take advantage of the resources and best practices we offer to help engage customers and maximize the benefits from these Smart Grid capabilities.

Another set of drivers involves utility operating characteristics pre- and post-investment, including the variables of electric energy and capacity costs specific to each geography. As examples of the former, utilities with automated meter reading pre-deployment are not likely to secure as much meter-reading cost reduction from the installation of Smart Meters as utilities with manual meter reading. Post-deployment, utilities can choose the extent to which they prioritize and utilize certain Distribution Automation capabilities such as Integrated Volt/VAr Control. As examples of the latter, geographies with higher-than-average electric energy and capacity costs are likely to see greater Smart Grid benefit-to-cost ratios relative to geographies with lower-than-average energy and capacity costs.

Another important variable is the speed with which a utility can begin realizing – and passing on to customers – cost savings from Smart Grid investments. Large Smart Grid deployments are enormous logistical undertakings that can take years to complete. It is not hard to imagine how the first Smart Grid investments a utility makes might require six years to begin paying off for customers – two to three years in field deployment; another year or so in software, process, and customer program development and employee training; and another few years to reach target customer participation levels.

Finally, regulatory rules and norms that can inhibit customer economic benefits exist in many states. For utilities that do business under traditional ratemaking practices, it is important to address the risk that lower sales volumes brought about by Smart Grid–enabled capabilities hinder utilities' ability to recover costs. Several potential solutions to this issue include, but are not limited to, the following:

- Incorporating anticipated sales volume reductions from Smart Grid capabilities into the ratemaking process
- Allowing investor-owned utilities to earn an incentive to maximize Smart Grid–related sales volume reductions in a manner similar to that for demand-side management programs
- Continuing dialog about how to improve traditional ratemaking to better address benefits that require sales volume reductions

Additional regulatory factors, such as those around billing and payment programs, may need to be addressed by stakeholders as various Smart Grid capabilities are deployed. The SGCC hopes this review will help to enable further dialogue and collaboration among stakeholders.

Recommendations for Researchers

This review indicates that the Smart Grid has opened up entire fields of research opportunities. Those that appeared to be priorities to us as we completed this review are summarized below.

Customer Engagement

The SGCC is at the forefront of research related to consumers' perceptions and attitudes toward electricity. This review confirms that our focus on this issue is well placed, and we encourage others to join us as we prioritize new efforts:

- What economic, environmental, and community benefit messages engage customers and raise program participation?
- What role can peer influences play in awareness, participation, and behavior change?
- What new products (such as free weekends) and services (such as outage information messages) made possible by the Smart Grid are of greatest interest to customers?

Identification and Communication of Best Practices

Because distribution utilities do not compete against one another, they have a unique opportunity to widely and openly share best practices. Our research indicates that there are several areas that would benefit from increased best practice dissemination among distribution utilities:

- What new uses are utilities finding for Smart Meter and Distribution Automation data?
- What are the best ways to measure Smart Grid benefits and impacts?
- How are stakeholders working to optimize the value drivers described in this review?

Renewable Generation Integration

There is a dearth of information about the integration of customer-sited and renewable generation. Questions for future research include:

- How much customer-sited generation can a traditional grid reliably and efficiently accommodate?
- How much additional customer-sited generation can Distribution Automation capabilities such as DERMs help accommodate?
- What are the economic, reliability, environmental, and customer choice benefits of this increase relative to costs?
- What are the limits and drivers of customer response to notices or price signals?

Recommendations for Stakeholders

The research presented in this review indicates that grid modernization can create direct economic benefit for customers in excess of costs. This review also indicates that significant indirect benefits – primarily from reliability improvements but also from reduced environmental impact – are available to society at large. This review also makes clear that multiple drivers, including those with significant inherent complexity, can considerably impact the level of benefit customers receive from Smart Grid investments.

The SGCC encourages all stakeholders (utilities, regulators, advocates, customers, and legislators) to prioritize collaboration in pursuit of workable solutions to increase customer participation, speed benefit recognition, and address regulatory opportunities.

7. APPENDICES

Reference Case and Ideal Case Benefit Assumptions

Utilities are not likely to experience the same benefits presented in the Reference Case or Ideal Case, as each utility's operating characteristics and market conditions are likely to differ from the assumptions presented in this report. To help report users adjust for specific situations, the primary benefit drivers are listed below along with the assumptions used to create the Reference Case and Ideal Case. Sources for assumptions are footnoted throughout the review.

Table 9. Reference Case and Ideal Case benefit assumptions

Capability	Primary Benefit Drivers	Reference Case Assumptions	Ideal Case Assumptions
Integrated Volt/VAr Control	• Average reduction in peak demand • Average reduction in energy use	• 3.5% peak reduction • n/a	• 3.5% peak reduction • 2.7% energy reduction
Remote Meter Reading	• Type of meter reading (manual or automated) prior to Smart Meter rollout • Policy regarding move ins/move outs (is prorating allowed between meter reads or must meters be read on customer move dates?)	• Routine monthly meter reads previously automated • Prorating prohibited	• Meter reading previously manual • Prorating prohibited
Time-Varying Rates	• Customer participation rates (opt in) • Customer response level to price differentials • Conservation impact • Average peak demand per residential customer • Value of generation capacity avoided • Average usage per residential customer per year • Value of electricity use avoided	• 2% participation • 20% load shift • 4% usage reduction • 2.575 kW/ customer (1) • $134.28/kW year (1) • 11,280 kWh/ year (1) • $0.0682/kWh (1)	• 20% participation • 20% load shift • 4% usage reduction • 2.575 kW/ customer (1) • $134.28/kW year (1) • 11,280 kWh/ year (1) • $0.0682/kWh (1)

Prepay and remote disconnect/ reconnect	• Customer participation rates • Conservation impact • Existence of remote disconnect prohibitions	• 2.5% participation • 11% usage reduction • No remote disconnect prohibitions	• 5% participation • 11% usage reduction • No remote disconnect prohibitions
Revenue Assurance	• Level of electricity theft prior to Smart Meter deployment • Average age of meters being replaced		
Customer Energy Management	• Customer participation rates • Feedback mechanism type • Conservation impact	• 2% participation • In-home display • 5% usage reduction	• 5% participation • In-home display • 5% usage reduction
Service Outage Management; Fault Location and Isolation	• Value assigned to a minute of reliability improvement	• $1.80/minute (weighted average opportunity cost to residential, commercial, industrial)	• $1.80/minute (weighted average opportunity cost to residential, commercial, industrial)
Renewable Generation Integration	• Difference in cost of relative to central resources • Difference in environmental impact vs. central • Value of environmental impact reductions • Ratio of customer-sited to central resources over time		

(1) These assumptions are used throughout the report as appropriate.

Calculation of Benefits

Table 10. Benefit driver assumptions for calculations

Variable	Assumption	Value
A	Average energy use per U.S. residential electric customer per year[68]	11,280 kWh
B	Average peak demand per U.S. residential electric customer[69]	2.575 kW
C	The variable cost of electricity per kWh[70]	$0.0682
D	The value of generation investments delayed or avoided per unit of demand reduced[71]	$134.28 per kW yr.
E	CO_2 equivalent emissions (lbs.) per kWh[72]	1.22
F	Percentage reduction in peak demand from IVVC	3.25%
G	The amount of electric use reduced per year from IVVC	2.7%
H_r	Assumed participation rate in time-varying rates, Reference Case	2%
H_i	Assumed participation rate in time-varying rates, Ideal Case[73]	20%
I	The amount of demand reduced at a point in time from "shifting" by customers participating in time-varying rates	20%
J	The amount of electric use reduced per year among those participating in time-varying rates[74]	4%
K	The amount of electric use reduced per year among those participating in prepayment programs	11%
L_r	Assumed participation rate in prepayment programs, Reference Case	2%
L_i	Assumed participation rate in prepayment programs, Ideal Case	5%
M	Billing and collection expense reduction per prepayment customer	$300

68 U.S. Energy Information Administration, *2011 Annual Electric Power Industry Report* (File 2, Electric sales, revenue, and average price, Column W, total consumers), April 2012.

69 Calculated based on 11,280 kWh per year for an average U.S. residential electric customer assuming a 50 percent capacity factor. Peak demand = (average demand/8,760 hours annually)/capacity factor.

70 U.S. Energy Information Administration, "Table 5.3. Average Retail Price of Electricity to Ultimate Consumers" (Line 14, 2011, Column D, Industrial), September 20, 2013.

71 Kathleen Spees, *Cost of New Entry Estimates for Combustion Turbine and Combined-Cycle Plants in PJM,* The Brattlle Group, August 24, 2011. Page 2, Table 1, final column average (PJM 2014/15 CT CONE).

72 U.S. Environmental Protection Agency, *eGRID 2012 Subregion GHG Output Emission Rates for Year 2009,* April 2012. Summary table 1, column = total output emissions rate (lb/MWh). http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf.

73 Testimony of J. Richard Hornby to the Arkansas PSC in Docket 10-109-U, Exhibit JRH-4, page 2, May 20, 2011. "OG&E assumes 20 percent of residential customers will voluntarily enroll in its VPP rates."

74 Chris King and Dan Delurey, "Efficiency and Demand Response: Twins, Siblings, or Cousins?" *Public Utilities Fortnightly,* March 2005, 55.

N	Average monthly bill per prepayment customer[75]	$110
O	Average days' sales outstanding[76]	53
P	Utility weighted average cost of capital (daily)[77]	0.0095%
Q	Bills per year	12
R	The amount of electric use reduced per year among those utilizing an in-home display (conservative end of the range found in research)	5%
S_r	Assumed participation rate in home energy management, Reference Case	2%
S_i	Assumed participation rate in home energy management, Ideal Case	5%

Table 11. Benefit calculations for Reference Case and Ideal Case

Capability	Calculation	Reference Case Value	Ideal Case Value
Integrated Volt/VAr Control peak demand reduction	B x D x F	$11.24	$11.24
Integrated Volt/VAr Control conservation benefit	A x C x G	N/A	$20.77
Integrated Volt/VAr Control CO_2e reduction	A x E x G	Likely	372 lbs.
Time-varying rate peak demand reduction	B x D x H x I	$1.38	$13.83
Time-varying rate conservation benefit	A x C x H x J	$0.62	$6.15
Time-varying rate CO_2e reduction	A x E x H x J	11 lbs.	110 lbs.
Prepayment program conservation benefit	A x C x K x L	$1.69	$4.23
Prepayment program conservation benefit per participant	A x C x K	$84.62	
Prepayment program billing, collection and interest reduction benefit	[M + (N x O x P x Q)] x L	$6.13	$15.33
Prepayment program CO_2e reduction	A x E x K x L	30 lbs.	76 lbs.
Customer energy management benefit	A x C x R x S	$0.77	$1.92
Customer energy management CO_2e reduction	A x E x R x S	14 lbs.	34 lbs.

75 U.S. Energy Information Administration, "Table 5A. Residential Average Monthly Bill by Census Division, and State 2011." Table 5_a, Line 66 (U.S. total), Column C ("Average Monthly Consumption").

76 Top-quartile (better than 75 percent) utilities. *Cash on the Meter* (white paper), Ernst & Young, May 2009, 6.

77 3.47 percent divided by 365 days. Aswath Damodaran, "Cost of Capital by Sector," January 2013. Analysis of 6,177 firms in the Value Line dataset; "Electric Utility (Central)."

Estimating the Economic Productivity Impact of Service Outages

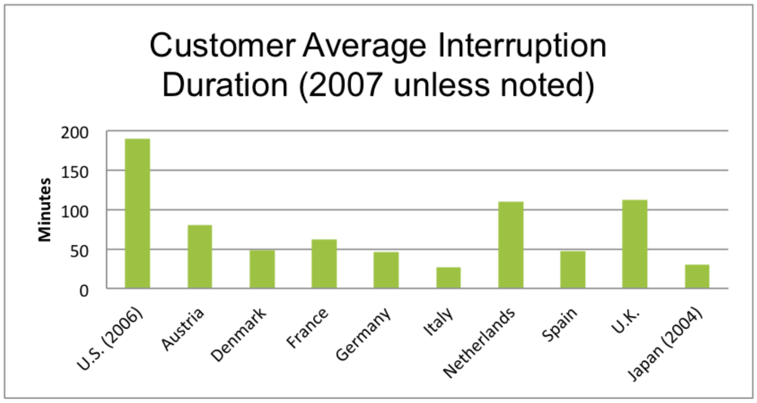
The cost to the U.S. economy of electric service outages is estimated in many studies. All the studies estimate large impacts on productivity – between $30 billion and $400 billion per year.[78] One of the better controlled and more often cited studies (conducted by Primen for EPRI) estimates the cost of power outages in the U.S. at between $104 billion and $164 billion a year.[79] A more relevant and more recent Lawrence Berkeley National Laboratory study estimates the opportunity cost at $80 billion annually.[80]

The high productivity costs of service outages stems from several sources:[81]

- Lost business sales
- Spoiled production runs
- Spoiled experiments
- Spoiled food
- Property damage (from failed protection systems)
- Associated health and medical issues

The U.S. economy competes with those of other nations. Issues inhibiting the productivity of the U.S. economy, including electric reliability, are a source of concern to lawmakers at the state and federal levels. A comparison of U.S. reliability indicating an opportunity for improvement follows. Research indicates the Smart Grid can significantly improve U.S. service outage performance.

Figure 9. Representative customer average interruption duration indices by nation[82]



78 Greg Rouse and John Kelly, *Electric Reliability: Problems, Progress, and Policy Solutions* (white paper), Galvin Electricity Initiative (now the Perfect Power Institute), February 2011, 4.

79 Electric Power Research Institute, *The Cost of Power Disturbances to Industrial and Digital Economy Companies* (study conducted by Primen), June 29, 2001, ES-3.

80 Kristina Hamachi LaCommare and Joseph H. Eto, *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers,* Lawrence Berkeley National Laboratory (for the U.S. Department of Energy), September 2004, 41.

81 Greg Rouse and John Kelly, *Electric Reliability: Problems, Progress, and Policy Solutions* (white paper), Galvin Electricity Initiative (now the Perfect Power Institute), February 2011, 4.

82 U.S. Source: Joseph H. Eto and Kristina Hamachi LaCommare, *Tracking the Reliability of the U.S. Electric Power System,* Lawrence Berkeley National Laboratory (for the U.S. Department of Energy), October 2008, 25. EU source: Council of European Energy Regulators, *4th Benchmarking Report on the Quality of Electric Supply,* 2008. Japan source: Masanori Kondo, "Activities of the Japan Electricity Task Force for the India Market" (presentation), March 9, 2007, 14.

Translating Reliability Improvements into Indirect Economic Benefits

Using the Lawrence Berkeley National Laboratory's estimate of $80 billion annually in service outage costs as a basis, we attempt to estimate the indirect economic benefits available from service outage reductions delivered by the Smart Grid. Dividing the LBNL estimate by the number of U.S. electric customers estimated by the Energy Information Administration (151.7 million),[83] we estimate an economic productivity impact equal to $527.35 per customer per year from service outages. By applying the U.S. System Average Interruption Duration Index of 292 minutes,[84] we arrive at an estimated economic productivity impact per minute of outage per customer of $1.80.

Commercial and Industrial customers who have more at stake are more interested in improving reliability than the average residential customer, who is more likely to be content with the average 99.95 percent uptime the average U.S. customer experiences.[85] The SGCC encourages stakeholders to consider the future – with increased customer reliance on electricity, increased likelihood of extreme weather events, and the increased reliability challenges likely to be imposed on the grid by electric vehicles and customer-owned generation – when assessing the value of investments in reliability-related Smart Grid capabilities.

83 U.S. Energy Information Administration, *2011 Annual Electric Power Industry Report* (File 2, Electric sales, revenue, and average price, Column W, total consumers), April 2012.

84 Joseph H. Eto and Kristina Hamachi LaCommare, *Tracking the Reliability of the U.S. Electric Power System,* Lawrence Berkeley National Laboratory (for the U.S. Department of Energy), October 2008, 25.

85 Greg Rouse and John Kelly, *Electric Reliability: Problems, Progress, and Policy Solutions* (white paper), Galvin Electricity Initiative (now the Perfect Power Institute), February 2011, iii.

SGIG Projects Used to Estimate Costs per Customer

Smart Meter Projects

- Baltimore Gas & Electric (MD)
- Central Maine Power (ME)
- Salt River Project #1 (AZ)
- Salt River Project #2 (AZ)
- Cleco Power (LA)
- South Mississippi Electric Power Association
- Lakeland Electric (FL)
- Denton County Electric Co-op (TX)
- Cobb Electric Co-op (GA)
- South Kentucky Rural Electric Co-op
- Talquin Electric Co-op (FL)
- Black Hills Electric Utility (CO)
- Black Hills Power (SD)
- Cheyenne Light Fuel & Power Company (WY)
- Entergy New Orleans (LA)
- Navajo Tribal Utility Association (AZ)
- Sioux Valley Southwestern Electric Co-op (SD)
- Woodruff Electric (AR)
- Allete Inc. (Minnesota Power)
- City of Fulton (MO)
- Marblehead Municipal Light Dept. (MA)
- Tri State Electric Membership Co-op (GA)
- Wellsboro Electric Co-op (PA)
- Stanton County Public Power District (NE)

Distribution Automation Projects

- Consolidated Edison Company of NY (NY)
- Avista Utilities (ID)
- PPL Electric Utility Corp. (PA)
- Atlantic City Electric Company (NJ)
- Snohomish County Public Utility District (WA)
- NSTAR Electric Co. (MA)
- Hawaiian Electric Company (HI)
- Memphis Light Gas & Water Division (TN)
- Northern Virginia Electric Co-op (VA)
- Wisconsin Power & Light (WI)
- Powder River Energy Corp. (WY)
- El Paso Electric (TX)

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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 21

Responding Witness: John P. Malloy

Q-21. Please refer to the chart on page 157 of Exhibit JPM -1 (AMS Business Case Appendix A-5), entitled “ePortal Customer Benefits Value Levers,” specifically the column “Calculation Assumptions,” which posits that 48% of customers will use the portal at least once, and that 36% of those customers will benefit from the energy granularity of AMS and achieve energy savings.

a) Please confirm that, calculating 36% of 48%, 17% of customers are projected to achieve energy savings.

b) Please confirm that this chart is limited to the residential class. If not, please disaggregate all figures by class.

A-21.

a) Confirmed.

b) Confirmed.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 22

Responding Witness: John P. Malloy

Q-22. Please refer to the Malloy testimony at page 21, line 1, where it is stated that the Companies have enrolled over 4,000 customers in the AMS Customer offering since enrollment began in June 2015.

a) How many of these are LG&E customers?

b) Please provide a breakdown by zip code of LG&E customers so enrolled.

c) How many LG&E customers so enrolled had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of customer enrollments in June 2015 and ending December 31, 2016?

A-22.

a) As of December 31, 2016 there were 2,429 LG&E customers actively enrolled.

b) See table below.

Zip	Customer Count
40010	3
40014	43
40023	13
40025	1
40026	17
40031	23
40047	8
40056	11
40059	49
40108	2
40118	8
40165	8
40202	5
40203	26

40204	57
40205	94
40206	64
40207	95
40208	21
40210	5
40211	10
40212	16
40213	29
40214	79
40215	33
40216	72
40217	118
40218	102
40219	62
40220	120
40222	55
40223	179
40228	41
40229	39
40241	225
40242	34
40243	77
40245	275
40258	40
40272	44
40291	85
40299	141
Grand Total	**2429**

c) 49 LG&E AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 23

Responding Witness: John P. Malloy

Q-23. Please refer to the Malloy testimony at page 21, lines 4 - 7, where it is stated that customers participating in the AMS Customer offering span "various…socioeconomic segments throughout the Companies Kentucky service territories." Please provide the data underlying this assertion, disaggregated for the LG&E service territory by zip code.

A-23. The Company has not performed the analysis requested. However, the basis of the assertion can be found in Appendix A-1 of Exhibit JPM-1, Demographics section beginning on page 98 of 169.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 24

Responding Witness: John P. Malloy

Q-24. Please provide the survey instrument used by Bellomy Research to conduct the Advanced Meter Service Participant Study attached as Appendix A-1 to Exhibit JHM-1 (hereinafter "AMS Participant Study").

A-24. See attached.

LG&E and KU Services Company
Advanced Meter Service Participant Survey – Residential
Email Study #16295

INTRO

We are conducting a survey to gather customer feedback about your experience with the Advanced Meter Service and **[LG&E, Kentucky Utilities]** would like to include your opinions.

As you answer the survey, please use the NEXT button at the bottom of the screen and not your browser to move to the next page. Once you answer a question you will not be able to return to the previous page.

If you decide to close the survey before completing it, you can go back into it; however, the survey will be started from the beginning.

S1. Do you or anyone in your household currently work for PPL, LG&E, Kentucky Utilities, or ODP?
- 1. Yes **[TERMINATE]**
- 2. No
- 98. Don't know **[TERMINATE]**

S2. Are you <u>currently</u> participating in the Advanced Meter Service?
- 1. Yes
- 2. No **[TERMINATE]**
- 98. Don't know **[TERMINATE]**

[SCREENER TERMINATE]
Thank you for your time. Unfortunately you do not qualify to continue with this survey.

Q1. This next question pertains to your experience with the Advanced Meter Service.

Overall, how satisfied are you with the Advanced Meter Service?

Not satisfied at all									Completely satisfied	Don't know
1	2	3	4	5	6	7	8	9	10	98 **[Don't show '98']**

Q1a. Why did you give this rating?

____

☐ No Comment

Q2. These next few questions pertain to the MyMeter dashboard, which allows you to track energy usage over time, maintain an energy-related profile of your home or property, and schedule usage threshold notifications.

How frequently do you access the MyMeter dashboard?

1. Daily
2. Two to three times a week
3. Weekly
4. Two to three times a month
5. Monthly
6. Every couple of months
7. Never

[IF Q2=7, Never accessed MyMeter dashboard]

Q2a. Why have you never accessed the MyMeter dashboard?

____

☐ No Comment

[IF Q2=7, Never accessed MyMeter dashboard, ASK Q2a THEN SKIP TO Q6]

Q3. How would you rate your overall satisfaction with the MyMeter dashboard?

Not satisfied at all									Completely satisfied	Don't know
1	2	3	4	5	6	7	8	9	10	98 **[Don't show '98']**

Q4. How satisfied are you with your online experience using the MyMeter dashboard, based on the following attributes?

Not satisfied at all									Completely satisfied	Don't know
1	2	3	4	5	6	7	8	9	10	98 **[Don't show '98']**

[RANDOMIZE, DYNAMIC DISPLAY – APPEAR ONE AT A TIME]

a. Ease of navigation
b. System is user-friendly
c. Ease of accessing the MyMeter dashboard
d. MyMeter dashboard content meets your expectations
e. MyMeter dashboard information is clear and easy to understand

[IF Q4_001=1-5, Dissatisfied with ease of navigation]
Q4a. Why did you rate the ease of navigating the MyMeter dashboard a **[INSERT RATING]**?

____

☐ No Comment

[IF Q4_002=1-5, Dissatisfied with system is user-friendly]
Q4b. Why did you rate the user-friendliness of the MyMeter dashboard a **[INSERT RATING]**?

____

☐ No Comment

[IF Q4_003=1-5, Dissatisfied with ease of accessing MyMeter dashboard]
Q4c. Why did you rate the ease of accessing the MyMeter dashboard a **[INSERT RATING]**?

____

☐ No Comment

[IF Q4_004=1-5, Dissatisfied with MyMeter dashboard content]
Q4d. Why did you rate the MyMeter dashboard content a **[INSERT RATING]**?

____

☐ No Comment

[IF Q4_005=1-5, Dissatisfied with MyMeter dashboard information is clear and easy to understand]

Q4e. Why did you rate the clarity of the MyMeter dashboard information a **[INSERT RATING]**?

____

□ No Comment

Q5. Which of the following features of the MyMeter dashboard have you used? *Please select all that apply.*

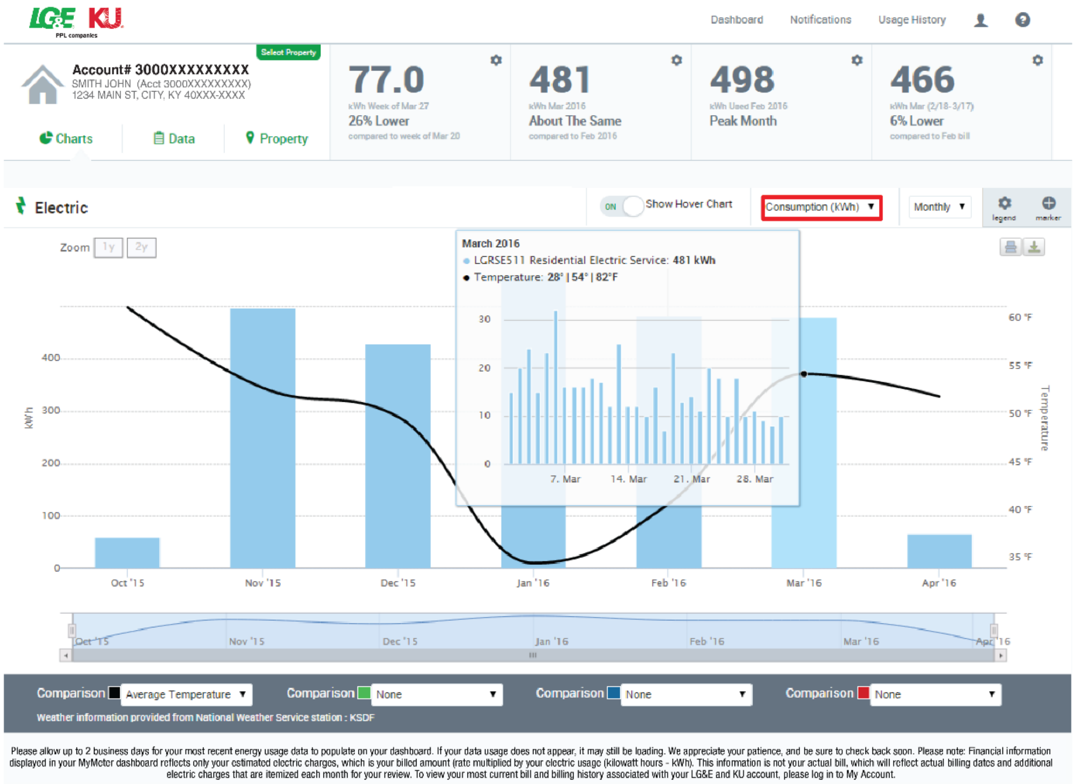
[RANDOMIZE]

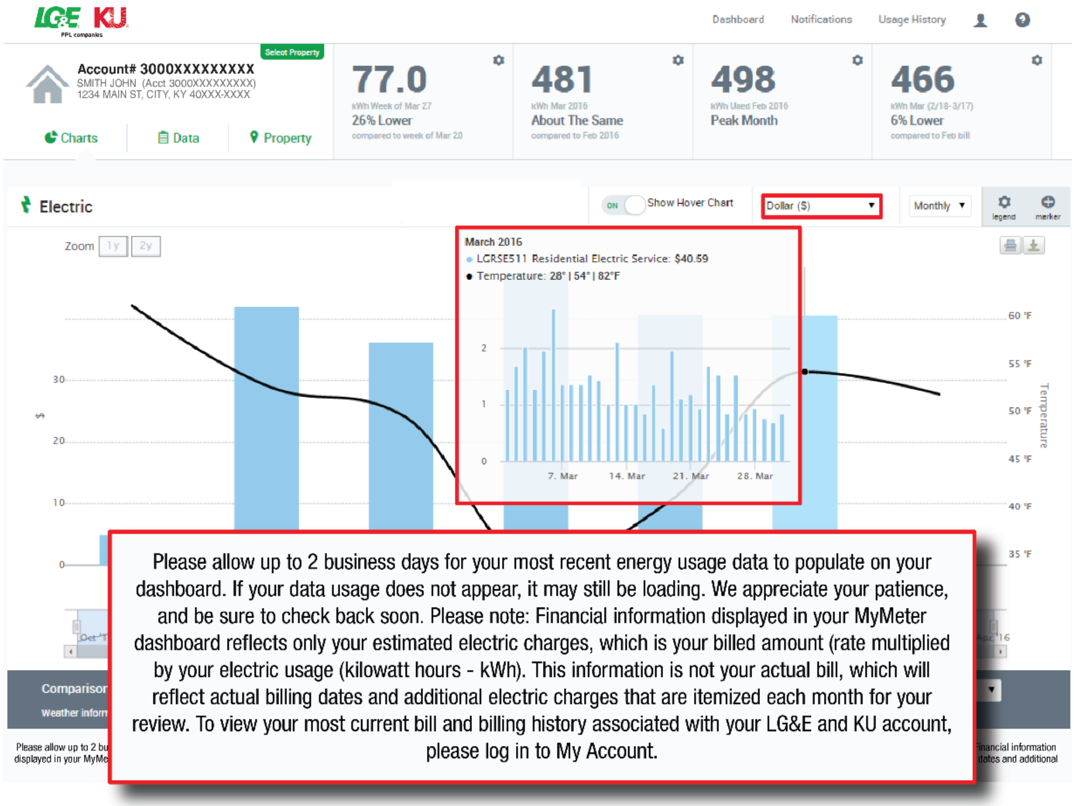
1. Track and compare your energy usage over time
2. Compare your energy use to local weather conditions
3. Compare your energy usage from the previous day or week
4. Use MyMeter's heat map feature to show trends in energy usage each day
5. Add "Energy markers" to your energy usage chart to help recall when you made changes that might impact usage
6. Create your own "Property Profile" to show your home's size, age, or types of appliances to help you better understand your energy usage
7. Schedule MyMeter notifications to send you text or email updates about your energy usage

Q6. **[LG&E, Kentucky Utilities]** is considering adding a new feature to the MyMeter dashboard which will give you the option to review your energy usage in terms of <u>dollars</u>, rather than just consumption (kilowatt hours - kWh).

Financial information displayed in your MyMeter dashboard would <u>only reflect your estimated electric charges</u>, which is your billed amount (rate) multiplied by your electric usage (kWh). This information would <u>not</u> replace your actual bill, which reflects actual billing dates and additional electric charges that are itemized each month for your review.

Below is an image of the MyMeter dashboard as it exists today followed by how this new feature would look. You'll see that the monthly chart view changed from displaying consumption in terms of kWh to dollars. Please also note the language at the bottom of the screen.


Dashboard
Notifications
Usage History
Select Property
Account# 3000XXXXXXXXX
SMITH JOHN (Acct 3000XXXXXXXXX)
1234 MAIN ST, CITY, KY 40XXX-XXXX
Charts
Data
Property
77.0
kWh Week of Mar 27
26% Lower
compared to week of Mar 20
481
kWh Mar 2016
About The Same
compared to Feb 2016
498
kWh Used Feb 2016
Peak Month
466
kWh Mar (2/18-3/17)
6% Lower
compared to Feb bill
Electric
ON
Show Hover Chart
Consumption (kWh)
Monthly
legend
marker
Zoom 1y 2y
March 2016
LGRSE511 Residential Electric Service: 481 kWh
Temperature: 28° | 54° | 82°F
7. Mar
14. Mar
21. Mar
28. Mar
kWh
Temperature
Oct '15
Nov '15
Dec '15
Jan '16
Feb '16
Mar '16
Apr '16
Comparison Average Temperature
Comparison None
Comparison None
Comparison None
Weather information provided from National Weather Service station : KSDF
Please allow up to 2 business days for your most recent energy usage data to populate on your dashboard. If your data usage does not appear, it may still be loading. We appreciate your patience, and be sure to check back soon. Please note: Financial information displayed in your MyMeter dashboard reflects only your estimated electric charges, which is your billed amount (rate multiplied by your electric usage (kilowatt hours - kWh). This information is not your actual bill, which will reflect actual billing dates and additional electric charges that are itemized each month for your review. To view your most current bill and billing history associated with your LG&E and KU account, please log in to My Account.



How interested are you in the new MyMeter dashboard feature shown?

Click here to view images. **[TEXT AS HYPERLINK TO VIEW IMAGES IN A SEPARATE TAB]**

5. Very interested
4. Somewhat interested
3. Neutral
2. Not very interested
1. Not interested at all

Q6a. Why did you give this rating?

____

☐ No Comment

Q7. How clear is it that the dollar amount outlined in the feature refers to usage and not the total bill amount?

Click here to view images. **[TEXT AS HYPERLINK TO VIEW IMAGES IN A SEPARATE TAB]**

5. Very clear
4. Somewhat clear
3. Neither clear nor confusing
2. Somewhat confusing
1. Very confusing

[IF Q2=7, Never accessed MyMeter dashboard, ASK Q7 THEN SKIP TO DEMO]

Q8. Which, if any, of the following steps have you taken to save energy as a result of your participation in the Advanced Meter Service? *Please select all that apply.*
[RANDOMIZE 1-6]

1. Replaced inefficient light bulbs with LED bulbs
2. Improved your home's insulation
3. Weather-stripped windows and doors
4. Programmed the temperature settings on your existing thermostat
5. Purchased new energy efficient appliances
6. Purchased a new thermostat
7. Other (please specify) ______________________ **[ANCHOR]**
8. None **[EXCLUSIVE] [ANCHOR]**

[IF Q8=5, Purchased new energy efficient appliances]

Q9. What type of appliances have you purchased <u>since joining</u> the Advanced Meter Service? *Please select all that apply.*

1. Refrigerator
2. Freezer
3. Dishwasher
4. Stove/Oven/Cooktop
5. Clothes Washer
6. Clothes Dryer
7. Water Heater
8. Other (please specify)_______________________________________

[IF Q8=6, Purchased new thermostat]

Q10. What type of thermostat did you purchase as a result of your participation in the Advanced Meter Service? *Please select all that apply.*

1. Programmable (allows temperature settings to be scheduled on an hourly and daily basis)

2. Wi-Fi enabled (thermostat is connected to a Wi-Fi network which allows for remote monitoring and temperature adjustment via the web)
3. Self-learning (thermostat learns to program itself to match the user's preferences over time based on the user's manual temperature adjustments)
4. Other (please specify) ________________________________

Q11. How likely are you to recommend the Advanced Meter Service to friends or family?

Not likely at all										Very likely
0	1	2	3	4	5	6	7	8	9	10

[IF Q11=0-6, Detractors]

Q11a. Why did you give this rating?

____

☐ No Comment

Q12. As a result of your participation in the Advanced Meter Service which, if any, of the following energy efficiency programs offered by **[LG&E, KU]** have you enrolled in? *Please select all that apply.*

[RANDOMIZE 1-7]

1. Demand Conservation
2. Fridge and Freezer Recycling
3. Smart Energy Profile
4. Online Home Energy Analysis
5. On-site Home Energy Analysis
6. Home Energy Rebates
7. WeCare Program
8. Other (please specify) ______________________ **[ANCHOR]**
9. Do not participate in any / Don't Know **[EXCLUSIVE] [ANCHOR]**

We'd like to conclude by asking a few questions for classification purposes.

C1. Please provide an estimate of the total living space in your home:

1. Under 800 square feet
2. 800 to 1,500 square feet

3. 1,501 to 2,500 square feet
4. 2,501 to 3,500 square feet
5. Over 3,500 square feet
98. Don't know
97. Prefer not to answer

C2. In what range does your age fall:

1. Under 18
2. 18 to 34
3. 35 to 44
4. 45 to 54
5. 55 to 64
6. 65 or over
97. Prefer not to answer

C3. What was the last grade or level of schooling that you completed?

1. 1st through 8th grade
2. Some high school
3. High school graduate or equivalent
4. Some college or technical school
5. College graduate
6. Graduate/post-graduate school
97. Prefer not to answer

C4. Which of the following income categories includes your household income?

1. Under $10,000
2. $10,000 to $20,000
3. Over $20,000 to $30,000
4. Over $30,000 to $40,000
5. Over $40,000 to $50,000
6. Over $50,000 to $75,000
7. Over $75,000 to $100,000
8. Over $100,000 to $150,000
9. Over $150,000 to $200,000
10. Over $200,000
97. Prefer not to answer

C5. What is your gender?

1. Male
2. Female

97. Prefer not to answer

[STANDARD CLOSING]

Thank you for your time. Your responses will assist **[LG&E, Kentucky Utilities]** in its efforts to continue to improve the Advanced Meter Service offering.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 25

Responding Witness: John P. Malloy

Q-25. Please refer to the chart entitled "Response Rate Summary" on page 59 of Exhibit JMH-1 (Appendix A-1), concerning the AMS Participant Study.

a) For the 1,010 emails delivered to LG&E customers, please provide a breakdown of residential customers by zip code.

b) Of the 1,010 emails delivered to LG&E customers, how many were delivered to customers who had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of AMS customer enrollments in June 2015 and ending December 31, 2016?

c) For the 179 surveys completed by LG&E customers, please provide a breakdown of residential customers by zip code.

d) Of the 179 surveys completed by LG&E customers, how many were completed by customers who had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of AMS customer enrollments in June 2015 and ending December 31, 2016?

A-25.

a) LG&E commercial customers, emails delivered = 8

Emails Delivered by Zip Code -LG&E Residential Only	
Zip Code	**# Emails**
40245	105
40241	98
40223	93
40217	69
40218	63
40205	51
40243	49

40207	40
40299	39
40220	36
40214	35
40222	29
40204	26
40291	25
40206	22
40059	21
40258	19
40229	18
40242	17
40219	15
40215	13
40031	11
40213	11
40216	11
40228	11
40014	10
40203	10
40272	10
40026	6
40056	6
40208	6
40118	5
40023	4
40047	4
40202	3
40212	3
40165	2
40210	2
40211	2
40010	1
42503	1
Total LG&E Residential	***1,002***

b) We are unable to match individual completed surveys to customer account numbers. We can state that 49 AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

c) LG&E commercial customers, completed surveys = 1

Completed Surveys by Zip Code -LG&E Residential Only	
Zip Code	**# CMPLTS**
40245	17
40217	16
40223	16
40241	15
40218	14
40205	13
40243	13
40204	9
40207	5
40214	5
40220	5
40222	5
40242	5
40059	4
40206	4
40291	4
40014	3
40216	3
40229	3
40258	3
40299	3
40031	2
40215	2
40219	2
40118	1
40202	1
40208	1
40213	1
40272	1
40023	1
40203	1
Total LG&E Residential	***178***

d) The Company is unable to match individual completed surveys to customer account numbers. The Company can state that 49 AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 26

Responding Witness: John P. Malloy

Q-26. Please refer to the graph entitled "Steps Taken to Save Energy" on page 87 of Exhibit JMH-1 (Appendix A-1), concerning the AMS Participant Study. For each energy saving step included in the graph, please:

a) provide the number of LG&E customer respondents taking that step, broken down by zip code;

b) provide the number of LG&E customer respondents taking that step, broken down by the income levels used by the AMS Participant Study to collect demographic information; and

c) indicate how many of the LG&E customer respondents taking that step had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of AMS customer enrollments in June 2015 and ending December 31, 2016.

A-26.

a) Base: LG&E residential customers who accessed MyMeter Dashboard (n=150)

Steps Taken to Save Energy by Zip Code - LG&E Residential Only								
Zip Code	Upgraded to LED Bulbs	Improved Home's Insulation	Weather-Stripped Windows and Doors	Programmed Thermostat Temperature Settings	Purchased New Energy Efficient Appliances	Purchased a New Thermostat	Other	None
40014	3	1	1	0	1	2	1	0
40023	1	0	0	0	1	0	0	0
40031	2	1	1	1	0	0	0	0
40059	3	1	1	3	1	0	1	1
40118	1	1	0	0	1	1	1	0
40202	0	0	0	1	0	0	1	0
40203	1	0	0	1	0	1	0	0
40204	6	2	5	6	2	3	0	0
40205	5	2	2	6	1	2	2	4
40206	2	1	2	3	0	0	0	0
40207	2	1	1	3	2	0	0	1
40208	1	1	0	1	0	0	0	0

40213	1	0	0	1	0	0	0	0
40214	3	1	1	0	2	2	0	0
40215	1	1	1	1	1	1	1	0
40216	1	1	0	1	1	0	1	0
40217	6	4	0	6	2	2	1	3
40218	8	2	3	4	3	1	1	1
40219	2	1	0	1	0	0	0	0
40220	2	2	1	1	1	2	0	1
40222	2	1	2	2	2	1	0	1
40223	7	1	1	5	3	3	2	6
40229	2	0	2	1	1	1	0	0
40241	5	0	2	6	1	2	2	1
40242	2	0	1	0	0	1	0	1
40243	4	1	2	5	2	0	2	2
40245	8	3	1	6	3	0	1	4
40258	1	0	0	0	0	0	0	1
40272	0	0	0	0	0	0	0	0
40291	3	0	1	1	1	2	0	0
40299	2	1	0	1	1	0	0	1
Total LG&E Residential	***87***	***30***	***31***	***67***	***33***	***27***	***17***	***28***

b) LG&E residential customers who accessed MyMeter Dashboard (n=150)

Steps Taken to Save Energy by Income - LG&E Residential Only								
Income Level	**Upgraded to LED Bulbs**	**Improved Home's Insulation**	**Weather-Stripped Windows and Doors**	**Programmed Thermostat Temperature Settings**	**Purchased New Energy Efficient Appliances**	**Purchased a New Thermostat**	**Other**	**None**
$40,000 or less	**8**	**3**	**4**	**4**	**3**	**4**	**3**	**0**
Under $10,000	2	0	1	2	1	1	1	0
$10,000 to $20,000	2	2	2	1	1	1	0	0
Over $20,000 to $30,000	3	1	0	0	1	2	2	0
Over $30,000 to $40,000	1	0	1	1	0	0	0	0
Over $40,000	**67**	**25**	**22**	**57**	**27**	**21**	**12**	**22**
Over $40,000 to $50,000	5	2	2	4	4	3	1	2
Over $50,000 to $75,000	12	7	4	15	2	6	0	5
Over $75,000 to $100,000	16	7	4	11	7	5	5	4
Over $100,000 to $150,000	14	2	6	13	7	5	4	6
Over $150,000 to $200,000	11	5	2	6	3	1	1	4
Over $200,000	9	2	4	8	4	1	1	1
Prefer not to answer	**12**	**2**	**5**	**6**	**3**	**2**	**2**	**6**
Total LG&E Residential	***87***	***30***	***31***	***67***	***33***	***27***	***17***	***28***

c) The Company is unable to match individual completed surveys to customer account numbers. The Company can state that 49 AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 27

Responding Witness: John P. Malloy

Q-27. Please refer to the graph entitled "Appliances Purchased" on page 88 of Exhibit JMH-1 (Appendix A-1), concerning the AMS Participant Study. For each appliance included in the graph (including "other"), please:

a) provide the number of LG&E customer respondents purchasing that appliance, broken down by zip code;

b) provide the number of LG&E customer respondents purchasing that appliance, broken down by the income levels used by the AMS Participant Study to collect demographic information; and

c) indicate how many of the LG&E customer respondents purchasing that appliance had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of AMS customer enrollments in June 2015 and ending December 31, 2016.

A-27.

a) Base: LG&E residential customers who accessed MyMeter Dashboard and Purchased New Energy Efficiency Appliances (n=33)

Appliances Purchased by Zip Code - LG&E Residential Only								
Zip Code	Refrigerator	Freezer	Dishwasher	Stove/Oven/Cooktop	Clothes Washer	Clothes Dryer	Water Heater	Other
40014	1	0	1	0	1	1	0	0
40023	0	0	1	0	1	1	0	0
40031	0	0	0	0	0	0	0	0
40059	0	0	0	0	1	1	0	0
40118	1	0	0	1	1	1	0	0
40202	0	0	0	0	0	0	0	0
40203	0	0	0	0	0	0	0	0
40204	0	0	1	0	1	1	0	0
40205	0	1	0	0	1	1	0	0
40206	0	0	0	0	0	0	0	0
40207	1	0	0	0	0	0	0	1
40208	0	0	0	0	0	0	0	0

40213	0	0	0	0	0	0	0	0
40214	0	0	2	0	0	0	0	0
40215	1	0	1	1	0	0	1	0
40216	0	0	0	0	1	1	0	0
40217	1	0	0	0	0	0	0	1
40218	2	1	0	1	0	0	1	0
40219	0	0	0	0	0	0	0	0
40220	1	0	1	1	1	1	0	0
40222	0	0	1	0	0	0	1	0
40223	2	0	0	0	0	0	0	1
40229	1	0	0	0	0	0	1	0
40241	0	0	1	1	0	0	1	1
40242	0	0	0	0	0	0	0	0
40243	0	1	0	0	0	0	0	1
40245	1	0	0	0	1	1	1	0
40258	0	0	0	0	0	0	0	0
40272	0	0	0	0	0	0	0	0
40291	0	0	0	0	0	0	0	1
40299	0	0	0	0	1	1	0	0
Total LG&E Residential	***12***	***3***	***9***	***5***	***10***	***10***	***6***	***6***

b) Base: LG&E residential customers who accessed MyMeter Dashboard and Purchased New Energy Efficiency Appliances (n=33)

Appliances Purchased by Income - LG&E Residential Only								
Income Level	**Refrigerator**	**Freezer**	**Dishwasher**	**Stove/Oven/Cooktop**	**Clothes Washer**	**Clothes Dryer**	**Water Heater**	**Other**
$40,000 or less	**3**	**0**	**0**	**2**	**1**	**1**	**1**	**0**
Under $10,000	1	0	0	0	0	0	0	0
$10,000 to $20,000	1	0	0	1	0	0	1	0
Over $20,000 to $30,000	1	0	0	1	1	1	0	0
Over $30,000 to $40,000	0	0	0	0	0	0	0	0
Over $40,000	**9**	**2**	**8**	**3**	**9**	**9**	**5**	**5**
Over $40,000 to $50,000	2	0	2	1	3	3	0	1
Over $50,000 to $75,000	1	0	0	0	1	1	0	0
Over $75,000 to $100,000	1	0	3	1	2	2	1	3
Over $100,000 to $150,000	3	1	2	1	1	1	3	0
Over $150,000 to $200,000	1	0	0	0	1	1	0	1
Over $200,000	1	1	1	0	1	1	1	0
Prefer not to answer	**0**	**1**	**1**	**0**	**0**	**0**	**0**	**1**
Total LG&E Residential	***12***	***3***	***9***	***5***	***10***	***10***	***6***	***6***

c) The company is unable to match individual completed surveys to customer account numbers. The Company can state that 49 AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 28

Responding Witness: John P. Malloy

Q-28. Please refer to the graph entitled "Type of Thermostat Purchased" on page 89 of Exhibit JMH-1 (Appendix A-1), concerning the AMS Participant Study. For each type of thermostat (including "other"), please:

a) provide the number of LG&E customer respondents purchasing that type of thermostat, broken down by zip code;

b) provide the number of LG&E customer respondents purchasing that type of thermostat, broken down by the income levels used by the AMS Participant Study to collect demographic information; and

c) indicate how many of the LG&E customer respondents purchasing that type of thermostat had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of AMS customer enrollments in June 2015 and ending December 31, 2016.

A-28.

a) Base: LG&E residential customers who accessed MyMeter Dashboard and Purchased a New Thermostat (n=27)

Type of Thermostat Purchased by Zip Code - LG&E Residential Only				
Zip Code	Programmable	WI-FI Enabled	Self-Learning	Other
40014	1	1	0	0
40023	0	0	0	0
40031	0	0	0	0
40059	0	0	0	0
40118	1	0	0	0
40202	0	0	0	0
40203	1	1	0	0
40204	3	1	1	2
40205	1	2	1	0
40206	0	0	0	0
40207	0	0	0	0
40208	0	0	0	0
40213	0	0	0	0

40214	1	2	2	0
40215	1	1	0	0
40216	0	0	0	0
40217	2	1	0	0
40218	1	0	0	0
40219	0	0	0	0
40220	1	1	0	0
40222	1	0	0	0
40223	3	1	0	0
40229	1	1	0	0
40241	2	0	0	0
40242	1	0	0	0
40243	0	0	0	0
40245	0	0	0	0
40258	0	0	0	0
40272	0	0	0	0
40291	1	0	1	0
40299	0	0	0	0
Total LG&E Residential	***22***	***12***	***5***	***2***

b) Base: LG&E residential customers who accessed MyMeter Dashboard and Purchased a New Thermostat (n=27)

Type of Thermostat Purchased by Income - LG&E Residential Only				
Income Level	**Programmable**	**WI-FI Enabled**	**Self-Learning**	**Other**
$40,000 or less	**4**	**0**	**0**	**1**
Under $10,000	1	0	0	1
$10,000 to $20,000	1	0	0	0
Over $20,000 to $30,000	2	0	0	0
Over $30,000 to $40,000	0	0	0	0
Over $40,000	**16**	**12**	**5**	**1**
Over $40,000 to $50,000	2	1	0	0
Over $50,000 to $75,000	5	3	1	1
Over $75,000 to $100,000	4	3	1	0
Over $100,000 to $150,000	4	4	1	0
Over $150,000 to $200,000	0	0	1	0
Over $200,000	1	1	1	0
Prefer not to answer	**2**	**0**	**0**	**0**
Total LG&E Residential	***22***	***12***	***5***	***2***

c) The Company is unable to match individual completed surveys to customer account numbers. The Company can state that 49 AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 29

Responding Witness: John P. Malloy

Q-29. Please refer to the graph entitled "Energy Efficiency Program Enrollment" on page 90 of Exhibit JMH-1 (Appendix A-1), concerning the AMS Participant Study. For each energy efficiency program (including "other"), please:

a) provide the number of LG&E customer respondents enrolling in that program, broken down by zip code;

b) provide the number of LG&E customer enrolling in that program, broken down by the income levels used by the AMS Participant Study to collect demographic information; and

c) indicate how many of the LG&E customer respondents enrolling in that program had a bill payment made by a third-party assistance provider during the period beginning twelve months prior to the start of AMS customer enrollments in June 2015 and ending December 31, 2016.

A-29. a) Base: LG&E residential customers who accessed MyMeter Dashboard (n=150)

Energy Efficiency Program Enrollment by Zip Code - LG&E Residential Only										
Zip Code	Demand Conservation	Fridge and Freezer Recycling	Smart Energy Profile	Online Home Energy Analysis	On-Site Home Energy Analysis	Home Energy Rebates	WeCare	Participated Prior to Joining AMS	Other	None
40014	1	0	0	0	0	1	0	0	1	1
40023	1	1	0	0	0	0	0	0	0	0
40031	1	0	0	0	0	0	0	0	0	1
40059	1	0	2	2	1	1	0	0	0	1
40118	1	0	0	0	0	0	0	0	0	0
40202	0	0	0	0	0	0	0	0	0	1
40203	1	0	1	1	0	0	0	0	0	0
40204	4	0	3	2	2	2	1	1	0	2
40205	6	1	4	1	3	3	0	1	0	3
40206	2	0	1	2	0	0	0	0	0	2
40207	1	0	0	1	1	2	0	0	0	3
40208	0	0	0	1	0	0	0	0	0	0
40213	1	0	0	0	0	0	0	0	0	0
40214	2	1	0	0	1	2	0	0	0	1
40215	0	0	0	0	1	1	0	0	0	0

40216	1	0	0	0	0	1	0	1	0	0
40217	3	1	2	1	1	2	0	0	0	8
40218	3	4	0	3	2	1	0	0	0	2
40219	1	1	0	0	0	0	0	0	0	1
40220	1	0	1	1	0	1	0	0	0	2
40222	2	0	1	2	1	2	1	0	0	1
40223	2	3	0	1	1	4	0	0	0	9
40229	1	1	1	1	1	1	0	0	0	1
40241	4	3	0	1	0	3	0	0	0	4
40242	1	0	1	1	1	0	0	0	0	2
40243	3	0	1	1	2	2	0	0	0	6
40245	3	2	5	3	2	5	1	0	0	4
40258	0	0	0	0	0	0	0	1	0	1
40272	0	0	0	0	0	0	0	0	0	0
40291	2	0	1	1	1	1	0	0	0	1
40299	1	1	1	0	0	2	0	0	0	1
Total LG&E Residential	***50***	***19***	***25***	***26***	***21***	***37***	***3***	***4***	***1***	***58***

b) Base: LG&E residential customers who accessed MyMeter Dashboard (n=150)

Energy Efficiency Program Enrollment by Income - LG&E Residential Only										
Income Level	**Demand Conservation**	**Fridge and Freezer Recycling**	**Smart Energy Profile**	**Online Home Energy Analysis**	**On-Site Home Energy Analysis**	**Home Energy Rebates**	**WeCare**	**Participated Prior to Joining AMS**	**Other**	**None**
$40,000 or less	**3**	**2**	**3**	**5**	**2**	**1**	**1**	**1**	**0**	**2**
Under $10,000	0	0	1	2	1	0	1	0	0	1
$10,000 to $20,000	0	1	0	1	1	1	0	0	0	0
Over $20,000 to $30,000	2	1	2	1	0	0	0	1	0	1
Over $30,000 to $40,000	1	0	0	1	0	0	0	0	0	0
Over $40,000	**42**	**15**	**19**	**18**	**15**	**34**	**1**	**3**	**1**	**44**
Over $40,000 to $50,000	5	1	1	1	1	4	0	0	1	3
Over $50,000 to $75,000	10	2	5	5	4	5	1	1	0	12
Over $75,000 to $100,000	12	6	4	6	3	10	0	0	0	6
Over $100,000 to $150,000	9	4	4	1	5	9	0	1	0	12
Over $150,000 to $200,000	4	0	3	4	1	2	0	1	0	6
Over $200,000	2	2	2	1	1	4	0	0	0	5
Prefer not to answer	**5**	**2**	**3**	**3**	**4**	**2**	**1**	**0**	**0**	**12**
Total LG&E Residential	***50***	***19***	***25***	***26***	***21***	***37***	***3***	***4***	***1***	***58***

c) The Company is are unable to match individual completed surveys to customer account numbers. The Company can state that 49 AMS opt-in customers received a payment from a third-party assistance provider during the specified time period of June 1, 2014 through December 31, 2016.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 30

Responding Witness: John P. Malloy

Q-30. Please provide the following information regarding use of the on-line My Account self-service site by LG&E's residential customers:

a) The total number of unique residential My Account registrants as of December 31, 2016, broken down by zip code, in Excel format.

b) Number of accounts in (a) belonging to customers who had a bill paid by a third party assistance provider in either 2015 or 2016.

c) Number of accounts in (a) belonging to customers who were disconnected for nonpayment during either of the years 7/1/2014 – 6/30/2015 or 7/1/2015 – 6/30/2016.

d) For each of the years 2015 and 2016, the total number of bill payments made via My Account, broken down by zip code, in Excel format.

e) Number of payments in (d) made by customers who had a bill paid by a third party assistance provider in either 2015 or 2016.

f) Number of customers who signed up for budget billing via My Account.

A-30.

a-c) See the attachment being provided in Excel format.

d-e) See the attachment being provided in Excel format.

f) 4,168 LG&E residential customers signed up for budget billing via My Account.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 31

Responding Witness: John P. Malloy

Q-31. Please provide the following information for each of the years 2015 and 2016:

a) Number of residential LG&E customers who used the on-line feature to start or move service, broken down by zip code.

b) Of the number in (a), number of customers who had a bill paid by a third party assistance provider in either year.

c) Number of residential customers who used the on-line feature to stop service, broken down by zip code.

d) Of the number in (c), number of customers who had a bill paid by a third party assistance provider in either year.

A-31. Data as requested by zip code and by utility is not available.

a-d) See the table below for the number of customers utilizing start, move, or stop service features on on-line.

Feature	2015	2016	LG&E customers with third party assistance provider payments
Start/Move Service	4,625	5,358	221
Stop Service	8,209	8,605	156

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 32

Responding Witness: John P. Malloy

Q-32. Please refer to the Malloy testimony at page 14, lines 10 – 14, regarding the introduction of Outage Texting and My Notifications. For each of these offerings, respectively, please provide the following information concerning residential customers in the LG&E service territory:

a) Total number of customers who have signed up for the service through December 31, 2016, broken down by zip code.

b) Of the number in (a), number of customers who had a bill paid by a third party assistance provider in either 2015 or 2016.

A-32.

a-b) Outage Texting is available to customers without the need to sign up. Further information on Outage Texting is available via the Company's website, https://lge-ku.com/outages/report/texting. Outage Texting works with our Trouble Order Entry system and data is available by zip code for customers who have utilized Outage Texting. See attachment for data in the Excel format.

My Notifications sign ups occur in My Account at a user level. As a result, data as requested by zip code and separated to the LG&E service territory only is not available. 83,096 customers across all of LG&E and KU have signed up for My Notifications as of December 31, 2016. Of the customers who signed up for My Notifications, 5,320 are LG&E customers and have had a bill paid by a third party assistance provider in either 2015 or 2016.

Number of Customers that have utilized Outage Texting through December 31, 2016

	a)	b)
Zip Code	**Number of Customers**	**Of a), Customers who have had a Bill Paid by a Third Party Assistance Provider in either 2015 or 2016**
40207	643	3
40291	435	10
40220	433	7
40205	432	-
40299	388	5
40272	306	10
40204	276	4
40014	269	5
40219	254	12
40031	249	-
40216	242	10
40218	232	6
40229	227	4
40223	226	2
40214	224	5
40241	224	-
40206	206	2
40059	190	-
40222	182	-
40258	180	8
40217	177	1
40213	133	1
40245	123	-
40243	101	1
40228	95	-
40215	93	9
40118	91	5
40165	77	1
40242	72	2
40056	64	-
40211	56	9
40208	52	2
40023	47	-
40026	45	-

Number of Customers that have utilized Outage Texting through December 31, 2016

	a)	b)
Zip Code	**Number of Customers**	**Of a), Customers who have had a Bill Paid by a Third Party Assistance Provider in either 2015 or 2016**
40212	45	7
40203	45	2
40108	30	-
40210	24	3
40077	17	-
40202	12	-
40055	12	-
40047	11	-
40010	9	-
40155	8	2
40109	3	-
40177	2	-
40209	2	-
40027	1	-
40025	1	-
40175	1	-
Total	**7,267**	**138**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 33

Responding Witness: John P. Malloy

Q-33. Please refer to page 17, lines 21 - 23 of the Malloy Testimony, concerning the Companies' "comprehensive look at smart meters when federal funding was available for smart-grid deployments under the American Reinvestment and Recovery Act," in which it was assisted by Accenture Consulting. Please provide the resulting analysis, conclusions and report(s).

A-33. See attached.

E.ON U.S.

Smart Meter/Grid Business Case Development

Final Progress Review

Material for Discussion

May 6, 2009

Meeting Objectives

- Review Phase I Development:
  Smart Meter/Grid Strategy Entry Options

- Phase II Project Overview and Recommendations
  - Project Description
  - Financials of Recommended Deployment
  - Conclusions/Recommendations

- Next Steps and Project Schedule

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Smart Metering/Grid Strategy Entry Options

Increasing Functionality – Benefit – Expense – Risk

Opt. 4

Smart Grid

Full AMI+
- Self healing capability
- Enhanced operational capability
- Line fault sensors
- Automated reclosers
- Automated Volt/VAR control
- Autonomous DR
- Integration of building controls
- Plug-in Hybrid Electric Vehicles
- Micro energy storage
- Rooftop solar energy

Opt. 3

C) AMI – Combined Relay and HAN

B) AMI – Home Area Network
- Appliance control
- Energy Display
- DSM
- Other Controls

A) AMI – Relay Integral Remote On/Off Relay
- Load limiting

AMI - Basic

AMR+
- TOU rates
- Distributed Generation monitoring
- Remote meter programming
- Power Quality monitoring/ reporting
- Outage response/monitoring

Opt. 2

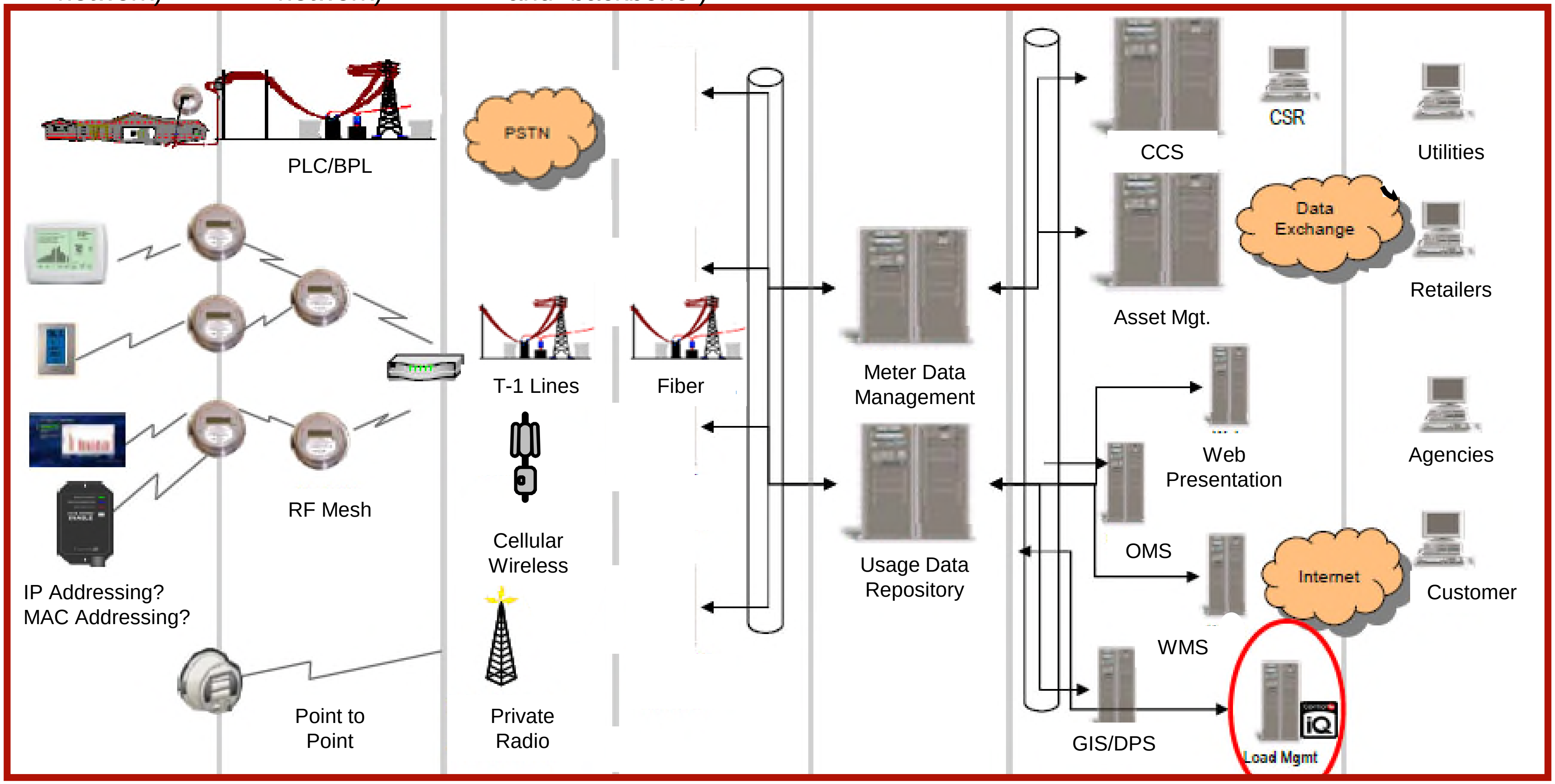
AMR
- Automated monthly reads
- End point data
- Tamper reporting

Opt. 1

Current

State

HAN (home area network) | LAN (local area network) | WAN/BackHaul (wide area network and "backbone") | Meter Data Management | Back-Office | External Apps



RF Mesh
WiFi
ZigBee
ERT

BlueTooth
Z-Wave
More …

MidHaul?
3G
Wireless?
Radio?

Many options over fiber:
Ethernet over fiber (office and plants)
MPLS between here and Germany
DWDM between BOC and Simpsonville

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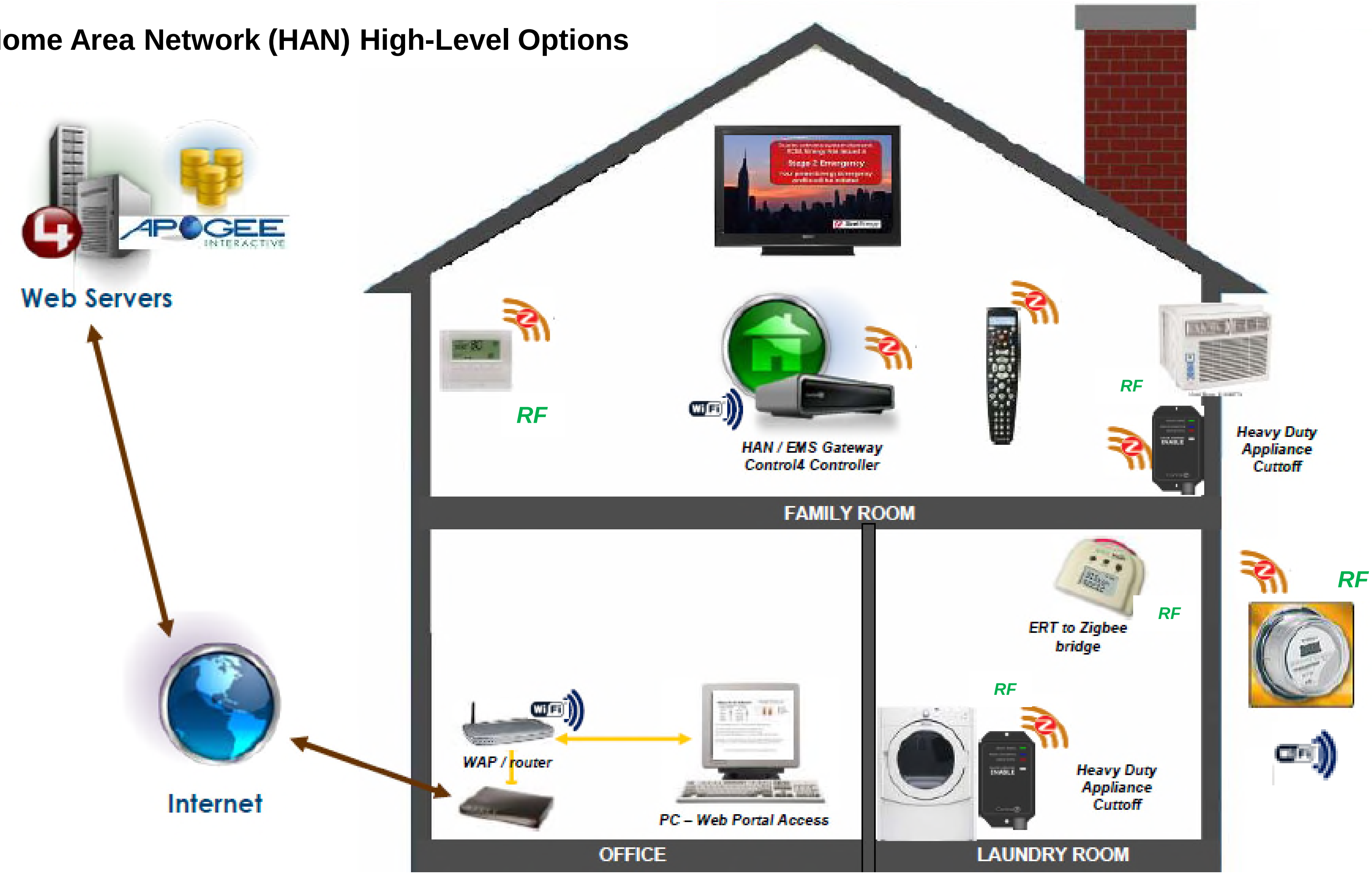
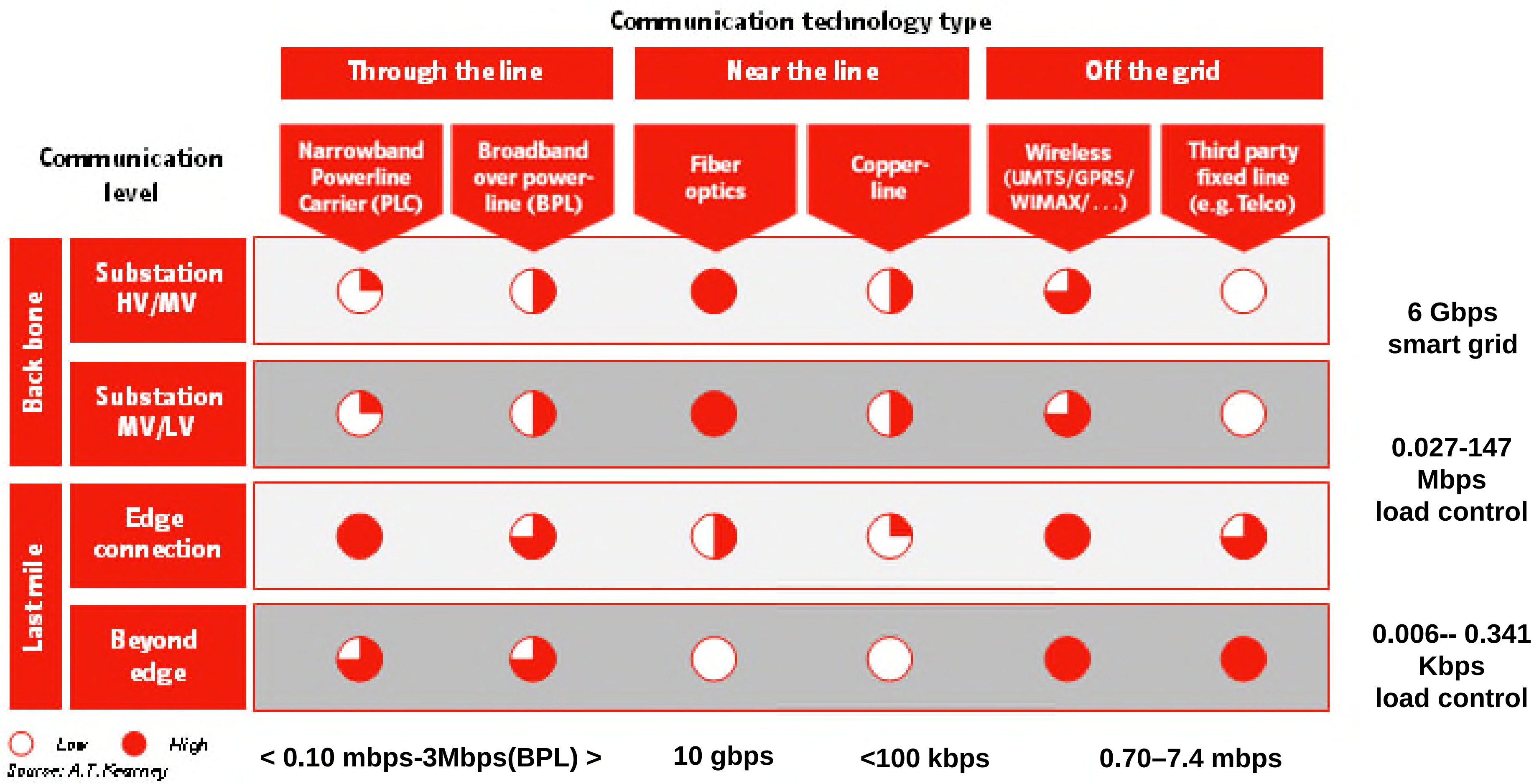
Home Area Network (HAN) High-Level Options



With our choice of comms in the meter, we decide if the meter will only speak to the devices we offer, or if the customer is able to "plug-in" and analyze/manage energy with retail products. WiFi is totally open; then ZigBee; then private RF.

Bandwidth is the definitive measure of smart grid communications.

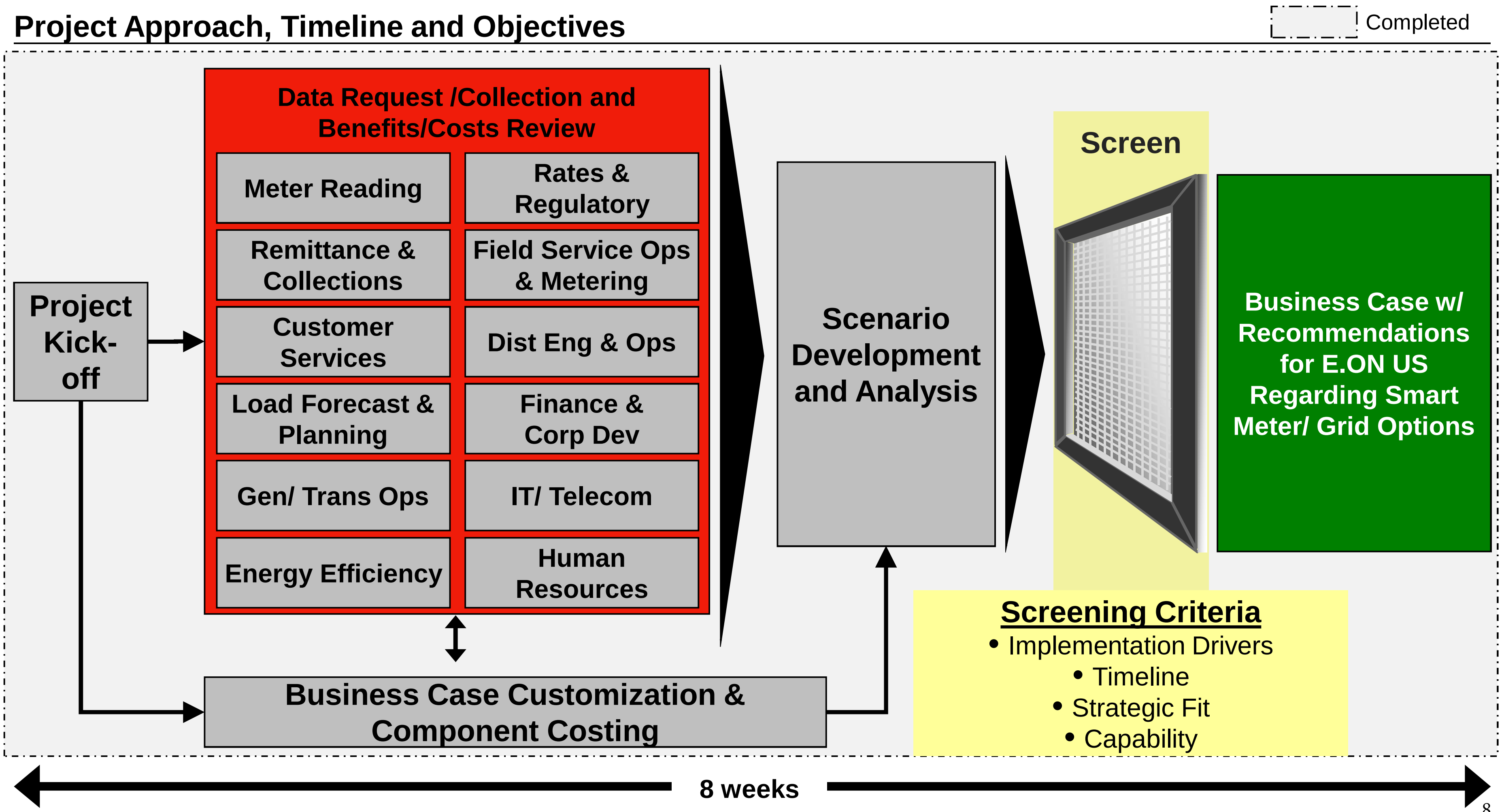


Phase II: Business Case Development

- Cross-organizational "deep dive", cost-benefit study of Smart Meter/Grid deployment options.
- Accenture retained for eight-week project.
- Excluded RFP/RFI on equipment and technology costs.
  Utilized Accenture's project experience. Targeted 85% accuracy of costs for Accenture deliverable.
  Internally assuming 25% contingency to allow for unknowns beyond Accenture capabilities.
- Objective was to identify a recommended deployment design to file with PSC
  and to pursue through Phase III project.

The project was completed on schedule

Project Approach, Timeline and Objectives



The project team focused upon cross-organizational cost-benefit analysis:

E.ON U.S. Core Project Team:

Butch Cockerill	Project Leader
Tony Ruckriegel	Co- Project Manager
Christopher Whelan	Co- Project Manager
David Cummings	Business Case Model Expert

E.ON U.S. Support Management Team:

John Wolfram	Marketing/Customer Service
Cheryl Bruner	Energy Efficiency

Accenture Core Team:

Andre Begosso	Project Lead
Curtis Bech	Business Case Model Specialist
Elaine Horn	Project Support
Chiara McPhee	Project Support

Subject Matter Experts:

Mike Hornung	Energy Efficiency
Rick Lovekamp	Regulatory Affairs
Richard Jones	Distribution Operations
Stuart Wilson	Energy Marketing
Don Thorn	Meter Assets
Joan Renfrow	Meter Reading
Eric Johnson	Telecommunications
Shannon Charnas	Finance
Barry Ray	Human Resources
Jason Jones	Information Technology
Scott Cooke	Generation Planning
Madhup Kumar	Energy Marketing
Jean Ann Pfisterer	Residential Service
Steve Woodworth	Distribution Operations

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AMI and Smart Grid deployment scenarios were evaluated.

One scenario is recommended.

Opt. 4

Smart Grid

Full AMI+

- Self healing capability
- Enhanced operational capability
- Line fault sensors
- Automated reclosers
- Automated Volt/VAR control
- Autonomous DR
- Integration of building controls
- Plug-in Hybrid Electric Vehicles
- Micro energy storage
- Rooftop solar energy

Opt. 3

C) AMI – Combined Relay and HAN

B) AMI – Home Area Network

- Appliance control
- Energy Display
- DSM
- Other Controls

A) AMI – Relay Integral Remote On/Off Relay

- Load limiting

AMI - Basic

AMR+

- TOU rates
- Distributed Generation monitoring
- Remote meter programming
- Power Quality monitoring/ reporting
- Outage response/monitoring

AMI with Relay and HAN

- Initial findings indicate that a rollout of AMI is the most financially viable scenario.
- Lay the foundation for a future Smart Grid deployment.

Smart Grid

- High implementation costs, plus the fact that many Smart Grid benefits are already captured in current rates, casts doubt on the near term financial justification of large-scale deployments of Smart Grid.

Recommended Deployment Design: Full AMI with Relay and HAN

This scenario models the development of an Advanced Metering Infrastructure (AMI) including the full rollout of Smart Meters throughout the entire service territory of LG&E, KU, and ODP (urban and rural) for all electric and gas customers. This full AMI deployment allows the utility to read and disconnect/reconnect meters remotely, and offer time-of-use rates. The Smart Meters, being HAN-enabled, include the Home-Area-Network chip (with protocols, such as ZigBee, WiFi, etc., yet to be determined) which enables communications and control between the utility and in-home devices (i.e., energy displays, appliances, etc.). This scenario assumes full ownership of telecom infrastructure (as opposed to leased lines.)

Deployment Schedule

- Urban Smart Meters –starts in year 1 and takes 2 years (Louisville / Lexington simultaneous)
- Rural Smart Meters – starts in year 3 and takes 5 years
- Urban Smart Grid – none
- Rural Smart Grid – none

Key Benefits

- Advanced meters eliminate the need for monthly meter reads
- There is a significant reduction in meter field stops (for disconnects and reconnects)
- System losses and under-metering, while recovered under current rates, will be also reduced

IT and Communications

- Systems required for Smart Meters include MDMS, CCS / Billing, OMS, GIS and Data Warehouse
- Ongoing IT maintenance of approx. $4.4MM annually include software support fees and IT support staff
- IT costs do include cyber security costs as meter read data is done over a private network
- Assuming roughly hourly meter reads, communications backbone requires upgrading

AMI with Relay and HAN

Breakdown of Capex

Nominal capex in 2009$ (in $MM) for LG&E and KU

	2010-2014		+15 yrs		Total	
Meters	121	+	21	=	142	▪ $80 for residential meters, $290 for C&I meters ▪ $30 for connect/disconnect relay
Distribution Equipment		+	-	=	-	▪ No Smart Grid equipment included
Installation	20	+	6	=	26	▪ Meter installation costs = $16 for urban & $32 for rural ▪ No Smart Grid installation cost
Comms	21	+	4	=	25	▪ AMI capex comms includes backhaul, collectors, LAN & head-end costs ▪ No Smart Grid communications costs included
IT Hardware	8	+	-	=	8	▪ IT systems implemented over 2 year rollout period for AMI
IT Software	9	+	-	=	9	▪ System requirements and estimated costs – MDMS (N-$2.4MM), CCS / Billing (M-$0.5MM), GIS (M-$2.7MM), OMS (M-$1.9MM), Data Warehouse (N-$1.9MM)
IT Implementation	6	+	-	=	6	▪ IT System Code: M = Modify, R = Replace, N = New
Total Capex	185	+	31	=	215	+ A&G burden cost of $30MM = **$245MM TOTAL**

Source: Accenture analysis

U.S.

AMI with Relay and HAN

Breakdown of Opex

Nominal opex in 2009$ (in $MM) for LG&E and KU

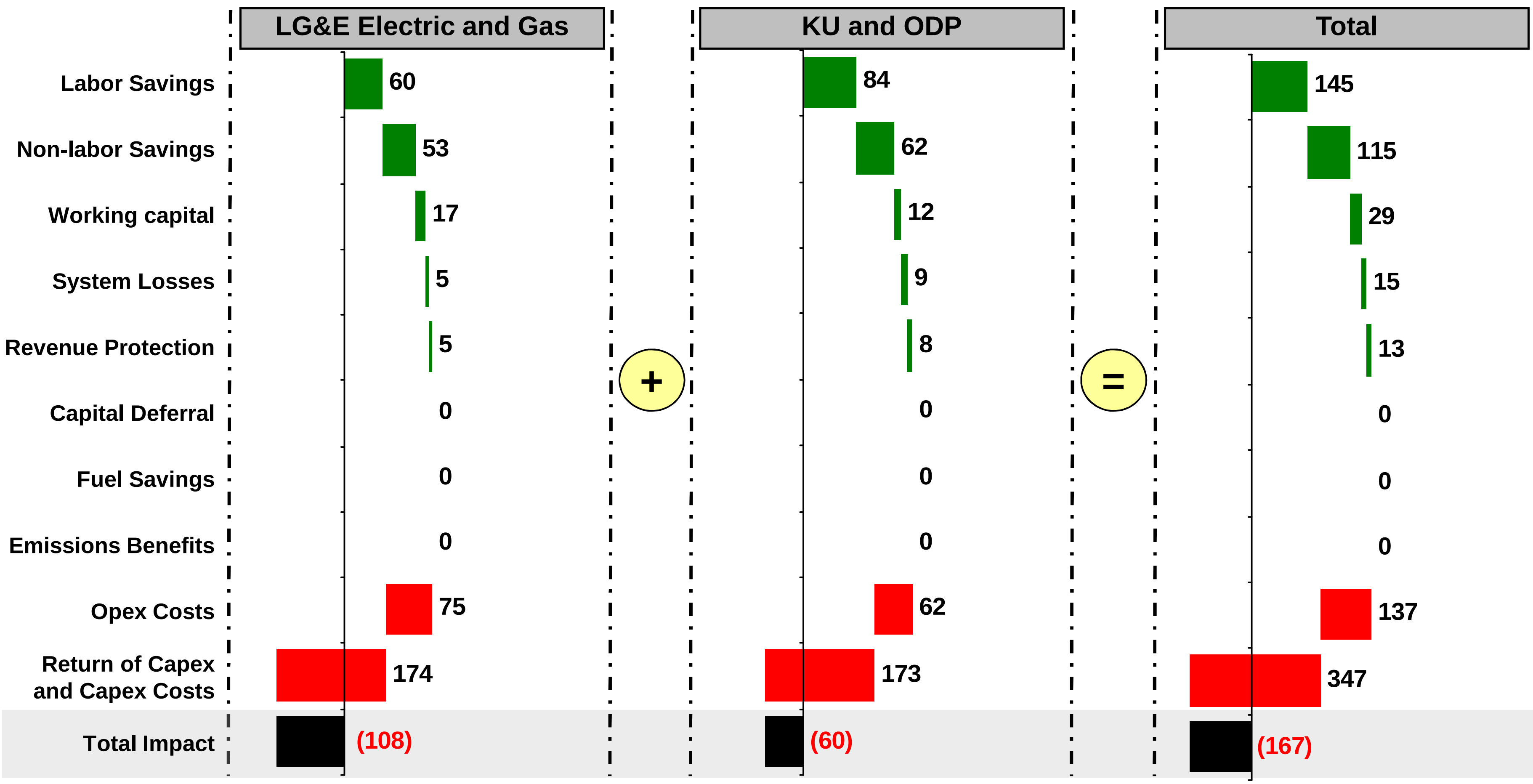
	2010-2014		+15 yrs		Total	
Program Mgmt	9	+	4	=	12	▪ Smart Meter program mgmt cost are about $8 per meter ▪ No Smart Grid program mgmt cost → could be 2-5 larger than SM
Comms	13	+	74	=	87	▪ ~$5 per meter O&M charge for building $25MM in new infrastructure ▪ Assumes 12 additional FTE's (telecom and network)
Business & Training	4	+	-	=	4	▪ Business & training costs are a function of the complexity of the IT systems being implemented
Ongoing SW	4	+	25	=	30	▪ Ongoing SW costs are calculated as 6% of the total cost for HW, SW, and implementation ▪ Ongoing IT costs are calculated as 12% of the total cost for HW, SW, and implementation ▪ Incremental FTE numbers were not estimated but their costs are in the opex forecasts
Ongoing IT	8	+	51	=	59	
Annual Maintenance	3	+	14	=	17	▪ Incremental maintenance = 1% of total Smart meter capex cost
Total Opex	41	+	168	=	210	

Source: Accenture analysis

AMI with Relay and HAN

Pre-tax Cost Benefit Analysis

25 year NPV in $MM for benefit and cost categories



Note: All benefits lag costs by 2 years to reflect regulatory considerations and the need for achieving scale of implementation; all numbers are rounded

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Full AMI with Relay and HAN

Customer Rate Impact – Best Case, 100% of Benefits Achieved

(Traditional Rate Cases Tied to LTP)

	LG&E - Electric			LG&E - Gas		
	Year 1-12	Year 13- 25	Total	Year 1-12	Year 13- 25	Total
Revenue Requirement (in $MM)	$ 131.03	$ (23.69)	$ 107.34	$ 25.18	$ (50.35)	$ (25.17)
Average Customer Impact						
Residential/Month (in $)	$ 1.02	$ (0.17)	$ 0.40	$ 0.37	$ (0.68)	$ (0.18)
Commercial/Month (in $)	$ 7.08	$ (1.18)	$ 2.78	$ 1.92	$ (3.54)	$ (0.92)
Industrial/Month (in $)	$ 439.40	$ (73.34)	$ 172.77	$ 27.16	$ (50.12)	$ (13.03)

	KU			ODP		
	Year 1-12	Year 13- 25	Total	Year 1-12	Year 13- 25	Total
Revenue Requirement (in $MM)	$ 104.82	$ (135.10)	$ (30.28)	$ 7.24	$ (4.40)	$ 2.84
Average Customer Impact						
Residential/Month (in $)	$ 0.59	$ (0.70)	$ (0.08)	$ 0.04	$ (0.02)	$ 0.01
Commercial/Month (in $)	$ 2.10	$ (2.50)	$ (0.29)	$ 0.15	$ (0.08)	$ 0.03
Industrial/Month (in $)	$ 114.59	$ (136.34)	$ (15.89)	$ 7.91	$ (4.44)	$ 1.49

* Assumes 25 year recovery period

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Full AMI with Relay and HAN

Customer Rate Impact – Worst Case, Benefits NOT Achieved

(Traditional Rate Cases Tied to LTP)

	LG&E - Electric			LG&E - Gas		
	Year 1-12	Year 13- 25	Total	Year 1-12	Year 13- 25	Total
Revenue Requirement (in $MM)	$ 210.80	$ 154.10	$ 364.90	$ 62.91	$ 43.90	$ 106.81
Average Customer Impact						
Residential/Month (in $)	$ 1.63	$ 1.10	$ 1.36	$ 0.93	$ 0.60	$ 0.76
Commercial/Month (in $)	$ 11.38	$ 7.68	$ 9.46	$ 4.79	$ 3.09	$ 3.91
Industrial/Month (in $)	$ 706.89	$ 477.01	$ 587.35	$ 67.84	$ 43.71	$ 55.29

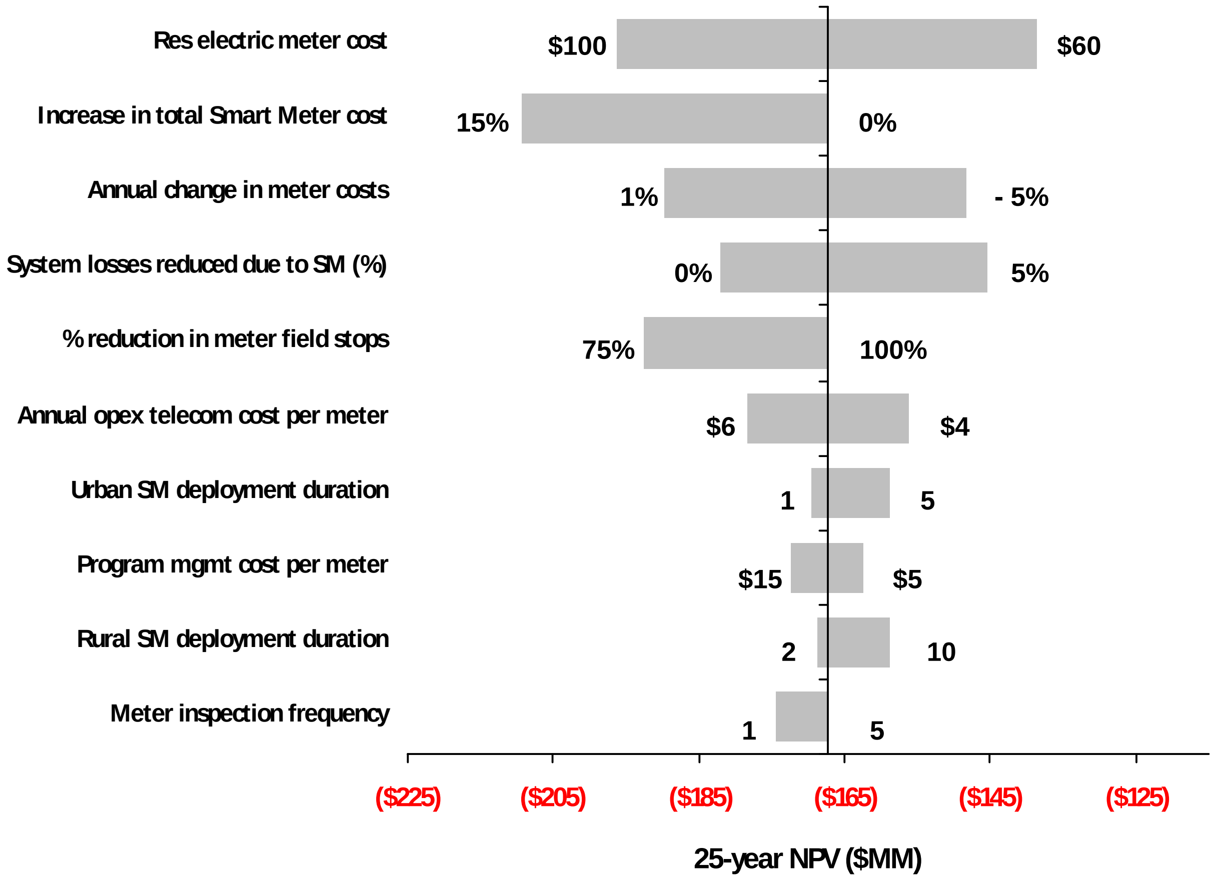
	KU			ODP		
	Year 1-12	Year 13- 25	Total	Year 1-12	Year 13- 25	Total
Revenue Requirement (in $MM)	$ 219.03	$ 232.56	$ 451.59	$ 12.58	$ 15.33	$ 27.91
Average Customer Impact						
Residential/Month (in $)	$ 1.23	$ 1.20	$ 1.21	$ 0.07	$ 0.08	$ 0.08
Commercial/Month (in $)	$ 4.39	$ 4.31	$ 4.35	$ 0.25	$ 0.28	$ 0.27
Industrial/Month (in $)	$ 239.46	$ 234.69	$ 236.98	$ 13.75	$ 15.47	$ 14.65

* Assumes 25 year recovery period

AMI with Relay and HAN

Sensitivity Analysis

Tornado analysis of key model inputs and their impact on the resulting 25 year NPV in $MM



Observations

- The meter cost is the most substantial cost and is the most significant driver of the overall NPV
- Very sensitive to total cost changes
- Understanding the impact of Smart Meters on system losses is key to any accurate estimation of benefits
- The duration of deployment periods is not a sensitive input – these parameters should be driven mainly by implementation considerations and limitations
- Because smart meters are forecasted to be installed in the short-term (2-5 years), declining meter costs has less of an impact on overall NPV than expected

Source: Accenture analysis

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AMI with Relay and HAN

Conclusions by Key Concern

Customer

- For a full rollout of AMI throughout all of E.ON U.S. territory, there is minimal impact to customer bills over planned recovery period
- AMI enhances offering of time and incentive based demand response programs and enables future HAN deployments
- Over time, relationship with customer is likely to change, requiring a review of Customer Service Representative roles, skills and capabilities

Financial

- 25 year NPV is ($108MM) and ($60MM) for LG&E and KU respectively
- ~80% of the benefits are associated with operational savings and the reduction of cost of contracts
- ~2/3rds of the capex cost is associated with meter equipment, approximately $142MM out of $215MM total

Regulatory

- Private network increases the impact on rates. However, necessary to ensure cyber security of network. Still creates option to increase services due to latent HAN card will provide the utility with a better understanding of the individual customers' load profile and allow them to offer more tailored conservation programs at marginal incremental cost
- Need to manage potential regulatory risks associated with inspecting / testing meters upon retirement
- Assume full continued recovery of existing meter assets.

Implementation

- Requires only 5 main IT systems and little upgrade to the communications backbone
- A key implementation consideration is building the workforce needed for any installation and support of new metering equipment
- RFQ process needs to be initiated in the near term to protect against rising meter prices due to increasing demand for advanced meter infrastructure

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Financial Summary – Cash Flows ($MM)

	Total	Y1	Y2	Y3	Y4-10	Y11-15	Y16-20
Total							
Full AMI with Relay and HAN	(455.1)	(81.3)	(82.8)	(28.4)	(150.6)	(54.5)	(57.5)
Full AMI with Relay, HAN and Full Comm. Backbone	(703.1)	(96.4)	(97.8)	(46.3)	(266.3)	(138.5)	(57.6)
Full AMI & Full Smart Grid	(1,496.4)	(120.4)	(123.1)	(88.7)	(568.5)	(383.4)	(212.2)
Capital Expenditure Cash Flows*							
Full AMI with Relay and HAN	(245.6)	(76.7)	(76.5)	(18.8)	(74.7)	0.6	0.5
Full AMI with Relay, HAN and Full Comm. Backbone	(493.5)	(91.8)	(91.5)	(36.8)	(190.4)	(83.4)	0.4
Full AMI & Full Smart Grid	(884.0)	(114.8)	(114.6)	(73.5)	(390.7)	(190.9)	0.5
Operating Expense Cash Flows**							
Full AMI with Relay and HAN	(209.6)	(4.6)	(6.4)	(9.6)	(75.9)	(55.1)	(58.0)
Full AMI with Relay, HAN and Full Comm. Backbone	(209.6)	(4.6)	(6.4)	(9.6)	(75.9)	(55.1)	(58.0)
Full AMI & Full Smart Grid	(612.4)	(5.6)	(8.6)	(15.2)	(177.8)	(192.6)	(212.8)

*Includes cost avoidance of mechanical meter replacements.
** Does not include savings

Our strategy focuses upon flexibility to adapt quickly as the landscape changes…

Core Architecture of our Strategy

- Consists of more mature technologies with the higher/most certain benefits
- Interoperable & forward compatible to maximize flexibility and minimize risk of obsolescence
- Additional capabilities added incrementally as the mature and/or become more cost justified

Smart Meters/DR and EE

- Home area network interface included in the smart meter spec. (e.g. Zigbee chip, WiFi, etc.)
- Open protocols to facilitate interoperability
- Initial roll out to include latent capabilities

Smart Grid (if legislated or approved)

- Initial roll out to focus on core capabilities such as network monitoring, fault detection and isolation, and power factor optimization

Communications

- Design communications with sufficient bandwidth/latency to deal with longer-term needs
- Design equipment to be communications agnostic

To pursue this strategy, E.ON should help the regulator address four major areas of uncertainty

Customer Needs

- Utility bills are relatively low – average $81/month – and most customers pay little attention to them
- Customers appear interested in many auxiliary services but their willingness to pay is unclear
- Current interests do not guarantee future demands
- The regulator must facilitate a Smart Grid that accommodate changing customer needs

Technology

- Currently, there is a heavy reliance on older proven technologies
- Development of new T&D technologies has been stymied by regulation
- Smart technologies can be tested via pilots but only **proven** by increasing the install base
- Regulator are used to long-term assets and are uncomfortable with allowing recovery on non-proven or short life cycle technologies

Economic

- Smart technologies are in their infancy so total cost to the consumer is uncertain
- Increasing the capital charge must be offset by a reduction in delivery cost
- While the utility must maintain good fiscal health to minimize the cost of capital, the regulator must allow a compelling rate of return to incentivize utility investments

Implementation

- The regulators key concern is system reliability
- Utilities are hesitant to install Smart technologies because their return on investment is only guaranteed once regulatory approval is granted

E.ON has just begun the Smart Technology journey that starts with strategic development and culminates with a full system design and implementation

1st Horizon – The Strategy

2nd Horizon – The Design

3rd Horizon – The Implementation

Today

- Develop Smart Meter / Grid Business Case
- Build scenario analysis – model impacts on end-to-end business
- Select strategy / deployment design
- Understand initial IT and telecom requirements
- Prepare capital requirement for internal budgeting process
- Brief KPSC and other key constituents about costs and benefits of Smart Technologies

4 Months

- Establish core project management team
- Create new operating model to support new strategy
- Map required capabilities and skills
- Thorough customer segmentation and different program designs
- In-depth design of system requirements, processes, capabilities, and implementation schedule
- RFQs and selection of vendors
- Gain internal capital approval

12 Months

- Set up program and project management office
- Mobilization of external vendors and E.ON resources
- Begin deployment of equipment, IT and Telecom infrastructure
- Delivery of meters, future systems and go-live
- Coordinate deployment in conjunction with of other DR/EE programs

2+ Years

Questions?

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Smart Grid
CEO/Sr. Officer Meeting

January 28, 2010

Objectives

- *Develop a common understanding of Smart Grid*
- *Review internal assessment to date*
- *Present key issues, industry considerations, and relative regulatory and legislative concerns*
- *Present go-forward strategy*

Agenda

• Smart Grid Overview	Cockerill
• Getting Smart about Smart Grid (Accenture)	Dave Bieber
	Tim Porter
• E.ON U.S. Pursuit of Smart Technology to date	Cockerill
• Technology Considerations	Mukundan
• Financial/Analytical Assessment	Sinclair
• Regulatory Construct	Bellar
• Federal and State Political Considerations	Beer/Siemens
• E.ON U.S. Strategy and Next Steps	Cockerill

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Smart Grid Overview

Butch Cockerill
Director, Revenue Collection

Three Functional Areas

- *Smart Meters and behind the meter*
- *Distribution Control and Automation*
- *Transmission Control and Automation*

Smart Grid of Tomorrow

Getting Smart about Smart Grid

Markets and Trends Overview - Accenture

Dave Bieber
Tim Porter

Key Questions to Consider

- *Why are companies investing in Smart Grid?*
- *What are companies doing?*
- *What ARE the companies biggest concerns?*
- *What SHOULD be their biggest concerns?*
- *How are companies thinking about the change?*

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Why are companies investing in Smart-Grid? (1 of 3)

- *To optimize operating costs and improve quality of cashflow*
- *To improve customer satisfaction by understanding customer consumption and helping them save energy*
- *To reduce carbon emissions*
- *To incorporate increased penetration of variable generation and RPS requirements*

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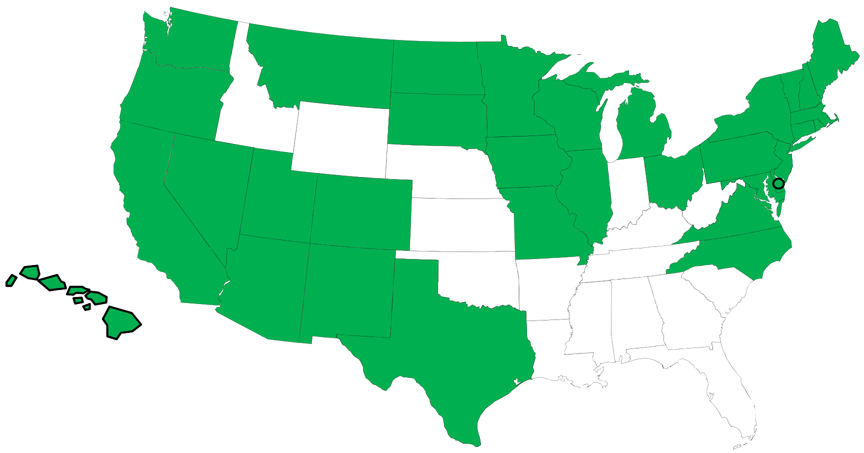
Why are companies investing in Smart-Grid? (2 of 3)
Market Driver – Renewable Portfolio Standards

States with Renewable Energy Mandates: 2009



Renewable Program Example Targets and Dates

STATE0	GOAL	YEAR	STATE	GOAL	YEAR	STATE	GOAL	YEAR
Arizona	15%	2025	Massachusetts	15%	2020	North Carolina	13%	2021
California	33%	2020	Michigan	10%	2015	Ohio	25%	2025
Colorado	20%	2020	Minnesota	25%	2025	Pennsylvania	18%	2020
Connecticut	23%	2020	Missouri	15%	2021	Rhode Island	16%	2020
Delaware	20%	2019	Montana	15%	2015	South Dakota	10%	2015
D.C.	20%	2020	Nevada	20%	2015	Texas	5889 MW	2015
Hawaii	20%	2020	New Hampshire	24%	2025	Utah	20%	2025
Illinois	25%	2025	New Jersey	23%	2021	Vermont	20%	2017
Iowa	105 MW	2020	New Mexico	20%	2020	Virginia	12%	2022
Maine	30%	2020	New York	24%	2013	Wisconsin	10%*	2015
Maryland	20%	2022	North Dakota	10%	2015	Washington	15%	2020

Renewable Mandates

- 33 States have adopted Renewable Portfolio Standards (RSPs) – four in consideration
- Covering >60% of electricity load
- Standard mandate – 20% of power generated by 2025

➢ *Potential Federal Standard: 25% by 2025 – in Congress*

*Power generating utilities in target States.
Source: *United States Statistical Abstract, 2008*

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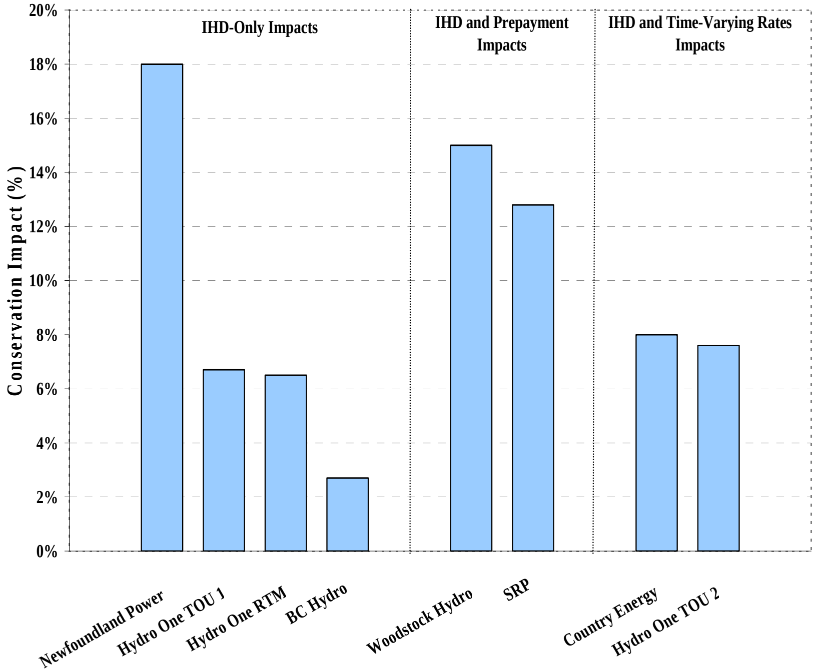
Why are companies investing in Smart-Grid? (3 of 3)

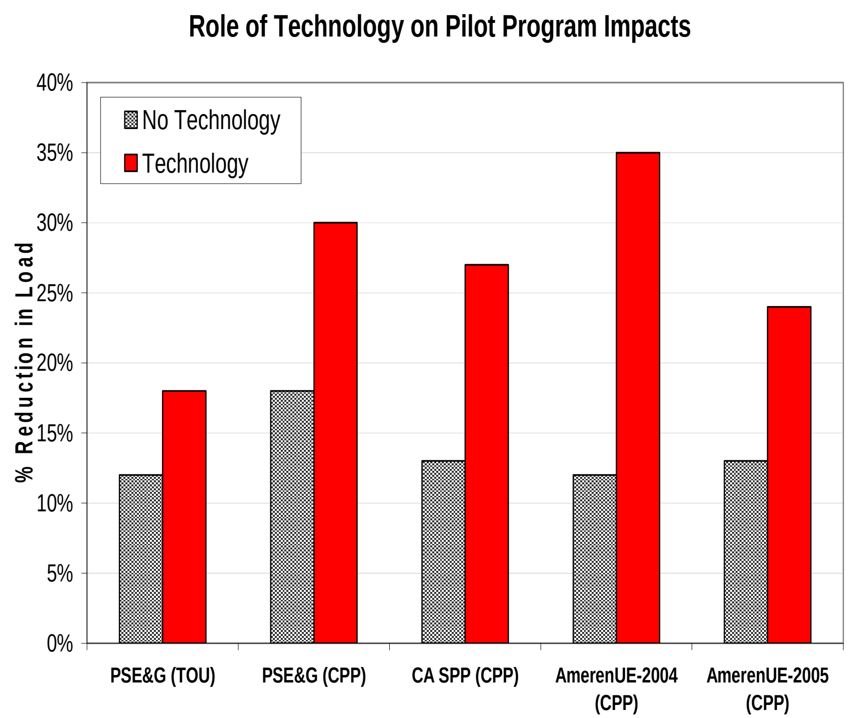
Best results through customer value-based interactions

Consumers conserve when their usage is displayed…



Consumers who actively use an IHD reduce their consumption of electricity by 14% and 7% when prepayment of electricity is and is not involved, respectively

…and respond more to dynamic price signal <u>and</u> enabling technology.



3% to 20% peak demand reduction with Price
27 to 44% reduction with Price + Technology

Source: Brattle Group

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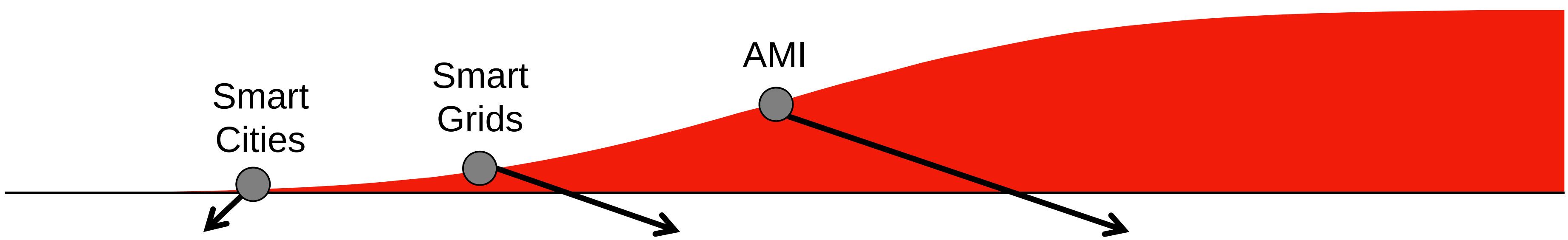
What are companies doing? (1 of 2)

Smart Grid Technology Adoption Curve

Early Adoption	Mass Adoption	Late Adoption



Smart Cities

- Cities are responsible for around 78% of global energy consumption
- Several initiatives across the globe
- Generally sponsored by a consortium of equipment providers or governments

Smart Grids

- Technology is at various stages of development
- Several initiatives testing different aspects of the technology – many sponsored by ARRA
- PUCs are mostly skeptical about tangible benefits

AMI

- Technology is being deployed across geographies
- Yet, only BGE has asked PUC to transition from flat rates to TOU as standard offer

Smart Cities Example – City of Amsterdam / Alliander (2 of 2)

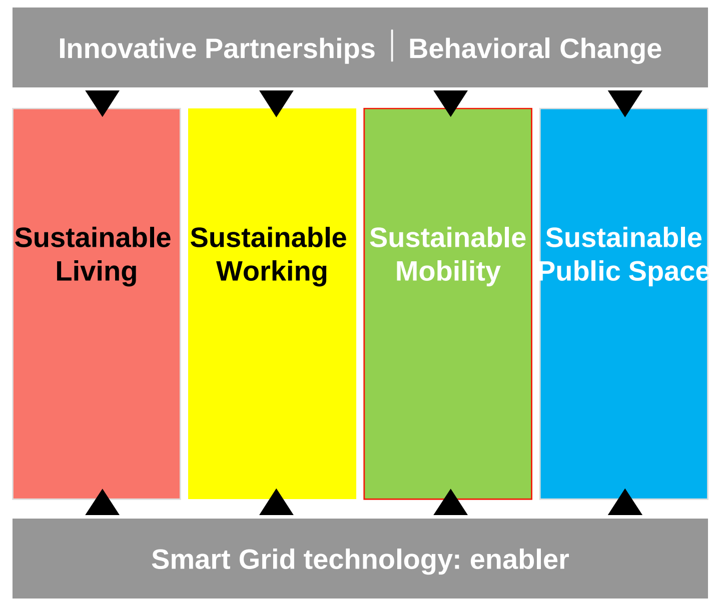
Amsterdam Smart City Aspirations

ASC objective is to meet ambitious EU 2020 climate goals through technology enabled sustainable solutions & changing customer behavior (40% reduction[1] in CO_2 by 2025)

Solution Concept

- Amsterdam Smart City is designed as an accelerator for climate/energy programs, bringing parties together and initiating projects that reduce CO_2 and yield local best practices for full scale roll out
- Amsterdam Smart City is based on 3 key principles:
  - Collective Effort – of all parties is required to realize CO_2 reductions
  - Technology Push/Demand Pull
  - Economic Viability – initiatives must make economic sense to all stakeholders to scale

Focus areas ASC



1 – 1990 levels

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What are the companies biggest concerns? (1 of 2)

- Regulatory recovery uncertainty
- Regulator wary about new technology viability and durability
- Supplier space dominated by start-ups and small companies
- Lack of technology standards and integration tools
- Expensive to implement
- Unaware of technology benefits
- Not comfortable with change or the value of the "bang-for-the-buck"

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What are the companies biggest concerns? (2 of 2)

ARRA – Observations on Stimulus Grants

- *Most recipients are planning to leverage grants to increase the pace of planned deployments (e.g. FPL, Centerpoint, Progress, Reliant, etc.)…*

- *…However, several questions remain*
  - **Ownership of assets** *and property encumbrance and implications for disposal or divestitures*
  - **Tax implications** *of the grant which could have a dramatic impact on the project itself*
  - *Challenge associated with* **the "Buy American" provision** *– some vendors have already been selected that may have unique products or capabilities*
  - **Implementation and administrative complexity** *requirements associated with tracking and reporting requirements*
  - **Timing of capital deployment**. *Utilities are unclear as to what guidelines the DoE wishes to impose related to the pace through which funds are spent*
  - **Payment of crews** *which occurs bi-weekly instead of weekly based on negotiated agreements with the unions*

Some utilities believe reporting, project oversight and other costs could total 30-40% of the grant

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What should be the companies biggest concerns? (1 of 2)

- *Customers – Ensuring that the program drives customer demand response and conservation that meets the regulatory agenda*
- *Regulators – Creating a new and much more transparent relationship with regulators that allows them to work with the utility*
- *Markets – Enabling and participating in the new markets that will be required to support expanded customer choice and integration of a growing number and diversity of supply options*
- *Operations – Construction and operation of the new intelligent network that focuses on delivering the outcomes of enhanced reliability and lower cost*

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What should be the companies biggest concerns? (2 of 2)
Smart Grid … much more than just technology

Key Workforce Questions

- What new skills or different skills will the organization need ?
- What behavioral / cultural changes are required of the organization to achieve the desired changes and business benefits? How do we get there?
- What type of leadership capabilities are needed to enable and support the changes?
- What is the new model of interacting with the customers in the future, and how can we best prepare our people?
- How can the organization absorb all the process, technology and infrastructure changes during deployment while also meeting current service obligations?

Implications for:

- Skills / Knowledge
- Jobs / Roles
- Culture
- Leadership
- Behaviors
- Organization Alignment
- Workforce Transition

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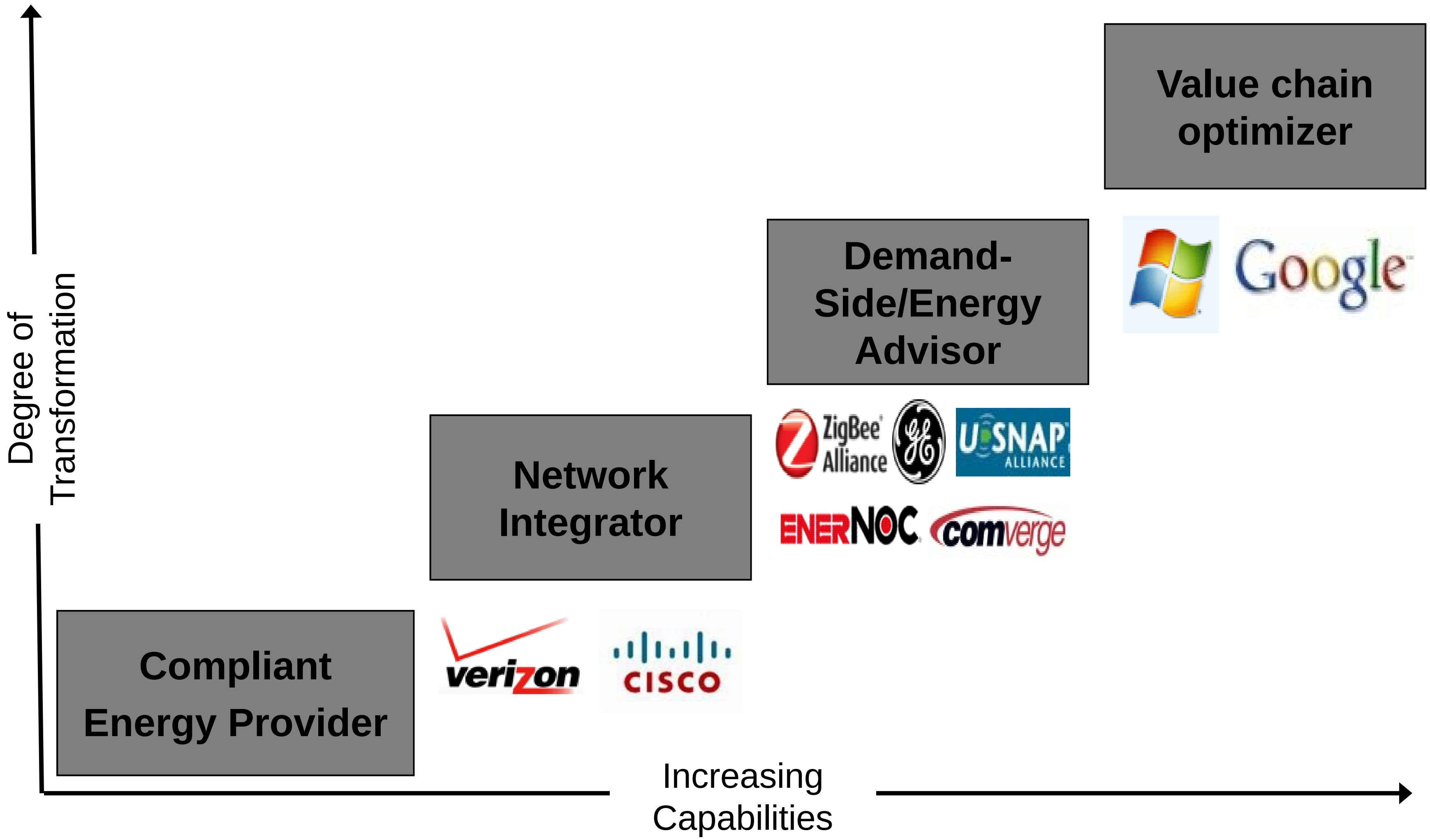
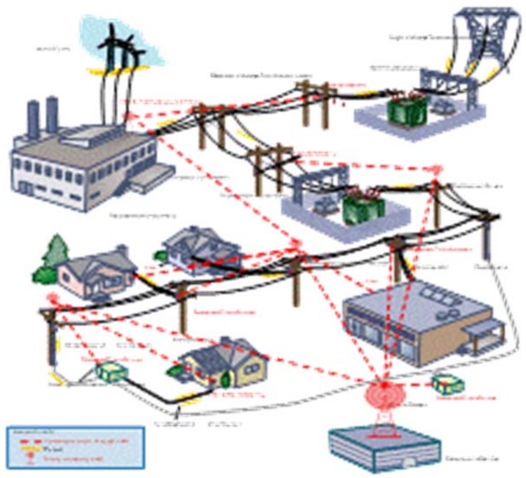
How are companies thinking about change?

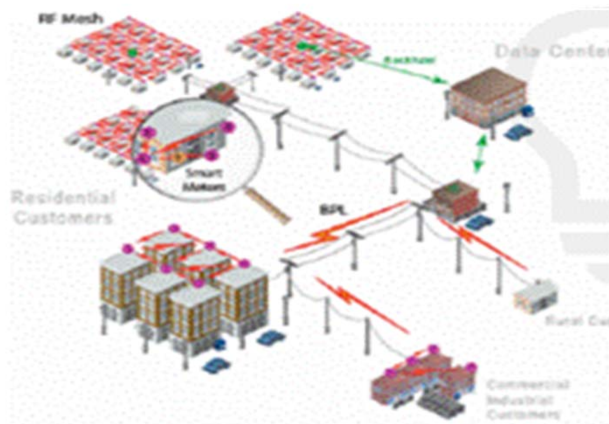


What makes a Smart Grid program successful?

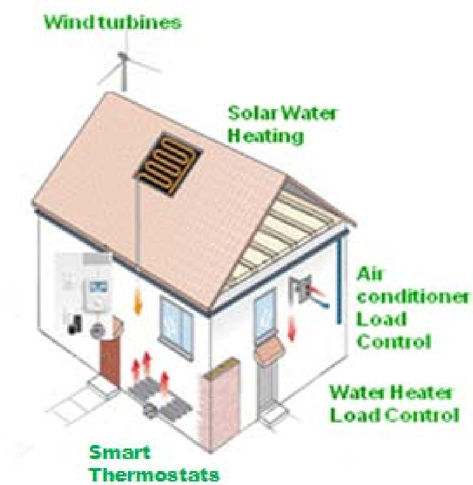
Smart Grid



Smart Meters



Smart Home



- Address the business holistically (strategy, process, people, and technology)
- Keep a pace consistent with the organization’s ability to absorb change
- Design with the end in mind… Data architecture is important.
- Be flexible to respond to changes (speed or direction) in the marketplace
- Focus in early delivery phases on immediate benefit realization (“quick wins”)
- Establish a program management office with a strong and unambiguous governance model to handle the complexities of a large scale program
- View security end-to-end

E.ON U.S. pursuit of Smart Technologies to date

Butch Cockerill
Director, Revenue Collection

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E.ON U.S. pursuit of Smart Technology to date

- Drivers
- Studies
  - LG&E Residential Smart Meter Pilot
  - Phase I
  - Phase II
- Deployment Scenarios

E.ON U.S. pursuit of Smart Technology to date

- Smart Technology Benefits
  - Operational Benefits
  - Deferred Capital Benefits
  - Societal Benefits

- Challenges
  - Technology
  - Financial
  - Change Management

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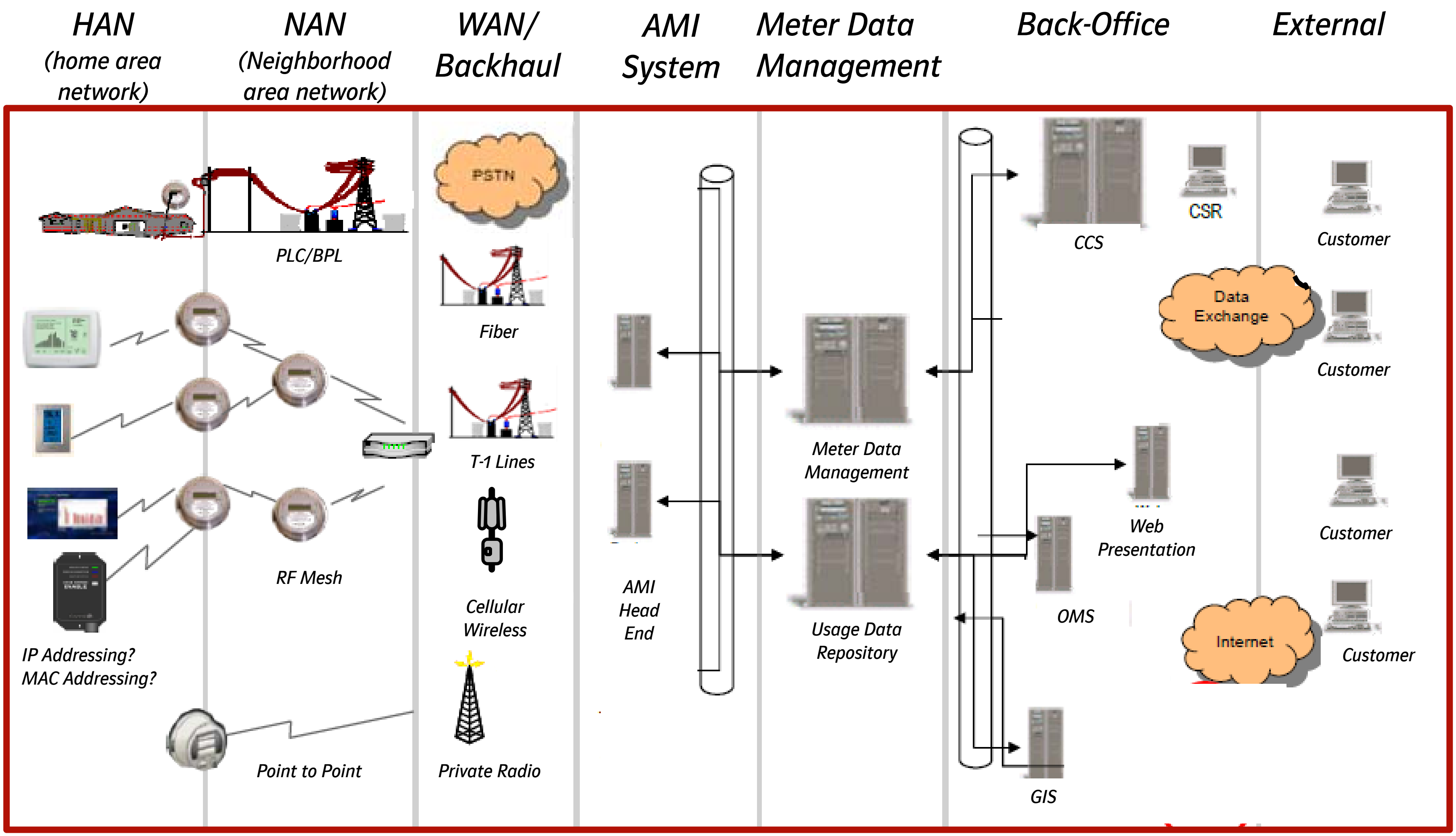
Technology Considerations

Priya Mukundan
Manager, IT Security & Administration


HAN
(home area network)
NAN
(Neighborhood area network)
WAN/ Backhaul
AMI System
Meter Data Management
Back-Office
External
PLC/BPL
PSTN
Fiber
T-1 Lines
Cellular Wireless
Private Radio
RF Mesh
IP Addressing?
MAC Addressing?
Point to Point
AMI Head End
Meter Data Management
Usage Data Repository
CCS
CSR
Data Exchange
Web Presentation
OMS
GIS
Internet
Customer
Customer
Customer
Customer

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Smart Grid vs. NERC CIP - Current

	NERC CIP is primarily concerned with	**Smart Grid includes this, but also**
Scope	*Bulk electric system*	*•Distribution systems* *•Home/customer networks*
Application Examples	*•Substation automation* *•Remote IED access*	*•Advanced metering infrastructure* *•Demand response* *•Outage management*
Typical Assets involved	*•Control systems* *•Substations*	*•Meters* *•Customer gateways* *•Distribution IED's*
Standards Process	*•FERC-NERC standards compliance*	*•NIST* *•Industry initiatives*

Evolving and needs to be monitored

http://www.elp.com/index/display/article-display/361178/articles/utility-automation-engineering-td/volume-14/issue-5/features/nerc-cip-amp-smart-grid-how-do-they-fit-together.html

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Potential Impact of NERC CIP compliance

- *Expensive establishment of physical and electronic security perimeters*
  - *Costs include capital and O&M (personnel and operating inefficiencies)*

- *In some cases, we may face decisions to pursue less functionality to avoid need to incur CIP compliance costs*

- *CIP rules can lead to very high penalties – up to $1 million per day per violation*

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Financial/Analytical Assessment

David Sinclair
Vice President, Energy Marketing

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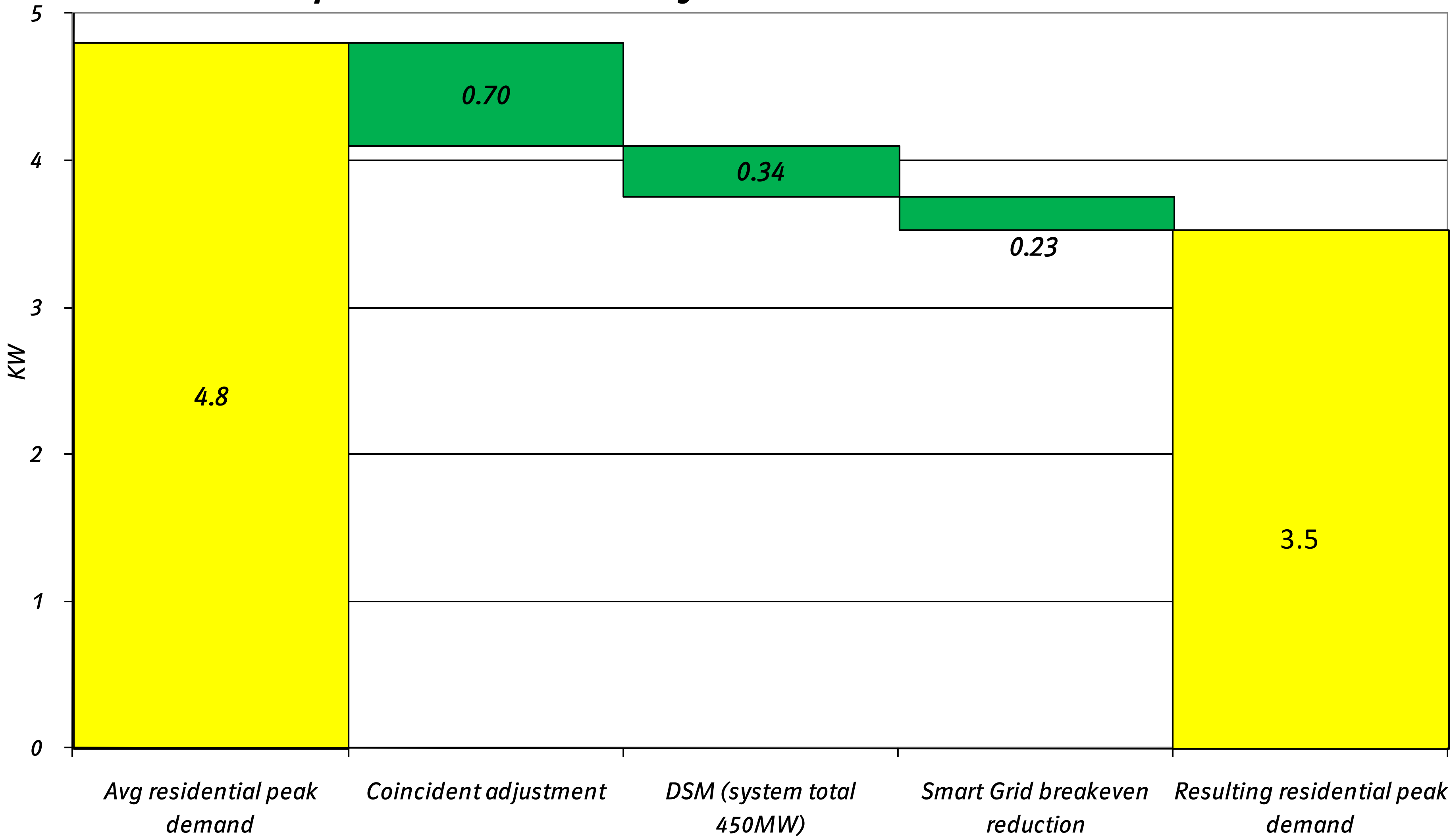
What are we trying to accomplish with Smart Grid?

- *Operational savings resulting from Smart Grid infrastructure*
- *Mechanism that enables the Company to send more complex price signals to consumers:*
  - *What behavioral objectives do we seek?*
  - *How will customers respond and will this change over time?*
  - *How will these price signals relate to costs (e.g., historical v. future)?*
  - *Will we discriminate among different end-uses?*
  - *What are the social implications of using price to alter behavior?*

Smart Grid must encourage reductions in the average residential peak demand beyond DSM levels



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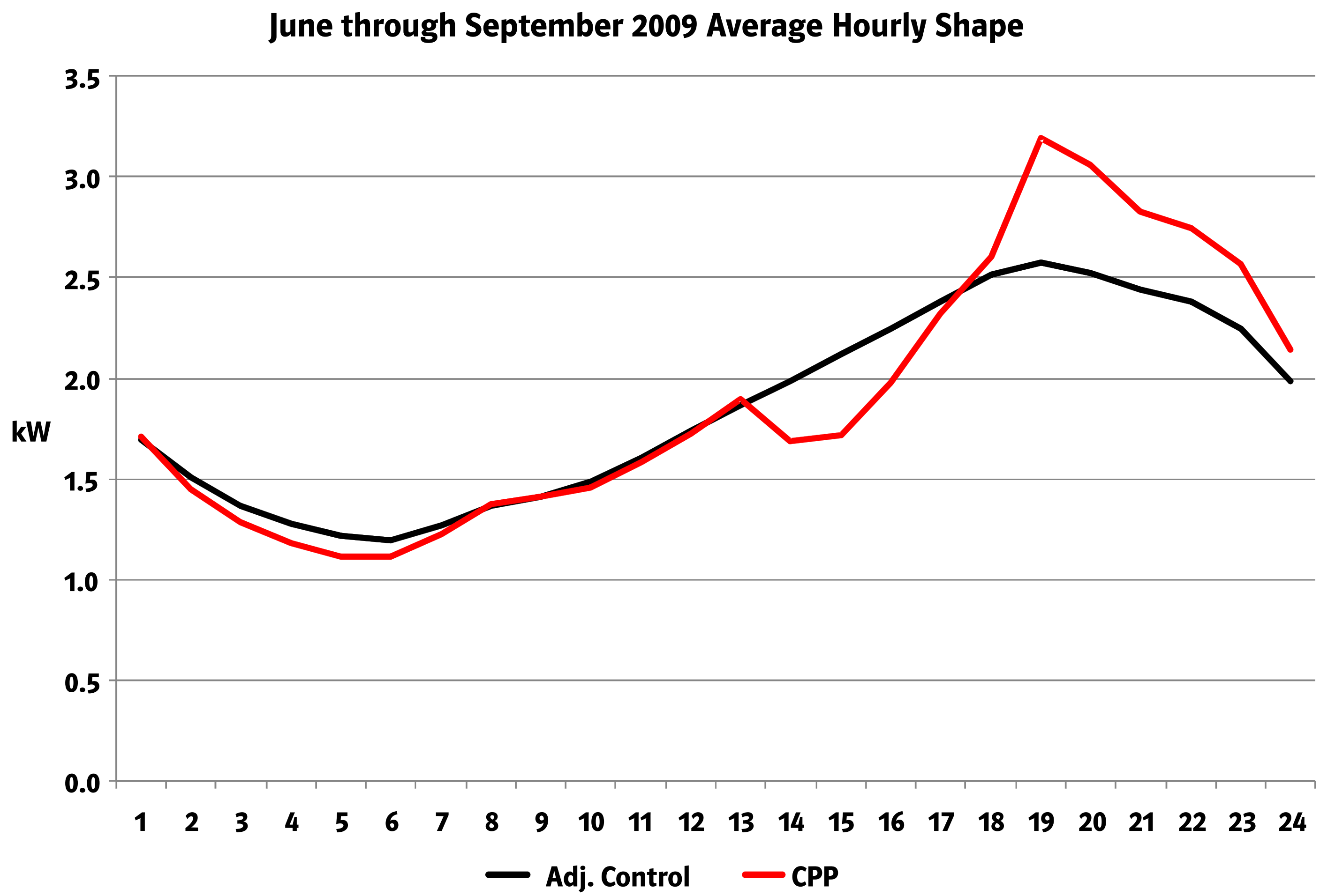
Breakeven of Smart Technology Scenarios

			Change in NPVRR		
Scenario	NPVRR Project	Peak/Energy Reduction	New Unit Capital	Production Cost	Total
1. AMI Only	$220	0.23 kW per customer*	($120)	($100)	($220)
2. AMI Only w/ Fiber Optics	$890	0.5 kW per customer* -3.4% energy**	($286)	($604)	($890)
3. AMI + Smart Grid	$877	0.5 kW per customer* -3.3% energy**	($283)	($594)	($877)
4. AMI + Smart Grid w/ Fiber Optics	$1,357	0.5 kW per customer* -6.6% energy**	($365)	($992)	($1357)

**Applied to residential customers*

***Applied to residential and commercial customers*

Compared to the control group, demand for the CPP group is reduced by 0.5 kW during the peak period, but then rebounds



Key Sources of Uncertainty

- *Impact of smart technology on load shape*
- *Impact of rate design on bounce back*
- *Cannibalization of Direct Load Control program*
- *Sustainability of demand response*
- *Cost*
- *Reaction from low-income advocates*

Regulatory Construct

Lonnie Bellar
Vice President, State Regulation and Rates

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Regulatory Construct - Recovery Options

- DSM Statute – KRS 278.285[1]
  - Capital and ROE - No precedent
  - Develop "Save-a-watt" plan – incentive tied to investment savings
- Modify existing DSM Statute
  - Add language for Smart Meter/Grid specific along with return on capital
- Base Rate Recovery
  - Regulatory Lag
  - Uncertainty of Recovery – mitigate with CCN
- Decoupling

[1]Next-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home.

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Regulatory Construct - Key Issues

- *Recovery for Retirement of existing meters ($78 million)*
- *Book life of new meters significantly less than existing meters*
- *Measurement and Verification of demand/energy savings*
- *Rate Design*
  - *Time-of-use*
  - *Demand charge for residential*
- *Current Responsive Pricing and Smart Meter Pilot programs*
- *Industrial opt-out provisions – excess burden on other customer classes*

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Regulatory Construct - Recommendations

- *Administrative Case No. 2008-00408*
  - *Manage to support desired goals*
- *Upcoming DSM/EE Filing*
  - *Foundation of Future Utility*
  - *Energy Education Center*
  - *AMI Blueprint Development*
- *Assessment of Pilot Programs*
  - *Responsive Pricing and Smart Meter Pilot*
  - *Real-Time Pricing*

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Federal and State Political Considerations

Mike Beer
Vice President, Federal Regulation and Policy

Federal Political and Regulatory Concerns

- States find open issues unsettling
  - Interoperability standards and obsolescence of existing equipment
  - Allocation of risk and responsibility between customer and shareholder
  - Cost/Benefit analysis difficult because benefits are speculative at this point
  - Uncertainty over customer acceptance of new technology and realization of benefits

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Federal Political and Regulatory Concerns

- *Potential disconnect between federal aspirations and realities of state economies*
  - *Cost recovery critical component for universal implementation of smart grid*
  - *Ultimate jurisdiction over cost recovery unsettled between state and federal regulators*
  - *Federal assumptions as to universal implementation fail to take into consideration state and regional differences*

Federal Political and Regulatory Concerns

- *Resolution of open issues and greater clarification of jurisdiction required to expedite implementation*
- *Projects not funded through stimulus package will require greater certainty with respect to cost recovery on front end*
- *Legislative changes at state level required to mitigate barriers to full-scale utility implementation*

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E.ON U.S. Strategy and Next Steps

Butch Cockerill
Director, Revenue Collection

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Key Themes

- *The emotional appeal of the smart grid technology gained massive industry attention accelerated by the federal stimulus funding. However, this heightened emotion is now slowly giving way to the realization of very difficult behavioral economics.*
- *Deployment of Smart Technologies will require the convergence of supply side and demand side planning.*
- *Cyber Security issues are complex, expensive, and continue to evolve.*
- *Distribution operational savings do not currently justify the costs of even a limited smart grid investment.*
- *Smart grid technology is an enabling device to allow the company to send more complex price signals to consumers. Currently we have a limited understanding of the potential opportunities and implications of using price to explicitly alter consumer demand.*
- *Associated rate design is a key strategic decision, cost based or "goal based" price signals*
- *Regulatory recovery (ability and method) highly dependent on cost-benefit case made for deployment of Smart Grid.*
- *Open jurisdictional questions and uncertainty over cost-recovery and rate treatment will slow full-scale deployment until resolved.*

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Strategy

- Deploy Smart Technologies over 10+ Years
  - Maximize flexibility with a focus on planning and education – allowing standards, technologies, and benefits to mature
  - 10+ year timeline with phased deployment to include;
    - Advanced Metering Infrastructure
    - Demand Response and Energy Efficiency
    - Smart Grid
    - Distributed Generation, storage, and Plug-In Electric Hybrid Vehicles

- Key Tenants to Smart Grid strategy
  - The flexibility designed into our strategy does not inhibit or constrain our ability to adapt to all potential futures
  - Key concept of our strategy is to not outpace technology
  - Investment in Smart Technologies will occur at the speed of value

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Next Steps

- *Blueprint Development Phase*
  - *Allows for the continuation of assessment*
- *Continue Smart Grid Steering Committee*
- *Develop working groups*
  - *To standardize Distribution and Transmission automation, and ensure the ease of integration when applicable*
  - *To open dialogue on integration of energy efficiency, electric vehicle tariff, distributed generation, distributed storage, etc.*

Smart Grid Steering Committee:

- *Chris Hermann – Overall Governance and Chair*
- *John Voyles – Transmission*
- *Greg Thomas – Distribution*
- *Lonnie Bellar – Regulatory*
- *Allyson Sturgeon – Legal*
- *David Sinclair – Forecasts and Economics*
- *Kent Blake – Financials*
- *Steve Phillips – NERC Cyber Oversight*
- *Brad Rives (TBD) – IT and Telecom*
- *John Malloy – Retail and Metering*

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Appendices

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Appendices - Table of Contents

David L. Bieber, North America Managing Director, Utilities, Accenture

- *David Bieber is the North America Managing Partner for Accenture's Utilities Practice. The utility practice focuses on helping its clients achieve high performance in all areas of their operations. Primary areas of focus include the development of high performance processes in customer care, revenue management, finance and performance management, generation, smart grid services, and trading and risk management. David is a member of our North American Resources Leadership Group.*
- *David has been with Accenture since 1983. During his career he has focused extensively on helping achieve high performance in customer care, information technology and corporate service operations. David has worked with several major utilities in helping them transform their customer service operations. In addition to his client work, David has sponsored several industry based alliances enabling Accenture to deliver additional value to its clients.*
- *David graduated from the City University of New York with a B.S. and M.P.S. in Computer Science and Economics*

Timothy P. Porter, Partner, Strategy, Accenture

- *Tim Porter is a Partner in Accenture's Resources Strategy practice based in Atlanta.*
- *Tim has been with Accenture since 1995. During his career he has specialized in corporate and retail strategy development, business transformation, operating model development, M&A targeting, merger integration, portfolio analysis, multi-year business planning, and customer acquisition for electricity, gas, water utilities, competitive energy retailers and merchant generation clients. Tim has most recently spent time helping to design and build the business architecture for a new competitive nuclear generation firm to be spun-off in 2010.*
- *Tim graduated from Harvard Business School with a Masters in Business Administration and from Georgia Institute of Technology with a Bachelor of Science degree in Mechanical Engineering. Prior to joining Accenture, Tim spent 6 years working at GE's Power Generation business where he helped to train naval officers to operate nuclear submarines.*

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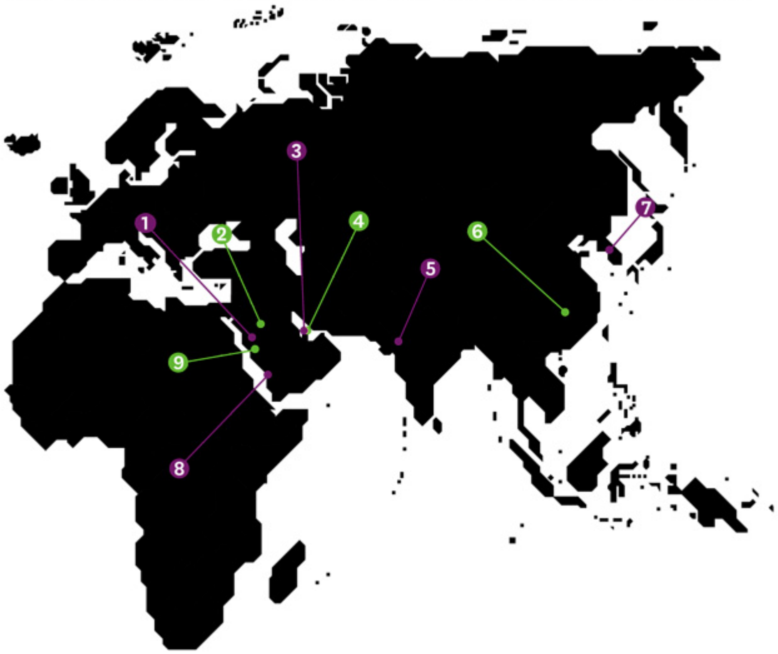
Smart Cities Initiatives and Results

Cisco's Big Bet on New Songdo: Creating Cities From Scratch

Climate (and Crowd) Control

CISCO ALREADY HAS EIGHT GREEN CITIES ON THE BOARDS, IN ADDITION TO NEW SONGDO. TWENTY MORE COULD FOLLOW.



1. **Medina Knowledge Economic City,** *Saudi Arabia*, population: 150,000. 2. **Prince Abdulaziz Bin Musaed Economic City,** *Saudi Arabia*, population: 80,000. 3. **Energy City Qatar,** *Qatar*, population: 200,000. 4. **The Pearl-Qatar,** *Qatar*, population: 30,000. 5. **Gujarat International Finance Tec-City,** *India*, population: 50,000. 6. **Meixi Lake,** *China*, population: 180,000. 7. **New Songdo City,** *South Korea*, population: 300,000. 8. **Jazan Economic City,** *Saudi Arabia*, population: 300,000. 9. **King Abdullah Economic City,** *Saudi Arabia*, population: 2 million

- The world is bracing for an influx of billions of new urbanites in the coming decades, and tech companies are rushing to build new green cities to house them
- Cisco has already demonstrated how its technology could be used to orchestrate the energy use in New Songdo's buildings, dialing up and down the heat, lights, and electricity
- Cisco’s next step will be to create a sort of urban operating system, and then to identify and create services that try to streamline everything from health care to education to traffic to shopping
- Cisco and Gale will take a slice of every transaction that runs through their software

Source – Fast Company, Feb 2010

Smart Cities Initiatives and Results
Portugal's Has Progressed "Smart City" Concept

PlanIT Valley in Portugal is intended to be the first completely newly built sustainable city in Europe and has included more than €13bn of investment.

Living PlanIT Mission

- Living PlanIT's (LP's) mission is to address the global sustainable urbanization challenge by focussing on the design, construction and support of Living PlanIT Research Cities

Living PlanIT Objectives

- Create a global benchmark for sustainable communities through the extensive use of renewable energy & the creation of exportable innovative intellectual property & products
- With an estimated 65,000 inhabitants at the end of Phase 1, and 130,000 upon completion in 2013, the project covers all aspects from physical infrastructure build to social and economic development (incl. retail, residential, hotels, hospitals, schools & a university)

Living PlanIT Progress

- Although currently in its embryonic stage, Living PlanIT is in the process of setting up its first Research City – PlanIT Valley covering 1,678 hectares in Northern Portugal

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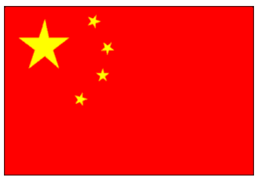
Smart Grids Initiatives and Results

China & Russia are in Early Planning & Exploration Stages

Country	*Smart Grids Developments*
• China 	• Chinese government targeted 20% energy efficiency improvement and application of 15% renewables sources in current 5 year plan • Several Chinese cities have smart city strategies or plans, none have yet to implement a solution ➢ Chongqing: targeted reduction of 65% in building energy consumption ➢ Chengdu: vision of creating an “Internet of Things” (self-configured wireless network ➢ Yangzhou: plans to take a leading position in the renewable energy equipment production industry ➢ Shenyang: 5 year “Smart City” plan; planned investment of RMB 300M
• Russia 	• Overall level of interest in Smart Technologies is quite high, although economic crisis driving investment only in economically feasible projects. • New Federal Law on energy efficiency just passed which mandates reduction of energy consumption by 40% by 2020 • Ministries of Energy and Economic Development are working on producing a country-wide plan for improving energy efficiency - at the moment there are no clear financial stimuli provided by the government

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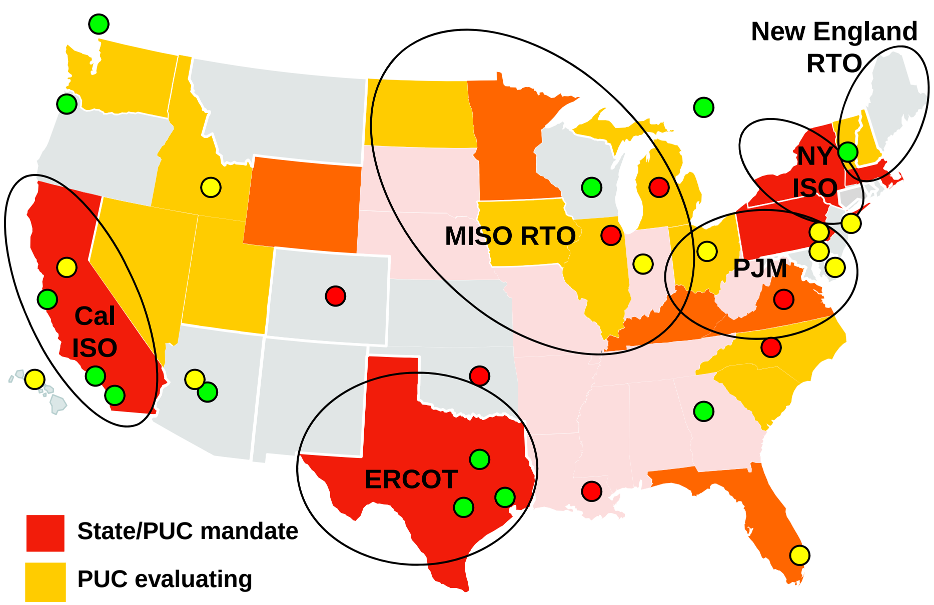
Smart Grids Initiatives and Results – In the U.S., smart grid is being driven primarily by regulatory mandate and by utilities in ISO/RTOs, but there is no consensus on approach

NON-EXHAUSTIVE



- State/PUC mandate
- PUC evaluating
- No-PUC activity; utility to lead
- PUC decided against mandates

- Full AMI deployment
- Plans for large deployment
- Pilot only

Xcel Energy
- Customer conservation, DR, renewable, and TOU pricing
- Investment in low GHG and renewables
- SmartGridCity pilot underway in Boulder, CO

Pacific Gas and Electric Company
- Installed 2.3 MM electric and gas meters with plan for 9.8 MM by 2011
- 14% of power mix from renewables – on target for 20% RPS
- Largest base of customer-installed solar – 30,000+

Southern Company
- 1 MM meters installed with plans for all 4.3 MM customers by 2013
- Demand-response program goal of 4.1GW reduction by 2020

Duke Energy
- Promoting efficiency as "fifth fuel"
- Focus on nuclear, clean coal, gas, and renewables
- Plans to install smart meters across territory by 2015

FPL
- Install 1MM smart meters in Miami; goal of all customers by 2014
- Investing in interconnected photovoltaic/solar thermal

Oncor
- Currently >350,000 meters installed with goal of 3 mil by 2012

BGE
- Filed with PUC in 2009 for 2 MM meters at $480 MM

Entergy
- Applied for $5M stimulus funding request for pilot project to help low-income customers

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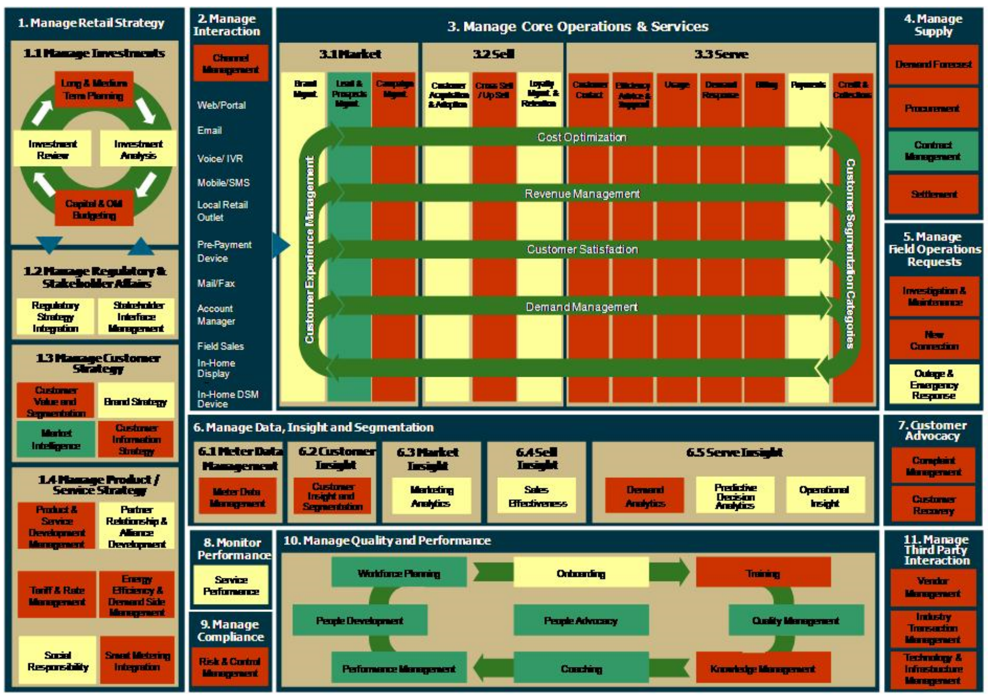
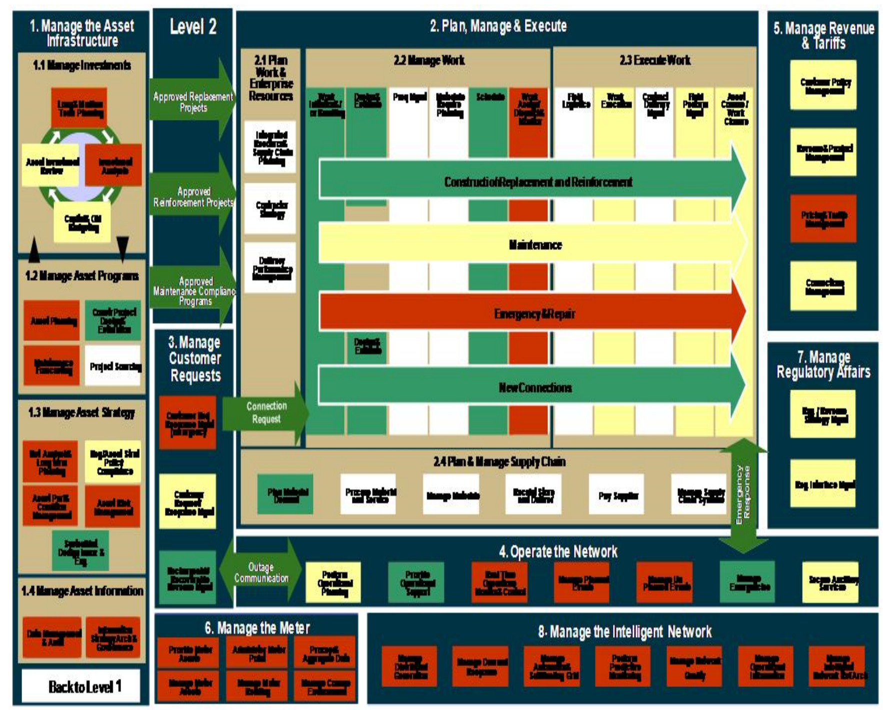
What should be the companies biggest concerns?

The Smart Grid Initiatives will have an impact on people & processes

Customer Operation Processes



T&D Processes



Low SMI Impact | Medium SMI Impact | High SMI Impact

Approximately 70% of the key T&D and Customer business processes have a medium-to-high impact from SG/SM initiatives

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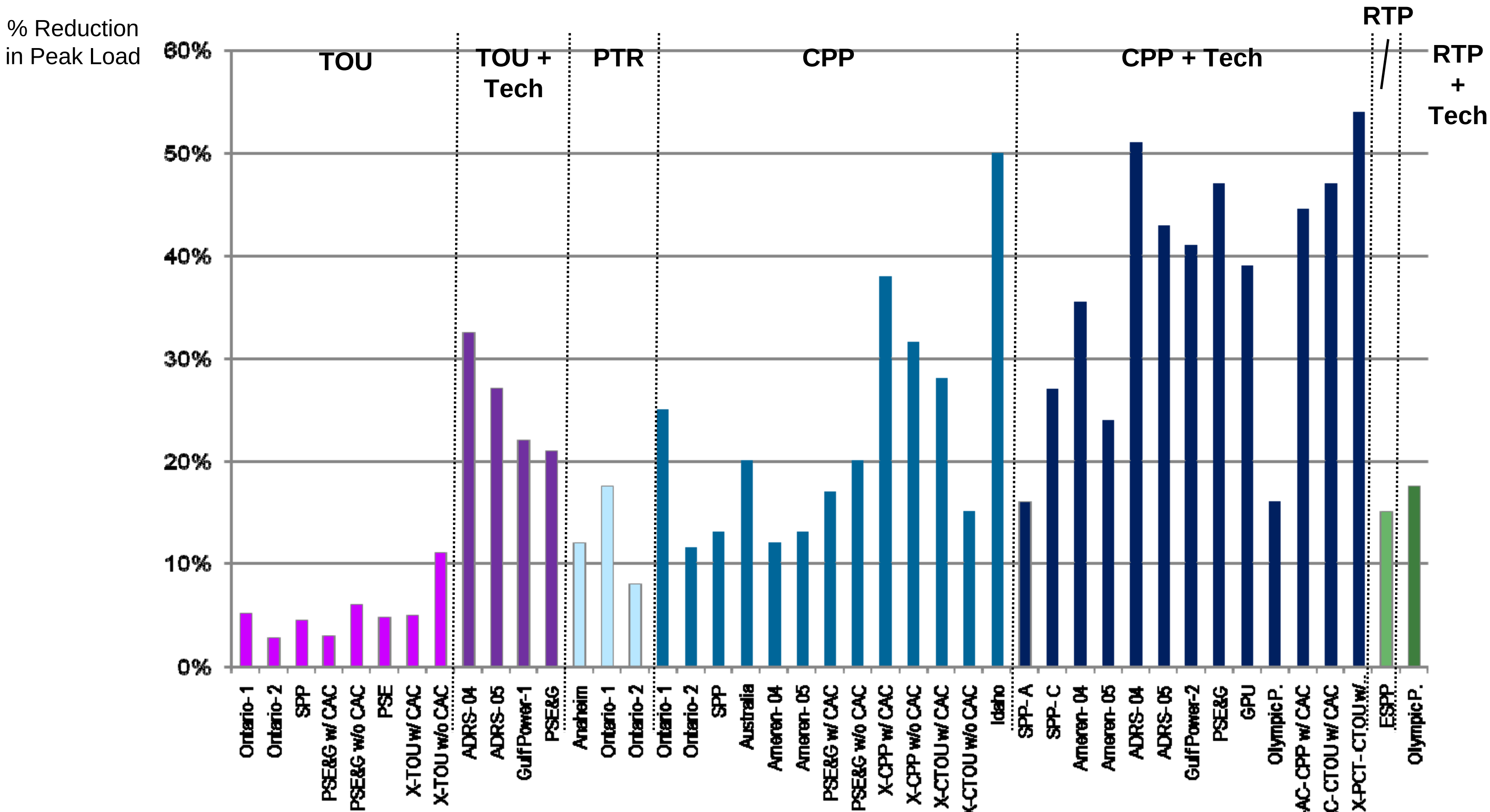
AMI (DSM Efficiency) Initiatives and Results

Usage Reductions Vary Across Program Types…

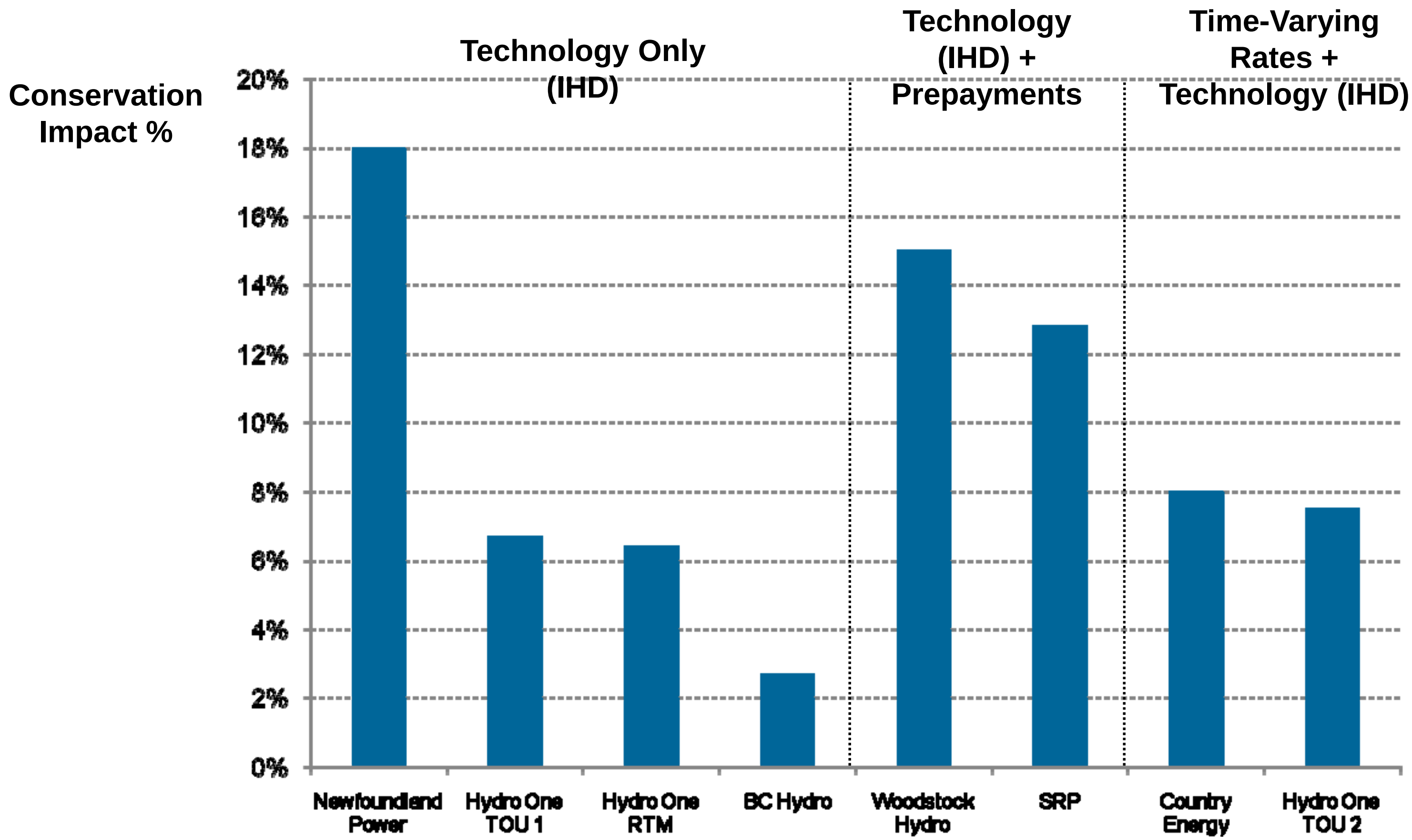


3% to 20% peak demand reduction with Price
27 to 44% reduction with Price + Technology

Source: Faruqui, Ahmad and Sanem Sergici. Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence, January 2009.

AMI (DSM Efficiency) Initiatives and Results

…Some DR Pilots Have Shown Overall Energy Reductions



Consumers who actively use an IHD reduce their consumption of electricity on average by 14% and 7% when prepayment of electricity is and is not involved, respectively

Source: Faruqui, Ahmad, Sergici, Sanem and Ahmed Sharif. The Impact of Informational Feedback on Energy Consumption.

DSM Programs – Established competitors are entering the markets…including Google, Microsoft, Panasonic, Apple, Intel, and others

Pike Research forecasts there will be >28 million energy displays installed by 2015, with 11MM people accessing home energy data from Web-based dashboards and 2.6 MM from mobile phones

Intel last week launched a Web site dedicated to its Home Dashboard Concept, a touch-screen display designed to help families control and reduce energy use. The Atom-based device will let people record video messages to other family members and, through third-party applications, let people look up information on online yellow pages or track packages over the Internet

Microsoft is seeking to partner with utilities installing smart meters to offer its Hohm application to customers, who can get online access to utility bills and real-time snapshots of electricity use. For every consumer Hohm provides recommendations on how to cut electricity and gas consumption, based on a lengthy questionnaire.

Apple plans home energy gateway with screen. Apple Computer in May filed two patents for use in a home energy-management system. The patents cover "an intelligent power-enabled communications port" and "intelligent power monitoring." Apple plans to create a HomePlug-based system that turns power outlets into conduits for audio, video and data. A device described in the patent describes a touch screen, speakers, media playback and a video projection system.

Google's PowerMeter is geared mainly at surfacing usage information to help consumers find ways to cut back on bills. It has signed on with a few utilities and smart meter makers to offer the energy-tracking dashboard through smart meters. It also offers that data through a home-monitoring device called The Energy Detective (TED) from Energy Inc. (a company that 3M's venture arm invested in last week)

The Phase II Business Case project team focused upon cross-organizational cost-benefit analysis:

E.ON U.S. Core Project Team:

Butch Cockerill	*Project Leader*
Tony Ruckriegel	*Co- Project Manager*
Christopher Whelan	*Co- Project Manager*
David Cumming	*Business Case Model Expert*

E.ON U.S. Support Management Team:

John Wolfram	*Marketing/Customer Service*
Cheryl Bruner	*Energy Efficiency*

Accenture Core Team:

Andre Begosso	*Project Lead*
Curtis Bech	*Business Case Model Specialist*
Elaine Horn	*Project Support*
Chiara McPhee	*Project Support*

Subject Matter Experts:

Mike Hornung	*Energy Efficiency*
Rick Lovekamp	*Regulatory Affairs*
Richard Jones	*Distribution Operations*
Stuart Wilson	*Energy Marketing*
Don Thorn	*Meter Assets*
Joan Renfrow	*Meter Reading*
Eric Johnson	*Telecommunications*
Shannon Charnas	*Finance*
Barry Ray	*Human Resources*
Jason Jones	*Information Technology*
Scott Cooke	*Generation Planning*
Jean Ann Pfisterer	*Residential Service*
Steve Woodworth	*Distribution Operations*

Residential Responsive Pricing and Smart Meter Pilot – Overview

- Pilot includes approximately 2,000 meters in the LG&E service territory
- Approved Responsive Pricing participation levels: 100 residential, 50 commercial
- Up to 400 additional customers to receive a combination of premise devices
- Time-of-use rate was designed to be revenue-neutral, i.e. a participating customer with a typical load profile would not experience a change in their annual electricity costs if the customer's usage pattern did not change
- Responsive pricing is voluntary and consists of four pricing periods
  - Low, Medium, High, and Critical Peak Pricing (CPP)
- Six routes were selected to represent entire service territory

Residential Responsive Pricing and Smart Meter Pilot – 2008 Assessment

- *Five CPP events were called in 2008*
- *Seven CPP events were called in 2009*
- *2009 analysis indicates that a load reduction in excess of 0.6 kW per participant is achievable at 2 p.m. on a 92˚ F day*
- *Load shapes for Responsive Pricing customers changed and resulted in load shifting from high-priced hours to lower-priced hours*
- *Load shifted from higher-price weekday hours to lower-priced weekend hours*

Scenario 1: *AMI Only for LG&E and KU (includes ODP)*

Includes: *Smart Meters + Relay (remote on/off) + HAN chip + utility hosted Web Portal + LG&E/KU owned communications backhaul (in lieu of public/leased communications) + IT Systems for AMI Only*

Excludes: *Smart Grid capabilities, In-Home devices, Fiber Optics network, IT Systems Required for Smart Grid, Societal Benefits (Carbon)*

Cost: *Total Cash Outlay (over 20 years): $555M = $304M Capital + $251M O&M*
Project NPVRR: $220M (includes operational savings)

Breakpoint: *Breakeven occurs with 1.9% reduction in system peak (modeled as 0.23 kW/customer or 5.6% reduction in residential peak) and NO CHANGE in total energy. Note: This reduction is in addition to the 6.5% peak reduction and 2.5% energy reduction already included in the 2010 LTP due to EE programs.*

Deployment: *10 years = 7 years to deploy meters (2 years in Lou and Lex, followed by 5 years in rural KU) + 3 years (2 years AMI design and planning + 1 year initial systems development)*

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Scenario 2: *AMI Only with Fiber Optics network for LG&E and KU (includes ODP)*

Includes: *Smart Meters + Relay (remote on/off) + HAN chip + utility hosted Web Portal + Owned Fiber Optics network from existing fiber backbone to substations + IT Systems for AMI Only*

Excludes: *Smart Grid capabilities, In-Home devices, IT Systems Required for Smart Grid, Societal Benefits (Carbon)*

Cost: *Total Cash Outlay (over 20 years): <u>$1,557M</u> = $1,283M Capital + $274M O&M*
Project NPVRR: $890M (includes operational savings)

Breakpoint: *Breakeven occurs with 5.7% reduction in system peak (modeled as 0.5 kW/customer or 12.2% reduction in residential peak) and 1.6% reduction in energy (modeled as a 3.4% reduction in residential and commercial sales). Note: This reduction is in addition to the 6.5% peak reduction and 2.5% energy reduction already included in the 2010 LTP due to EE programs.*

Deployment: *10+ years = 7 years to deploy meters (2 years in Lou and Lex, followed by 5 years in rural KU) + 3 years design and planning (2 years AMI design and planning + 1 year systems development), concurrent with 10+ years fiber optics network engineering design and deployment*

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Scenario 3: *AMI and Smart Grid for LG&E and KU (includes ODP)*

Includes: *AMI (Smart Meters + Relay [remote on/off] + HAN chip + utility hosted Web Portal) + Smart Grid (Automation of distribution equipment [sensors and monitoring devices on reclosers, switches, capacitor banks, etc.] and distribution communications networks – SCADA) + LG&E/KU owned communication backhaul + All Required IT Systems*

Excludes: *In-Home devices, Fiber Optics network, Societal Benefits (Carbon)*

Cost: *Total Cash Outlay (over 20 years): $1,795M = $1,061M Capital + $734M O&M*
Project NPVRR: $877M (includes operational savings)

Breakpoint: *Breakeven occurs with 5.7% reduction in peak (modeled as 0.5 kW/customer or 12.2% reduction in residential peak) and 1.5% reduction in energy (modeled as a 3.3% reduction in residential and commercial sales). Note: This reduction is in addition to the 6.5% peak reduction and 2.5% energy reduction already included in the 2010 LTP due to EE programs.*

Deployment: *10+ years*

Scenario 4: *AMI and Smart Grid with Fiber Optics Network for LG&E and KU (includes ODP)*

Includes: *AMI (Smart Meters + Relay [remote on/off] + HAN chip + utility hosted Web Portal) + Smart Grid (Automation of distribution equipment [sensors and monitoring devices on reclosers, switches, capacitor banks, etc.] and distribution communications networks – SCADA) + LG&E/KU owned Fiber Optics network from existing fiber backbone to substations + All Required IT Systems*

Excludes: *In-Home devices, Societal Benefits (Carbon)*

Cost: *Total Cash Outlay (over 20 years): <u>$2,510M</u> = $1,752M Capital + $758M O&M*
Project NPVRR: $1,357M (includes operational savings)

Breakpoint: *Breakeven occurs with 7.3% reduction in peak (modeled as 0.5 kW/customer or 12.2% reduction in residential peak) and 3% reduction in energy (modeled as a 6.6% reduction in residential and commercial sales). Note: This reduction is in addition to the 6.5% peak reduction and 2.5% energy reduction already included in the 2010 LTP due to EE programs.*

Deployment: *10+ years*

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Smart Meter/Grid Scenario Assumptions/Issues

- *Transmission Smart Grid analysis (performed separately) would take minimum 10 years to deploy at a high-level (estimate) cost of $70 million to fully automate (does not include communications)*
- *AMI design and planning consists of the following:*
  - *IT Systems: selection of IT Systems Integrator ; selection of required new IT systems; and design and planning for all required AMI IT system interfaces*
  - *Communication: analysis, design, and planning for "best available" communication channels; NO fiber analysis included*
  - *Smart Meters: selection of technology and vendor; analysis and design of smart meter network*
  - *HAN: analysis and selection of in-home communication technology; design and planning for Web portal*
- *No customer in-home devices are included in any scenario*
- *No analysis, design, or planning for any Smart Grid components*

Smart Meter/Grid Scenario Assumptions/Issues

- *AMI implementation planning and design will take eighteen (18) to twenty-four (24) months*
- *Scenarios which include fiber optic network assumes build out of fiber optics from existing communications backbone to substations (does not include fiber optics to the customer)*
- *The costs included herein are estimates based on consultant's (Accenture) previous experience. Actual costs may increase or decrease based on design (pending standards and security requirements), implementation schedule, and vendor selection*
- *Costs do not include allowances for system obsolesce or upgrades over the deployment period*
- *Business Case assumes full recovery of existing meter assets*
- *Breakpoints in peak and energy reductions are assumed based on variable rates structures (time of use and Critical Peak Pricing) comparable to current LG&E Residential Responsive Pricing and Smart Meter Pilot program*

Smart Meter/Grid Scenario Assumptions/Issues

- *Key Issues for Success*
  - *Sufficient resources (capital and human) to allow all phases of deployment to run concurrently*
  - *A key implementation consideration in advancement of AMI deployment is early development and empowerment of a dedicated project management team*
  - *Education (communications plan) of regulators, key constituents and customers is critical*
  - *Revenue Recovery methodology which includes pricing plan that adequately incents customers to embrace this new technology and respond appropriately to pricing signals*
  - *Over time, relationship with customer in order to ensure continued adoption of the technology and response to price signals*

Standards

- *2007 Energy Independence and Security Act (EISA)*
  - *"National Institute of Standards and Technology (NIST)… shall have primary responsibility to* ***coordinate development of a framework that includes protocols and model standards*** *for information management to achieve interoperability of smart grid devices and systems …"*

Phase 1: Identify an initial set of consensus standards and develop a roadmap to fill the gap

Phase 2: Establish a public/private standards panel to provide on-going recommendations for revised/new standards

Phase 3: Testing and Certification Framework

2009 *2010*

Standards – Status

- Phase I - Complete
  - 15 standards are included in the NIST Framework and Roadmap for Interoperability Standards, Release 1.0
  - Electric Power Research Institute (EPRI) has since released a list of 70 additional standards that were required.

- Phase II – In progress
  - NIST identified 14 of these as requiring urgent resolution and issued Priority Action Plans (PAP's) with completion dates in 2009-2010
  - Smart Grid Interoperability Panel has been created

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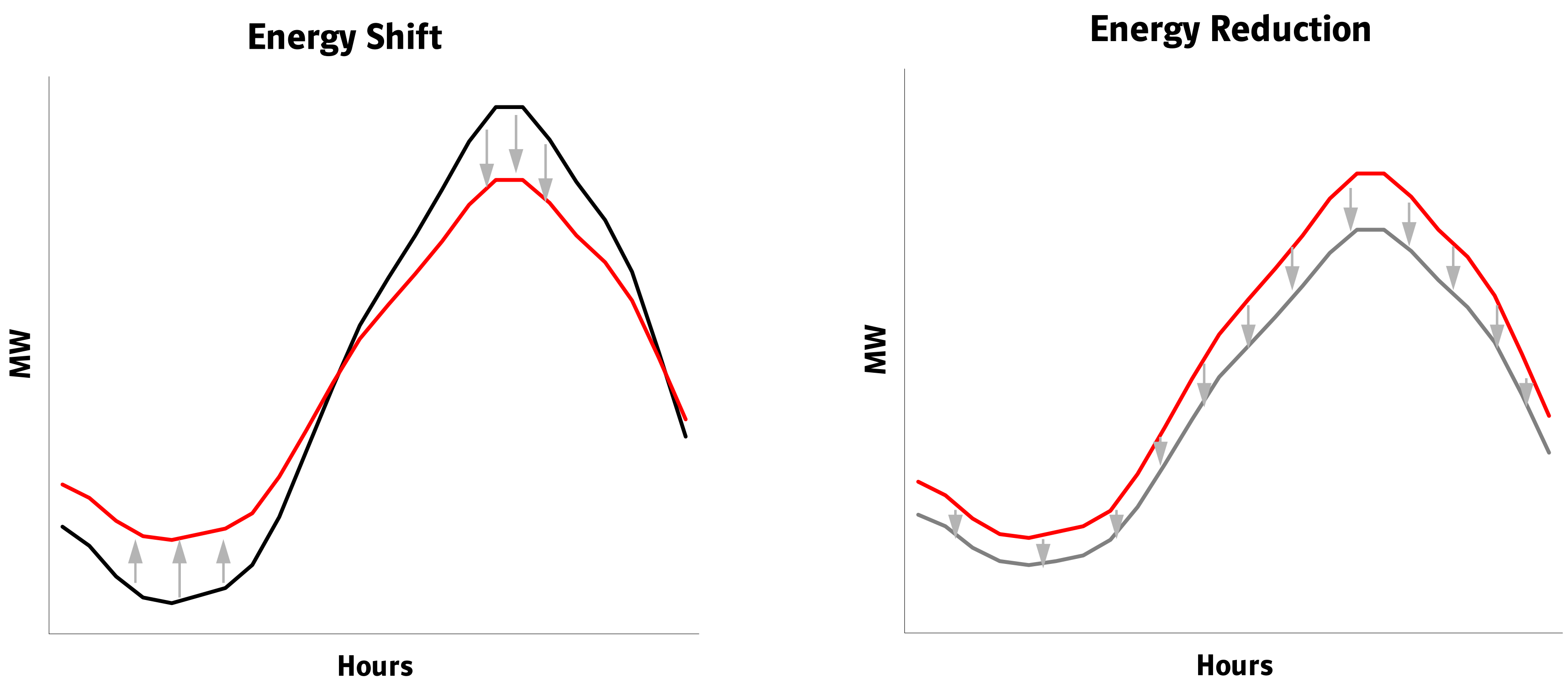
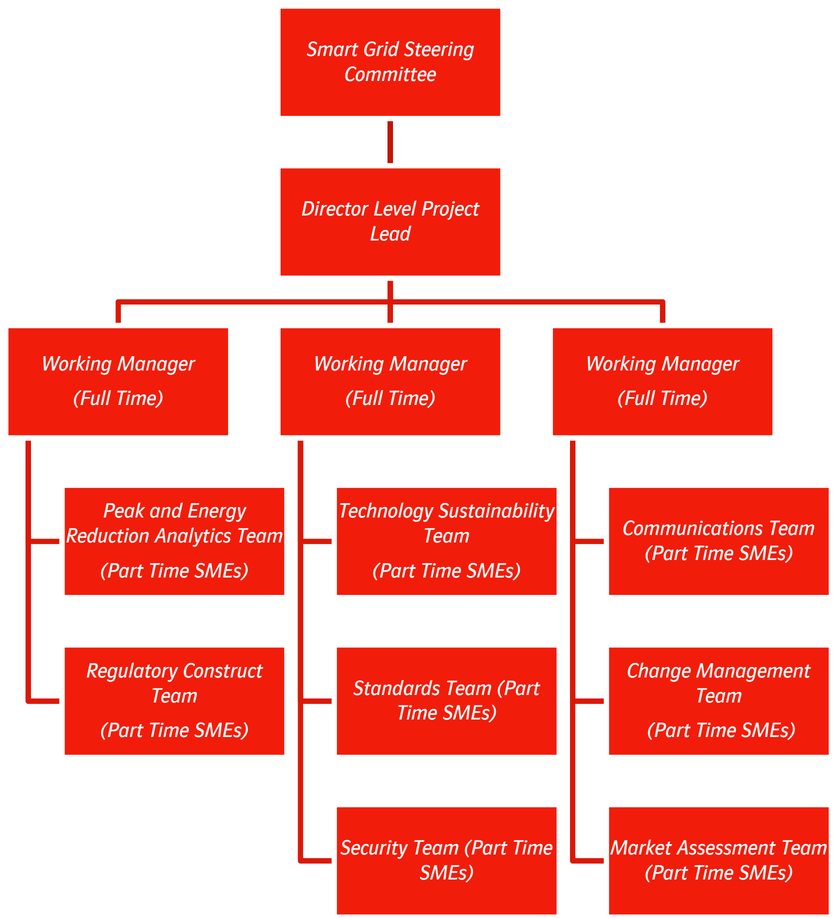
Cyber Security Standards

- *Cyber Security Coordination Task Group (CSCTG) established with over 200 participants*
- *First Draft of NIST Interagency report posted in September 2009 – currently in 60 day review*
- *Final recommendation will be published March/April 2010*
- *Open Smart Grid is our venue for participation in definition of requirements for the standards*
- *Monitor EEI SmartGrid workroom for related activity*

Impact of smart technology on load profile was modeled in two ways



Proposed Working Groups



Update on Responsive Pricing & Smart Metering Pilot Program

John P. Malloy
VP, Energy Delivery — Retail Business

Program Overview

- *Combine Time-Of-Use Rate (including critical peak pricing component) with In-Home Displays, Programmable Thermostats, and Load-Control Switches to encourage customers to actively manage consumption*
- *Allow E.ON U.S. to determine if customers, given pricing signals and the tools and information, will shift electricity use to times when overall consumption and costs are lower*
- *Opportunity to test effectiveness and determine savings from the automated metering component of the smart meters*
- *Approx. 2,000 customers, representative of entire LG&E service territory*
- *3-year pilot duration — 2008 through 2010*

E.ON U.S. Broad Aim:

- *To develop, implement and promote cost-effective offerings that help customers better manage their own consumption of electricity*

Implementation Summary

	Qty.	Meter	Thermo-stat	In-Home Display	Water Heater Control	Control Type
Responsive Rate Customer Group	150	✓	✓	✓	✓	Responsive Pricing Rate
Thermostat and Display Group	150	✓	✓	✓		No Rate Control
Demand Conservation Group	150	✓	✓		✓	Standard Load Control Program
Display Only Group	100	✓		✓		No Rate Control
Control Group	1450	✓				No Rate Control
Total	**2000**	✓	**450**	**400**	**300**	

Status of Deployment

- *1,677 of 1,754 electric meters have been deployed in six geographic areas*
- *The remaining 77 of 127 three-phase commercial meters currently being installed*
- *Smart meters are currently being read over the "mesh network" with approximately 99% on-time daily reads*
- *97 (of potential 100) residential customers and 2 (of potential 50) commercial customers are on the Responsive Pricing rate*
- *Marketing to fill the remaining non-RRP customer groups is in progress with installation to begin the week of September 8, 2008*
- *6 Critical Peak Pricing events have occurred to date related to the Responsive Pricing Program*
- *Automated system enabled identification of 2 meter tampering events*

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Going Forward

- *Initial Analysis of energy and capacity impacts to commence in 2008 Q4, after cooling season concludes*
- *The 2008 Q4 initial analysis will include not only the energy/capacity impacts, but the customer behavioral patterns and attitudes*
- *Full analysis of 2008 implementation to be complete and filed with Kentucky Public Service Commission in April 2009*
- *Currently re-evaluating the Marketing Strategy for the commercial Responsive Pricing Program*

e·on U.S.

2008 Integrated Resource Plan

Smart Metering is included in resource plan modeling for 2008-2022 in multiple scenarios to show range of possible implementation outcomes:

- **Base Case** – *Voluntary (70,000 Residential Customers)*

Recoverable Energy Efficiency Program Costs (Note 1)	*$56 Million*
Capital Meter Costs (Rate Based)	*$7 Million*
Total Cost of Program	*$63 Million*

- **High Case** – *Mandatory (713,000 Residential Customers)*

Recoverable Energy Efficiency Program Costs (Note 1)	*$552 Million*
Capital Meter Costs (Rate Based)	*$76 Million*
Total Cost of Program	*$628 Million*

Note 1 – initial financial assessment indicates smart metering and smart grid program will NOT be included in future DSM filings

Future Strategy

- *Combined Utilities adopted smart meter infrastructure platform in early May (smart meter as condition of service - electric)*
- *Future implementation of Smart Metering driven by several factors:*
  - *Consumer behavior*
  - *Technology advances and scope*
  - *Costs — Capital and O&M*
  - *Regulatory and Legislative requirements*
    - *Federal Gov't formed team to facilitate North American communication protocol standards.*
- *Major implementation will have significant cost impacts to the utilities — $500m to $1B over several years — and will be subject to close scrutiny by regulators, customers, industry experts, and other stakeholders*
- *Long term strategy – internal discussions underway*
    - *Capital considerations*
    - *Economic sustainability*
    - *Destruction of wealth considerations*
    - *Advancing economic development efforts*

Industry Overview

Global

The "advanced metering infrastructure" has less than a six percent overall market penetration in the US, and only five percent among commercial customers, according to the independent analyst firm Research Reports International. Outside the US, smart meters are spreading rapidly. Among the main suppliers of smart meters in Europe is Echelon. In North America – Landis+Gyrcq

Industry Overview

National

Ameren

- *Most progressive – installed over 700,000 smart meters to date. Goal of one million by 2010*

Duke

- *Duke "Proposes" smart meters across Indiana (no action to date). Partnering with Echelon. Will attempt to steer communication protocol standards*

DTE Announces "Smart Meter" Swap-Out"

- *Michigan's largest utility says it plans to swap out customers' old electric meters with new ones that can be read remotely. DTE Energy is starting with a pilot program but eventually plans to spend $350 million replacing 4 million electric meters.*

E.ON U.S.

General Electric Partnership

- GE will develop "Smart Appliances" able to receive and respond to pricing signals from the Smart Meter mesh network
- Various GE DSM-ready household appliances will be installed in 10–20 homes of GE employees participating in the LG&E pilot (EPRI closing on like program)
- This partnership will test the ability of "Smart Appliances" to respond to pricing signals — rescheduled defrost, self-clean cycles, etc.
- Initial contractual term is 12 months
- Public announcement scheduled for later this month
- GE seeks long term partnership with EON-US for additional advancements in innovative products and services.

Appendix

Responsive Pricing/Smart Metering

IRP Case — Voluntary (70,000 Residential Customers)

$ Thousands	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Total
Program Management	150	155	159	164	169	174	179	1,150
Program Clerical	65	67	69	71	73	75	78	498
Total Program Labor	215	222	228	235	242	249	257	1,648
Advertising	310	306	312	424	433	442	450	2,677
Data Processing	50	51	52	53	54	55	56	371
Office Supplies & Expenses	12	12	12	13	13	13	14	89
Outside Services - Purchase/Install								0
Control & Display Devises	3,775	3,851	3,928	4,006	4,086	4,168	4,251	28,065
Outside Services - Administration	120	122	125	127	130	132	135	891
Program Ongoing Operating Costs	600	1,224	1,873	2,547	3,247	3,975	4,730	18,196
Evaluation	356	405	457	518	574	632	693	3,635
Total Recoverable Energy Efficiency Program Costs	**$5,438**	**$6,193**	**$6,987**	**$7,923**	**$8,779**	**$9,666**	**$10,586**	**$55,572**
Capital Cost of Meters (Rate Based)	1,000	1,020	1,040	1,061	1,082	1,104	1,126	7,433
Total Cost of Program	**$6,438**	**$7,213**	**$8,027**	**$8,984**	**$9,861**	**$10,770**	**$11,712**	**$63,005**

Responsive Pricing/Smart Metering

High Case — Mandatory (713,000 Residential Customers)

$ Thousands	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Total**
Program Management	1,527	1,573	1,620	1,669	1,719	1,770	1,823	11,701
Program Clerical	662	682	702	723	745	767	790	5,071
Total Program Labor	2,189	2,255	2,322	2,392	2,464	2,537	2,613	16,772
Advertising	1,578	1,558	1,589	2,161	2,204	2,248	2,293	13,631
Data Processing	509	519	530	540	551	562	573	3,784
Office Supplies & Expenses	122	125	127	130	132	135	138	909
Outside Services - Purchase/Install								0
Control & Display Devises	38,430	39,198	39,982	40,782	41,597	42,429	43,278	285,696
Outside Services - Administration	1,222	1,246	1,271	1,296	1,322	1,349	1,376	9,082
Program Ongoing Operating Costs	6,108	12,460	19,064	25,927	33,057	40,462	48,150	185,228
Evaluation	3,621	4,124	4,653	5,277	5,847	6,438	7,050	37,010
Total Recoverable Energy Efficiency Program Costs	**$53,779**	**$61,485**	**$69,538**	**$78,505**	**$87,174**	**$96,160**	**$105,471**	**$552,112**
Capital Cost of Meters (Rate Based)	10,186	10,389	10,597	10,809	11,025	11,246	11,471	75,723
Total Cost of Program	**$63,965**	**$71,874**	**$80,135**	**$89,314**	**$98,199**	**$107,406**	**$116,942**	**$627,835**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 34

Responding Witness: John P. Malloy

Q-34. Please provide copies of all studies, analyses, reports or other resources the Companies have produced, consulted or reviewed regarding the impacts of AMS deployment on low income utility customers. Please include documents regarding the experience in other jurisdictions that have deployed smart meters as well as those projecting impacts in the Companies' service territories.

A-34. LG&E has not investigated the extent to which low income utility customers in other jurisdictions deploying smart meters have participated in these or similar benefits.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 35

Responding Witness: John P. Malloy

Q-35. Please confirm that LG&E intends to utilize the remote disconnection capabilities of AMS to disconnect residential electric accounts for non-payment, but not residential gas accounts. If this is not confirmed, please explain.

A-35. Confirmed.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 36

Responding Witness: John P. Malloy

Q-36. When does LG&E intend to implement remote service switching to disconnect residential customers in Jefferson County for nonpayment?

A-36. This capability is not available until Release 4, currently projected to begin in the fourth quarter of 2018 or the beginning of 2019 as shown in the chart on page 45 of 169 in Exhibit JPM-1

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 37

Responding Witness: John P. Malloy

Q-37. Please provide breakdowns of, respectively:

a) the current cost of disconnecting a residential LG&E electric-only customer for non-payment;

b) the current cost of disconnecting a residential LG&E combined (gas and electric) customer for non-payment;

c) the projected cost of disconnecting a residential LG&E electric-only customer for nonpayment upon implementation of remote disconnection; and

d) the projected cost of disconnecting a residential LG&E combined customer for nonpayment upon implementation of remote disconnection.

A-37.

a. The current cost of disconnecting a residential LG&E electric-only customer for non-payment is $14.22.

b. The current cost of disconnecting a residential LG&E combined (gas and electric) customer for non-payment is $14.22.

c. The Companies have assumed no incremental cost beyond the cost of providing the meter, network, and systems, to remotely disconnecting an electric customer.

d. The Companies have assumed no incremental cost beyond the cost of providing the meter, network, and systems, to remotely disconnecting the electric part of a combined customer and the cost to disconnect the gas part of a combined customer remains unchanged.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 38

Responding Witness: John P. Malloy

Q-38. Please provide breakdowns of, respectively:

a) the current cost of reconnecting a residential LG&E electric-only customer disconnected for non-payment;

b) the current cost of reconnecting a residential LG&E combined (gas and electric) customer disconnected for non-payment;

c) the projected cost of reconnecting a residential LG&E electric-only customer disconnected for nonpayment upon implementation of remote reconnection; and

d) the projected cost of reconnecting a residential LG&E combined customer disconnected for nonpayment upon implementation of remote reconnection of electric service.

A-38.

a. The current cost of reconnecting a residential LG&E electric-only customer for non-payment is $14.22.

b. The current cost of reconnecting a residential LG&E combined (gas and electric) customer for non-payment is $14.22.

c. The Companies have assumed no incremental cost beyond the cost of providing the meter, network, and systems, to remotely reconnecting an electric customer

d. The Companies have assumed no incremental cost beyond the cost of providing the meter, network, and systems, to remotely reconnecting the electric part of a combined customer and the cost to disconnect the gas part of a combined customer remains unchanged.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 39

Responding Witness: John P. Malloy

Q-39. Please provide copies of all policies, procedures and safeguards LG&E will implement regarding the use of remote service switching to disconnect residential accounts for nonpayment, and subsequently reconnecting them.

A-39. See the response to AG 1-357.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 40

Responding Witness: John P. Malloy

Q-40. Please refer to the Malloy Testimony at page 17, lines 8-15, where projected savings over the 20-year life of the fully deployed metering system are discussed.

a) Please provide a breakdown of the cited benefits between the LG&E and KU service territories.

b) For the LG&E service territory, please indicate in dollars and as a percentage of the total the extent to which the cited savings will result from remote (as opposed to manual) disconnection for nonpayment of residential customers.

c) Please explain the calculation used to arrive at the figures in (b).

A-40.

a. The benefits have not been calculated by individual utility.

b. The savings associated with all Meter Services, which includes disconnects, is shown in Exhibit JPM-1, page 152 of 169.

c. See the answer to b above.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 41

Responding Witness: John P. Malloy

Q-41. In reference to the residential electric accounts included in each of the reports requested in Information Request 9, above, please provide the following:

a) Number of accounts disconnected after the disconnection date specified in the 10-day notice provided the customer pursuant to LG&E's Terms and Conditions and 807 KAR 5:006 Section 15(1)(f)(1), broken down by zip code.

b) Average number of days elapsing between the disconnection date specified in the 10-day notice and the actual date of disconnection, broken down by zip code.

c) Median number of days elapsing between the disconnection date specified in the 10-day notice and the actual date of disconnection, broken down by zip code.

A-41. a – c) See attached.

Number of accounts disconnected after the date specified on 10-day letter

LG&E	
Zip Code	**7.1.2014 - 6.30.2015**
40014	3
40023	1
40026	1
40047	1
40059	1
40109	1
40118	9
40202	3
40203	31
40204	2
40206	3
40207	10
40208	11
40210	12
40211	20
40212	22
40213	11
40214	20
40215	15
40216	18
40217	4
40218	13
40219	11
40220	7
40222	1
40223	1
40228	4
40229	8
40241	4
40245	6
40258	13
40272	5
40291	10
40299	2
Total	**284**

LG&E	
Zip Code	**7.1.2015 - 6.30.2016**
40014	4
40031	3
40047	3
40057	2
40059	2
40108	2
40118	6
40160	6
40165	6
40177	2
40202	1
40203	15
40204	2
40205	3
40206	12
40207	6
40208	9
40210	13
40211	22
40212	20
40213	5
40214	16
40215	19
40216	25
40217	7
40218	7
40219	11
40220	5
40223	4
40228	6
40229	15
40241	3
40245	3
40258	12
40272	13
40291	15
40299	7
Total	**312**

Question B	
Average Days to Disconnect	
LGE Customers	
Zip Code	7.1.2014 - 6.30.2015
40004	0
40014	1
40023	2
40026	1
40047	0
40057	0
40059	1
40067	0
40108	0
40109	1
40118	2
40160	0
40165	0
40175	0
40177	0
40202	1
40203	0
40204	0
40205	0
40206	1
40207	1
40208	1
40210	0
40211	0
40212	1
40213	1
40214	1
40215	1
40216	0
40217	1
40218	1
40219	0
40220	0
40222	0
40223	0
40228	0
40229	1
40241	1
40242	0
40243	0
40245	1
40258	1
40272	0
40291	1
40299	0
42701	0

Question B	
Average Days to Disconnect	
LGE Customers	
Zip Code	7.1.2015 - 6.30.2016
40004	0
40010	0
40014	0
40023	0
40026	0
40031	0
40047	0
40057	1
40059	1
40108	1
40118	1
40160	1
40165	0
40177	2
40202	0
40203	1
40204	0
40205	1
40206	1
40207	1
40208	0
40209	0
40210	0
40211	0
40212	0
40213	0
40214	0
40215	0
40216	0
40217	1
40218	0
40219	0
40220	0
40222	0
40223	0
40228	1
40229	0
40241	0
40242	0
40243	0
40245	0
40258	0
40272	0
40291	0
40299	0

Question C	
Median Days to Disconnect	
LGE Customers	
Zip Code	7.1.2014 - 6.30.2015
40004	0.0
40014	0.0
40023	2.0
40026	1.0
40047	0.0
40057	0.0
40059	0.0
40067	0.0
40108	0.0
40109	0.5
40118	1.5
40160	0.0
40165	0.0
40175	0.0
40177	0.0
40202	1.0
40203	0.0
40204	0.0
40205	0.0
40206	1.0
40207	1.0
40208	0.5
40210	0.0
40211	0.0
40212	0.0
40213	0.0
40214	0.0
40215	0.0
40216	0.0
40217	1.0
40218	0.0
40219	0.0
40220	0.0
40222	0.0
40223	0.0
40228	0.0
40229	0.0
40241	0.5
40242	0.0
40243	0.0
40245	0.0
40258	0.0
40272	0.0
40291	0.0
40299	0.0
42701	0.0

Question C	
Median Days to Disconnect	
LGE Customers	
Zip Code	7.1.2015 - 6.30.2016
40004	0.0
40010	0.0
40014	0.0
40023	0.0
40026	0.0
40031	0.3
40047	0.0
40057	0.5
40059	0.0
40108	1.0
40118	0.0
40160	1.0
40165	0.0
40177	1.5
40202	0.0
40203	0.0
40204	0.0
40205	0.0
40206	0.0
40207	0.0
40208	0.0
40209	0.0
40210	0.0
40211	0.0
40212	0.0
40213	0.0
40214	0.0
40215	0.0
40216	0.0
40217	0.3
40218	0.0
40219	0.0
40220	0.0
40222	0.0
40223	0.0
40228	0.0
40229	0.0
40241	0.0
40242	0.0
40243	0.0
40245	0.0
40258	0.0
40272	0.0
40291	0.0
40299	0.0
42701	0.0

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries
Dated January 11, 2017

Question No. 42

Responding Witness: John P. Malloy

Q-42. For each of the years 2015 and 2016, please provide the number of accounts for which a payment was made by a third-party assistance provider after the disconnection date specified in the 10-day notice but before service was disconnected.

A-42. LG&E does not have a business reason to maintain ongoing files with the requested information segregated according to requested parameters.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Request for Information of Association of Community Ministries Dated January 11, 2017

Question No. 43

Responding Witness: John P. Malloy

Q-43. Please refer to page 26 of the Malloy testimony at lines 3 through 5, where it is stated that “the ability to remotely switch service can help avoid injuries” and that “[s]ince 2011, Field Services Personnel have encountered about 80 physical threats related to disconnections per year on average.”

a) Please define what is meant by “physical threat” in this context.

b) How many injuries have occurred during this time period?

A-43.

a) The Company defines “physical threat” as any threat to do bodily harm to Company employees or our business partners. These threats range from in-person verbal threats, in-person threats involving a weapon and called-in threats via telephone.

b) Since the Company began tracking in 2010, there have been 4 Company employees and business partners who have been assaulted with minor injury.