CITY COUNCIL WORKSHOP
AGENDA
MUNICIPAL CENTER MEETING ROOMS ABC
11/13/2012

ELECTRIC RATES

A. CALL TO ORDER:

B. INTRODUCTION:

C. PRESENTATION:

1. Electric Rate Workshop

D. ADJOURNMENT:

Any individual with a disability requesting a reasonable accommodation in order to participate in a public meeting should contact the Accessibility Coordinator at least 48 hours in advance of the scheduled meeting. The Accessibility Coordinator can be reached in person at 400 S. Eagle Street, Naperville, IL., via telephone at 630-420-6725 or 630-305-5205 (TDD) or via e-mail at manningm@naperville.il.us. Every effort will be made to allow for meeting participation.

Naperville

Electric Rate Workshop

Municipal Center – Council Chambers

November 13, 2012

5:00 PM

Call to Order	**5:00 pm**
Electric Rates	**5:10 pm**
Adjournment	**7:00 pm**

Electric Cost of Service and Rate Design Study

Presented to the
City of Naperville, IL
Electric Rate Workshop
November 13, 2012

Agenda

- Background
- Need for the Study
- Financial Forecast
- Cost of Service Analysis
- Standard Electric Rates & Typical Bills
- Time of Use Electric Rates & Typical Bills
- Demand Response Initiative

Background

- Current Electric Rates Implemented in 2007
- Power Supply contract with Goldman Sachs Expired
- New Power Supply contract with IMEA in 2011
- Major Capital Investment Projects
- Non-power supply operating expenses stable
- Customer load growth relatively flat
- Naperville Smart Grid Initiative

Need for Rate Modifications

- Existing rates reflect old power supply structure (energy charge only)
- New rates reflect new IMEA power supply structure (energy + demand charge)
- New rate classes required to provide options for customers

Rate Study Components

Steps	Issue
Financial Forecast	Revenue Adequacy
Cost-of-Service	Revenue Responsibility
Rate Design	Revenue Recovery

Financial Forecast

- Review and Summarize Historical Information
- Revenue Forecast
  - Customers
  - Sales
  - Revenues from Sales and Other Sources
- Expenditure Forecast
  - O&M Expense Including Purchased Power
  - Capital Requirements
  - Debt Service
- Develop Net Income and Cash Flow Analysis

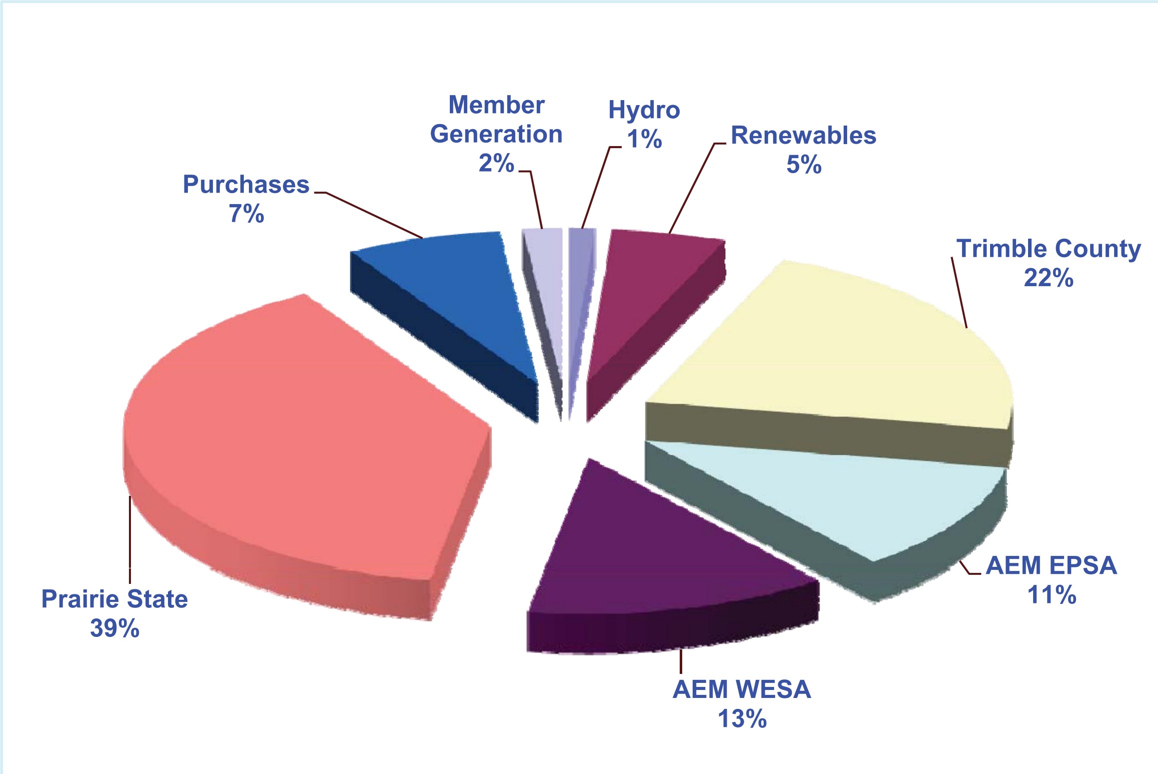
Financial Forecast

- Reviewed Net Income & Cash Flow Analysis Results
  - Developed Financial Plan
  - Reviewed Financial Plan with City Staff
  - Determined Level of Revenue Adjustments Needed through forecast

Key Assumptions

- Customer Growth
- Modest Energy Sales Growth <~1.0% / year
- TOU rates penetration of ~1.0% / year
- Limited growth in solar PV (net metering) and plug in hybrid electric vehicles (PHEV)
- Projected Expenses Reflect:
  - O&M Expense Including Illinois Municipal Electric Agency (IMEA) Purchased Power Supply Contract Details
  - Capital Improvement Plan
  - Debt Service

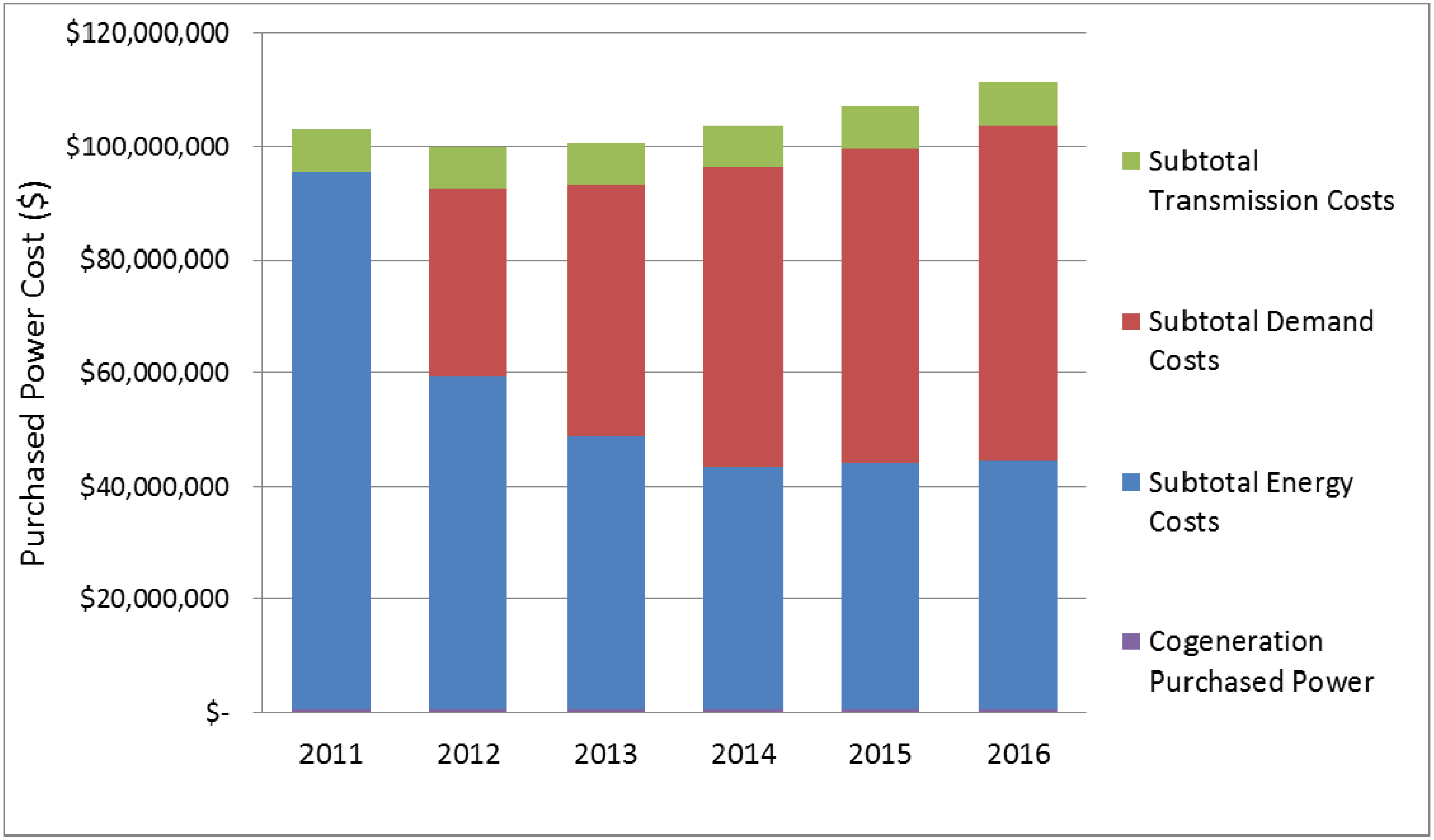
Projected Energy Sources -



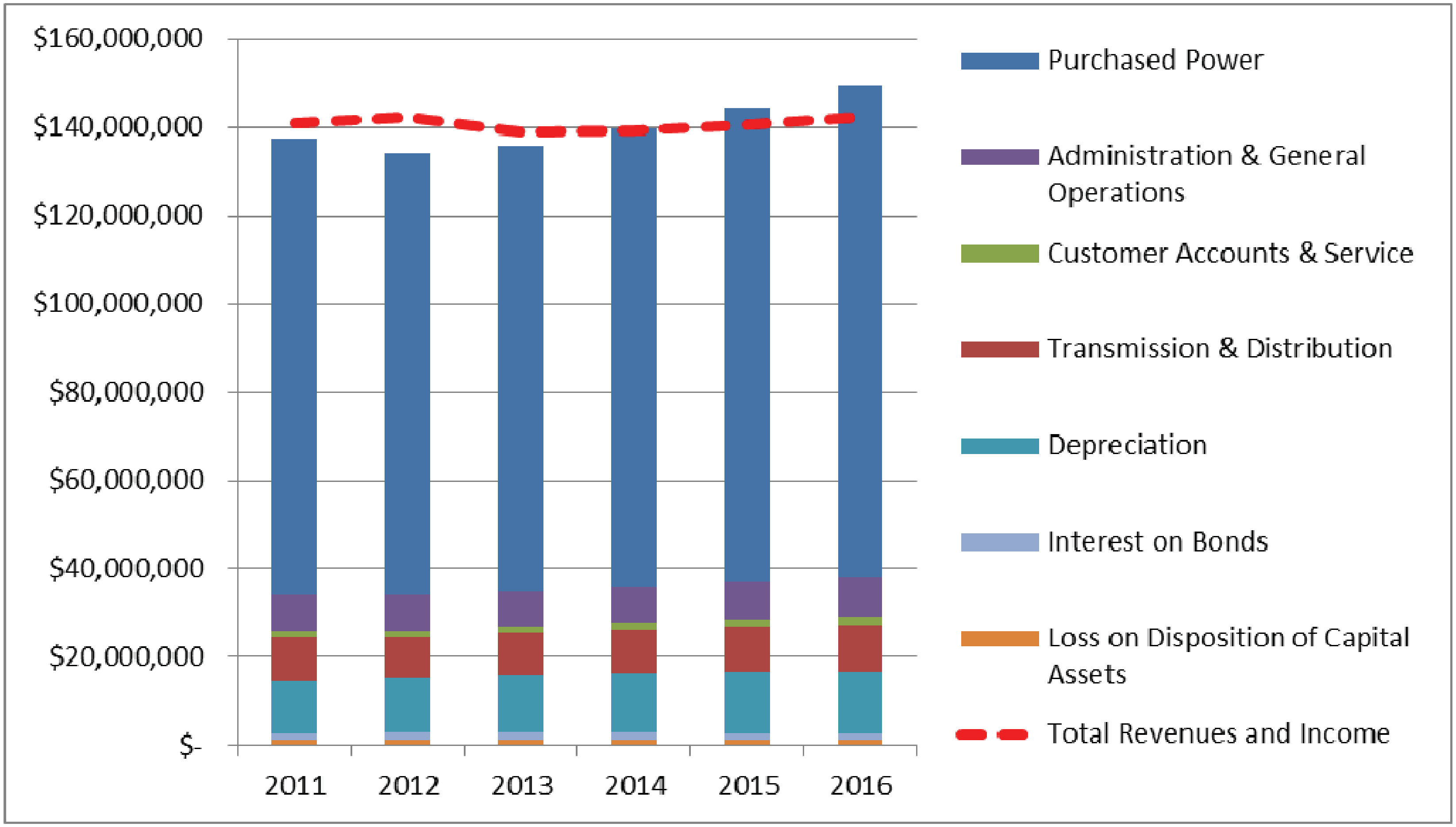
- *61% from IMEA-owned coal resources, (Prairie State and Trimble County)*
- *24% from Ameren Energy Marketing (AEM) market mix**
- *7% purchases from PJM/MISO market mix**
- *6% from wind/hydro*
- *2% from member- owned natural gas and diesel generation*

*AEM sources of energy – 66% coal, 18% nuclear, 9% natural gas, 5% wind, 1% hydro, 1% unknown (Source – Illinois Commerce Commission)
*PJM sources of energy – 45% coal, 35% nuclear, 16% natural gas, 4% other (Source – Illinois Commerce Commission)
*MISO capacity mix – 51% coal, 23% natural gas, 7% oil/gas, 6.8% wind, 6% nuclear, 3% oil, 2% hydro, 1.2% other (Source – MISO website)

Purchased Power Cost Forecast



Revenue Requirements Forecast



Financial Assessment

- Reviewed Results for Five Year Period
- Financial Targets:
  - Maintain Positive Net Income
  - Debt Service Coverage Requirements
- Determined Revenue Adjustments
  - FY 2012 – *0.0 percent*
  - FY 2013 – *0.0 percent*
  - FY 2014 – 2.0 percent
  - FY 2015 – 2.0 percent
  - FY 2016 – 2.0 percent

Electric Rate Comparison

Naperville vs. ComEd and Surrounding Municipally-Owned Electric Utilities

Geneva	**-4.8%**
Princeton	**+1.1%**
Batavia	**+3.8%**
St. Charles	**+9.8%**
ComEd	**+23%**
Winnetka	**+28.3%**

***Based on 923kWh/month/Residential Customer**

Cost of Service – Unbundle Costs

- Purchased Power Costs
  - 2007 – 2011: All Energy Costs (kWh)
  - 2012 – 2016: Both Energy (kWh) and Demand (kW) Costs
- Transmission & Distribution Costs
  - No major changes
- Customer Cost
  - No major changes

Cost of Service Summary

- No revenue increases required for FY12 & FY13
- No significant cost reallocation between classes
- Power supply cost structure changes drive customer retail rate design changes for :
  - General Service
  - Primary
  - Transmission

Rate Design Analysis

Considering Cost of Service Analysis

- Restructured existing standard retail rates
- General Service over 50 kW move to General Service Demand
- Developed new TOU retail rates
- Developed other retail rate alternatives

Rate Implementation Strategy

- Implement new standard retail rates
- Implement new TOU retail rates
- Consider future across the board adjustments for FY14; FY15; and FY16
- Generate Adequate Revenues
- Meet City's Policies and Objectives

Proposed Standard Rates

Proposed Standard Electric Rates

- Customer charges all stay the same
- No change to standard Residential Service
- No change to standard General Service
- General Service Split into two classes
  - General Service (GS); less than 50 kW
  - General Service Demand (GSD); greater than 50 kW
- Larger customers will see lower energy charges and higher demand charges
- Demand – Highest hour of energy usage

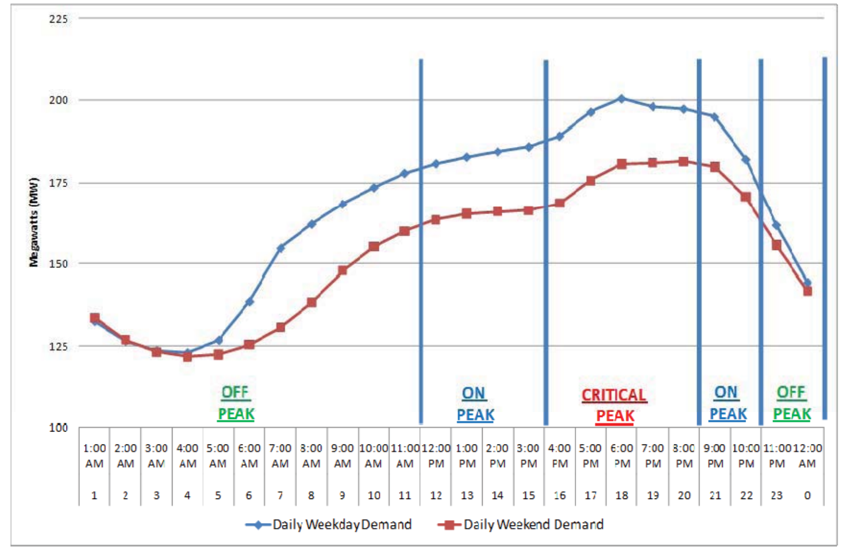
Proposed Standard Electric Rates

	Units	Existing	Proposed
RESIDENTIAL SERVICE			
Customer Charge	$/month	$ 11.1000	$ 11.1000
Energy Charge	$/kWh	$ 0.0868	$ 0.0868
GENERAL SERVICE (< 50 kW)			
Customer Charge	$/month	$ 21.6500	$ 21.6500
Energy Charge	$/kWh	$ 0.0871	$ 0.0871
GENERAL SERVICE DEMAND (> 50 kW)			
Customer Charge	$/month	$ 21.6500	$ 21.6500
Energy Charge	$/kWh	$ 0.0871	$ 0.0405
Monthly Demand Charge	$/kW	$ -	$ 17.6250
Reactive Demand Charge	$/kVar	$ -	$ -
PRIMARY SERVICE			
Customer Charge	$/month	$ 52.3500	$ 52.3500
Energy Charge	$/kWh	$ 0.0776	$ 0.0400
Monthly Demand Charge	$/kW	$ -	$ 17.3500
Reactive Demand Charge	$/kVar	$ -	$ -
TRANSMISSION SERVICE			
Customer Charge	$/month	$ 52.3500	$ 52.3500
Energy Charge	$/kWh	$ 0.0693	$ 0.0394
Monthly Demand Charge	$/kW	$ -	$ 13.7700
Reactive Demand Charge	$/kVar	$ -	$ -

Proposed Time of Use Rates

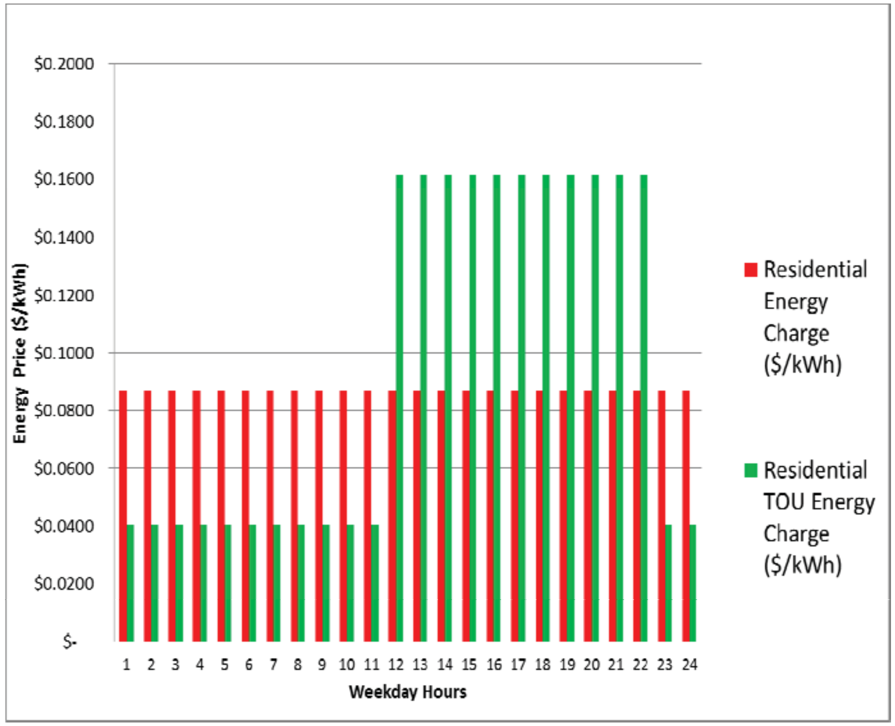
Time of Use Rate Strategy

- Considered Naperville system daily load shape
- Considered IMEA power supply cost structure
- Considered new metering capabilities
- For a typical customer, TOU Bill = Standard Bill



Residential TOU

Average Residential Customer	Units	Standard Rate		TOU Rate	
Customer Charge	$/month	$	11.1000	$	11.1000
Critical Peak Energy Charge	$/kWh	$	-	$	0.1615
On-Peak Energy Charge	$/kWh	$	-	$	0.1615
Off-Peak Energy Charge	$/kWh	$	-	$	0.0405
Flat Energy Charge	$/kWh	$	0.0868	$	-
Critical Peak Energy	kWh		172		172
On-Peak Energy	kWh		181		181
Off-Peak Energy	kWh		569		569
Total Energy	kWh		923		923
Critical Peak Energy Charges	$	$	-	$	28
On-Peak Energy Charges	$	$	-	$	29
Off-Peak Energy Charges	$	$	-	$	23
Flat Energy Charges	$	$	81	$	-
Total Energy Charges	$	$	81	$	80
Average Monthly Bill	$	$	92	$	91

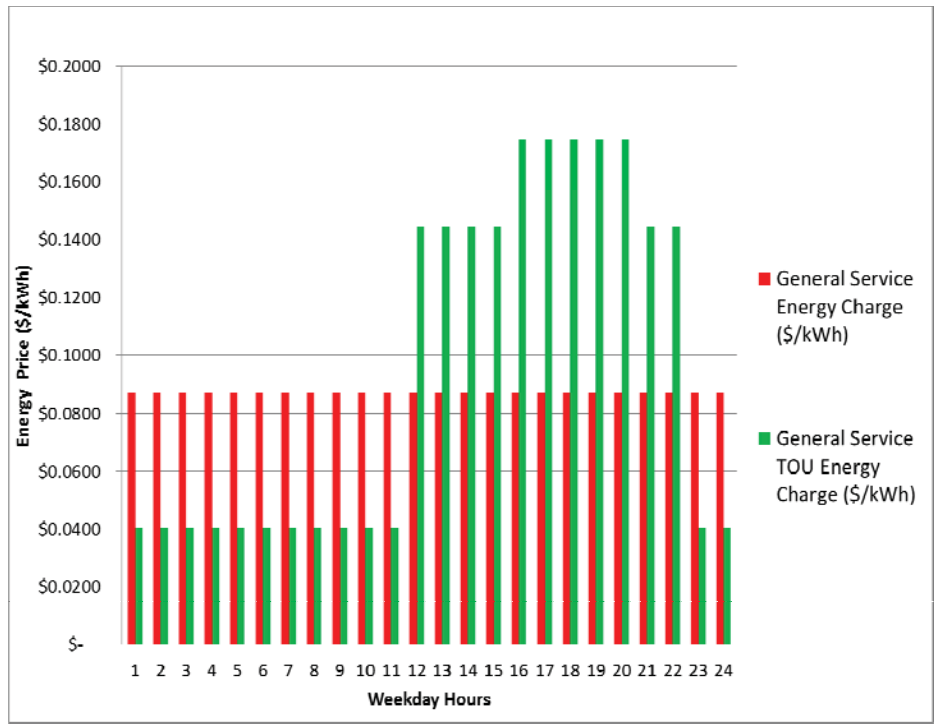


Time of Use Staff Recommendations

- Designate 9:00p.m. to 11:00p.m. as off-peak rather than on-peak hours for the Residential TOU rate class
- Increase critical peak and on-peak energy rates from \$.1615/kWh to \$.1775/kWh based on cost of service analysis
- Require customers to remain on TOU rates for a minimum of 12 months after switching from standard rates
- Allow customers a one-time option to switch back to standard rates at any time

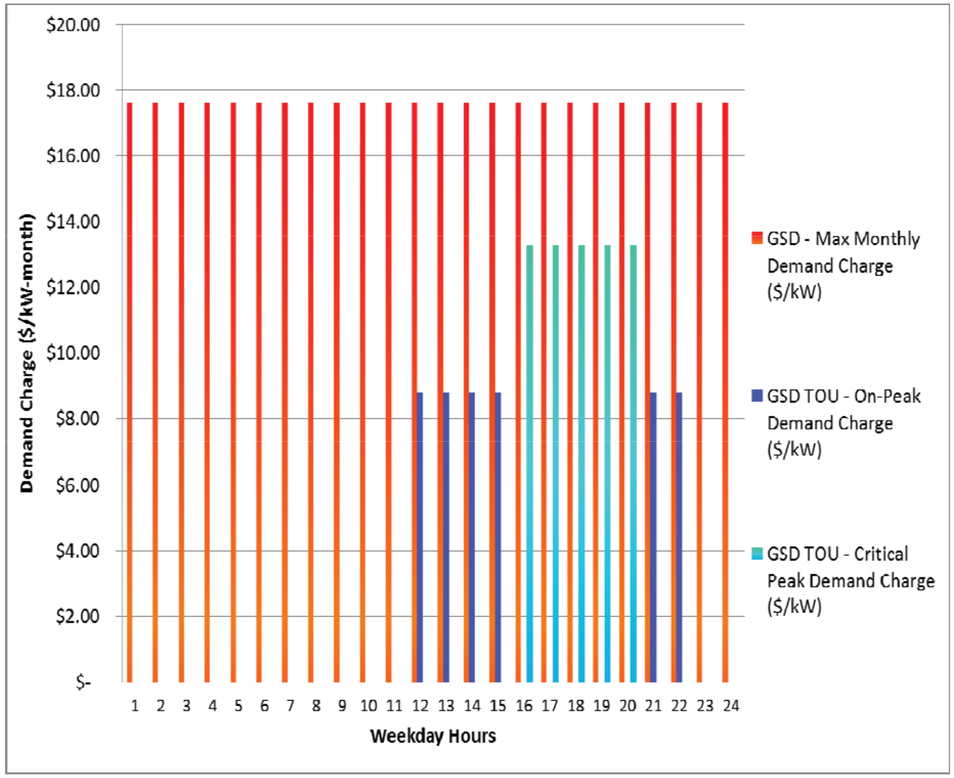
General Service TOU

Average General Service Customer	Units	Standard Rate		TOU Rate	
Customer Charge	$/month	$	21.6500	$	21.6500
Critical Peak Energy Charge	$/kWh	$	-	$	0.1745
On-Peak Energy Charge	$/kWh	$	-	$	0.1445
Off-Peak Energy Charge	$/kWh	$	-	$	0.0405
Flat Energy Charge	$/kWh	$	0.0871	$	-
Critical Peak Energy	kWh		1,632		1,632
On-Peak Energy	kWh		1,902		1,902
Off-Peak Energy	kWh		5,401		5,401
Total Energy	kWh		8,935		8,935
Critical Peak Energy Charges	$	$	-	$	285
On-Peak Energy Charges	$	$	-	$	275
Off-Peak Energy Charges	$	$	-	$	219
Flat Energy Charges	$	$	779	$	-
Total Energy Charges	$	$	779	$	778
Average Monthly Bill	$	$	801	$	800



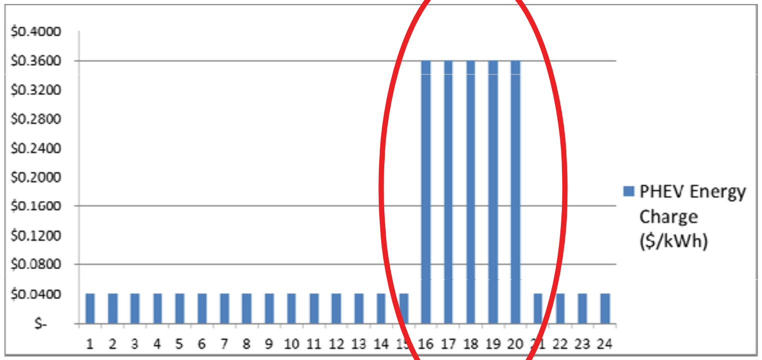
General Service Demand TOU

Average General Service Demand Customer	Units	Standard Rate	TOU Rate
Customer Charge	$/month	$ 21.6500	$ 21.6500
Flat Energy Charge	$/kWh	$ 0.0405	$ 0.0405
Critical Peak Demand Charge	$/kW	$ -	$ 13.2800
On-Peak Demand Charge	$/kW	$ -	$ 8.8000
Off-Peak Demand Charge	$/kW	$ -	$ -
Maximum Monthly Demand Charge	$/kW	$ 17.6250	$ -
Total Energy	kWh	63,937	63,937
Critical Peak Demand	kW	169	169
On-Peak Demand	kW	169	169
Off-Peak Demand	kW	169	169
Maximum Monthly Demand	kW	169	169
Total Energy Charges	$	$ 2,589	$ 2,589
Critical Peak Demand Charges	$	$ -	$ 2,245
On-Peak Demand Charges	$	$ -	$ 1,488
Off-Peak Demand Charges	$	$ -	$ -
Maximum Monthly Demand Charges	$	$ 2,980	$ -
Total Demand Charges	$	$ 2,980	$ 3,733
Average Monthly Bill	$	$ 5,591	$ 6,344



PHEV TOU Rates

- Plug in Hybrid / Electric Vehicles (PHEV) rates
- PHEV TOU energy rates designed to incentivize off-peak charging
- *PHEV rates will mirror the TOU rate for each rate class to encourage customers to migrate to TOU rates from standard/flat rates**



Critical Peak Period
4:00 pm to 9:00 pm

*See Electric Rate Workshop Memorandum #2, Page 2

Proposed Demand Response Initiative

Demand Response Incentive

City Controlled Energy Reduction

- Residential customer chooses to sign-up and participate in program
- Customer notified 24 hours in advance of planned event by e-mail, text or through ePortal.
- City sends signal to adjust thermostat setting by 3-5 °F for
  - Up to 5 events per month
  - Up to 3 hours per event or a maximum of 15 hours per month
  - Reduces system peak demand and reduces Naperville power supply costs

- Savings passed along to customers in form of a bill credit each month
- Residential Customer Class Credit :
  - $2.08/month fixed bill credit or $24.96 per year
  - $0.62/kWh variable credit (estimated $11.62 per month with five events)
- Customers can receive additional variable credit if other power usage is reduced during event

Demand Response Incentive

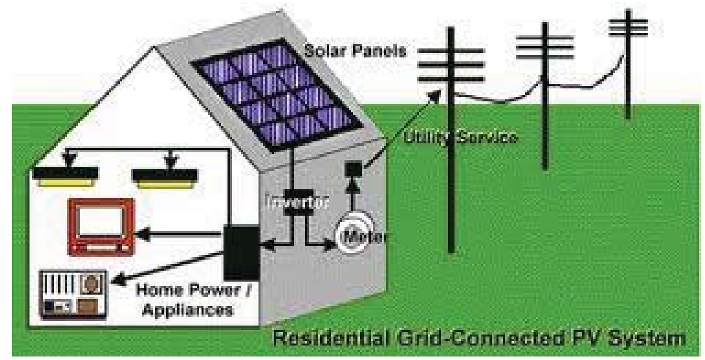
Customer Controlled Energy Reduction

- Customer chooses to sign up and participate in program
- Customer notified 24 hours in advance of planned event by e-mail, text or through ePortal.
- Customer adjusts thermostat or reduces power usage in another manner at their discretion.
- Up to 5 events per month
- Up to 3 hours per events or a maximum of 15 hours per month
- Reduces system peak demand and reduces Naperville power supply costs
- Savings passed along to customers in form of a bill credit each month:
- Residential Customer Class Credit:
  - $0.62/kWh variable credit
- Other Customer Class Credit:
  - $0.89/kWh variable credit

Net Metering Rates

- Net Metering Rates available to all customer classes
  - Standard Net Meter Rates
  - TOU Net Meter Rates

- Customer receives bill credit for kWh exported back to electric utility



- Credit equals energy rates (-$/kWh)

Council Consensus

- Endorse proposed rate structure
- Prepare ordinance for proposed rate structure
  - Implement standard rates beginning January 1, 2013
  - Implement TOU rates and demand response programs beginning May 1, 2013
  - Implement 2% rate increases on May 1, 2013; May 1,2014; and May 1, 2015

Electric Cost of Service Study and Rate Adjustment Considerations

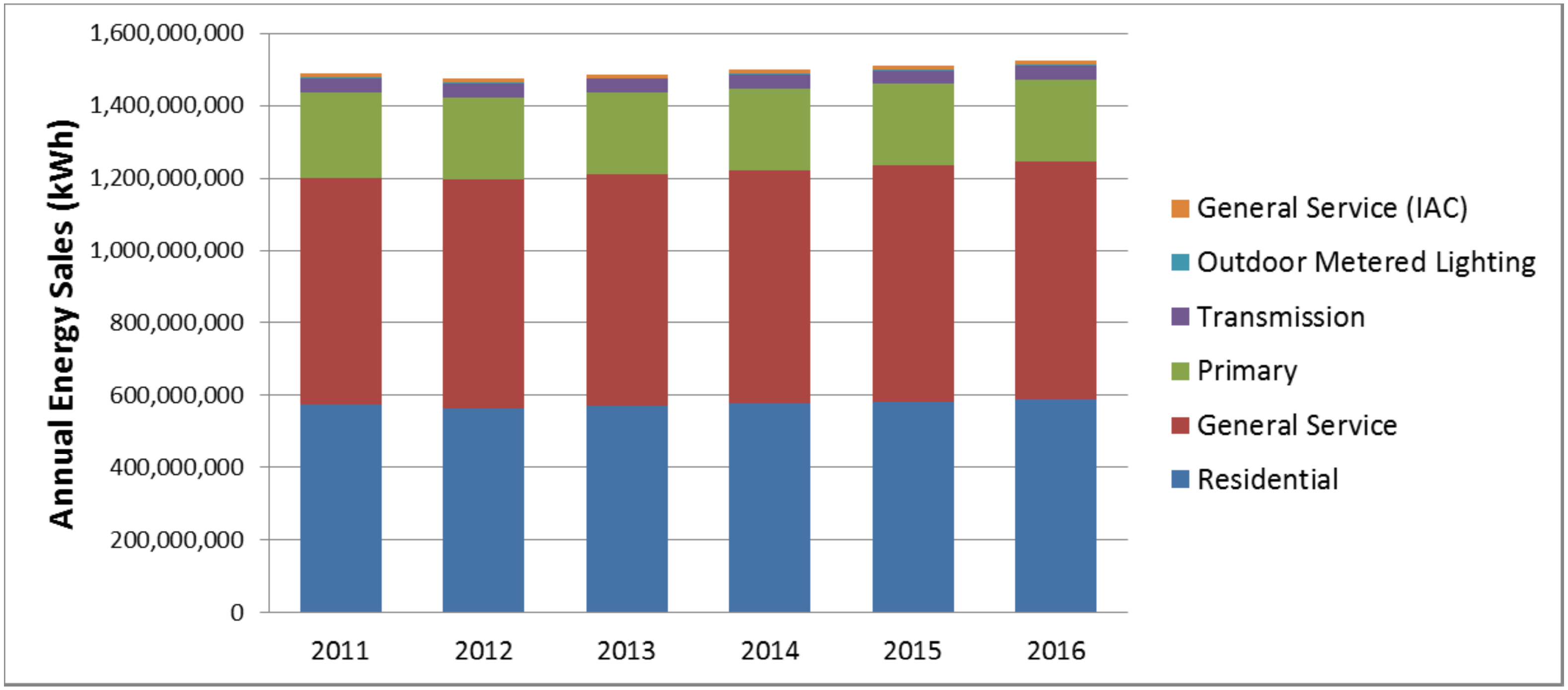
Questions

Supplemental Workshop Material

Energy Sales Forecast

Customer Class	Budget	Forecast				
	2011	2012	2013	2014	2015	2016
	kWh	kWh	kWh	kWh	kWh	kWh
Residential	575,861,270	566,355,609	572,019,165	577,739,357	583,516,750	589,351,918
General Service	623,985,582	630,980,699	637,290,506	643,663,411	650,100,045	656,601,046
Primary	234,173,960	225,407,541	225,407,541	225,407,541	225,407,541	225,407,541
Transmission	40,574,708	37,614,068	37,614,068	37,614,068	37,614,068	37,614,068
Outdoor Metered Lighting	2,781,141	3,049,966	3,080,465	3,111,270	3,142,383	3,173,806
General Service (IAC)	12,095,965	10,316,102	10,419,263	10,523,456	10,628,690	10,734,977
Total Sales - Existing Classes	1,489,472,626	1,473,723,985	1,485,831,009	1,498,059,103	1,510,409,478	1,522,883,357
Percentage Growth		-1.06%	0.82%	0.82%	0.82%	0.83%

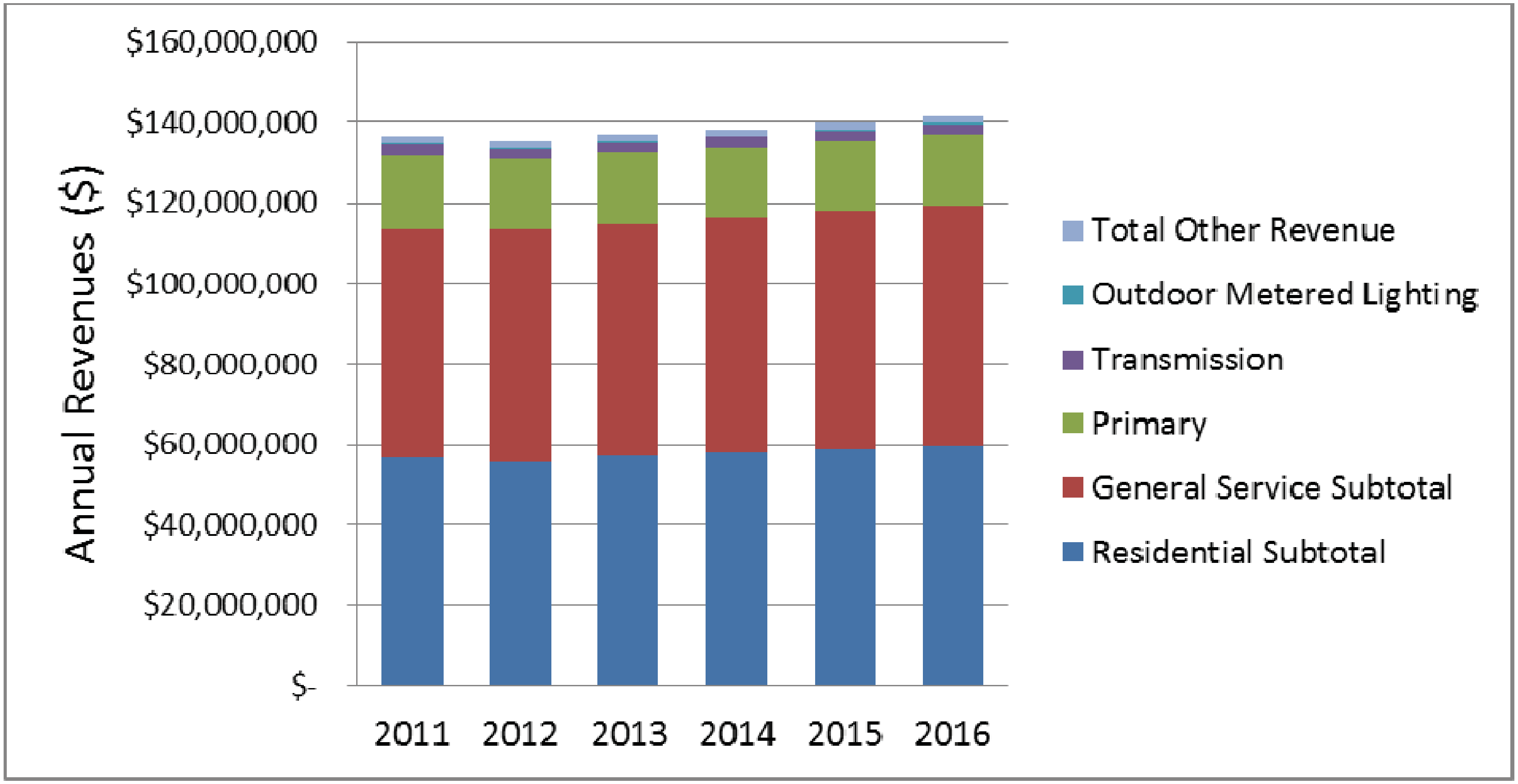
Energy Sales Forecast



Revenue Forecast at Current Rates

Description	Budget	Forecast				
	2011	2012	2013	2014	2015	2016
Retail Rate Revenues						
Residential	$ 56,729,800	$ 55,132,700	$ 55,119,000	$ 55,098,800	$ 55,073,400	$ 55,041,500
Residential Net Metering	$ -	$ -	$ (16,200)	$ (32,000)	$ (47,600)	$ (62,800)
Residential EV/PHEV	$ -	$ -	$ 170,100	$ 261,100	$ 410,800	$ 564,000
Residential TOU	$ -	$ 839,500	$ 1,412,900	$ 1,998,300	$ 2,594,800	$ 3,203,300
Residential TOU Net Metering	$ -	$ -	$ (300)	$ (1,300)	$ (2,400)	$ (3,700)
Residential TOU EV/PHEV	$ -	$ -	$ 315,900	$ 485,000	$ 763,000	$ 1,047,500
Residential Subtotal	$ 56,729,800	$ 55,972,200	$ 57,001,400	$ 57,809,900	$ 58,792,000	$ 59,789,800
General Service	$ 55,862,900	$ 55,642,700	$ 55,622,100	$ 55,607,100	$ 55,578,700	$ 55,546,400
General Service Net Metering	$ -	$ -	$ (6,600)	$ (13,300)	$ (17,700)	$ (24,300)
General Service TOU	$ -	$ 844,700	$ 1,430,200	$ 2,015,600	$ 2,620,400	$ 3,234,800
General Service TOU Net Metering	$ -	$ -	$ -	$ -	$ (1,100)	$ (1,100)
General Service Subtotal	$ 55,862,900	$ 56,487,400	$ 57,045,700	$ 57,609,400	$ 58,180,300	$ 58,755,800
Primary	$ 18,177,600	$ 17,497,300	$ 17,497,300	$ 17,497,300	$ 17,497,300	$ 17,497,300
Transmission	$ 2,812,400	$ 2,607,300	$ 2,607,300	$ 2,607,300	$ 2,607,300	$ 2,607,300
Outdoor Metered Lighting	$ 291,300	$ 316,900	$ 320,100	$ 323,300	$ 326,500	$ 329,700
General Service (IAC)	$ 1,075,200	$ 920,300	$ 929,500	$ 938,800	$ 948,200	$ 957,700
Total Retail Rate Revenue	$ 134,949,200	$ 133,801,400	$ 135,401,300	$ 136,786,000	$ 138,351,600	$ 139,937,600
Other Operating Revenues						
Other Charges for Service	$ 263,600	$ 263,600	$ 263,600	$ 263,600	$ 263,600	$ 263,600
Internal Services	$ 123,600	$ 123,600	$ 123,600	$ 123,600	$ 123,600	$ 123,600
Miscellaneous	$ 1,190,000	$ 1,190,000	$ 1,190,000	$ 1,190,000	$ 1,190,000	$ 1,190,000
Total Other Revenue	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200
Total Operating Revenue	$ 136,526,400	$ 135,378,600	$ 136,978,500	$ 138,363,200	$ 139,928,800	$ 141,514,800
Percentage Growth		-0.84%	1.18%	1.01%	1.13%	1.13%

Revenue Forecast at Current Rates



Purchased Power Cost Forecast

Description	2011	2012	2013	2014	2015	2016
Energy Costs	$ 94,844,000	$ 51,371,000	$ 43,259,000	$ 39,143,000	$ 39,759,000	$ 39,926,000
Premium Adjustment Costs	$ -	$ 7,487,000	$ 4,954,000	$ 3,870,000	$ 3,909,000	$ 3,949,000
Subtotal Energy Costs	$ 94,844,000	$ 58,858,000	$ 48,213,000	$ 43,013,000	$ 43,668,000	$ 43,875,000
Demand Cost	$ -	$ 26,050,000	$ 36,649,000	$ 45,091,000	$ 47,736,000	$ 51,730,000
IMEA New Member Debt Service	$ -	$ 7,077,000	$ 7,721,000	$ 7,721,000	$ 7,721,000	$ 7,721,000
Subtotal Demand Costs	$ -	$ 33,127,000	$ 44,370,000	$ 52,812,000	$ 55,457,000	$ 59,451,000
J. Aron Transmission Cost	$ 7,780,500	$ 646,900	$ -	$ -	$ -	$ -
IMEA Transmission Cost	$ -	$ 6,823,600	$ 7,433,000	$ 7,497,400	$ 7,570,100	$ 7,643,600
Subtotal Transmission Costs	$ 7,780,500	$ 7,470,500	$ 7,433,000	$ 7,497,400	$ 7,570,100	$ 7,643,600
Total Power Supply Cost ($)	$ 102,624,500	$ 99,455,500	$ 100,016,000	$ 103,322,400	$ 106,695,100	$ 110,969,600
Total Power Supply Energy (MWh)	1,552,450	1,518,134	1,533,931	1,548,256	1,563,929	1,579,798
Total Power Supply Cost ($/MWh)	$ 66.10	$ 65.51	$ 65.20	$ 66.73	$ 68.22	$ 70.24
Cogeneration Purchased Power	$ 559,500	$ 480,700	$ 496,400	$ 512,600	$ 530,600	$ 545,100
Total Purchased Power Cost ($)	$ 103,184,000	$ 99,936,200	$ 100,512,400	$ 103,835,000	$ 107,225,700	$ 111,514,700
Percentage Growth (%)		-3.15%	0.58%	3.31%	3.27%	4.00%

Operating Expense Forecast

Expense Category	Budget	Forecast				
	2011	2012	2013	2014	2015	2016
Purchased Power	$ 103,184,000	$ 99,936,200	$ 100,512,400	$ 103,835,000	$ 107,225,700	$ 111,514,700
Transmission Operations	$ 14,500	$ 13,600	$ 13,900	$ 14,200	$ 14,700	$ 15,200
Transmission Maintenance	$ 23,000	$ 16,100	$ 16,100	$ 17,200	$ 17,400	$ 18,700
Distribution Operations	$ 5,649,700	$ 5,361,000	$ 5,424,400	$ 5,652,300	$ 5,822,300	$ 6,001,000
Distribution Maintenance	$ 4,547,000	$ 3,994,100	$ 4,003,100	$ 4,188,900	$ 4,435,300	$ 4,608,300
Customer Accounts	$ 99,700	$ 97,800	$ 97,900	$ 104,000	$ 114,000	$ 118,400
Customer Service Operations	$ 1,169,100	$ 1,145,500	$ 1,146,200	$ 1,216,800	$ 1,334,800	$ 1,385,000
Administration & General Operations	$ 7,547,100	$ 7,528,800	$ 7,573,900	$ 7,693,000	$ 7,961,200	$ 8,201,100
Administration & General	$ 661,800	$ 651,500	$ 655,200	$ 700,400	$ 741,200	$ 760,700
Total O&M Expense	$ 122,895,900	$ 118,744,600	$ 119,443,100	$ 123,421,800	$ 127,666,600	$ 132,623,100
Percentage Growth (%)		-3.38%	0.59%	3.33%	3.44%	3.88%

Projected Net Income - No Adjustments

Description	Budget 2011	Projected Annual Net Income 2012	2013	2014	2015	2016
Retail Rate Revenues	$ 134,949,200	$ 133,801,400	$ 135,401,300	$ 136,786,000	$ 138,351,600	$ 139,937,600
Additional Revenue from Adjustments	$ -	$ -	$ -	$ -	$ -	$ -
Other Operating Revenues	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200
Total Operating Revenues	$ 136,526,400	$ 135,378,600	$ 136,978,500	$ 138,363,200	$ 139,928,800	$ 141,514,800
Operation and Maintenance Expenses	$ (122,895,900)	$ (118,831,500)	$ (119,903,400)	$ (123,882,100)	$ (128,126,900)	$ (133,083,400)
Depreciation Expense	$ (11,712,700)	$ (12,489,200)	$ (13,161,400)	$ (13,489,900)	$ (13,784,200)	$ (14,115,400)
Total Operating Expenses	$ (134,608,600)	$ (131,320,700)	$ (133,064,800)	$ (137,372,000)	$ (141,911,100)	$ (147,198,800)
Total Non-Operating Revenue (Expense)	$ 1,507,900	$ 3,875,300	$ (1,171,100)	$ (2,191,000)	$ (2,093,200)	$ (1,979,700)
Net Income	$ 3,425,700	$ 7,933,200	$ 2,742,600	$ (1,199,800)	$ (4,075,500)	$ (7,663,700)

Projected Net Margins - With Adjustments

Description	Budget 2011	Projected Annual Net Income 2012	2013	2014	2015	2016
Retail Rate Revenues	$ 134,949,200	$ 133,801,400	$ 135,401,300	$ 136,786,000	$ 138,351,600	$ 139,937,600
Additional Revenue from Adjustments	$ -	$ -	$ -	$ 2,735,700	$ 5,589,400	$ 8,565,300
Other Operating Revenues	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200
Total Operating Revenues	$ 136,526,400	$ 135,378,600	$ 136,978,500	$ 141,098,900	$ 145,518,200	$ 150,080,100
Operation and Maintenance Expenses	$ (122,895,900)	$ (118,831,500)	$ (119,903,400)	$ (123,882,100)	$ (128,126,900)	$ (133,083,400)
Depreciation Expense	$ (11,712,700)	$ (12,489,200)	$ (13,161,400)	$ (13,489,900)	$ (13,784,200)	$ (14,115,400)
Total Operating Expenses	$ (134,608,600)	$ (131,320,700)	$ (133,064,800)	$ (137,372,000)	$ (141,911,100)	$ (147,198,800)
Total Non-Operating Revenue (Expense)	$ 1,507,900	$ 3,875,300	$ (1,171,100)	$ (2,191,000)	$ (2,093,200)	$ (1,979,700)
Net Income	$ 3,425,700	$ 7,933,200	$ 2,742,600	$ 1,535,900	$ 1,513,900	$ 901,600

Cost-of-Service Analysis

- Revenue Requirements Established
- Unbundled Revenue Requirements
  – Power Supply (Energy, Demand, Transmission)
  – Transmission (Local Transmission System)
  – Distribution (Primary & Secondary)
  – Customer
- Develop Allocation Factors
- Assigned Costs to Classes
- Summarized Results

Cost of Service – Unbundle Costs

	Adjusted Test Year	KW	KWH	TDEL	TDEL2	DIST - P	DIST - S	CUST
	($)	($)	($)	($)	($)	($)	($)	($)
OPERATING EXPENSES								
Total Power Supply	99,936,200	33,127,000	59,338,700	7,470,500	-	-	-	-
Total Transmission O&M	29,700	-	-	-	29,700	-	-	-
Total Distribution O&M	9,354,900	-	-	-	-	7,306,212	2,048,688	-
Total Customer Accounts	97,900	-	-	-	-	-	-	97,900
Total Customer Service	1,145,500	-	-	-	-	-	-	1,145,500
Total Admin & General	8,180,400	-	-	-	-	3,194,462	895,738	4,090,200
Total Operating & Maintenance Expenses	118,831,500	33,127,000	59,338,700	7,470,500	29,700	10,534,609	2,953,941	5,377,050
OTHER REVENUE REQUIREMENTS								
Depreciation Expense	12,489,200	-	-	-	918,803	8,275,184	2,320,391	974,822
Interest Expense	1,750,100	-	-	-	128,751	1,159,594	325,154	136,601
(Gain)/Loss on Disposal of Capital Assets	1,180,000	-	-	-	86,810	781,853	219,234	92,103
Net Margins	1,824,200	508,537	910,917	114,681	456	161,718	45,346	82,544
Total Other Revenue Requirements	17,243,500	508,537	910,917	114,681	1,134,820	10,378,350	2,910,126	1,286,069
	-	-	-	-	-	-	-	-
Total Cost of Service	136,075,000	33,635,537	60,249,617	7,585,181	1,164,520	20,912,958	5,864,067	6,663,119
OTHER REVENUES								
Other Operating Revenue	(1,577,200)	(389,858)	(698,333)	(87,917)	(13,498)	(242,395)	(67,968)	(77,230)
Net Investment Income	(93,400)	(23,087)	(41,355)	(5,206)	(799)	(14,354)	(4,025)	(4,573)
DOJ-Aurora-Tech Grant	-	-	-	-	-	-	-	-
Smart Grid Grant	-	-	-	-	-	-	-	-
Capital Fees	(603,000)	-	-	-	(44,361)	(399,540)	(112,032)	(47,066)
Total Other Revenues	(2,273,600)	(412,945)	(739,688)	(93,124)	(58,658)	(656,290)	(184,026)	(128,870)
Net Base Rate Revenue Requirement	133,801,400	33,222,592	59,509,929	7,492,057	1,105,862	20,256,669	5,680,041	6,534,250

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SINCE 1898

Cost of Service Summary

	Total System	Residential	Residential TOU	General Service	General Service TOU	Primary	Transmission	Outdoor Metered Lighting	General Service (IAC)
Summary of Cost of Service									
Energy Cost:									
Energy Sales (kWh)	1,473,723,985	557,862,133	8,493,476	621,545,647	9,435,052	225,407,541	37,614,068	3,049,966	10,316,102
Total Cost	$ 59,509,929	$ 22,592,855	$ 343,977	$ 25,171,974	$ 382,110	$ 8,995,040	$ 1,482,661	$ 123,521	$ 417,792
Dollars/kWh	$ 0.0404	$ 0.0405	$ 0.0405	$ 0.0405	$ 0.0405	$ 0.0399	$ 0.0394	$ 0.0405	$ 0.0405
Demand Cost (Total):									
Contribution to System NCP (kW)	276,721	122,256	1,861	109,275	1,659	31,177	7,933	746	1,814
Total Cost	$ 67,757,221	$ 27,961,557	$ 425,716	$ 29,227,492	$ 443,673	$ 8,103,205	$ 959,787	$ 150,689	$ 485,103
$/kW-mo	$ 20.40	$ 19.06	$ 19.06	$ 22.29	$ 22.29	$ 21.66	$ 10.08	$ 16.82	$ 22.29
Customer Service:									
Number of Customers	57,240	50,378	767	5,797	88	9	1	116	84
Total Cost	$ 6,534,250	$ 5,749,896	$ 87,542	$ 661,660	$ 10,044	$ 2,054	$ 228	$ 13,257	$ 9,568
$/Customer/Month	$ 9.51	$ 9.51	$ 9.51	$ 9.51	$ 9.51	$ 19.02	$ 19.02	$ 9.51	$ 9.51
Revenue Requirement Before Adjustments	$ 133,801,400	$ 56,304,308	$ 857,236	$ 55,061,125	$ 835,827	$ 17,100,299	$ 2,442,676	$ 287,466	$ 912,463
Lighting Depreciation Adjustment [1]	$ 0	$ (25,958)	$ (395)	$ (2,987)	$ (45)	$ (5)	$ (1)	$ 29,434	$ (43)
Total Cost:									
Dollars	$ 133,801,400	$ 56,278,350	$ 856,840	$ 55,058,138	$ 835,782	$ 17,100,295	$ 2,442,676	$ 316,900	$ 912,420
Dollars/kWh	$ 0.0908	$ 0.1009	$ 0.1009	$ 0.0886	$ 0.0886	$ 0.0759	$ 0.0649	$ 0.1039	$ 0.0884
Comparison of Revenues ($)									
Revenue Requirement	$ 133,801,400	$ 56,278,350	$ 856,840	$ 55,058,138	$ 835,782	$ 17,100,295	$ 2,442,676	$ 316,900	$ 912,420
Gen. by Existing Rates	133,801,400	$ 55,132,700	$ 839,500	$ 55,642,700	$ 844,700	$ 17,497,300	$ 2,607,300	$ 316,900	$ 920,300
Dollar Difference	**$ -**	**$ 1,145,650**	**$ 17,340**	**$ (584,562)**	**$ (8,918)**	**$ (397,005)**	**$ (164,624)**	**$ -**	**$ (7,880)**
Revenue Adjustment Required	**0.00%**	**2.08%**	**2.07%**	**-1.05%**	**-1.06%**	**-2.27%**	**-6.31%**	**0.00%**	**-0.86%**

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General Service Demand

General Service Demand	Energy	Load Factor	Demand	Total Bill Existing	Total Bill Proposed	Bill Change
	kWh	%	kW	$	$	$
	63,937	43.00%	207	$ 5,591	$ 6,259	$ 669
	63,937	48.00%	185	$ 5,591	$ 5,872	$ 281
Average =>	**63,937**	**52.52%**	**169**	**$ 5,591**	**$ 5,591**	**$ 0**
	63,937	58.00%	153	$ 5,591	$ 5,308	$ (283)
	63,937	63.00%	141	$ 5,591	$ 5,096	$ (494)

Primary Service

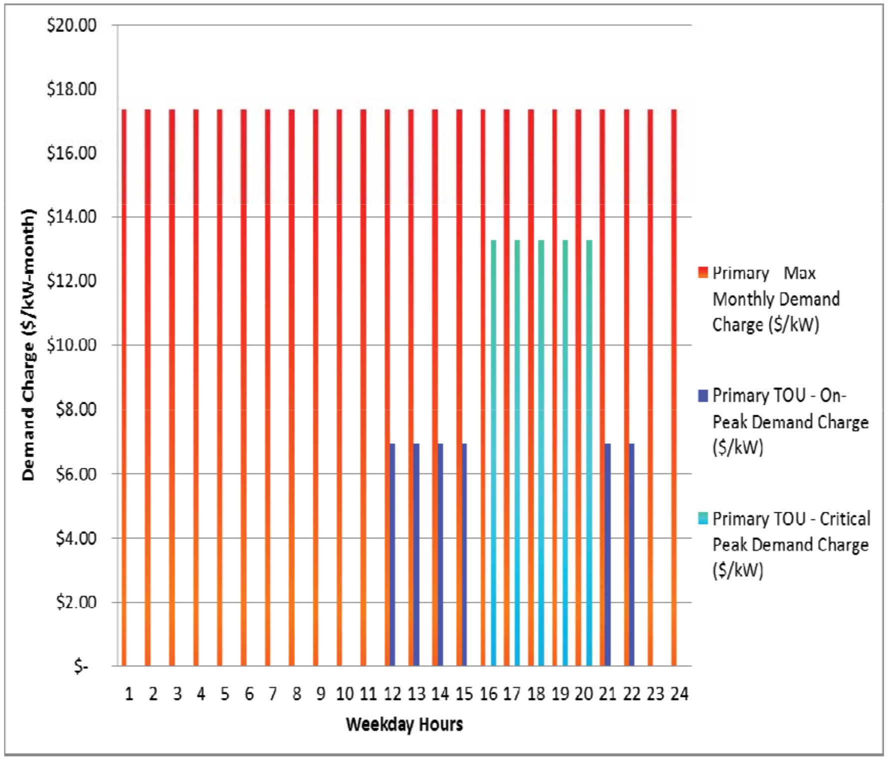
Primary Service	Energy	Load Factor	Demand	Total Bill Existing	Total Bill Proposed	Bill Change
	kWh	%	kW	$	$	$
	2,087,107	54.00%	5,368	$ 162,012	$ 176,671	$ 14,660
	2,087,107	59.00%	4,913	$ 162,012	$ 168,777	$ 6,765
Average =>	**2,087,107**	**64.09%**	**4,523**	**$ 162,012**	**$ 162,011**	**$ (1)**
	2,087,107	69.00%	4,201	$ 162,012	$ 156,424	$ (5,588)
	2,087,107	74.00%	3,917	$ 162,012	$ 151,497	$ (10,515)

Transmission Service

Transmission Service	Energy	Load Factor	Demand	Total Bill Existing	Total Bill Proposed	Bill Change
	kWh	%	kW	$	$	$
	3,134,506	54.00%	8,062	$ 217,274	$ 234,566	$ 17,292
	3,134,506	59.00%	7,379	$ 217,274	$ 225,161	$ 7,887
Average =>	**3,134,506**	**63.97%**	**6,806**	**$ 217,274**	**$ 217,271**	**$ (3)**
	3,134,506	69.00%	6,309	$ 217,274	$ 210,427	$ (6,847)
	3,134,506	74.00%	5,883	$ 217,274	$ 204,561	$ (12,713)

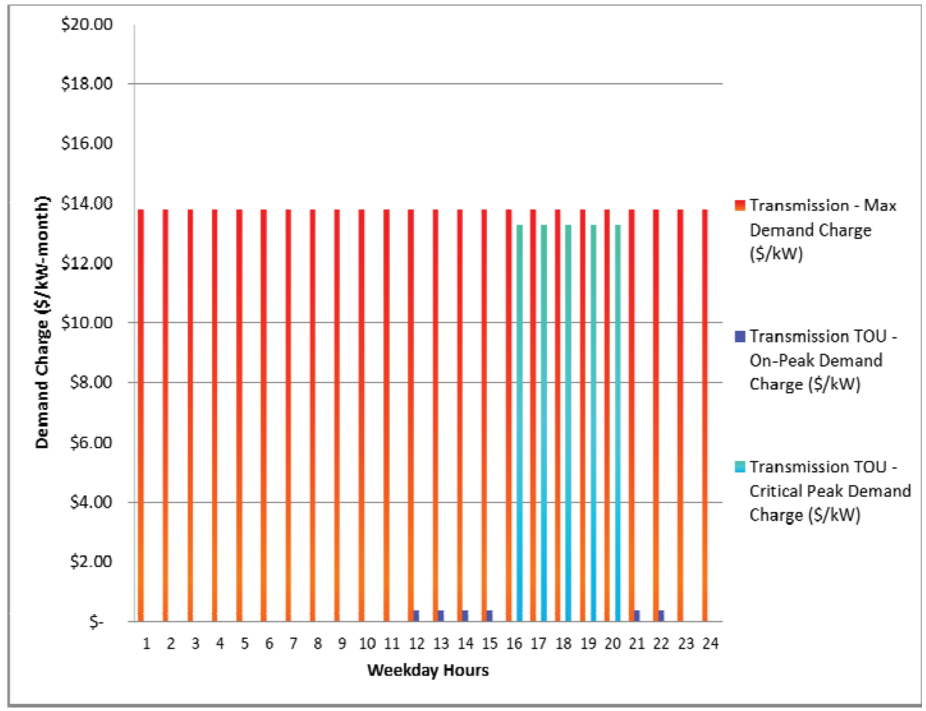
Primary TOU

Average Primary Service Customer	Units	Standard Rate		TOU Rate	
Customer Charge	$/month	$	52.3500	$	52.3500
Flat Energy Charge	$/kWh	$	0.0400	$	0.0400
Critical Peak Demand Charge	$/kW	$	-	$	13.2800
On-Peak Demand Charge	$/kW	$	-	$	6.9500
Off-Peak Demand Charge	$/kW	$	-	$	-
Maximum Monthly Demand Charge	$/kW	$	17.3500	$	-
Total Energy	kWh		2,087,107		2,087,107
Critical Peak Demand	kW		3,375		3,375
On-Peak Demand	kW		3,429		3,429
Off-Peak Demand	kW		3,339		3,339
Maximum Monthly Demand	kW		3,429		3,429
Total Energy Charges	$	$	83,484	$	83,484
Critical Peak Demand Charges	$	$	-	$	44,822
On-Peak Demand Charges	$	$	-	$	23,834
Off-Peak Demand Charges	$	$	-	$	-
Maximum Monthly Demand Charges	$	$	59,499	$	-
Total Demand Charges	$	$	59,499	$	68,656
Average Monthly Bill	$	$	143,036	$	152,192



Transmission TOU

Average Transmission Service Customer	Units	Standard Rate	TOU Rate
Customer Charge	$/month	$ 52.3500	$ 52.3500
Flat Energy Charge	$/kWh	$ 0.0394	$ 0.0394
Critical Peak Demand Charge	$/kW	$ -	$ 13.2800
On-Peak Demand Charge	$/kW	$ -	$ 0.3600
Off-Peak Demand Charge	$/kW	$ -	$ -
Maximum Monthly Demand Charge	$/kW	$ 13.7700	$ -
Total Energy	kWh	3,134,506	3,134,506
Critical Peak Demand	kW	6,182.08	6,182.08
On-Peak Demand	kW	7,176.70	7,176.70
Off-Peak Demand	kW	7,757.22	7,757.22
Maximum Monthly Demand	kW	7,757.22	7,757.22
Total Energy Charges	$	$ 123,500	$ 123,500
Critical Peak Demand Charges	$	$ -	$ 82,098
On-Peak Demand Charges	$	$ -	$ 2,584
Off-Peak Demand Charges	$	$ -	$ -
Maximum Monthly Demand Charges	$	$ 106,817	$ -
Total Demand Charges	$	$ 106,817	$ 84,682
Average Monthly Bill	$	$ 230,369	$ 208,233



Electric Rate Workshop Material Included in Packet

- Memorandum #1 dated October 12, 2012 - Standard Rates
- Memorandum #2 dated October 19, 2012 - TOU/Electric Vehicle Rates
- Memorandum #3 dated October 26, 2012 - Demand Response Programs
- Rate Study Executive Summary

CITY OF NAPERVILLE
MEMORANDUM

DATE: October 12, 2012

TO: Doug Krieger, City Manager

THROUGH: Marcie Schatz, Deputy City Manager

FROM: Mark Curran, Director of Public Utilities-Electric

SUBJECT: **Electric Rate Workshop Memorandum #1**

PURPOSE:
This is the first in a series of memorandums to be disseminated prior to the Electric Rate Workshop scheduled for Tuesday, November 13, 2012. The purpose of these memoranda is to provide Council with results of the Electric Retail Cost-of-Service and Rate Design Study completed in October 2011 for the Department of Public Utilities-Electric (DPU-E). The results of this study are the foundation for the discussion that will take place on November 13.

BACKGROUND:
DPU-E retained Burns & McDonnell Engineering Company (B&M) of Kansas City, Missouri, to prepare a Cost-of-Service and Rate Design Study for the electric utility. In the study, historical costs of providing electric service to customers were analyzed and future cost projections were used to determine annual system revenue requirements. In addition, a number of rate classifications were created and are proposed to be added so DPU-E can begin offering time-of-use (TOU), electric vehicle (EV), plug-in hybrid electric vehicle (PHEV), and net metering services (for those customers who generate some of their own electricity) associated with the Naperville Smart Grid Initiative (NSGI).

DISCUSSION:
The load forecast for the study was based on a five-year forecast of class-specific energy sales and peak demand for the electric utility. The forecast included three years of historical data and annual projections through 2016. The second phase of the study completed was the determination of the annual revenue requirements for the electric utility. The annual revenue requirements analysis was used as the basis for the subsequent phases of the project, e.g. the cost-of-service analysis and rate design. In order to determine the annual revenue requirement, a five-year financial forecast of the operations of the electric utility was developed.

The third phase of the study completed was the development of the cost-of-service analysis to properly allocate the expenses to the most appropriate customer class. Costs assigned to each rate class include energy, demand, and customer related expenses. Once the test period cost of service was established for each rate classification, standard retail rates were examined to ensure the rates recover the appropriate amount of revenue for the electric utility.

B&M proposed no revenue adjustments until May 1, 2013, based on the cost-of-service results. Two percent rate increases for all classes are recommended for implementation on May 1, 2013; May 1, 2014; and May 1, 2015.

No changes are recommended to the current rates for residential, General Service customers with less than 50kW demand (small commercial customers) and metered outdoor lighting. These rates are listed below:

	Customer Charge	Energy Charge
Residential Customer	$11.10/mo	$.0868/kWh
General Service (<50kWh)	$21.65/mo	$.0871/kWh
Metered Outdoor Lighting	$21.65/mo	$.0940/kWh

Due to the billing structure of the Illinois Municipal Electric Agency (IMEA) purchase power agreement effective June 1, 2011, some rate classes were modified to include energy and demand charges to more appropriately recover costs. The classes modified the three largest commercial classifications: General Service with monthly demand of 50kW or greater, Primary Metering Service, and Transmission Metering Service. Although modified to include energy and demand charges, these rate classes will recover the same revenue as when each class only had an energy charge with the demand rolled in.

General Service Customers with a Monthly demand of 50kWh or Greater

General Service customers with a monthly demand of 50kW or greater will have the same customer charge of $21.65/mo and a reduced energy charge of $.0405/kWh. These customers will now also have a monthly demand charge of $17.625/kW. Based on the average usage and demand for customers in General Service Demand class, the proposed rates and resulting revenues are equal to those under the existing General Service rate schedule. However, those customers with load factors over 52.52% will see an overall bill reduction while customers with load factors below 52.52% will see an overall bill increase. Load factor refers to the steadiness or consistency of the flow of electricity to the customer. For example, a customer whose flow did not change during an entire billing period would have a load factor of 100%.

Primary Metering Customers

Primary metering customers are currently billed a monthly customer charge of $52.35 and an energy charge of $.0776/kWh. The proposed rates include the same monthly customer charge, a reduced energy charge of $.0400/kWh, and a monthly demand charge of $17.35/kW. The proposed rates achieve revenue neutrality, but those customers with load factors over 64.09% will see an overall bill reduction while customers with load factors below 64.09% will see an overall bill increase.

Transmission Metering Customers

Transmission Metering Service customers were previously billed a monthly customer charge of $52.35 and an energy charge of $.0693/kWh. Rates approved by Council and implemented July 1, 2012, included the same monthly customer charge, an energy charge of $.0394/kWh, and a monthly demand charge of $13.77/kW. BP is the only customer currently in this rate class.

The NSGI e-Portal will be active in early 2013, and will allow customers with demand charges to monitor their demand and energy usage on a daily basis in order to assist them in controlling their power costs.

B&M developed TOU rates for the Residential, General Service, General Service with monthly demand of 50kW or greater, Primary Metering Service, and Transmission Metering Service customer classes (See Attached Table 1-5). The TOU rates developed for the study will provide customers with rate options that enable reductions in their costs of electricity and improve the efficiency of the Naperville electric system operations through monetary incentives to shift load from on-peak and critical peak hours to off-peak hours (See Attached Figure 7-1).

More in-depth information on TOU rates, electric Vehicle (EV), plug-in hybrid electric vehicle (PHEV), and net metering services will be provided in my next memorandum to be distributed to Council on Friday, October 19, 2012. I will be providing information on proposed residential and non-residential Demand Response Programs in my memorandum on October 26, 2012. I have proposed a meeting with the Public Utilities Advisory Board on Thursday, October 25, 2012, to review all of the proposed rates prior to the Electric Rate Workshop on Tuesday, November 13, 2012.

<u>RECOMMENDATION</u>
Please forward this report to the City Council in the Manager's Memorandum.

power agreement, some rate structures were modified to more appropriately recover costs. Section 6.0 provides a discussion on the rate design considerations taken and modifications made to each rate structure from which standard rates are billed. A summary of the existing and proposed electric rates for the main rate classifications is presented in Table 1-4. Additional details are also provided in Appendix A of this report.

Table 1-4: Existing and Proposed Standard Rates Summary
Naperville Department of Public Utilities

	Units		Existing		Proposed
Residential Service					
Customer Charge	$/month	$	11.1000	$	11.1000
Energy Charge	$/kWh	$	0.0868	$	0.0868
General Service (< 50 kW)					
Customer Charge	$/month	$	21.6500	$	21.6500
Energy Charge	$/kWh	$	0.0871	$	0.0871
General Service Demand (> 50 kW)					
Customer Charge	$/month	$	21.6500	$	21.6500
Energy Charge	$/kWh	$	0.0871	$	0.0405
Monthly Demand Charge	$/kW	$	-	$	17.6250
Reactive Demand Charge	$/kVar	$	-	$	-
Primary Service					
Customer Charge	$/month	$	52.3500	$	52.3500
Energy Charge	$/kWh	$	0.0776	$	0.0400
Monthly Demand Charge	$/kW	$	-	$	17.3500
Reactive Demand Charge	$/kVar	$	-	$	-
Transmission Service					
Customer Charge	$/month	$	52.3500	$	52.3500
Energy Charge	$/kWh	$	0.0693	$	0.0394
Monthly Demand Charge	$/kW	$	-	$	13.7700
Reactive Demand Charge	$/kVar	$	-	$	-

1.6 TIME OF USE RATE DESIGN

In addition to the development of standard rates for the major Naperville customer classes, Burns & McDonnell developed time-of-use (TOU) rates for the Residential, General Service, General Service Demand, Primary Service, and Transmission Service customer classes. The cost-of-service analysis described in Section 5.0 of this report served as one input into the TOU rate design analysis. Input from Naperville was also taken into consideration in the development of the proposed TOU rates and structures. The TOU rates developed for the study will provide customers with rate options that enable reductions in their costs of electricity and improve the efficiency of Naperville electric system operations through monetary incentives to shift load from on-peak and critical peak hours to off-peak hours. A summary of the proposed TOU electric rates for the main rate classifications is presented in Table 1-5. Additional details are also provided in Appendix A of this report.

CITY OF NAPERVILLE
MEMORANDUM

DATE: October 19, 2012

TO: Doug Krieger, City Manager

THROUGH: Marcie Schatz, Deputy City Manager

FROM: Mark Curran, Director of Public Utilities-Electric

SUBJECT: **Electric Rate Workshop Memorandum #2**

PURPOSE:

This is the second in a series of memorandums to be distributed prior to the Electric Rate Workshop scheduled for Tuesday, November 13, 2012. The purpose of these memoranda is to provide Council with results of the Electric Retail Cost-of-Service and Rate Design Study completed in October 2011 for the Department of Public Utilities-Electric (DPU-E). The results of this study are the foundation for the discussion that will take place on November 13.

BACKGROUND:

DPU-E retained Burns & McDonnell Engineering Company (B&M) of Kansas City, Missouri, to prepare a Cost-of-Service and Rate Design Study for the electric utility. B&M proposed no revenue adjustments until May 1, 2013, based on the cost-of-service results. Two percent rate increases for all classes are recommended for implementation on May 1, 2013; May 1, 2014; and May 1, 2015.

In the study, historical costs of providing electric service to customers were analyzed and future cost projections were used to determine annual system revenue requirements. In addition, a number of rate classifications were created so DPU-E can begin offering time-of-use (TOU), electric vehicle (EV), plug-in hybrid electric vehicle (PHEV), and net metering services (for those customers who generate some of their own electricity) associated with the Naperville Smart Grid Initiative (NSGI).

DISCUSSION:

The discussion in the first Electric Rate Workshop memorandum focused primarily on standard/flat rate schedules for all customer classes. This memorandum will address the proposed rate design for time-of-use (TOU), electric vehicle (EV), plug-in hybrid electric vehicle (PHEV), and net metering services.

The City pays the Illinois Municipal Electric Agency (IMEA) for the energy we purchase as well as a demand charge based on the highest hour of usage during the monthly billing period. To the extent that we can improve the balance of energy usage throughout the day thereby reducing the peak demand, the City can reduce the demand charge paid to IMEA. This cost savings can then be passed on to our customers.

B&M developed TOU rates for Residential, General Service, General Service with monthly demand of 50kW or greater, Primary Metering Service, and Transmission Metering Service customer classes. These TOU rates will provide customers with rate options that enable reductions in their electricity costs and also improve the efficiency of the Naperville electric system operations. If the customer can shift their load from on-peak and critical peak hours to off-peak hours, they are able to take advantage of lower electrical rates.

Time of Use Hours
The TOU hours proposed by B & M are:

- *On-peak hours:* Monday through Friday 12:00 p.m. to 4:00 p.m. and 9:00 p.m. to 11:00 p.m.
- *Critical peak hours:* Monday through Friday 4:00 p.m. to 9:00 p.m. The peak or maximum hour of usage predominantly occurs during the critical peak hours.
- *Off peak hours:* All other weekday hours and weekend hours are designated off-peak hours.

Staff recommends one change to the B & M recommendations, designating 9:00 p.m. to 11:00 p.m. as off-peak rather than on-peak for the Residential TOU rate class. We believe this change will allow a greater number of customers to take advantage of TOU rates. This recommended change, reflected in Attachment 1, requires the critical peak and on-peak energy rates to increase from $.1615/kWh to $.1775/kWh based on the cost-of-service analysis.

The study includes a recommendation to require customers to remain on TOU rates for a minimum of 12 months after switching from the flat rate schedule. Staff would recommend that a customer is allowed a one-time option to switch back to flat rates at any time.

Electric Vehicle/Plug-in Hybrid Electric Vehicle Rates
B&M developed a TOU classification and rate for those customers who desire to purchase and receive electricity for use in EV or PHEV. The TOU rates developed in this study were based on the cost of providing service to EV/PHEV customers during the critical peak, on-peak, and off-peak hours of the day. The proposed rates include an energy charge of $.36/kWh for critical peak and on-peak usage, and an energy charge of $.0405/kWh for off-peak usage for both Residential and General Service customer classes.

Staff recommends charging the proposed residential TOU rate of $.1775/kWh for residential EV/PHEV usage during critical peak and on-peak periods instead of $.36/kWh. This change from the study will encourage owners of EV/PHEV to take advantage of TOU rates rather than remaining on standard/flat rates. The rate for off-peak usage is already recommended to be the same for residential and EV/PHEV use at $.0405/kWh. The recommended rates for General Service EV/PHEV also mirror the TOU rates for the rate class.

Net Metering Rates
The Council passed a net metering ordinance in 2010 which allows for the installation of small on-site solar photovoltaic and wind energy installations on customer's premises. The energy produced by a Renewable Energy System shall be utilized on-site, except for net metering as authorized by the Department of Public Utilities-Electric (DPU-E) and other appropriate regulatory agencies required by law. The energy exported from the Renewable Energy system to the DPU-E distribution system will be credited off of the customer's monthly bill at the customer's retail rate classification.

I will be providing in-depth information on proposed residential and non-residential Demand Response Programs in my next memorandum to be distributed to Council on Friday, October 26, 2012. I have scheduled a meeting with the Public Utilities Advisory Board on Thursday, October 25, 2012, to review all of the proposed rates prior to the Electric Rate Workshop on Tuesday, November 13, 2012.

RECOMMENDATION
Please forward this report to the City Council in the Manager's Memorandum.

Attachment 1
Proposed Rate Structure- Flat Rates vs. TOU Rates

Residential TOU	*Proposed Standard/Flat Rate*	*Proposed TOU Rate*
Customer Charge	$11.1000	$11.1000
Critical Peak Energy Charge[1]	-	$.1775
On-Peak Energy Charge[1]	-	$.1775
Off-Peak Energy Charge	-	$0.0405
Flat Energy Charge	$0.0868	

1. The table reflects the staff recommendation for Residential Critical Peak and On-Peak energy charges of $.1775/kWh to reflect the Off-Peak hours beginning at 9:00 p.m. If Off-Peak hours begin at 11:00 p.m., as recommended by Burns and McDonnell, Critical Peak and On-Peak energy charges would be $.1615/kWh.

General Service TOU	*Proposed Standard/Flat Rate*	*Proposed TOU Rate*
Customer Charge	$21.6500	$21.6500
Critical Peak Energy Charge	-	$.1745
On-Peak Energy Charge	-	$.1445
Off-Peak Energy Charge	-	$0.0405
Flat Energy Charge	$0.0871	

General Service (Commercial) Demand TOU	*Proposed Standard/Flat Rate*	*Proposed TOU Rate*
Customer Charge	$21.6500	$21.6500
Critical Peak Energy Charge	-	$0.0405
On-Peak Energy Charge	-	$0.0405
Off-Peak Energy Charge	-	$0.0405
Flat Energy Charge	$0.0405	-
Critical Peak Demand Charge	-	$13.2800
On-Peak Demand Charge	-	$8.8000
Off-Peak Demand Charge	-	-
Maximum Monthly Demand Charge	$17.6250	-
Reactive Demand Charge	-	-

Primary Metering TOU	*Proposed Standard/Flat Rate*	*Proposed TOU Rate*
Customer Charge	$52.3500	$52.3500
Critical Peak Energy Charge	-	$0.0400
On-Peak Energy Charge	-	$0.0400
Off-Peak Energy Charge	-	$0.0400
Flat Energy Charge	$0.0400	-
Critical Peak Demand Charge	-	$13.2800
On-Peak Demand Charge	-	$6.9500
Off-Peak Demand Charge	-	-
Maximum Monthly Demand Charge	$17.3500	-
Reactive Demand Charge	-	-

Transmission TOU	*Proposed Standard/Flat Rate*	*Proposed TOU Rate*
Customer Charge	$52.3500	$52.3500
Critical Peak Energy Charge	-	$0.0394
On-Peak Energy Charge	-	$0.0394
Off-Peak Energy Charge	-	$0.0394
Flat Energy Charge	$0.0394	-
Critical Peak Demand Charge	-	$13.2800
On-Peak Demand Charge	-	$0.3600
Off-Peak Demand Charge	-	-
Maximum Monthly Demand Charge	$13.7700	-
Reactive Demand Charge	-	-

CITY OF NAPERVILLE
MANAGER'S MEMORANDUM

DATE: October 26, 2012

TO: Doug Krieger, City Manager

THROUGH: Marcie Schatz, Deputy City Manager

FROM: Mark Curran, Director of Public Utilities-Electric

SUBJECT: **Electric Rate Workshop Memorandum #3**

PURPOSE:
This is the third in a series of memorandums to be distributed prior to the Electric Rate Workshop scheduled for Tuesday, November 13, 2012. The purpose of these memoranda is to provide Council with results of the Electric Retail Cost-of-Service and Rate Design Study completed in October 2011 for the Department of Public Utilities-Electric (DPU-E). The results of this study are the foundation for the discussion that will take place on November 13.

BACKGROUND:
DPU-E retained Burns & McDonnell Engineering Company (B&M) of Kansas City, Missouri, to prepare a Cost-of-Service and Rate Design Study for the electric utility. In the study, historical costs of providing electric service to customers were analyzed and future cost projections were used to determine annual system revenue requirements. In addition, a number of rate classifications were created and are proposed to be added so DPU-E can begin offering time-of-use (TOU), electric vehicle (EV), plug-in hybrid electric vehicle (PHEV), and net metering services associated with the Naperville Smart Grid Initiative (NSGI).

DISCUSSION:
The discussion in the first Electric Rate Workshop memorandum focused primarily on standard/flat rate schedules for all customer classes. The second memorandum addressed the proposed rate design for time-of-use (TOU), electric vehicle (EV), plug-in hybrid electric vehicle (PHEV), and net metering services. B&M proposed no revenue adjustments until May 1, 2013, based on the cost-of-service results. Two percent rate increases for all classes are recommended for implementation on May 1, 2013; May 1, 2014; and May 1, 2015.

This memorandum will discuss the proposed Demand Response Programs to be provided by the electric utility. Demand Response Programs are designed to enable customers to voluntarily contribute to energy load reduction during times of peak demand and receive financial incentives for participating in these programs. Demand response programs reduce energy costs and contribute to power system integrity during hours of peak usage.

Residential Demand Response Program
Under the proposed program, residential customers choosing to participate in the program would purchase and install a Naperville approved Programmable Controllable Thermostat (PCT) in their home which would be capable of receiving digital signals from the electric utility through the new smart grid network. Customers would be reimbursed on a monthly basis for allowing the utility to increase the temperature in the home via the PCT on peak usage days. The estimated reimbursement amount for participating in the program is based on our estimated power supply demand charge savings from reducing electrical load during the peak hour of the month.

For the average residential customer in Naperville using 11,000 kWh per year, the estimated kWh reduction realized from increasing the temperature set point 3-5 degrees during the system peak hour is approximately 1.25 kWh or an average peak load reduction of 1.25 kW.

The annual demand response benefit to the electric utility is proposed to be passed back to the residential customers participating in the program through both a fixed and variable credit. The fixed credit would be in the form of a $2.08 per month bill credit. The fixed bill credit would be provided for all 12 months of the year for a total credit to the customer of $24.96 per year.

The variable credit would be passed back to participating customers in the form of a $0.62/kWh credit during the hours in which a demand response event is initiated. We have estimated demand response events will need to be initiated in the summer months of May through September up to 5 days per month, 3 hours per day, or a maximum of 15 hours per month. The average residential customer could see a monthly variable credit of up to $11.62 if demand response events are initiated 3 hours per day for the maximum 5 days in a summer month. Demand Response events may be called in other months if beneficial to both customers and the electric utility. The variable credit will also be given to customers who install a Naperville approved load disconnect device on other in-house loads such as a pool pump or hot tub. The electric utility will send a signal to these devices in a similar manner as to the PCT during demand response events.

The variable credit will be calculated by the smart grid Load Control Management System by comparing the customer usage during the demand response event with the average usage during the comparable time period for the previous 7 days. Customers will be notified 24 hours in advance of a planned demand response event by e-mail, text, or through the ePortal. Customers will be able to override control of their thermostat if they do not want to participate in a demand response event, but will be removed from the program for a year if they do so 3 times in one season.

Residential customers that do not install a Naperville approved PCT will be allowed to participate in the Demand Response Program. Customers will receive the variable credit of $0.62/kWh, but will not receive the $2.08 per month fixed credit. Participating customers will be notified of a demand response event 24 hours in advance in the same manner as customers with a city approved PCT.

Non-Residential Demand Response Program
The demand response variable credit amount for General Service, General Service Demand, Primary Metering, and Transmission Metering customer classes will be $0.89/kWh. Non-residential customers will not receive a fixed monthly credit for participating in the program. Customers will be notified of a demand response event and the variable credit will be calculated in the same manner as for residential customers. Customers in the Primary Metering and Transmission Metering class will only be allowed to participate in this program if on time-of-use (TOU) rates.

I will be distributing workshop slides to the Council prior to the Electric Rate Workshop on Tuesday, November 13, 2012.

RECOMMENDATION
Please forward this report to the City Council in the Manager's Memorandum.

Report on the

Retail Cost of Service and Rate Design Study

for the

Naperville Department of Public Utilities - Electric Utility

Project Number 60368

2011

Burns & McDonnell
SINCE 1898

SECTION 1.0
EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

1.1 INTRODUCTION

The Naperville, Illinois Department of Public Utilities (Naperville) retained Burns & McDonnell Engineering Company (Burns & McDonnell) of Kansas City, Missouri to prepare a Cost-of-Service and Rate Design Study (the Study) for the Naperville electric utility. This report describes the approach followed and the assumptions made in the completion of the analyses for Naperville and presents the results of the Study, including the proposed new retail electric rates.

The previous electric cost-of-service and rate study for the Naperville electric utility was completed in 2006. Since the completion of the last study, Naperville signed a new 24-year purchased power agreement with Illinois Municipal Electric Agency (IMEA) that will restructure how purchased power will be billed to Naperville beginning June 1, 2011. As was the case in recent years with Goldman Sachs, the electric utility's power provider since June 2007, the overall cost of power is projected to rise for the foreseeable future. Additional major capital investments are also expected in the next several years.

For the Study, Naperville desired to analyze historical costs of providing electric service to its customers and to incorporate projections of future costs into its annual system revenue requirement. In addition, Naperville wishes to add a number of rate classifications so the electric utility can begin offering time-of-use (TOU), plug-in hybrid and electric vehicle (PHEV), and net metering services associated with its on-going smart grid build-out.

1.2 LOAD FORECAST

The load forecast developed for the Study is a five-year forecast of class-specific energy sales and peak demand for the Naperville electric utility. The forecast includes three years of historical data through FY 2010, budget year estimations for FY 2011, and annual projections through FY 2016. The load forecast was prepared in a bottom-up fashion. Class-specific data was acquired from Naperville and used for class-specific forecasts. These were then combined to develop the forecast of total energy sales at the system level. A forecast of system peak demand was developed separately and compared to historical annual load factors for reasonableness. The load forecast forms the basis for the subsequent analyses for the Study.

Table 1-1 presents the annual net system energy sales for the system for each year of the load forecast. As illustrated, annual net system energy sales are projected to decrease by approximately 1 percent between FY 2011 and FY 2012 due primarily to the above average temperatures and associated energy sales in the summer of FY 2011.

Table 1-1: Projected System Energy Sales
Naperville Department of Public Utilities

Customer Class	Budget	Forecast				
	2011	2012	2013	2014	2015	2016
	kWh	kWh	kWh	kWh	kWh	kWh
Residential	575,861,270	557,862,133	557,723,106	557,518,904	557,261,168	556,939,396
Residential Net Metering	0	0	-186,482	-369,158	-548,029	-723,093
Residential EV/PHEV	0	0	3,309,963	5,069,323	7,898,844	10,742,935
Residential TOU	0	8,493,476	14,296,059	20,220,453	26,255,582	32,412,522
Residential TOU Net Metering	0	0	-3,806	-15,223	-26,640	-41,863
Residential TOU EV/PHEV	0	0	85,053	183,287	372,222	625,378
Residential Subtotal	575,861,270	566,355,609	575,223,892	582,607,585	591,213,148	599,955,274
General Service	623,985,582	621,545,647	621,315,248	621,147,947	620,829,942	620,469,086
General Service Net Metering	0	0	-76,115	-152,230	-202,974	-279,089
General Service EV/PHEV	0	0	0	0	0	0
General Service TOU	0	9,435,052	15,975,258	22,515,465	29,270,104	36,131,960
General Service TOU Net Metering	0	0	0	0	-12,686	-12,686
General Service TOU EV/PHEV	0	0	0	0	0	0
General Service Subtotal	623,985,582	630,980,699	637,214,391	643,511,181	649,884,386	656,309,271
Primary	234,173,960	225,407,541	225,407,541	225,407,541	225,407,541	225,407,541
Primary Net Metering	0	0	0	0	0	0
Primary EV/PHEV	0	0	0	0	0	0
Primary TOU	0	0	0	0	0	0
Primary TOU Net Metering	0	0	0	0	0	0
Primary TOU EV/PHEV	0	0	0	0	0	0
Primary Subtotal	234,173,960	225,407,541	225,407,541	225,407,541	225,407,541	225,407,541
Transmission	40,574,708	37,614,068	37,614,068	37,614,068	37,614,068	37,614,068
Transmission Net Metering	0	0	0	0	0	0
Transmission EV/PHEV	0	0	0	0	0	0
Transmission TOU	0	0	0	0	0	0
Transmission TOU Net Metering	0	0	0	0	0	0
Transmission TOU EV/PHEV	0	0	0	0	0	0
Transmission Subtotal	40,574,708	37,614,068	37,614,068	37,614,068	37,614,068	37,614,068
Outdoor Metered Lighting	2,781,141	3,049,966	3,080,465	3,111,270	3,142,383	3,173,806
General Service (IAC)	12,095,965	10,316,102	10,419,263	10,523,456	10,628,690	10,734,977
Subtotal Other	14,877,106	13,366,068	13,499,728	13,634,726	13,771,073	13,908,784
Total Gross System Sales	1,489,472,626	1,473,723,985	1,488,959,622	1,502,775,102	1,517,890,216	1,533,194,939
Less Cogeneration Purchases	-9,592,724	-9,592,724	-9,592,724	-9,592,724	-9,592,724	-9,592,724
Total Net System Sales	1,479,879,902	1,464,131,262	1,479,366,898	1,493,182,378	1,508,297,493	1,523,602,215
Percentage Growth		-1.06%	1.04%	0.93%	1.01%	1.01%

1.3 REVENUE REQUIREMENT ANALYSIS

The second phase of the Study completed was the determination of the annual revenue requirements of the Naperville electric utility. The annual revenue requirements analysis was used as the basis for the subsequent phases of the project, i.e. the cost-of-service analysis and rate design. In order to determine the annual revenue requirements, a five-year financial forecast of the operations of the Naperville electric utility was developed.

The financial forecast was developed to estimate Naperville's annual revenue requirement and included projections of annual operating revenues, operating expenses, net non-operating income, and the resulting net income, as well as projections of plant investment, debt service, and other cash flows from budget FY 2011 and forecast FY 2012 through FY 2016. The Forecast included consideration of annual levels of internally generated funds from operations and Naperville's projected capital expenditure requirements. These estimates were used to forecast Naperville's need for additional funds through retail rate adjustments, transfers from reserves, and/or external capital financing. The evaluation of whether any required additional funds would be derived from revenue increases or externally through debt financing, was based on input from Naperville staff. The projections developed in the financial forecast were summarized in pro forma statements of projected net income and cash flows. The annual revenue requirement was determined from these pro forma financial statements.

Projected annual net income for each year of the financial forecast was determined by deducting the estimated net non-operating expense estimates from the net operating income, plus net transfers, for each respective year. Based on the projections presented in Table 1-2, Naperville should be able to generate positive operating income and positive net income from FY 2011 to FY 2013. Beginning in FY 2014, purchased power expenses are projected to begin to increase annually on a dollars-per-megawatt hour basis by approximately two percent per year. Without corresponding rate increases in FY 2014, 2015, and 2016 the annual rate revenue would fall short of covering Naperville's annual costs resulting in negative net income.

Table 1-2: Projected Annual Statement of Net Income

Naperville Department of Public Utilities

Description				Budget	Projected Annual Net Income				
				2011	2012	2013	2014	2015	2016
Operating Revenues									
Annual Rate Revenues									
Residential				$ 56,729,800	$ 55,972,200	$ 57,001,400	$ 57,809,900	$ 58,792,000	$ 59,789,800
General Service				$ 55,862,900	$ 56,487,400	$ 57,045,700	$ 57,609,400	$ 58,180,300	$ 58,755,800
Primary				$ 18,177,600	$ 17,497,300	$ 17,497,300	$ 17,497,300	$ 17,497,300	$ 17,497,300
Transmission				$ 2,812,400	$ 2,607,300	$ 2,607,300	$ 2,607,300	$ 2,607,300	$ 2,607,300
Lighting				$ 291,300	$ 316,900	$ 320,100	$ 323,300	$ 326,500	$ 329,700
General Service (IAC)				$ 1,075,200	$ 920,300	$ 929,500	$ 938,800	$ 948,200	$ 957,700
Rate Revenues				$ 134,949,200	$ 133,801,400	$ 135,401,300	$ 136,786,000	$ 138,351,600	$ 139,937,600
Proposed Rate Revenue Adjustments									
Date of Implementation		Revenue Adjustment	Months Effective						
May 1	FY 2011	0.00%	12	$ -	$ -	$ -	$ -	$ -	$ -
May 1	FY 2012	0.00%	12		$ -	$ -	$ -	$ -	$ -
May 1	FY 2013	0.00%	12			$ -	$ -	$ -	$ -
May 1	FY 2014	2.00%	12				$ 2,735,700	$ 2,767,000	$ 2,798,800
May 1	FY 2015	2.00%	12					$ 2,822,400	$ 2,854,700
May 1	FY 2016	2.00%	12						$ 2,911,800
Revenue from Adjustments				$ -	$ -	$ -	$ 2,735,700	$ 5,589,400	$ 8,565,300
Annual Rate Revenues with Rate Increase				$ 134,949,200	$ 133,801,400	$ 135,401,300	$ 139,521,700	$ 143,941,000	$ 148,502,900
Other Charges for Services Revenues				$ 263,600	$ 263,600	$ 263,600	$ 263,600	$ 263,600	$ 263,600
Internal Services Revenues				$ 123,600	$ 123,600	$ 123,600	$ 123,600	$ 123,600	$ 123,600
Miscellaneous Revenues				$ 1,190,000	$ 1,190,000	$ 1,190,000	$ 1,190,000	$ 1,190,000	$ 1,190,000
Total Other Operating Revenues				$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200	$ 1,577,200
Total Operating Revenue				$ 136,526,400	$ 135,378,600	$ 136,978,500	$ 141,098,900	$ 145,518,200	$ 150,080,100
Operating Expenses									
Purchased Power				$ 103,184,000	$ 99,936,200	$ 100,512,400	$ 103,835,000	$ 107,225,700	$ 111,514,700
Transmission Operations				$ 14,500	$ 13,600	$ 13,900	$ 14,200	$ 14,700	$ 15,200
Transmission Maintenance				$ 23,000	$ 16,100	$ 16,100	$ 17,200	$ 17,400	$ 18,700
Distribution Operations				$ 5,649,700	$ 5,361,000	$ 5,424,400	$ 5,652,300	$ 5,822,300	$ 6,001,000
Distribution Maintenance				$ 4,547,000	$ 3,994,100	$ 4,003,100	$ 4,188,900	$ 4,435,300	$ 4,608,300
Customer Accounts				$ 99,700	$ 97,800	$ 97,900	$ 104,000	$ 114,000	$ 118,400
Customer Service Operations				$ 1,169,100	$ 1,145,500	$ 1,146,200	$ 1,216,800	$ 1,334,800	$ 1,385,000
Administration & General Operations				$ 7,547,100	$ 7,528,800	$ 7,573,900	$ 7,693,000	$ 7,961,200	$ 8,201,100
Administration & General				$ 661,800	$ 651,500	$ 655,200	$ 700,400	$ 741,200	$ 760,700
Adjustment to Match CAFR				$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Operating Expenses (Fund 410)				$ 122,895,900	$ 118,744,600	$ 119,443,100	$ 123,421,800	$ 127,666,600	$ 132,623,100
Subtotal Operating Expenses (Fund 414)				$ -	$ 86,900	$ 460,300	$ 460,300	$ 460,300	$ 460,300
Total Operating Expenses				$ 122,895,900	$ 118,831,500	$ 119,903,400	$ 123,882,100	$ 128,126,900	$ 133,083,400
Operating Income Before Depreciation				$ 13,630,500	$ 16,547,100	$ 17,075,100	$ 17,216,800	$ 17,391,300	$ 16,996,700
Depreciation				$ (11,712,700)	$ (12,489,200)	$ (13,161,400)	$ (13,489,900)	$ (13,784,200)	$ (14,115,400)
Operating Income (Loss)				$ 1,917,800	$ 4,057,900	$ 3,913,700	$ 3,726,900	$ 3,607,100	$ 2,881,300
Non-Operating Revenues (Expenses):									
Net Investment Income				$ 93,400	$ 93,400	$ 93,400	$ 93,400	$ 93,400	$ 93,400
DOJ-Aurora-Tech Grant				$ -	$ -	$ -	$ -	$ -	$ -
Smart Grid Grant				$ 3,599,000	$ 6,109,000	$ 1,107,300		$ -	$ -
Capital Fees				$ 621,000	$ 603,000	$ 604,000	$ 605,000	$ 606,000	$ 607,000
Gain/(Loss) on Disposal of Capital Assets				$ (1,180,000)	$ (1,180,000)	$ (1,180,000)	$ (1,180,000)	$ (1,180,000)	$ (1,180,000)
Interest on Bonds				$ (1,625,500)	$ (1,750,100)	$ (1,795,800)	$ (1,709,400)	$ (1,612,600)	$ (1,500,100)
Total Non-Operating Revenue (Expense)				$ 1,507,900	$ 3,875,300	$ (1,171,100)	$ (2,191,000)	$ (2,093,200)	$ (1,979,700)
Net Income (Loss) Before Contributions & Transfers				$ 3,425,700	$ 7,933,200	$ 2,742,600	$ 1,535,900	$ 1,513,900	$ 901,600
Transfers In				$ -	$ -	$ -	$ -	$ -	$ -
Transfers Out				$ -	$ -	$ -	$ -	$ -	$ -
Change in Net Assets				**$ 3,425,700**	**$ 7,933,200**	**$ 2,742,600**	**$ 1,535,900**	**$ 1,513,900**	**$ 901,600**
Total net assets, May 1				$ 221,052,044	$ 224,477,744	$ 232,410,944	$ 235,153,544	$ 236,689,444	$ 238,203,344
Change in Net Assets				$ 3,425,700	$ 7,933,200	$ 2,742,600	$ 1,535,900	$ 1,513,900	$ 901,600
Total net assets, April 30				$ 224,477,744	$ 232,410,944	$ 235,153,544	$ 236,689,444	$ 238,203,344	$ 239,104,944
Debt Service Coverage									
Operating Income Before Depreciation				$ 13,630,500	$ 16,547,100	$ 17,075,100	$ 17,216,800	$ 17,391,300	$ 16,996,700
Annual Debt Service				$ 3,976,000	$ 5,671,300	$ 4,736,700	$ 5,307,500	$ 5,498,400	$ 3,919,900
Debt Service Coverage				3.43	2.92	3.60	3.24	3.16	4.34
Minimum Debt Service Coverage				2.00	2.00	2.00	2.00	2.00	2.00

1.4 COST-OF-SERVICE ANALYSIS

The third phase of the Study completed was the development of the cost-of-service analysis. The annual revenue requirement for FY 2012 developed from the financial forecast, described in Section 4.0 of this report, was used as the basis for the cost-of-service analysis.

The cost-of-service analysis was developed based on numerous assumptions which were reviewed and approved by Naperville staff. Section 5.0 explains the bases of the assignments and the allocations used in the cost-of-service analysis. Tables showing the assignment of the annual revenue requirement among functional services, as well as the development of allocation factors and the allocation of the annual revenue requirement to Naperville's rate classifications, are also presented in Section 5 of this report.

The results of the cost-of-service analysis and the allocation of the annual revenue requirement to Naperville's rate classes are presented on Table 1-3. The results are broken down into energy-related costs, expressed in both dollars and cents/kWh; demand-related costs, expressed in both dollars and dollars per kW of system power supply billing demand per month; and customer-related costs, expressed in dollars per customer per month. The total cost-of-service is expressed in both dollars and cents per kWh.

Naperville's rate revenue requirement of $133.8 million and the total projected system sales of 1,473,724 MWh translate to an average cost of 9.08 cents/kWh. Table 1-3 also shows the cost of providing service to each class. For example, the portion allocated to the Residential rate classes in FY 2012 totals $56.2 million. Based on the total energy sales from Residential customers of 557,862 MWh, the average cost of providing service to the residential customer class is 10.09 cents/kWh. Residential customers only pay for the energy they consume and thus, the total cost of providing energy and demand is rolled into the rate energy charge.

Table 1-3: Cost-of-Service Summary
Naperville Department of Public Utilities

	Total System	Residential	Residential TOU	General Service	General Service TOU	Primary	Transmission	Outdoor Metered Lighting	General Service (IAC)
SUMMARY OF COST SERVICE									
Energy Cost:									
Energy Sales (kWh)	1,473,723,985	557,862,133	8,493,476	621,545,647	9,435,052	225,407,541	37,614,068	3,049,966	10,316,102
Total Cost	$59,509,929	$22,592,855	$343,977	$25,171,974	$382,110	$8,995,040	$1,482,661	$123,521	$417,792
Dollars/kWh	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Demand Cost (Peak):									
Contribution to Adjusted Coincident Peak (kW)	200,200	75,407	1,148	88,235	1,339	27,682	4,563	362	1,464
Total Cost	$40,714,649	$15,336,922	$233,505	$17,943,291	$272,379	$5,629,042	$928,083	$73,614	$297,814
$/kW-mo	$16.95	$16.95	$16.95	$16.95	$16.95	$16.95	$16.95	$16.95	$16.95
Demand Cost (Transmission):									
Contribution to Coincident Peak (kW)	276,721	122,256	1,861	109,275	1,659	31,177	7,933	746	1,814
Total Cost	$1,105,862	$488,571	$7,439	$436,696	$6,629	$124,591	$31,704	$2,983	$7,248
$/kW-mo	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33	$0.33
Demand Cost (Distribution - Primary):									
Contribution to NCP (kW)	262,360	119,332	1,817	106,662	1,619	30,431	N/A	729	1,770
Total Cost	$20,256,669	$9,213,567	$140,277	$8,235,307	$125,012	$2,349,571	$0	$56,249	$136,685
$/kW-mo	$6.43	$6.43	$6.43	$6.43	$6.43	$6.43	N/A	$6.43	$6.43
Demand Cost (Distribution - Secondary):									
Contribution to Lighting NCP (kW)	228,668	117,654	1,791	105,162	1,596	0	0	718	1,745
Total Cost	$5,680,041	$2,922,497	$44,495	$2,612,198	$39,653	$0	$0	$17,842	$43,356
$/kW-mo	$2.07	$2.07	$2.07	$2.07	$2.07	N/A	N/A	$2.07	$2.07
Demand Cost (Total):									
Contribution to NCP (kW)	276,721	122,256	1,861	109,275	1,659	31,177	7,933	746	1,814
Total Cost	$67,757,221	$27,961,557	$425,716	$29,227,492	$443,673	$8,103,205	$959,787	$150,689	$485,103
$/kW-mo	$20.40	$19.06	$19.06	$22.29	$22.29	$21.66	$10.08	$16.82	$22.29
Customer Service:									
Number of Customers	57,240	50,378	767	5,797	88	9	1	116	84
Total Cost	$6,534,250	$5,749,896	$87,542	$661,660	$10,044	$2,054	$228	$13,257	$9,568
$/Customer/Month	$9.51	$9.51	$9.51	$9.51	$9.51	$19.02	$19.02	$9.51	$9.51
Revenue Requirement Before Adjustments	$ 133,801,400	$ 56,304,308	$ 857,236	$ 55,061,125	$ 835,827	$ 17,100,299	$ 2,442,676	$ 287,466	$ 912,463
Lighting Depreciation Adjustment [1]	$ 0	$ (25,958)	$ (395)	$ (2,987)	$ (45)	$ (5)	$ (1)	$ 29,434	$ (43)
Total Cost:									
Dollars	$ 133,801,400	$ 56,278,350	$ 856,840	$ 55,058,138	$ 835,782	$ 17,100,295	$ 2,442,676	$ 316,900	$ 912,420
Dollars/kWh	0.0908	0.1009	0.1009	0.0886	0.0886	0.0759	0.0649	0.1039	0.0884
Percent of Total Revenue Requirement	100.00%	42.06%	0.64%	41.15%	0.62%	12.78%	1.83%	0.24%	0.68%
COMPARISON OF REVENUES ($)									
Revenue Requirement	133,801,400	56,278,350	856,840	55,058,138	835,782	17,100,295	2,442,676	316,900	912,420
Gen. by Existing Rates	133,801,400	55,132,700	839,500	55,642,700	844,700	17,497,300	2,607,300	316,900	920,300
Dollar Difference	-	1,145,650	17,340	(584,562)	(8,918)	(397,005)	(164,624)	-	(7,880)
Revenue Adjustment Required	0.00%	2.08%	2.07%	-1.05%	-1.06%	-2.27%	-6.31%	0.00%	-0.86%

[1] The lighting depreciation adjustment is made based on Naperville's policies and objectives for lighting cost recovery and rate calculation procedures. The cost is allocated to the other customer classes as a credit based on the unweighted customer allocation factor

1.5 STANDARD RATE DESIGN

Once the test period cost of service was established for each rate classification, standard retail rates were examined to ensure the rates recover the appropriate amount of revenue for the utility. The cost-of-service analysis described in Section 5.0 of this report served as one input into the standard rate analysis and design of revised retail electric rates. Input from Naperville was also taken into consideration in the development of the proposed standard rates and structures. As discussed in Section 4.0, the financial forecast indicated that Naperville requires no overall test period revenue adjustment to retail rates at this time. In addition, the cost of service results indicated each class is currently recovering revenue within an acceptable range of its actual cost of service; therefore, Burns & McDonnell proposed no revenue adjustments based on the cost-of-service results. However, due to the billing structure of the new Naperville-IMEA purchased power agreement, some rate structures were modified to more appropriately recover costs. Section 6.0 provides a discussion on the rate design considerations taken and modifications made to each rate structure from which standard rates are billed. A summary of the existing and proposed electric rates for the main rate classifications is presented in Table 1-4. Additional details are also provided in Appendix A of this report.

Table 1-4: Existing and Proposed Standard Rates Summary
Naperville Department of Public Utilities

	Units		Existing		Proposed
Residential Service					
Customer Charge	$/month	$	11.1000	$	11.1000
Energy Charge	$/kWh	$	0.0868	$	0.0868
General Service (< 50 kW)					
Customer Charge	$/month	$	21.6500	$	21.6500
Energy Charge	$/kWh	$	0.0871	$	0.0871
General Service Demand (> 50 kW)					
Customer Charge	$/month	$	21.6500	$	21.6500
Energy Charge	$/kWh	$	0.0871	$	0.0405
Monthly Demand Charge	$/kW	$	-	$	17.6250
Reactive Demand Charge	$/kVar	$	-	$	-
Primary Service					
Customer Charge	$/month	$	52.3500	$	52.3500
Energy Charge	$/kWh	$	0.0776	$	0.0400
Monthly Demand Charge	$/kW	$	-	$	17.3500
Reactive Demand Charge	$/kVar	$	-	$	-
Transmission Service					
Customer Charge	$/month	$	52.3500	$	52.3500
Energy Charge	$/kWh	$	0.0693	$	0.0394
Monthly Demand Charge	$/kW	$	-	$	13.7700
Reactive Demand Charge	$/kVar	$	-	$	-

1.6 TIME OF USE RATE DESIGN

In addition to the development of standard rates for the major Naperville customer classes, Burns & McDonnell developed time-of-use (TOU) rates for the Residential, General Service, General Service Demand, Primary Service, and Transmission Service customer classes. The cost-of-service analysis described in Section 5.0 of this report served as one input into the TOU rate design analysis. Input from Naperville was also taken into consideration in the development of the proposed TOU rates and structures. The TOU rates developed for the study will provide customers with rate options that enable reductions in their costs of electricity and improve the efficiency of Naperville electric system operations through monetary incentives to shift load from on-peak and critical peak hours to off-peak hours. A summary of the proposed TOU electric rates for the main rate classifications is presented in Table 1-5. Additional details are also provided in Appendix A of this report.

Table 1-5: Proposed Time of Use Rates Summary
Naperville Department of Public Utilities

	Units	Proposed Standard Rate	Proposed TOU Rate
Residential TOU			
Customer Charge	$/month	$ 11.1000	$ 11.1000
Critical Peak Energy Charge	$/kWh	$ -	$ 0.1615
On-Peak Energy Charge	$/kWh	$ -	$ 0.1615
Off-Peak Energy Charge	$/kWh	$ -	$ 0.0405
Flat Energy Charge	$/kWh	$ 0.0868	$ -
General Service TOU			
Customer Charge	$/month	$ 21.6500	$ 21.6500
Critical Peak Energy Charge	$/kWh	$ -	$ 0.1745
On-Peak Energy Charge	$/kWh	$ -	$ 0.1445
Off-Peak Energy Charge	$/kWh	$ -	$ 0.0405
Flat Energy Charge	$/kWh	$ 0.0871	$ -
General Service Demand TOU			
Customer Charge	$/month	$ 21.6500	$ 21.6500
Critical Peak Energy Charge	$/kWh	$ -	$ 0.0405
On-Peak Energy Charge	$/kWh	$ -	$ 0.0405
Off-Peak Energy Charge	$/kWh	$ -	$ 0.0405
Flat Energy Charge	$/kWh	$ 0.0405	$ -
Critical Peak Demand Charge	$/kW	$ -	$ 13.2800
On-Peak Demand Charge	$/kW	$ -	$ 8.8000
Off-Peak Demand Charge	$/kW	$ -	$ -
Maximum Monthly Demand Charge	$/kW	$ 17.6250	$ -
Reactive Demand Charge	$/kVar	$ -	$ -
Primary TOU			
Customer Charge	$/month	$ 52.3500	$ 52.3500
Critical Peak Energy Charge	$/kWh	$ -	$ 0.0400
On-Peak Energy Charge	$/kWh	$ -	$ 0.0400
Off-Peak Energy Charge	$/kWh	$ -	$ 0.0400
Flat Energy Charge	$/kWh	$ 0.0400	$ -
Critical Peak Demand Charge	$/kW	$ -	$ 13.2800
On-Peak Demand Charge	$/kW	$ -	$ 6.9500
Off-Peak Demand Charge	$/kW	$ -	$ -
Maximum Monthly Demand Charge	$/kW	$ 17.3500	$ -
Reactive Demand Charge	$/kVar	$ -	$ -
Transmission TOU			
Customer Charge	$/month	$ 52.3500	$ 52.3500
Critical Peak Energy Charge	$/kWh	$ -	$ 0.0394
On-Peak Energy Charge	$/kWh	$ -	$ 0.0394
Off-Peak Energy Charge	$/kWh	$ -	$ 0.0394
Flat Energy Charge	$/kWh	$ 0.0394	$ -
Critical Peak Demand Charge	$/kW	$ -	$ 13.2800
On-Peak Demand Charge	$/kW	$ -	$ 0.3600
Off-Peak Demand Charge	$/kW	$ -	$ -
Maximum Monthly Demand Charge	$/kW	$ 13.7700	$ -
Reactive Demand Charge	$/kVar	$ -	$ -

1.7 FEE STRUCTURE REVIEW

Burns & McDonnell reviewed and validated Naperville's methodologies and calculations for determining the proposed fees, charges, and penalties. A summary of the fee structure review is provided in Section 8 with the recommended fees and charges provided in Appendix B.

1.8 RECOMMENDATIONS

Burns & McDonnell recommends the following actions be implemented as a result of the analysis completed in this study:

1. Naperville should adopt the proposed five-year financial plan for the Naperville electric utility, as set forth in Section 4.0.
2. Naperville should consider implementation of the proposed retail electric rates for the Naperville electric utility, as set forth in Section 6.0 and Section 7.0.
3. Naperville should consider implementation of the proposed retail electric rates (based on across-the-board increases, for the proposed rate classifications) for the subsequent years FY 2014 through FY 2016, for the Naperville electric utility, as set forth in Section 5.0, to be effective May 1 of each fiscal year.
4. Naperville should monitor the financial position of the Naperville electric utility, including adequacy of cost recovery and cash balances on an on-going basis to ensure that the implementation of the proposed rates is maintaining its financial requirements.

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