**Xcel Energy - North Dakota Electric**
**2013 URD Cable Outage, Review, and Replacement Summary**
(Compliance Report - Case Nos. PU-10-657, PU-11-55)

EXHIBIT
tabbies
PSC-8

| # | Date of Cable Failure | Outage Duration (Hr:Min) | Service Area | Customers Impacted | Date of Engineering Review[1] | Meets Criteria to Replace?[2] | Footage To Replace | Scope of Replacement[3] | Date of Work Order | Date Project Started | Date Project Completed | Note |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jan-01 9:59 PM | 4:01 | Fargo | 79 | Jan-07 | Yes | 1,360 | Multiple | Feb-06 | May-21 | | |
| 2 | Jan-06 8:07 PM | 11:45 | Fargo | 287 | Jan-14 | Yes | 1,312 | Multiple | Feb-15 | Jul-01 | | |
| 3 | Jan-24 4:00 AM | 3:12 | Grand Forks | 112 | N/A | No | | | | | | |
| 4 | Jan-26 8:00 PM | 3:06 | Fargo | 42 | Jan-28 | No | | | | | | |
| 5 | Jan-31 1:26 PM | 1:31 | Fargo | 102 | Feb-04 | Yes | | Multiple | Feb-20 | In Design | | a |
| 6 | Feb-08 8:17 PM | 2:13 | Fargo | 81 | Feb-11 | No | | | | | | |
| 7 | Feb-16 10:13 AM | 2:25 | Grand Forks | 1,139 | Feb-18 | No | | | | | | b |
| 8 | Feb-19 12:40 PM | 3:05 | Grand Forks | 866 | N/A | No | | | | | | |
| 9 | Feb-24 4:51 AM | 2:01 | Fargo | 167 | N/A | No | | | | | | |
| 10 | Mar-06 5:36 AM | 2:54 | Fargo | 39 | N/A | No | | | | | | |
| 11 | Mar-06 2:29 PM | 0:34 | Fargo | 3,476 | Mar-11 | Yes | 849 | Segment | Mar-08 | Mar-12 | Apr-22 | c |
| 12 | Mar-29 5:03 PM | 1:06 | Grand Forks | 1,359 | N/A | No | | | | | | |
| 13 | Apr-04 9:00 AM | 3:03 | Fargo | 107 | N/A | No | | | | | | |
| 14 | Apr-04 3:40 PM | 2:04 | Minot | 2,361 | Apr-08 | Yes | 2,111 | Segment | May-07 | August | | c |
| 15 | Apr-16 6:50 AM | 2:00 | Fargo | 7 | N/A | No | | | | | | |
| 16 | Apr-18 4:23 AM | 2:47 | Fargo | 145 | Apr-22 | No | | | | | | |
| 17 | Apr-19 5:48 PM | 1:32 | Fargo | 85 | N/A | No | | | | | | |
| 18 | Apr-21 6:14 AM | 0:06 | Minot | 7 | Apr-29 | No | | | | | | |
| 19 | Apr-21 11:58 AM | 2:17 | Fargo | 161 | May-27 | No | | | | | | |
| 20 | Apr-27 12:38 PM | 4:22 | Fargo | 2 | N/A | No | | | | | | |
| 21 | May-01 8:13 AM | 3:37 | Minot | 136 | Jun-03 | Yes | 1,992 | Multiple | May-07 | Jun-17 | Jul-05 | |
| 22 | May-02 1:56 AM | 4:24 | Fargo | 147 | May-27 | No | | | | | | |
| 23 | May-02 11:17 PM | 6:29 | Grand Forks | 3 | N/A | No | | | | | | |
| 24 | May-04 5:33 AM | 2:12 | Fargo | 113 | N/A | No | | | | | | |
| 25 | May-10 5:56 AM | 2:06 | Fargo | 37 | May-13 | No | | | | | | |
| 26 | May-30 6:49 AM | 1:56 | Fargo | 1 | Jun-10 | Yes | 194 | Multiple | Jun-14 | Being Designed | | |
| 27 | May-31 2:51 PM | 1:19 | Fargo | 1 | Jun-10 | Yes | 194 | Multiple | Jun-14 | Being Designed | | |
| 28 | Jun-01 10:54 PM | 2:39 | Minot | 137 | Jun-03 | Yes | 1,992 | Multiple | May-17 | Jun-17 | Jul-05 | |
| 29 | Jun-05 6:35 PM | 0:45 | Fargo | 151 | Jun-10 | Yes | 522 | Segment | Jun-14 | Being Designed | | |
| 30 | Jun-06 1:28 AM | 2:39 | Grand Forks | 165 | N/A | No | | | | | | |
| 31 | Jun-14 1:19 AM | 5:17 | Fargo | 77 | Jun-17 | Yes | 95 | Segment | Jun-18 | Being Designed | | |
| 32 | Jun-19 10:17 PM | 10:13 | Fargo | 1 | N/A | No | | | | | | |
| 33 | Jun-21 8:14 PM | 1:06 | Minot | 52 | Jun-24 | No | | | | | | |

[1] The Company's Reliability Management System ("REMS") compiles and processes outage-related information and will flag an engineering review if one of the protective devices (i.e., fuse, breaker, recloser) designed to isolate the fault and protect the system operates *twice within a two year period*. The review will determine if a failed cable qualifies for replacement. A designation of "NA" in this column indicates that REMS did not flag such a review for this event.

[2] See URD Cable Replacement Guidelines summary, attached. Cable may also qualify for replacement under the current 500 MCM replacement program funded under Case. No. PU-10-657.

[3] Based on our replacement guidelines, primary cable replacements can involve 1) a single cable segment, 2) multiple cable segments, 3) all common vintaged cable on a radial, or 4) all common vintaged

EXHIBIT
tabbies
PSC-9



PSC
Exhibit 9

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# Executive Summary

- This study encompasses revenue, cost of goods sold, and O&M metrics based on 2011 electric FERC data. The O&M metrics, except transmission and production metrics, are calculated from per customer and per retail sales perspectives.
- The Comparison Summary, found on the next page, summarizes the results. Xcel Energy and our four operating companies' ranking as compared to the peer operating companies are shown in these four categories: top decile, top quartile, second quartile, and below second quartile.
- Compared to the peer operating companies, the Xcel Energy four operating companies rankings for 2011 were:

| | Top Decile | Top Quartile | 2nd Quartile | Below 2nd Quartile |
|---|---|---|---|---|
| NSPM | 0 | 0 | 12 | 10 |
| NSPW | 1 | 7 | 6 | 5 |
| PSCo | 1 | 5 | 11 | 5 |
| SPS | 5 | 6 | 3 | 8 |

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# Comparison Summary

Top Decile
Top Quartile
2nd Quartile
Below 2nd Quartile

| | Xcel Energy | NSPM | NSPW | PSCo | SPS |
|---|---|---|---|---|---|
| Retail Revenue per Retail Customer | | | | | |
| Retail Revenue per MWh Sold | | | | | |
| Retail MWh Sales per Retail Customer | | | | | |
| Percent Fuel Cost of Retail Revenue | | | | | |
| Total Fuel Costs per MWh Generated | | | | | |
| Percent Purchased Power Cost of Retail Revenue | | | N/A | | |
| Purchased Power Costs per MWh Purchased | | | N/A | | |
| Percent Purchased Power MWh per Retail Sales MWh | | | N/A | | |
| Percent Non-Fuel O&M of Retail Revenue | | | | | |
| Non-Fuel O&M per Retail Customer | | | | | |
| A&G O&M per Retail Customer | | | | | |
| Customer Care Costs per Retail Customer | | | | | |
| Distribution O&M per Retail Customer | | | | | |
| Non-Fuel O&M per Retail MWh Sales | | | | | |
| A&G O&M per Retail MWh Sales | | | | | |
| Customer Care Costs per Retail MWh Sales | | | | | |
| Distribution O&M per Retail MWh Sales | | | | | |
| Production Non-Fuel O&M per MWh Generated | | | | | |
| Steam Non-Fuel O&M per Steam MWh Generated | | | | | |
| Transmission O&M per MWh Throughput | | | | | |
| Transmission O&M per Line Mile | | | | | |
| Transmission MWh Throughput per Line Mile | | | | | |

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# Introduction

- This study identifies Xcel Energy's current cost structure standing relative to peer companies used in other corporate analyses.
- The data source for the study is *FERC Form No.1: Annual Report of Major Utilities, Licensees and Others* as compiled by SNL Financial.
- The study is based on year 2011 electric FERC data for peer utilities as well as Xcel Energy companies.
- The peer companies in this study are the shareholder-owned utilities in the EEI Index, listed on the next page.
- Each page includes graphs comparing the performance of Xcel Energy and its operating companies with the peer operating company top decile, top quartile, and second quartile for the metric in the page title.
- Details of the metric numerators and denominators are presented in the Appendix, beginning on page 14.
- Gas FERC data is not as complete and, therefore, gas costs are not part of the comparison study.
- This study presents key metrics only. Please contact Vicki McCarl If you are interested in other metrics or more details about the metrics included in this report.

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# EEI Index Companies

American Electric Power Company
ALLETE, Inc
Alliant Energy
Ameren Corporation
Avista Corporation
Black Hills Corporation
Central Vermont Public Service Corporation
CH Energy Group
Cleo Corporation
CMS Energy Corporation
Consolidated Edison
Dominion Resources
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Entergy Corporation
Exelon Corporation
First Energy Corp.
Great Plains Energy
Hawaiian Electric Industries
IDACORP
Integrys Energy Group
MDU Resources Group
MGE Energy
NextEra Energy
NiSource
Northeast Utilities
NorthWestern Corporation
NV Energy
OGE Energy Corp.
Otter Tail Corporation
Pepco Holdings
PG&E Corporation
PNM Resources
Pinnacle West Capital Corporation
Portland General Electric
PPL Corporation
Progress Energy
Public Service Enterprise Group
SCANA Corporation
Sempra Energy
Southern Company
TECO Energy
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Vectren Corporation
Westar Energy
Wisconsin Energy Corporation
Xcel Energy

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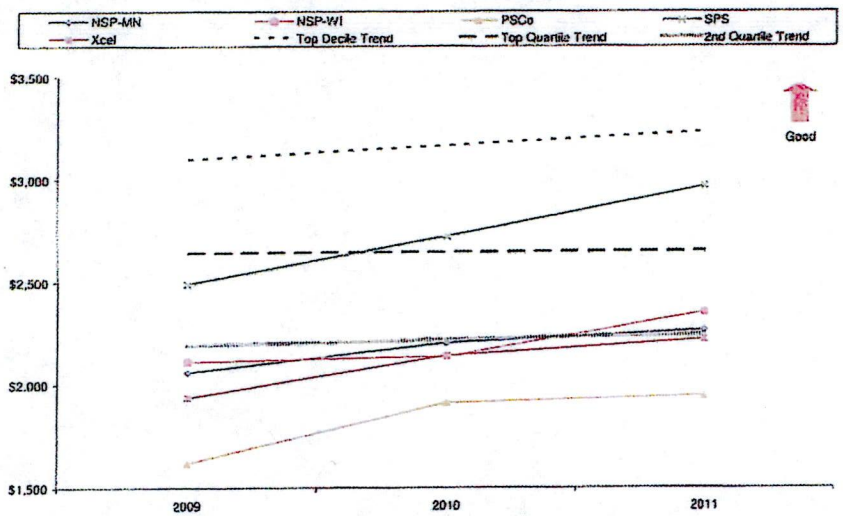
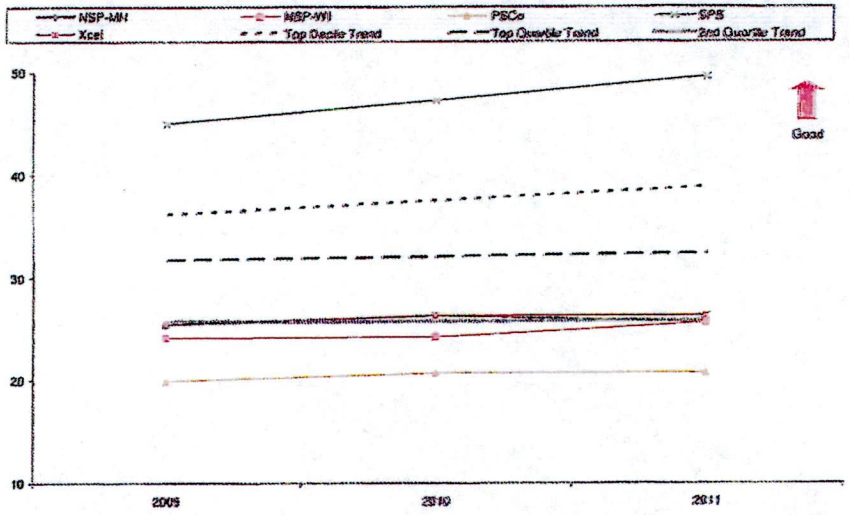
# Retail Revenue Comparison

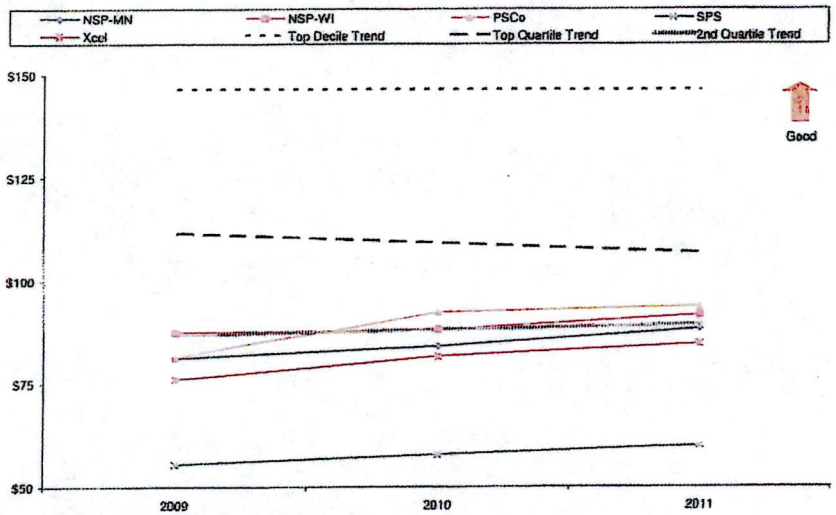
## Retail Revenue per Retail Customer




## MWh Sales per Retail Customer




## Retail Revenue per MWh Sold




Metric details can found on page 16

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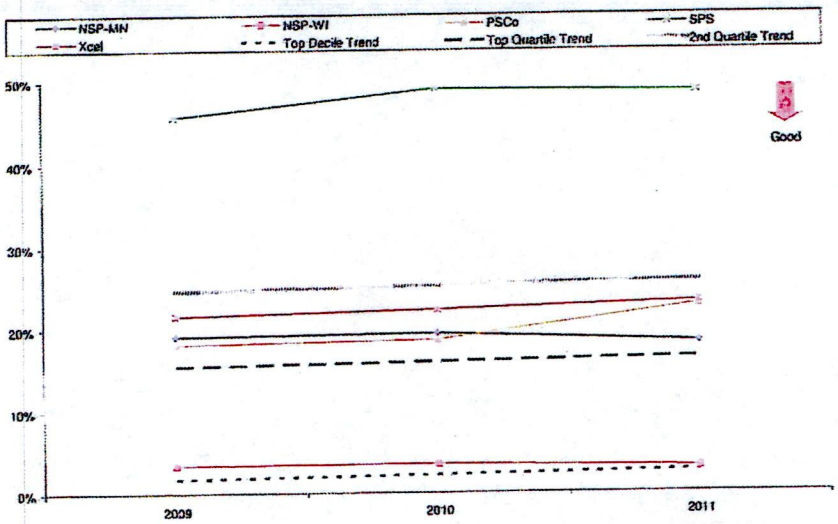
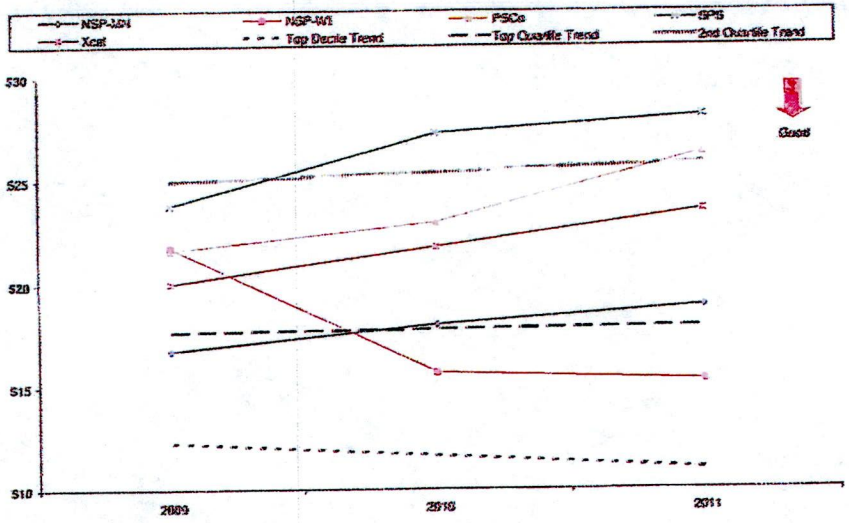
# Fuel Costs

**Percent Fuel Cost of Retail Revenue**




**Fuel Cost per MWh Generated**




Metric details can found on pages 16, 17 and 22.

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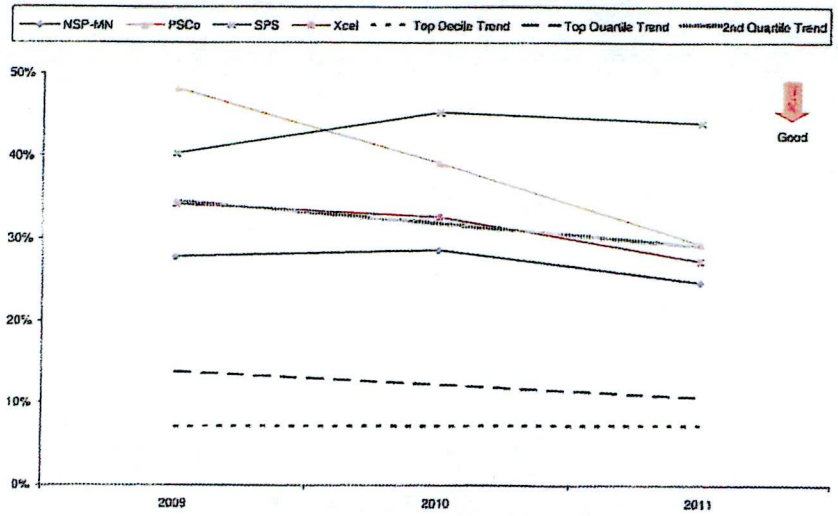
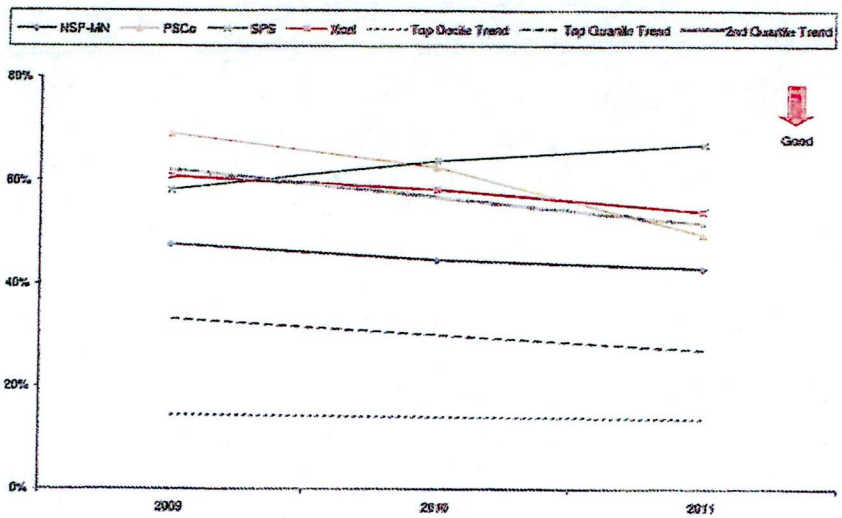
# Purchased Power Costs

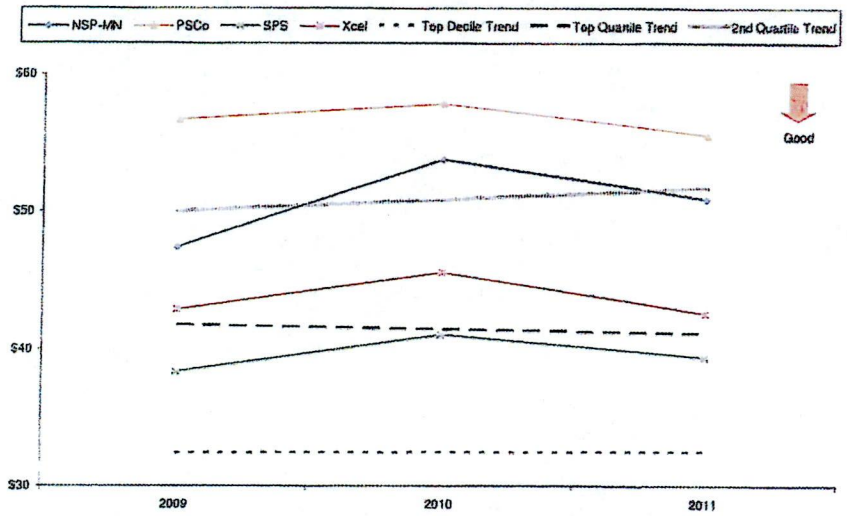
## Percent Purchased Power Cost of Retail Revenue




## Percent Purchased Power MWh of Retail Sales MWh




## Purchased Power Cost per MWh Purchased




Metric details can found on pages 16 and 17.

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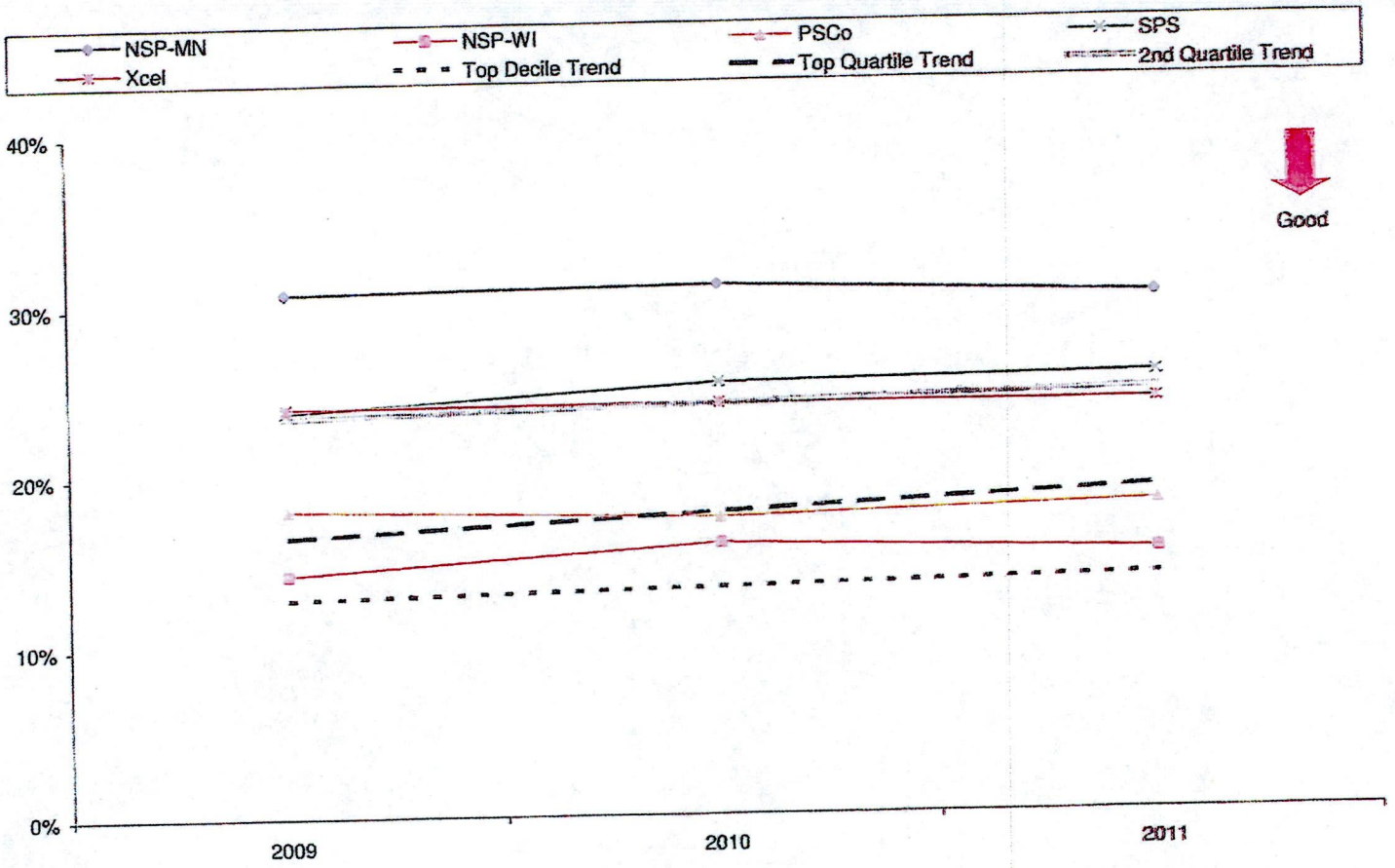
# Percent Non-Fuel O&M of Retail Revenue
## Excluding Customer Assistance and Pension & Benefit Costs




Metric details can found on pages 16 and 18.

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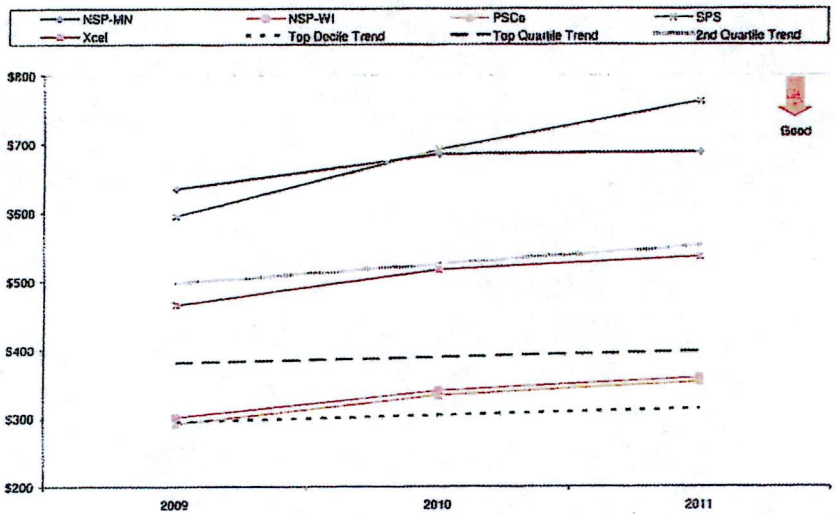
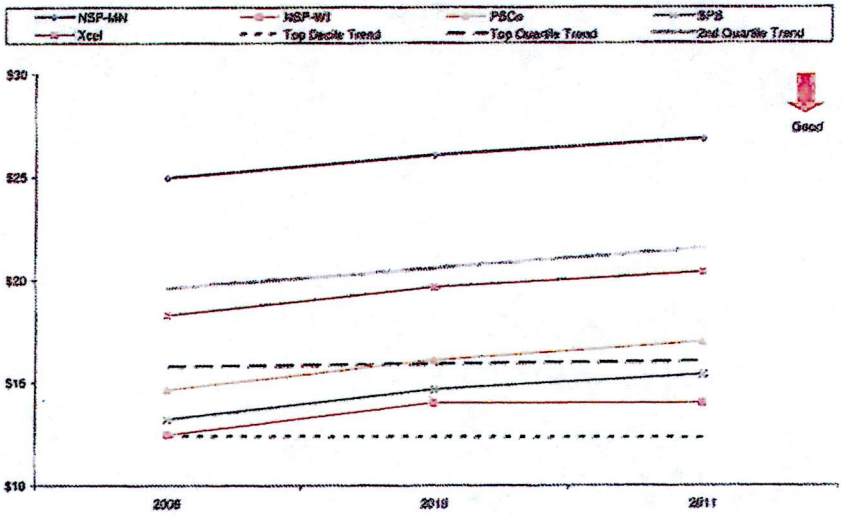
# Non-Fuel O&M
## Excluding Customer Assistance and Pension & Benefit Costs

**Per Retail Customer**




**Per Retail MWh Sales**




Metric details can found on pages 16 and 18.

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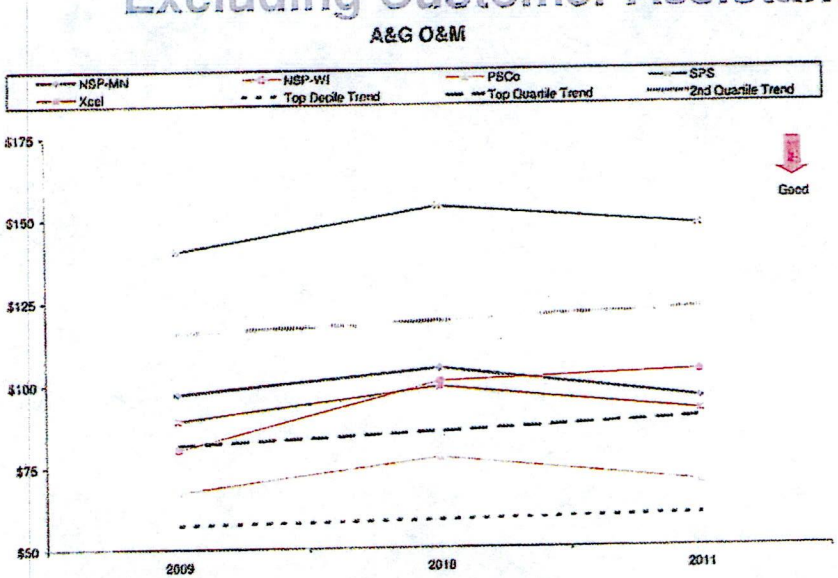
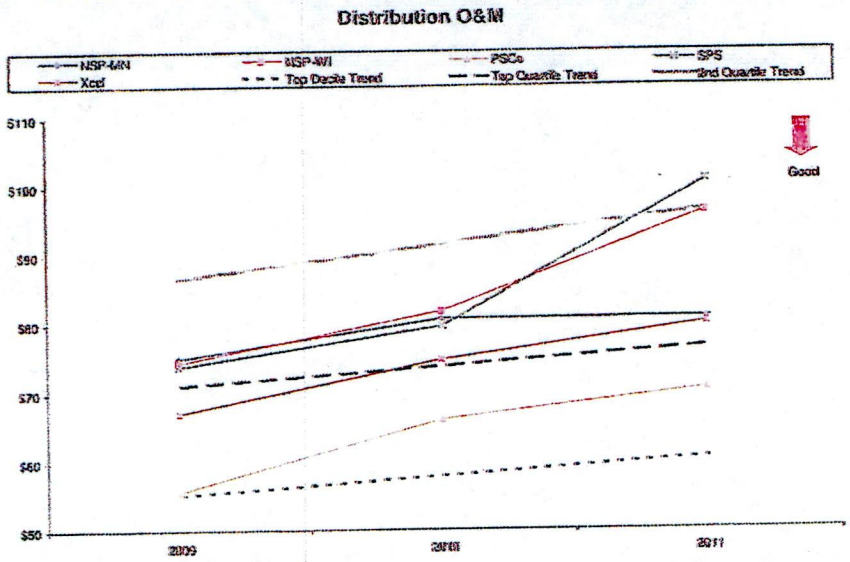
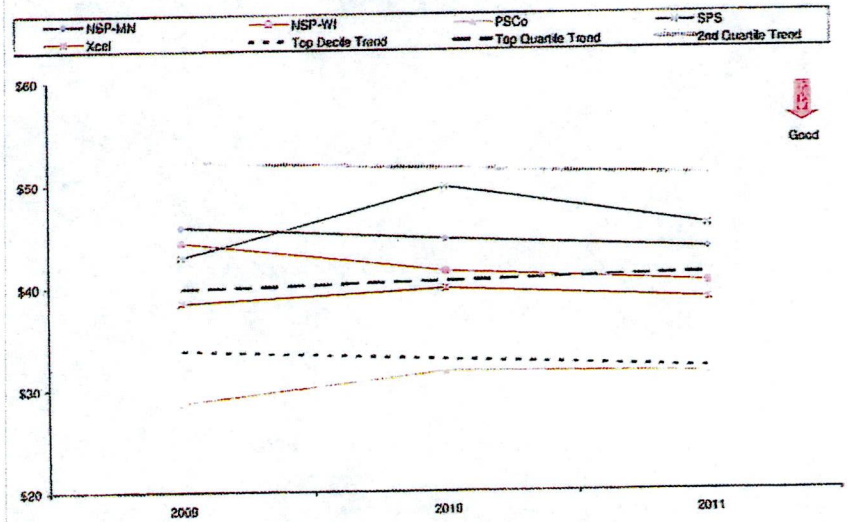
# Components of Non-Fuel O&M per Retail Customer
## Excluding Customer Assistance and Pension & Benefit Costs




Metric details can found on pages 16 and 19.

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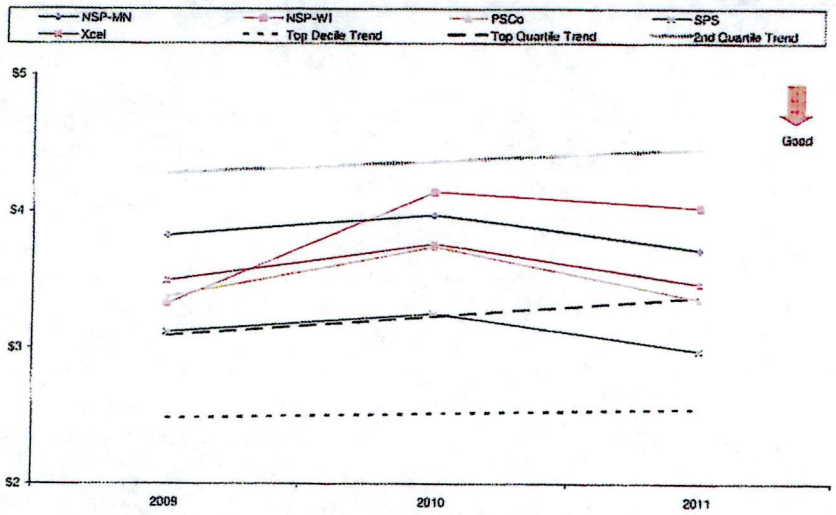
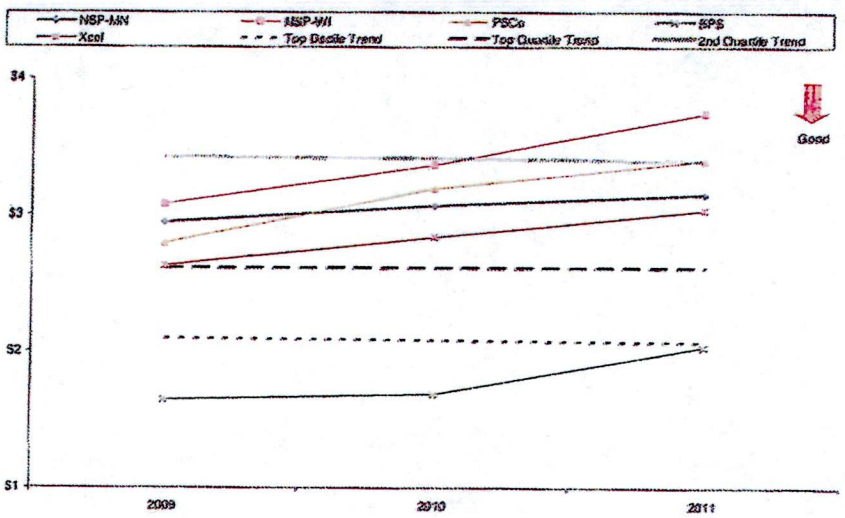
# Components of Non-Fuel O&M per Retail MWh Sales
## Excluding Customer Assistance and Pension & Benefit Costs

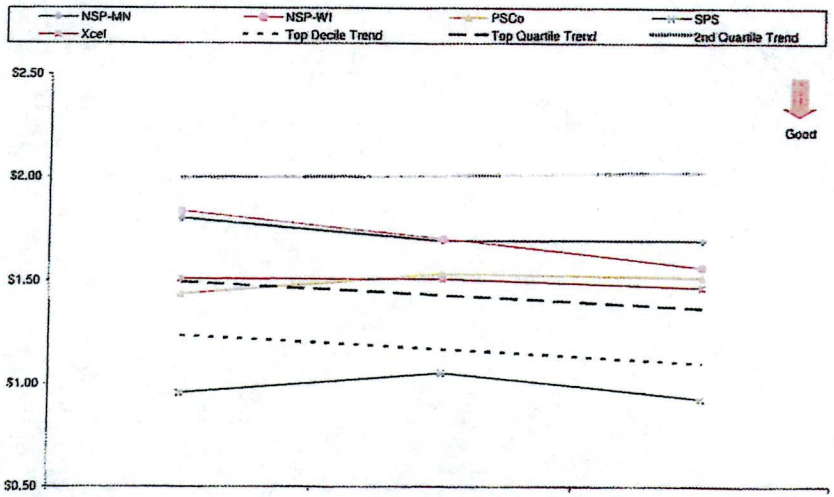
A&G O&M




Distribution O&M




Customer Care O&M




Metric details can found on pages 16 and 19.

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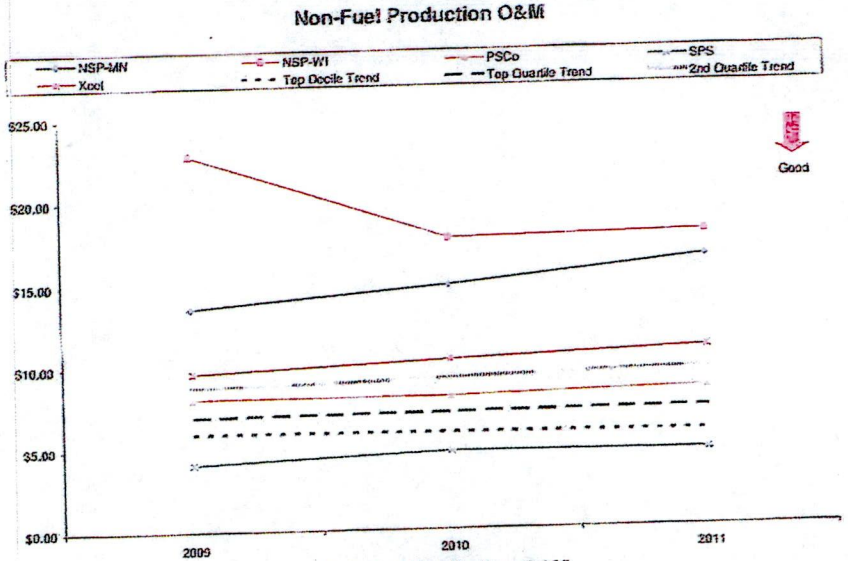
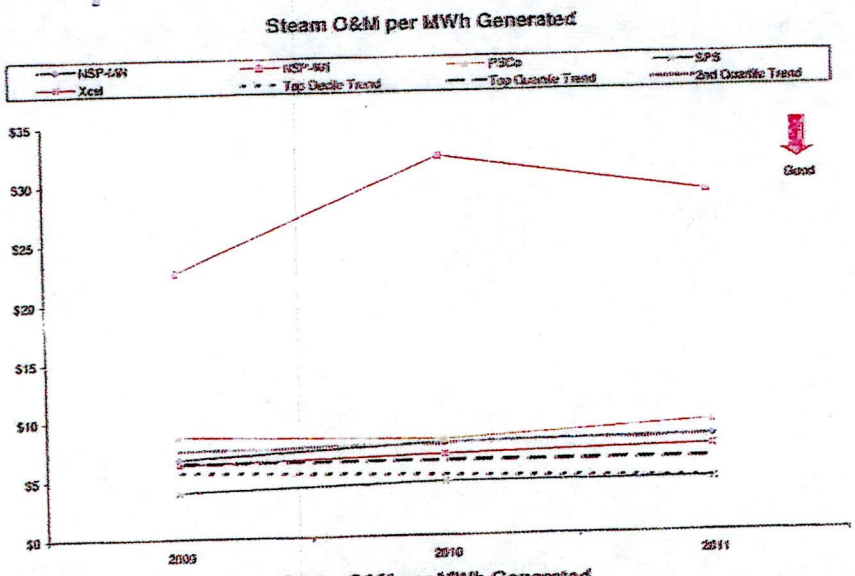
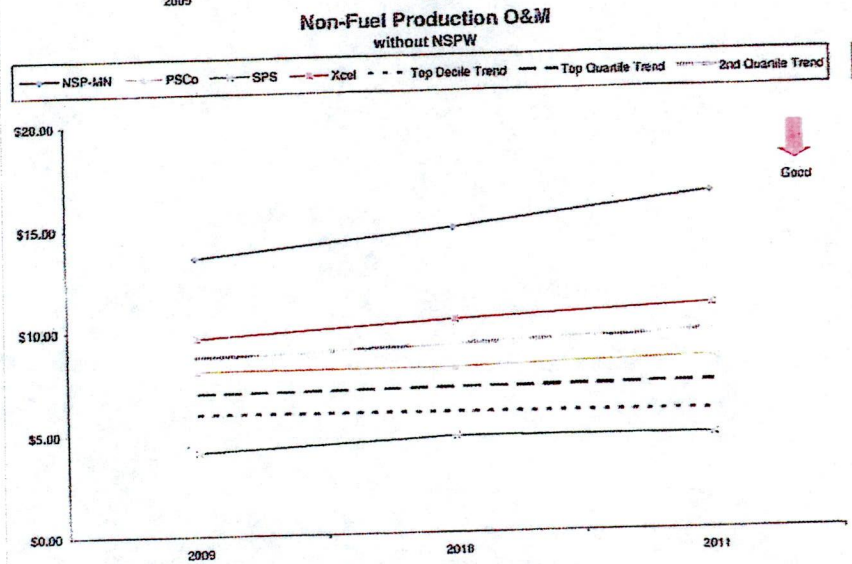
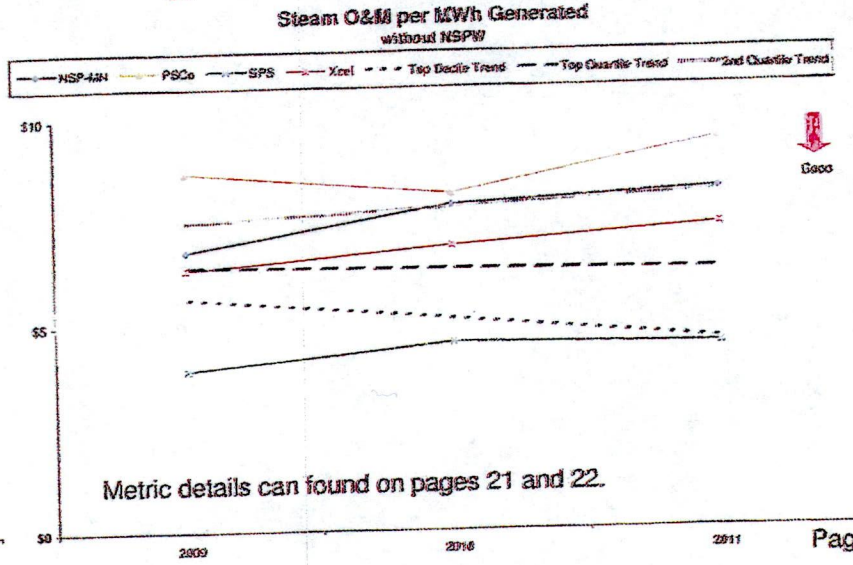
# Production Non-Fuel O&M per MWh Generated




Metric details can found on pages 21 and 22.

# Transmission O&M

## Excluding Transmission by Others (FERC Account 565)

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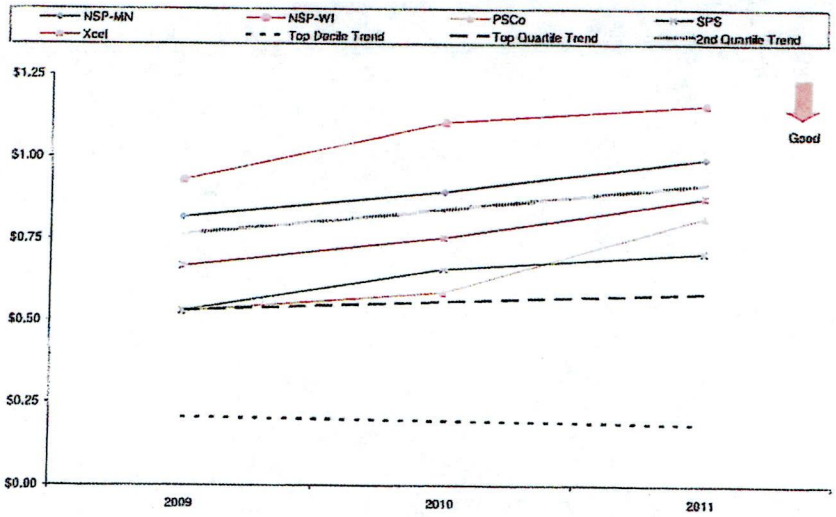
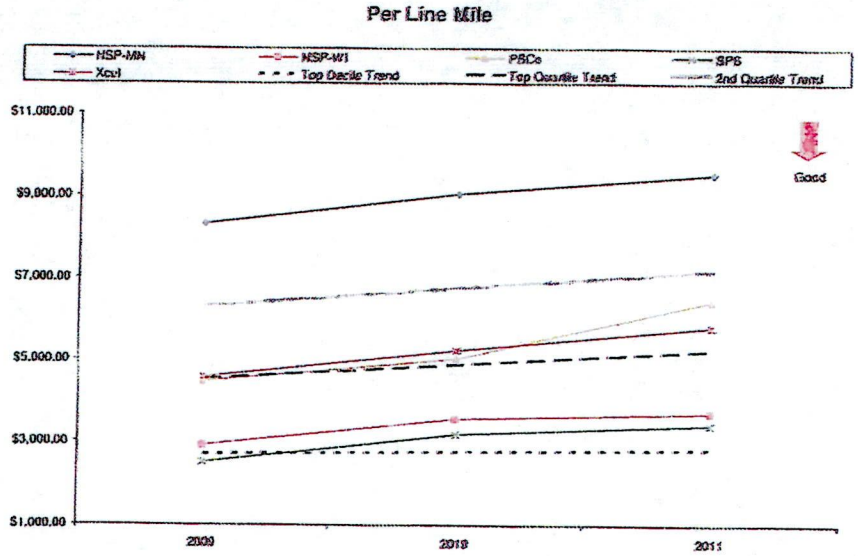
### Per MWh Throughput

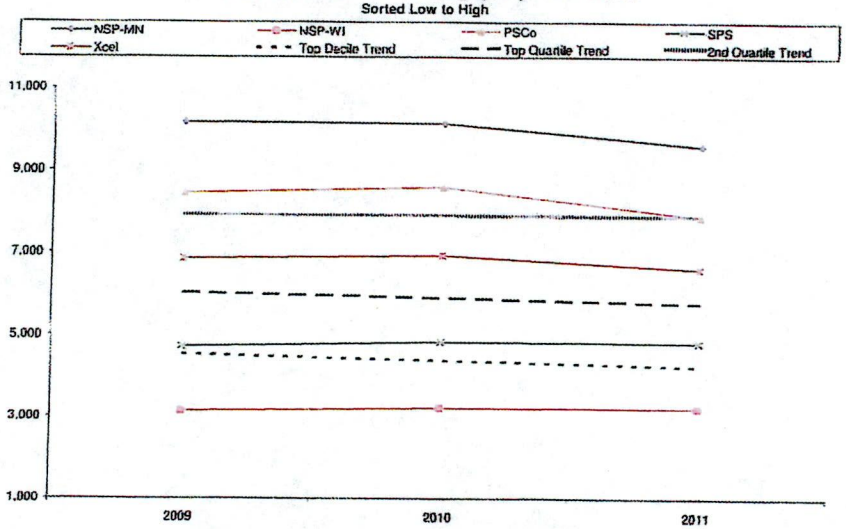



### Per Line Mile




### Transmission MWh Throughput per Line Mile

Sorted Low to High




Metric details can found on pages 19 and 20.

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# Appendix

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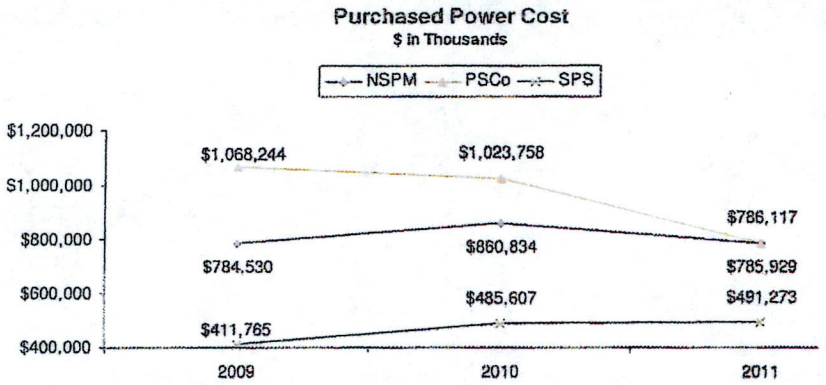
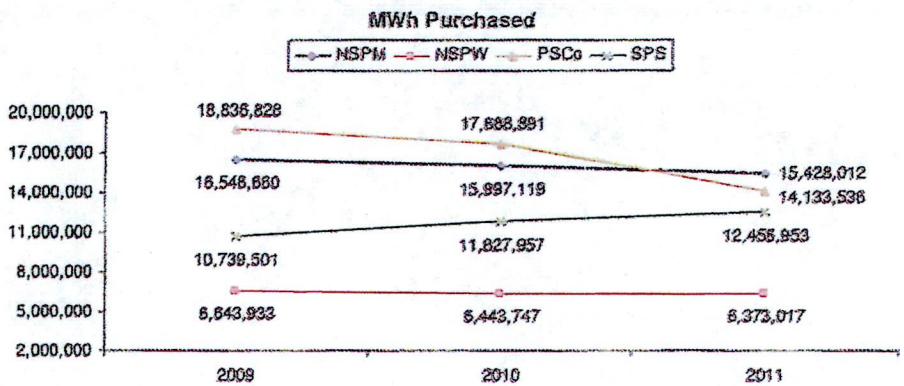
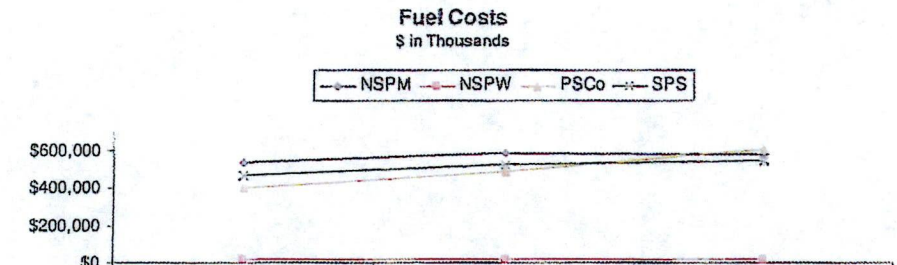
# Purchased Power and Fuel




| | 2009 | 2010 | 2011 |
|---|---|---|---|
| NSPM | $540,107 | $584,276 | $581,879 |
| NSPW | $18,868 | $19,546 | $18,250 |
| PSCo | $403,262 | $487,909 | $611,530 |
| SPS | $467,289 | $526,016 | $542,785 |

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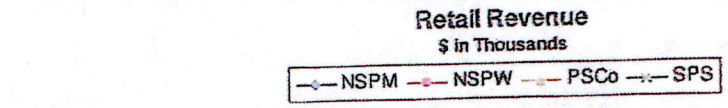
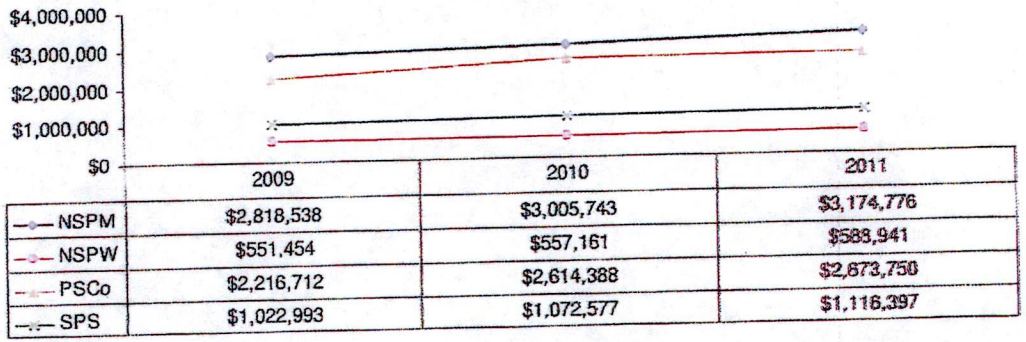
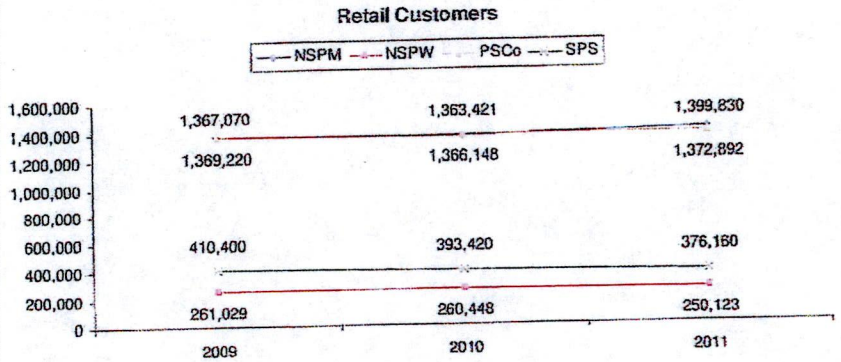
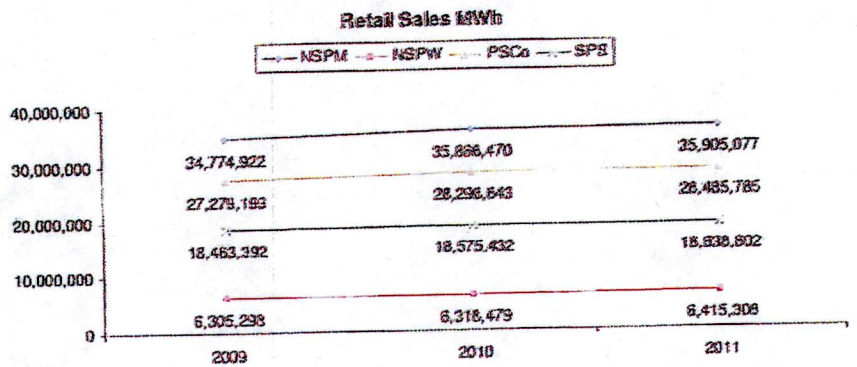
# Retail Revenue




| | 2009 | 2010 | 2011 |
|---|---|---|---|
| NSPM | $2,818,538 | $3,005,743 | $3,174,776 |
| NSPW | $551,454 | $557,161 | $588,941 |
| PSCo | $2,216,712 | $2,614,388 | $2,873,750 |
| SPS | $1,022,993 | $1,072,577 | $1,116,397 |



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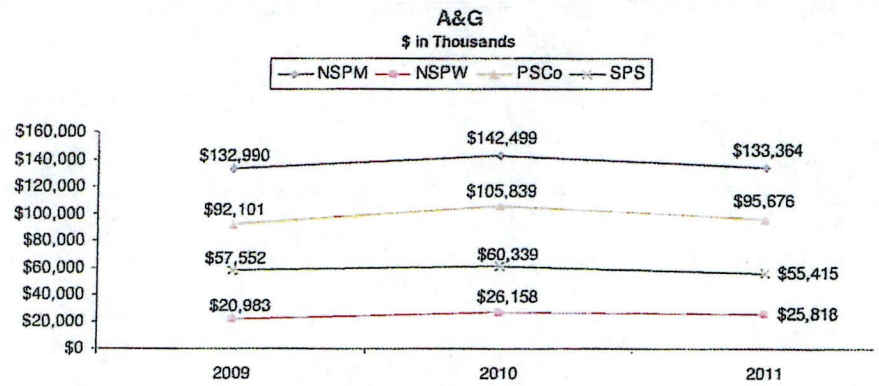
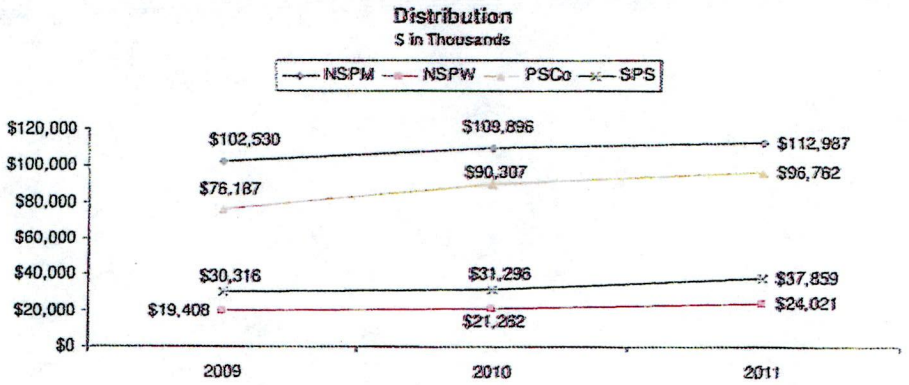
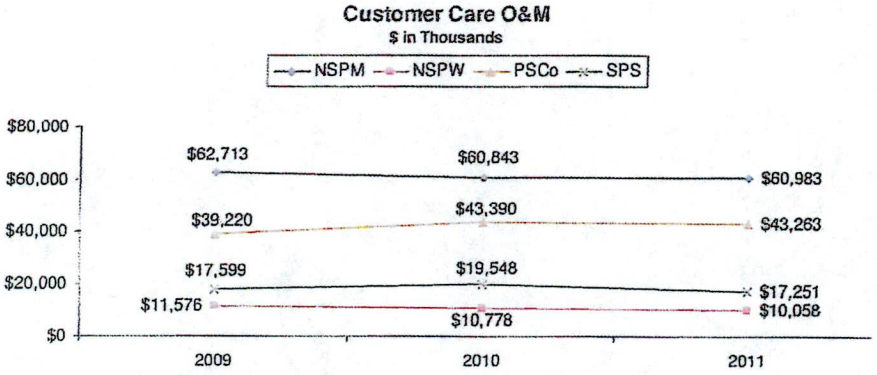
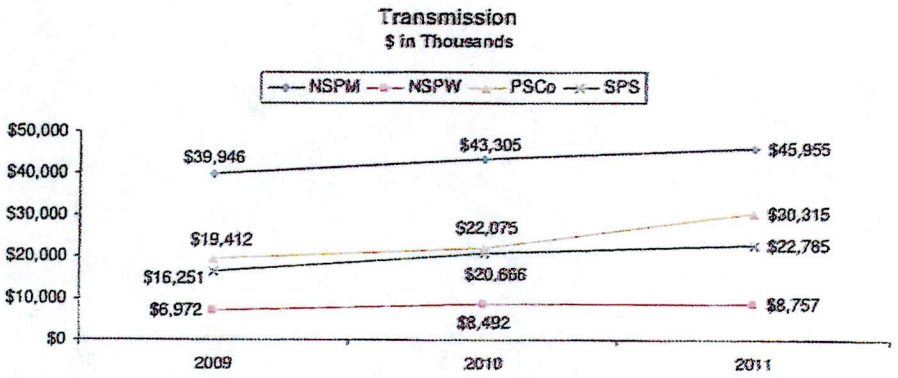
# A&G, Customer Care, Distribution, Transmission O&M Costs

## Excluding Customer Assistance, Pension & Benefits, Transmission by Others



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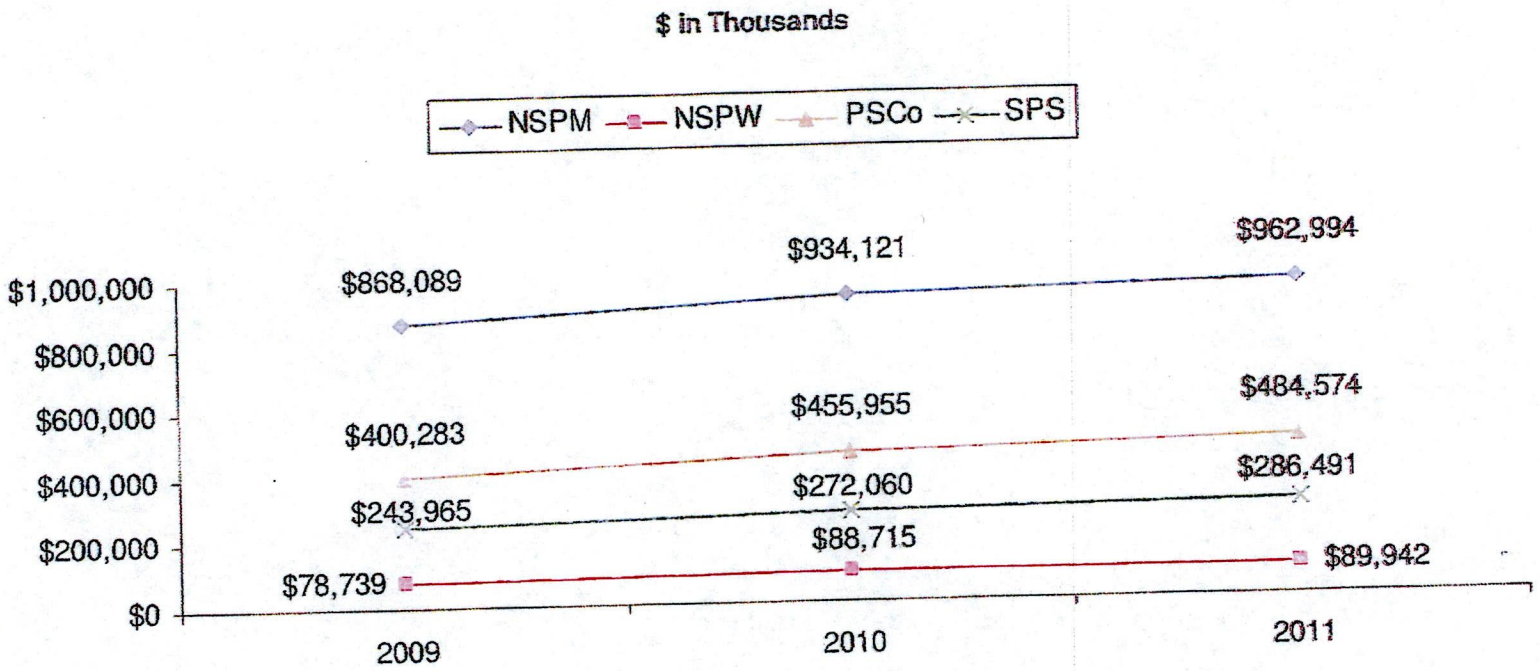
# Non-Fuel O&M Costs
## Excluding Customer Assistance and Pension & Benefits Costs



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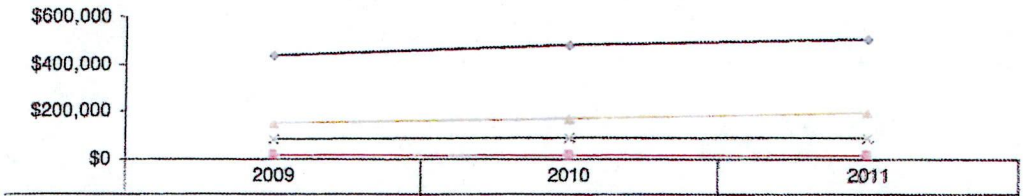
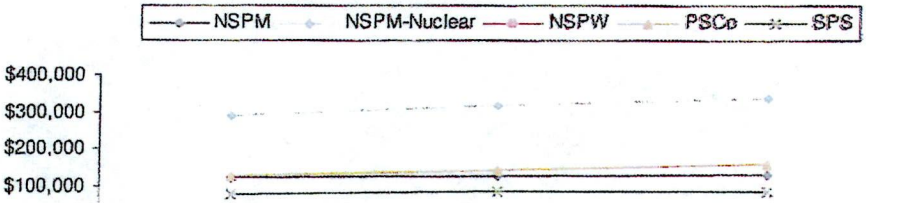
# Production Non-Fuel O&M Costs

**Non-Fuel Production O&M (All Generation)**
$ in Thousands




| | 2009 | 2010 | 2011 |
|---|---|---|---|
| NSPM | $438,304 | $481,848 | $504,458 |
| NSPW | $19,764 | $21,988 | $21,254 |
| PSCo | $150,579 | $171,749 | $195,991 |
| SPS | $80,012 | $90,931 | $89,661 |

**Steam and Nuclear O&M**
$ in Thousands




| | 2009 | 2010 | 2011 |
|---|---|---|---|
| NSPM | $121,636 | $127,273 | $131,787 |
| NSPM-Nuclear | $290,280 | $319,069 | $337,559 |
| NSPW | $8,062 | $10,350 | $8,370 |
| PSCo | $127,157 | $143,489 | $158,411 |

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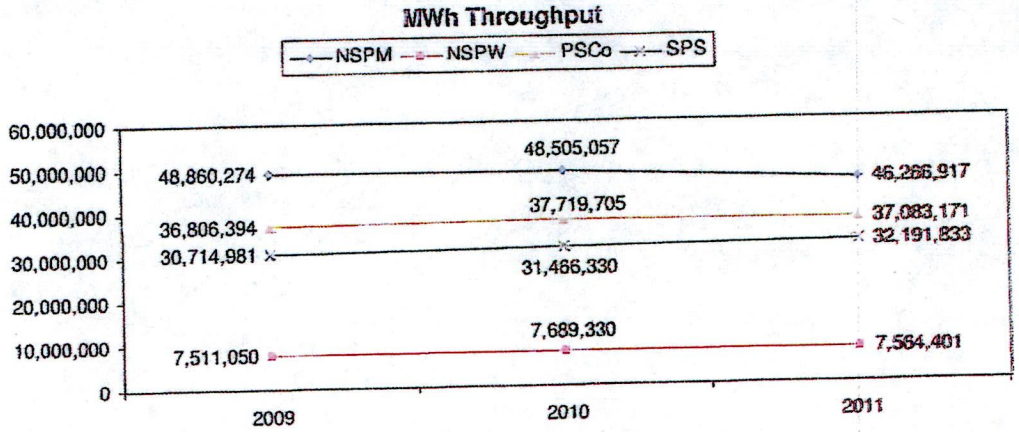
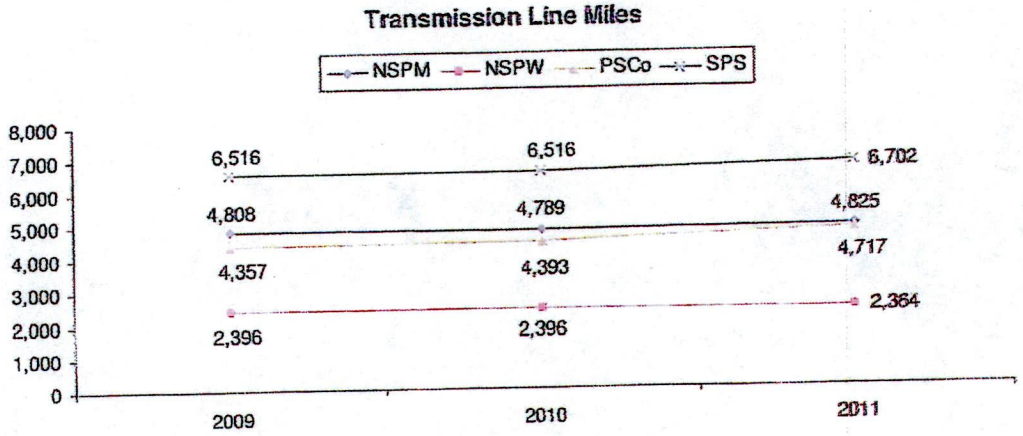
# Transmission MWh Throughput and Line Miles



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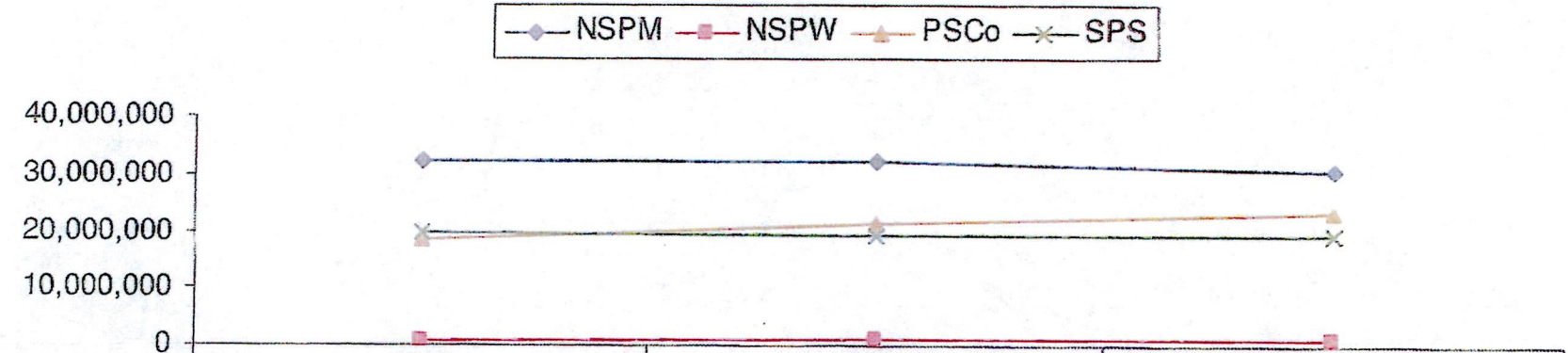
# Net MWh Generation




| | 2009 | 2010 | 2011 |
|---|---|---|---|
| NSPM | 32,269,127 | 32,465,850 | 30,793,266 |
| NSPW | 867,117 | 1,245,583 | 1,191,384 |
| PSCo | 18,650,353 | 21,258,200 | 23,247,462 |
| SPS | 19,654,550 | 19,303,403 | 19,327,229 |

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# 2013 Electric FERC Comparison Study
## Based on 2012 FERC Data

**May 2013**

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# Table of Contents

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# Executive Summary

- This study encompasses revenue, cost of goods sold, and O&M metrics based on 2012 electric FERC data. The O&M metrics, except transmission and production metrics, are calculated from per customer and per retail sales perspectives.
- The Comparison Summary, found on the next page, summarizes the results. Xcel Energy and our four operating companies' ranking as compared to the peer operating companies are shown in these three categories: top quartile, second quartile, and below second quartile.
- Compared to the peer operating companies, the Xcel Energy four operating companies rankings for 2013 were:

| | Top Quartile | 2nd Quartile | Below 2nd Quartile |
|---|---|---|---|
| NSPM | 2 metrics | 8 metrics | 12 metrics |
| NSPW | 7 metrics | 9 metrics | 3 metrics |
| PSCo | 9 metrics | 10 metrics | 3 metrics |
| SPS | 10 metrics | 5 metrics | 7 metrics |

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# Comparison Summary

Top Quartile
2nd Quartile
Below 2nd Quartile

| Metrics | Xcel Energy | NSPM | NSPW | PSCo | SPS |
|---|---|---|---|---|---|
| Retail Revenue per Retail Customer | | | | | |
| Retail Revenue per MWh Sold | | | | | |
| Retail MWh Sales per Retail Customer | | | | | |
| Percent Fuel Cost of Retail Revenue | | | | | |
| Total Fuel Costs per MWh Generated | | | | | |
| Percent Purchased Power Cost of Retail Revenue | | | N/A | | |
| Purchased Power Costs per MWh Purchased | | | N/A | | |
| Percent Purchased Power MWh per Retail Sales MWh | | | N/A | | |
| Percent Non-Fuel O&M of Retail Revenue | | | | | |
| Non-Fuel O&M per Retail Customer | | | | | |
| A&G O&M per Retail Customer | | | | | |
| Customer Care Costs per Retail Customer | | | | | |
| Distribution O&M per Retail Customer | | | | | |
| Non-Fuel O&M per Retail MWh Sales | | | | | |
| A&G O&M per Retail MWh Sales | | | | | |
| Customer Care Costs per Retail MWh Sales | | | | | |
| Distribution O&M per Retail MWh Sales | | | | | |
| Production Non-Fuel O&M per MWh Generated | | | | | |
| Steam Non-Fuel O&M per Steam MWh Generated | | | | | |
| Transmission O&M per MWh Throughput | | | | | |
| Transmission O&M per Line Mile | | | | | |
| Transmission MWh Throughput per Line Mile | | | | | |

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# Introduction

- This study identifies Xcel Energy's current cost structure standing relative to peer companies used in other corporate analyses.
- The data source for the study is *FERC Form No.1: Annual Report of Major Utilities, Licensees and Others* as compiled by SNL Financial.
- The study is based on year 2012 electric FERC data for peer utilities as well as Xcel Energy companies.
- The peer companies in this study are the investor-owned utilities in the EEI Index, listed on the next page.
- Each page includes graphs comparing the performance of Xcel Energy and its operating companies with the peer operating company top quartile, second quartile, and below second quartile for the metric in the page title.
- Details of the metric numerators and denominators are presented in the Appendix, beginning on page 15.
- Gas FERC data is not as complete and, therefore, gas costs are not part of the comparison study.
- This study presents key metrics only. Please contact Vicki McCarl If you are interested in other metrics or more details about the metrics included in this report.

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# EEI Index Companies

American Electric Power Company
ALLETE, Inc
Alliant Energy
Ameren Corporation
Avista Corporation
Black Hills Corporation
Central Vermont Public Service Corporation
CH Energy Group
Cleo Corporation
CMS Energy Corporation
Consolidated Edison
Dominion Resources
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Entergy Corporation
Exelon Corporation
First Energy Corp.
Great Plains Energy
Hawaiian Electric Industries
IDACORP
Integrys Energy Group
MDU Resources Group
MGE Energy
NextEra Energy
NiSource
Northeast Utilities
NorthWestern Corporation
NV Energy
OGE Energy Corp.
Otter Tail Corporation
Pepco Holdings
PG&E Corporation
PNM Resources
Pinnacle West Capital Corporation
Portland General Electric
PPL Corporation
Progress Energy
Public Service Enterprise Group
SCANA Corporation
Sempra Energy
Southern Company
TECO Energy
UIL Holdings Corporation
UniSource Energy Corporation
Unitil Corporation
Vectren Corporation
Westar Energy
Wisconsin Energy Corporation
Xcel Energy

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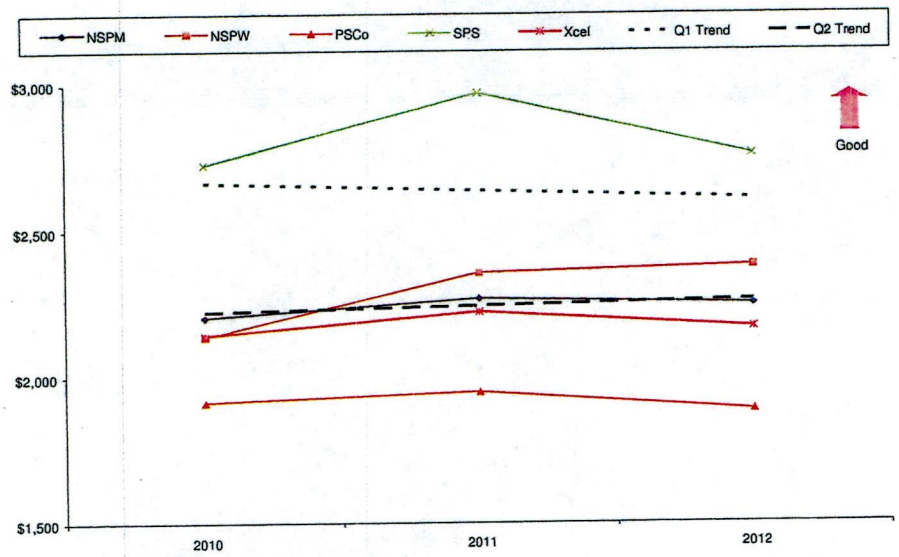
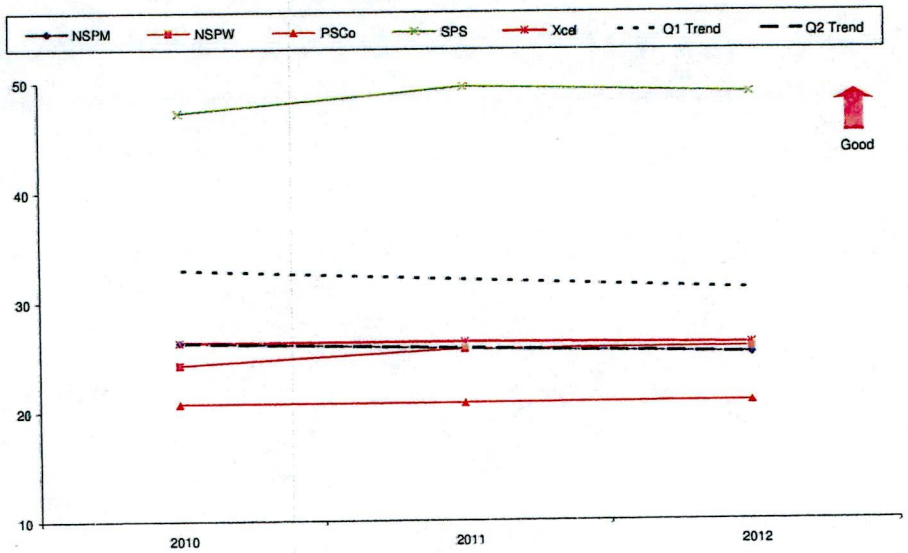
# Retail Revenue Comparison

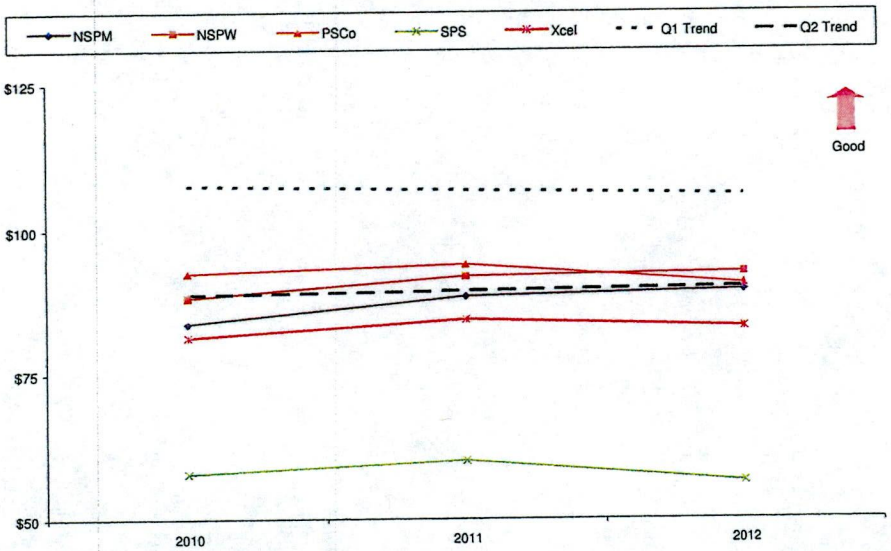
## Retail Revenue per Retail Customer




## MWh Sales per Retail Customer




## Retail Revenue per MWh Sold




Metric details can found on page 16

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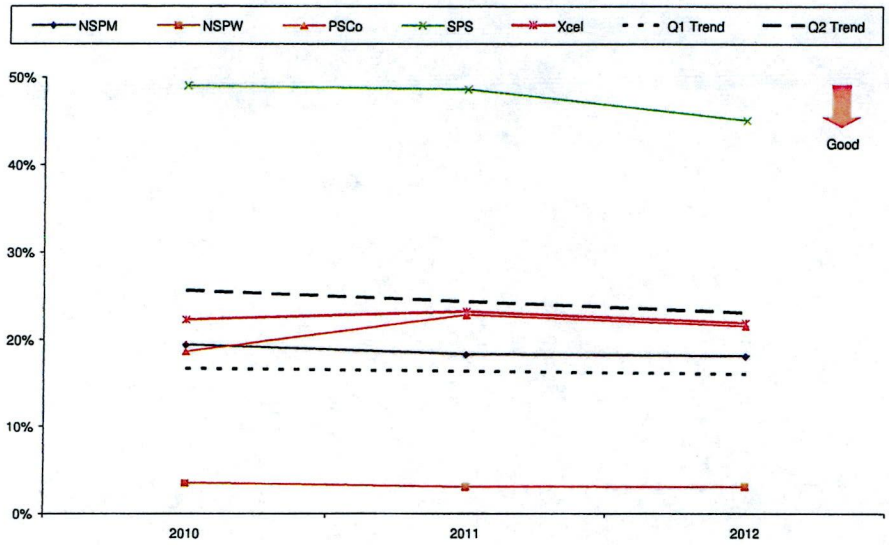
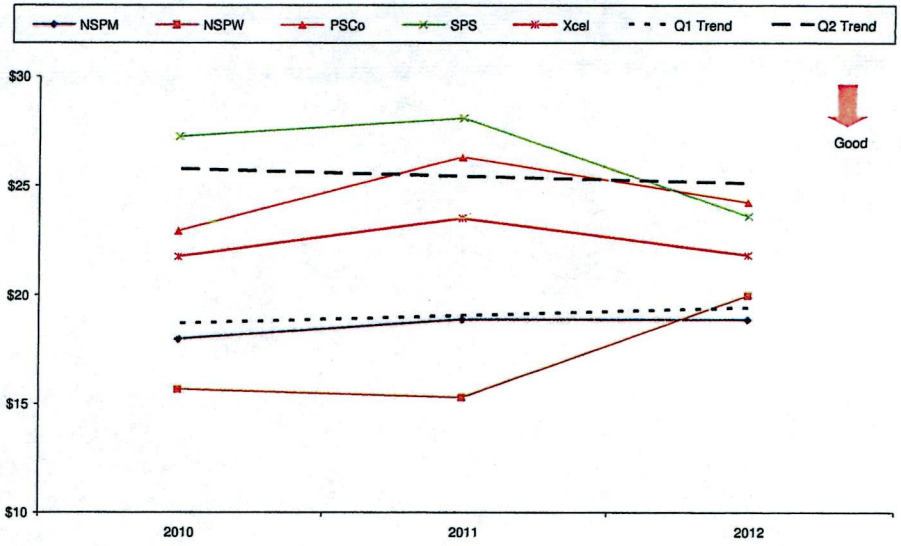
# Fuel Costs

**Percent Fuel Cost of Retail Revenue**




**Fuel Cost per MWh Generated**




Metric details can found on pages 16, 17 and 22.

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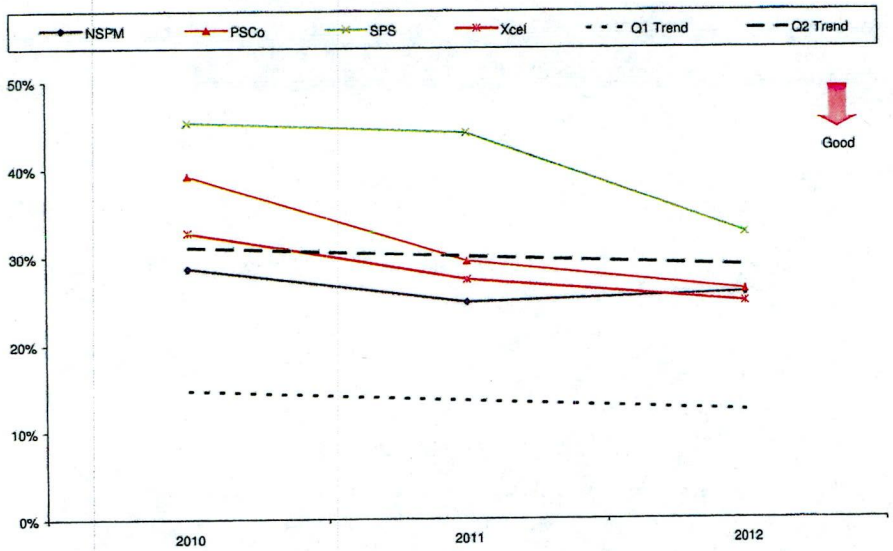
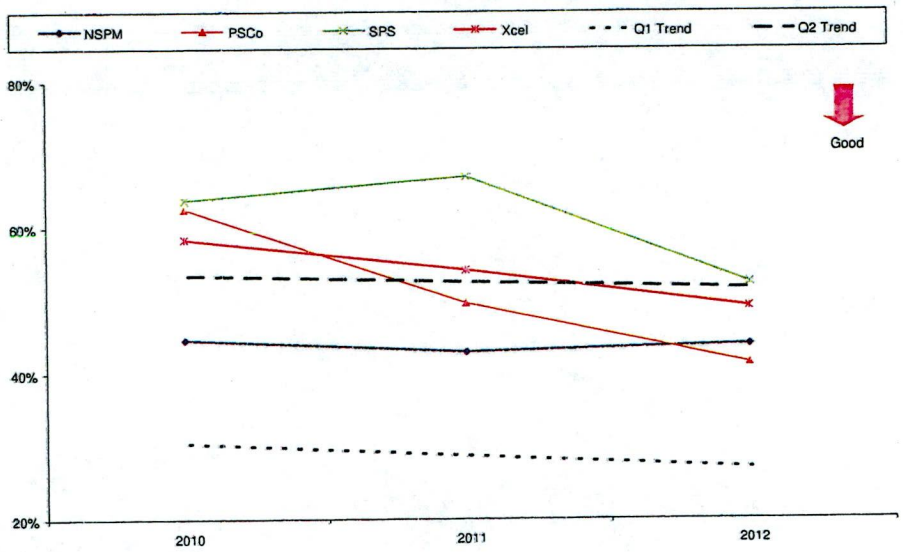
# Purchased Power Costs

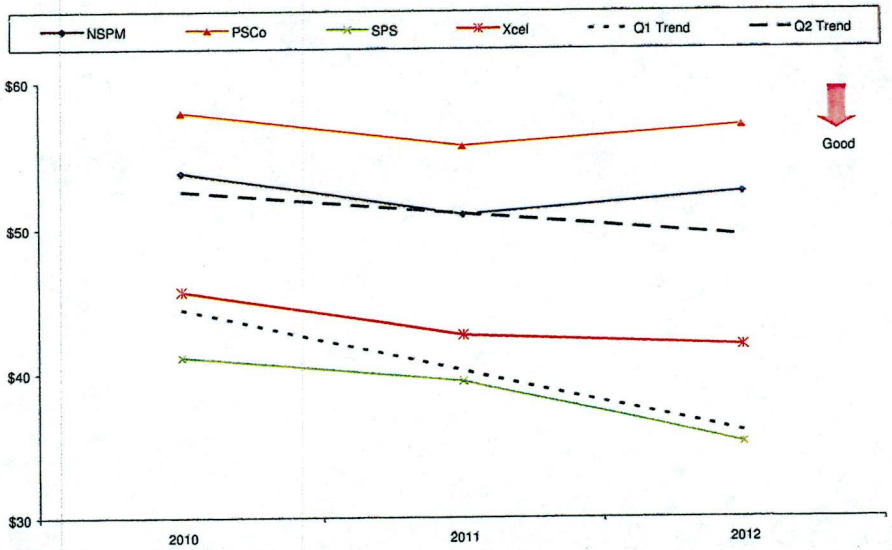
**Percent Purchased Power Cost of Retail Revenue**




**Percent Purchased Power MWh of Retail Sales MWh**




**PPA Cost per MWh Purchased**




Metric details can found on pages 16 and 17.

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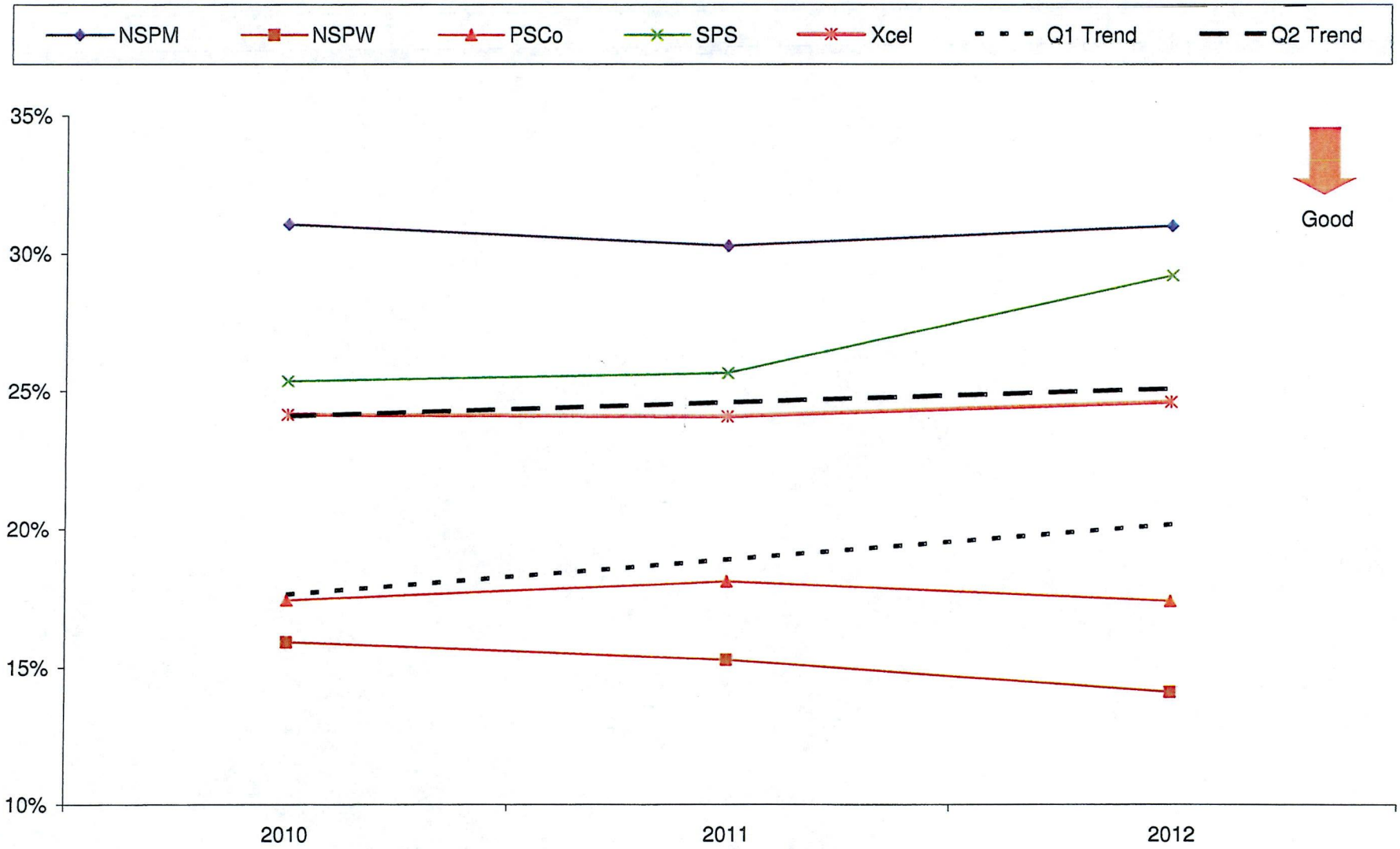
# Percent Non-Fuel O&M of Retail Revenue

## Excluding Customer Assistance and Pension & Benefit Costs




Metric details can found on pages 16 and 18.

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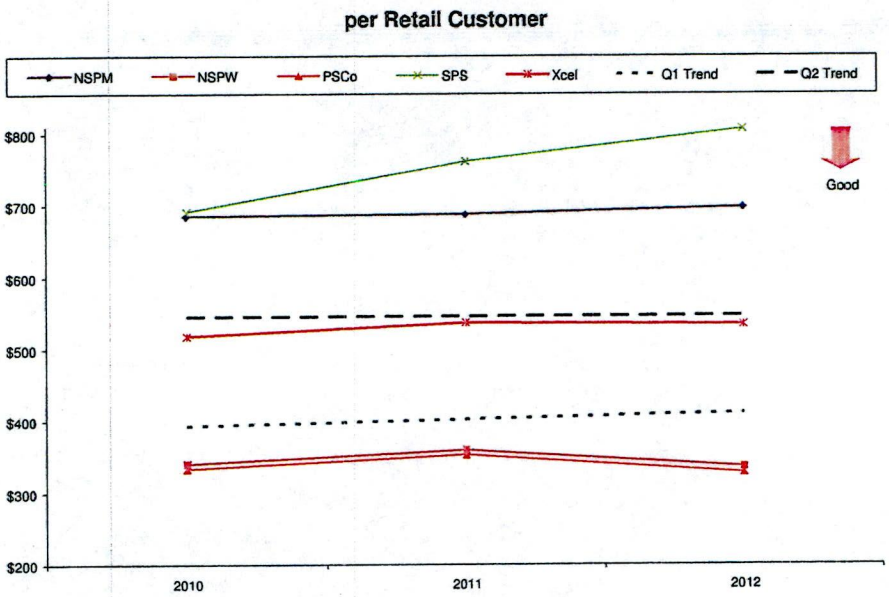
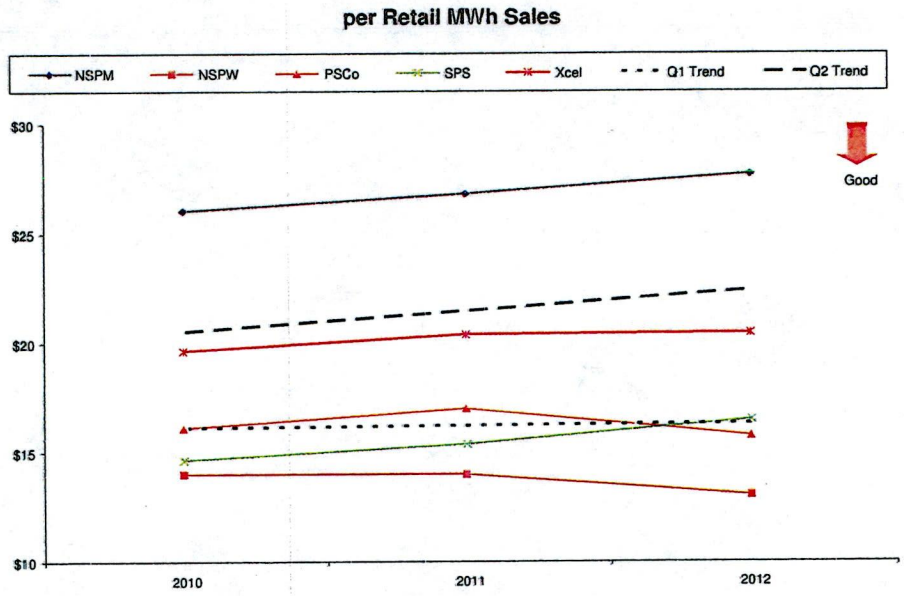
# Non-Fuel O&M
## Excluding Customer Assistance and Pension & Benefit Costs




Metric details can found on pages 16 and 18.

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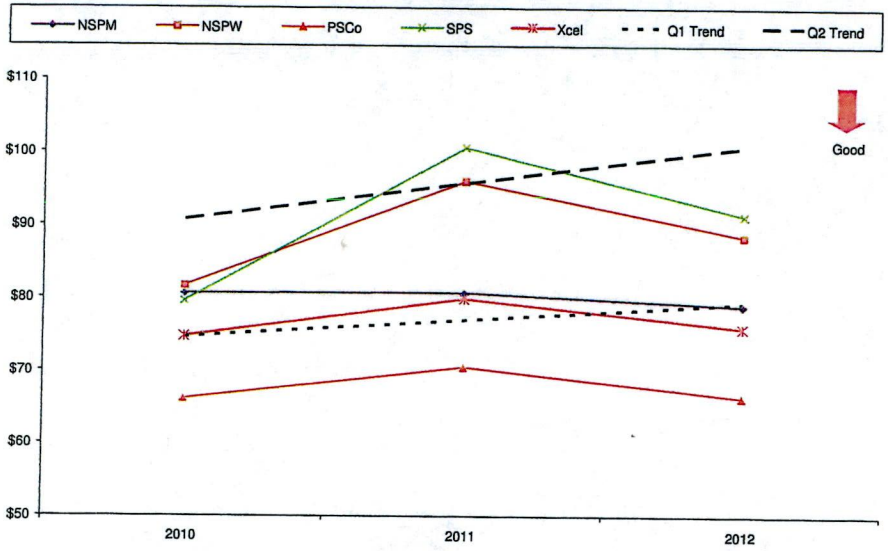
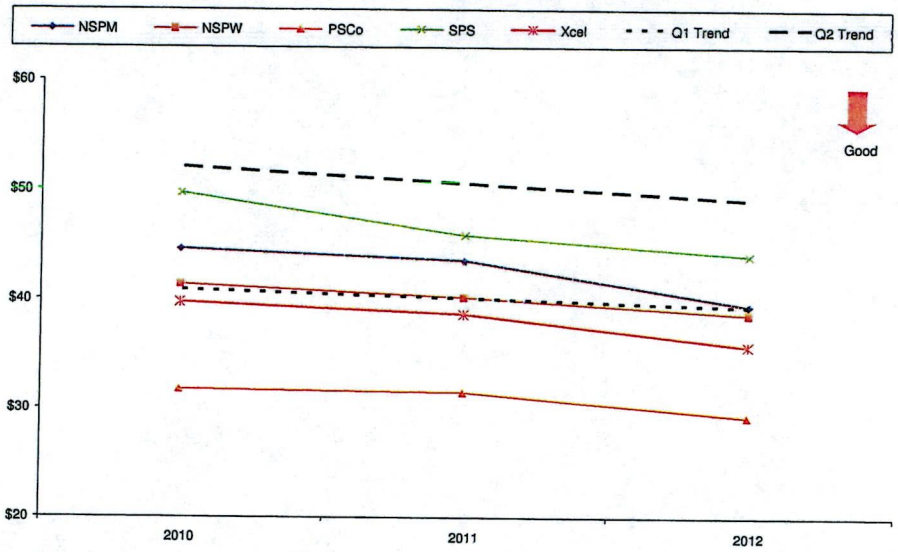
# Components of Non-Fuel O&M per Retail Customer
## Excluding Customer Assistance and Pension & Benefit Costs

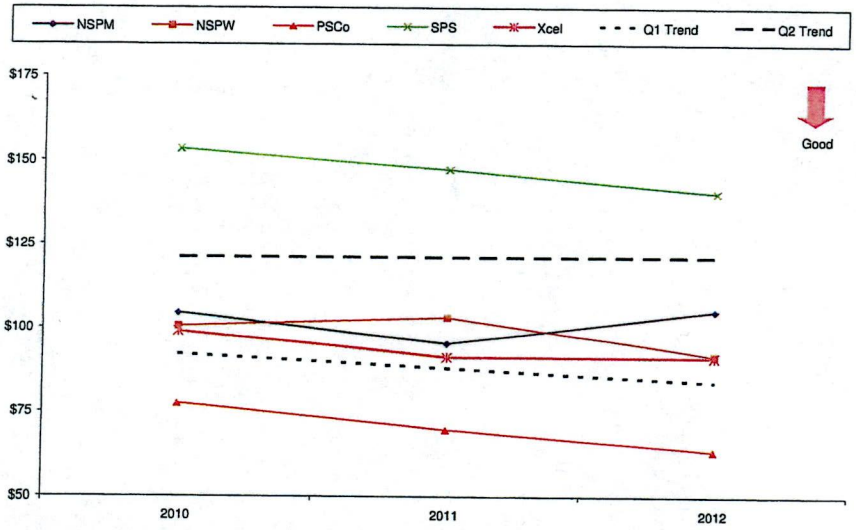
**Distribution O&M**




**Customer Care O&M**




**A&G O&M**




Metric details can found on pages 16 and 19.

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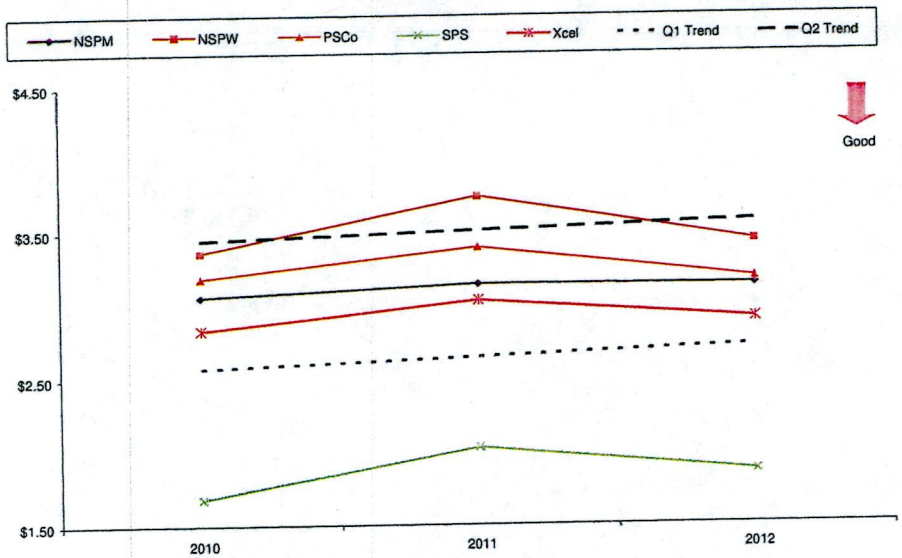
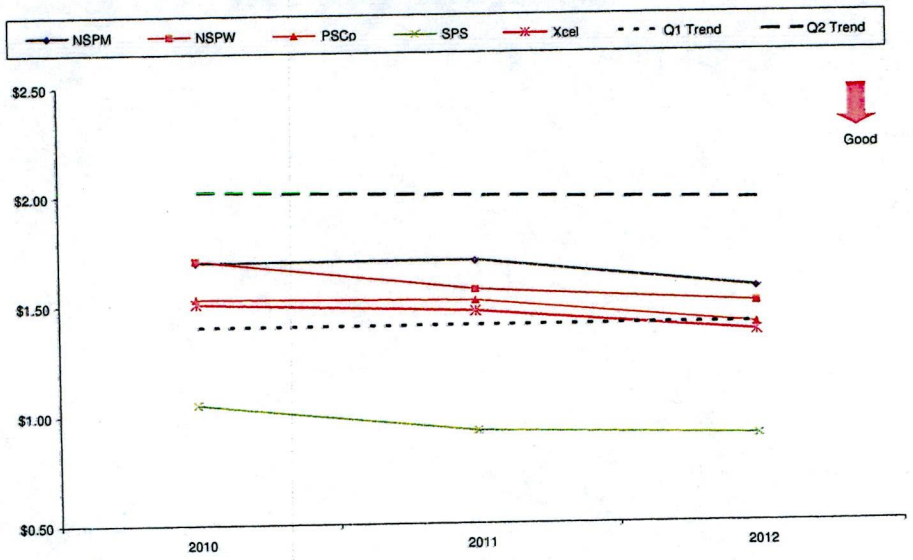
# Components of Non-Fuel O&M per Retail MWh Sales Excluding Customer Assistance and Pension & Benefit Costs

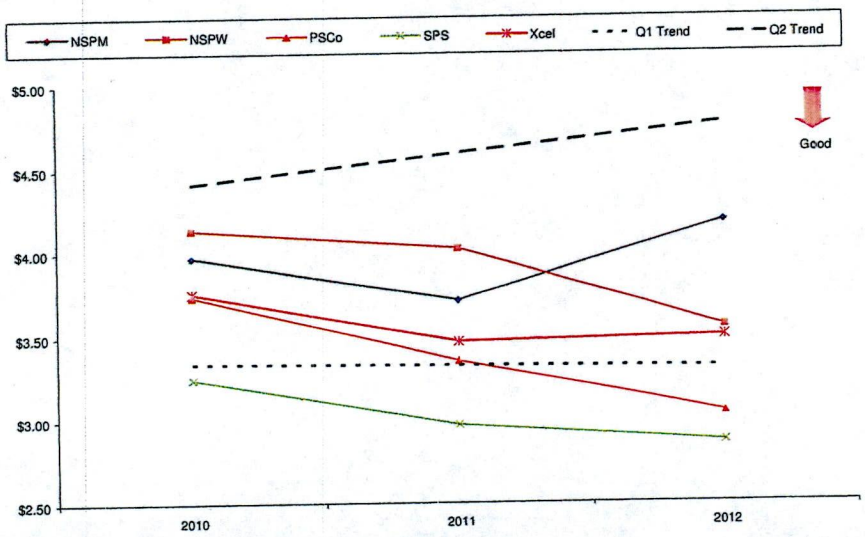
**Distribution O&M**




**Customer Care O&M**




**A&G O&M**




Metric details can found on pages 16 and 19.

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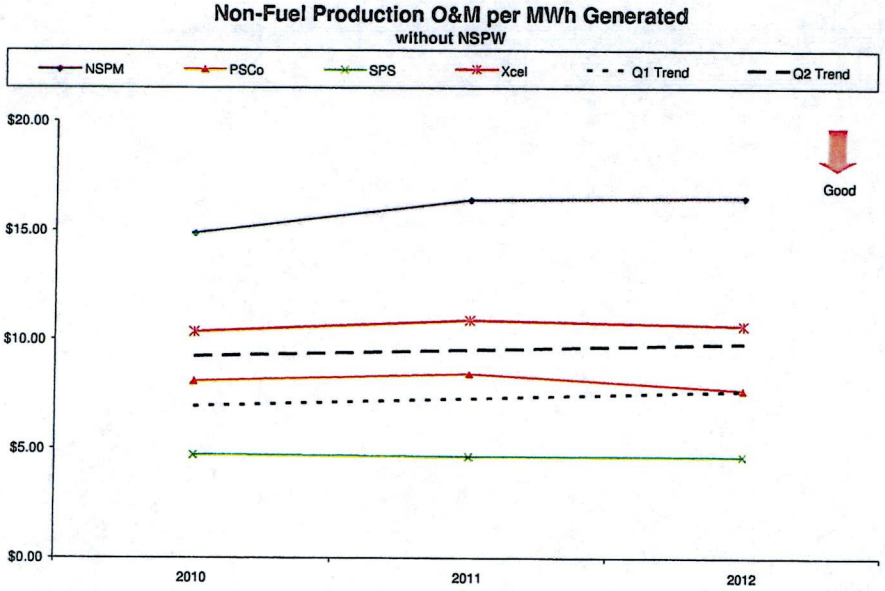
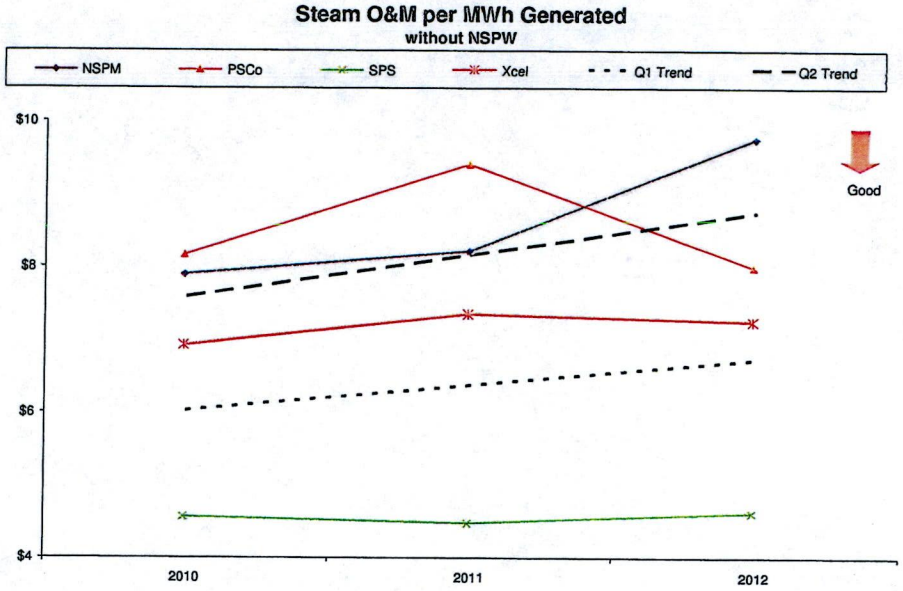
# Production Non-Fuel O&M per MWh Generated




Metric details can found on pages 21 and 22.

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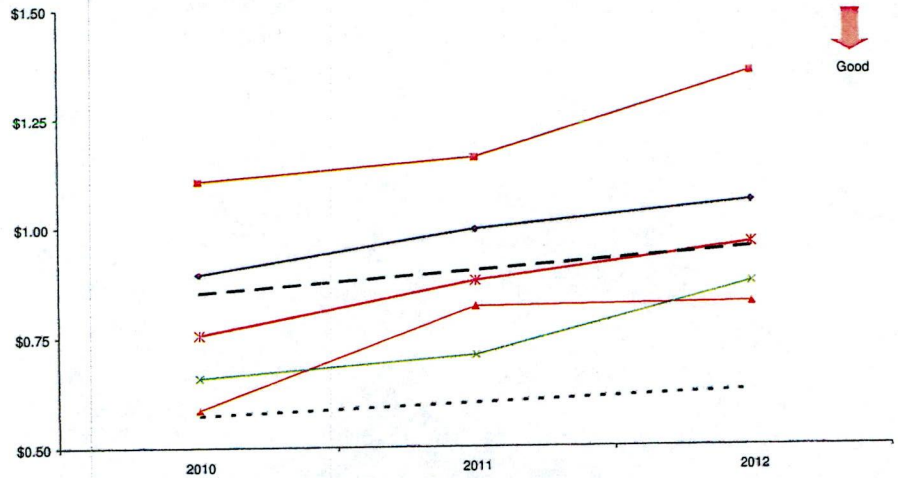
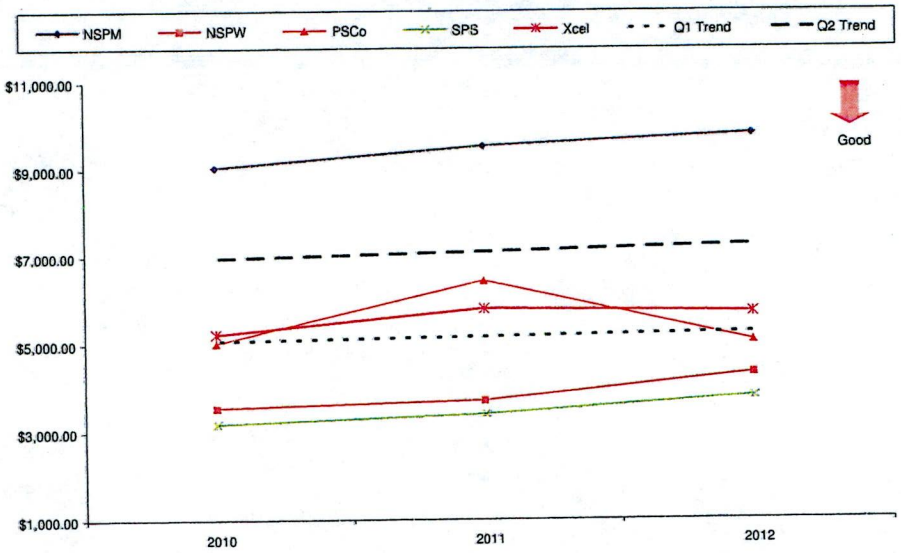
# Transmission O&M

## Excluding Transmission by Others (FERC Account 565)

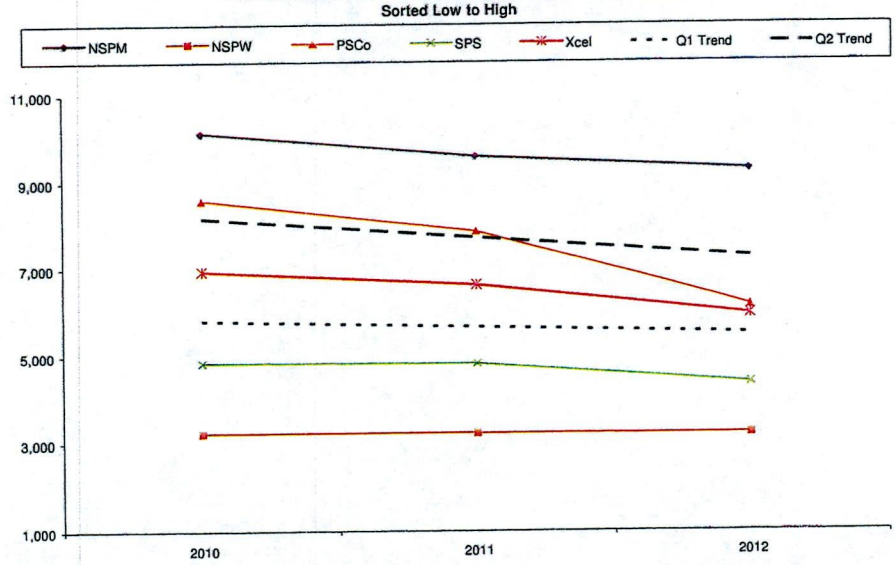
**per MWh Throughput**




**per Line Mile**




**Transmission MWh Throughput per Line Mile**
Sorted Low to High




Metric details can found on pages 19 and 20.

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# Appendix

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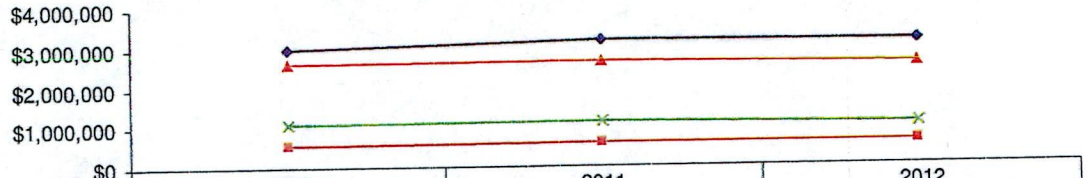
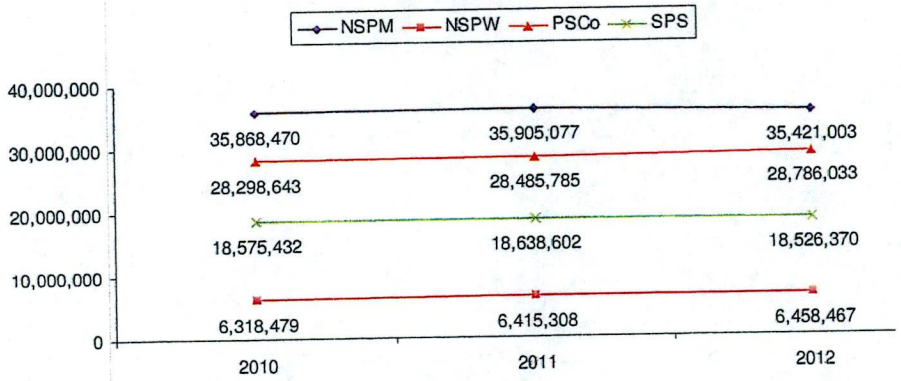
# Retail Revenue, Sales and Customers

**Retail Revenue**
**$ in Thousands**

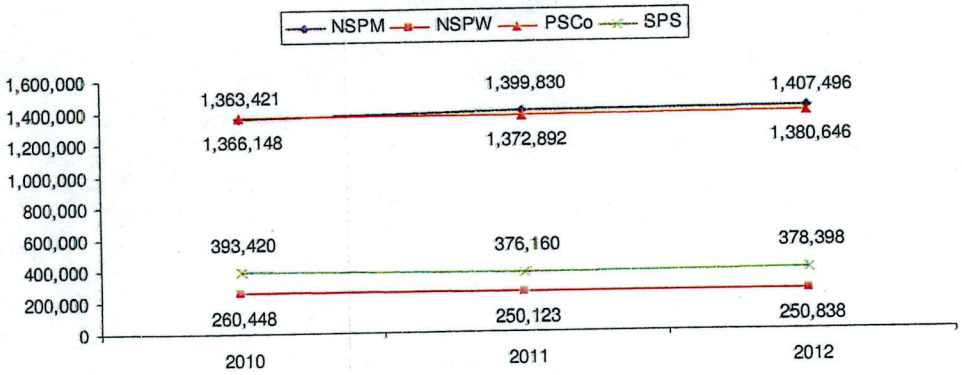



| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | $3,005,743 | $3,174,776 | $3,164,704 |
| NSPW | $557,161 | $588,941 | $596,811 |
| PSCo | $2,614,388 | $2,673,750 | $2,603,796 |
| SPS | $1,072,577 | $1,116,397 | $1,043,971 |

**Retail Sales MWh**




**Retail Customers**



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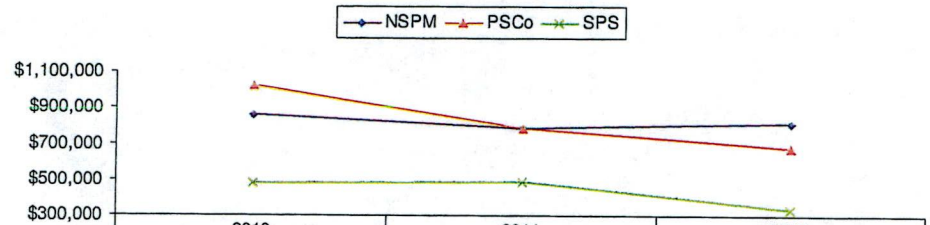
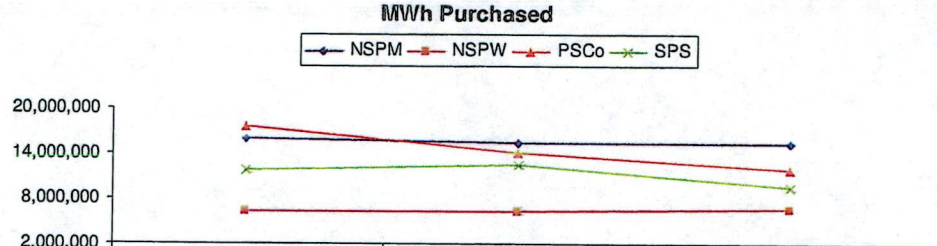
# Purchased Power and Fuel

**Purchased Power Cost**
$ in Thousands



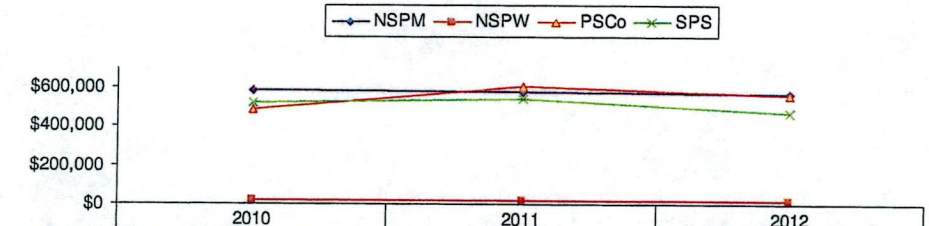

| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | 860,834 | 785,929 | 815,111 |
| PSCo | 1,023,758 | 786,117 | 679,013 |
| SPS | 485,607 | 491,273 | 339,969 |

**MWh Purchased**




| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | 15,997,119 | 15,428,012 | 15,541,472 |
| NSPW | 6,443,747 | 6,373,017 | 6,639,679 |
| PSCo | 17,688,891 | 14,133,536 | 11,917,824 |
| SPS | 11,827,957 | 12,456,953 | 9,686,098 |

**Fuel Costs**
$ in Thousands




| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | $584,276 | $581,879 | $573,851 |
| NSPW | $19,546 | $18,250 | $18,697 |
| PSCo | $487,909 | $611,530 | $562,411 |
| SPS | $526,016 | $542,785 | $470,719 |

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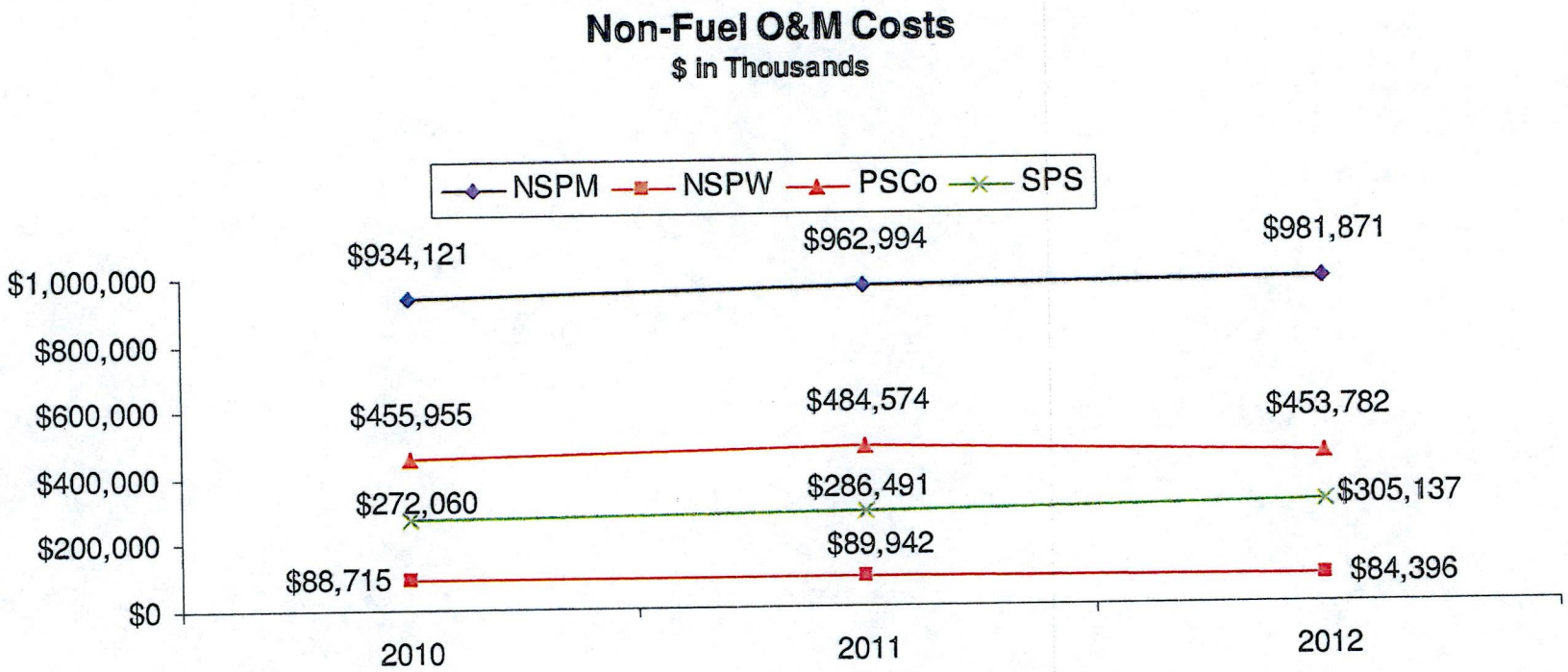
# Non-Fuel O&M Costs
## Excluding Customer Assistance and Pension & Benefits Costs



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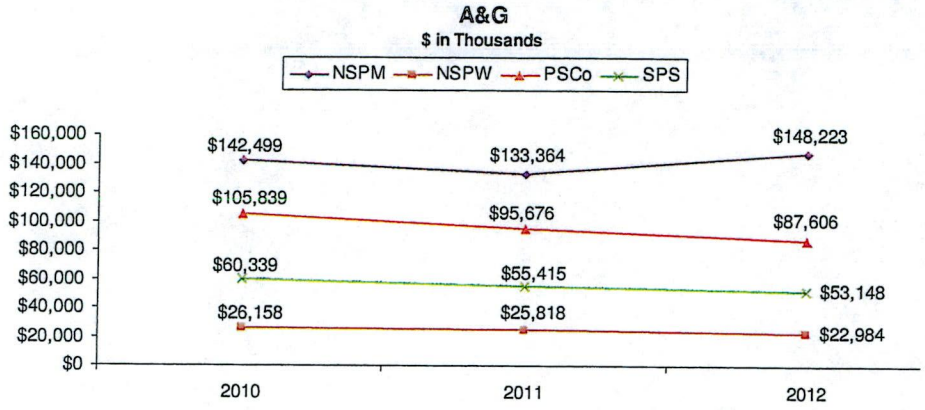
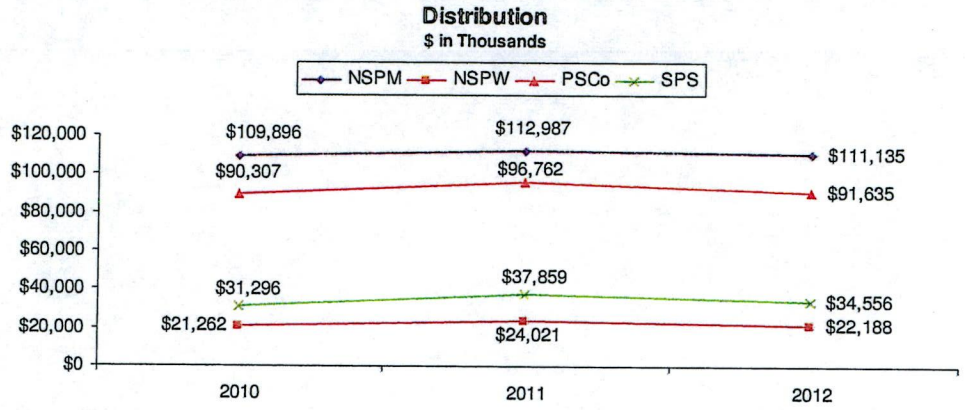
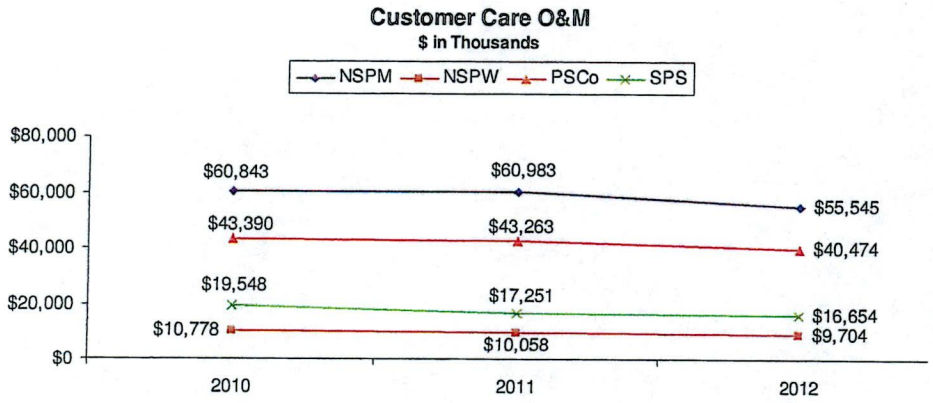
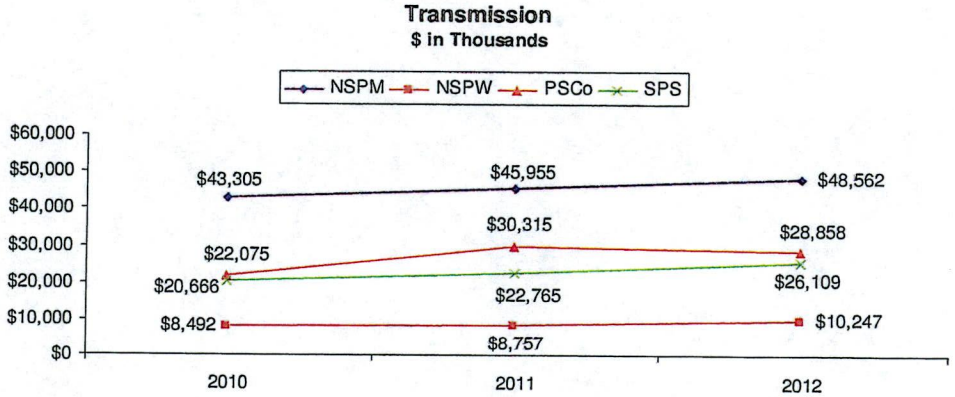
# A&G, Customer Care, Distribution, Transmission O&M Costs

## Excluding Customer Assistance, Pension & Benefits, Transmission by Others



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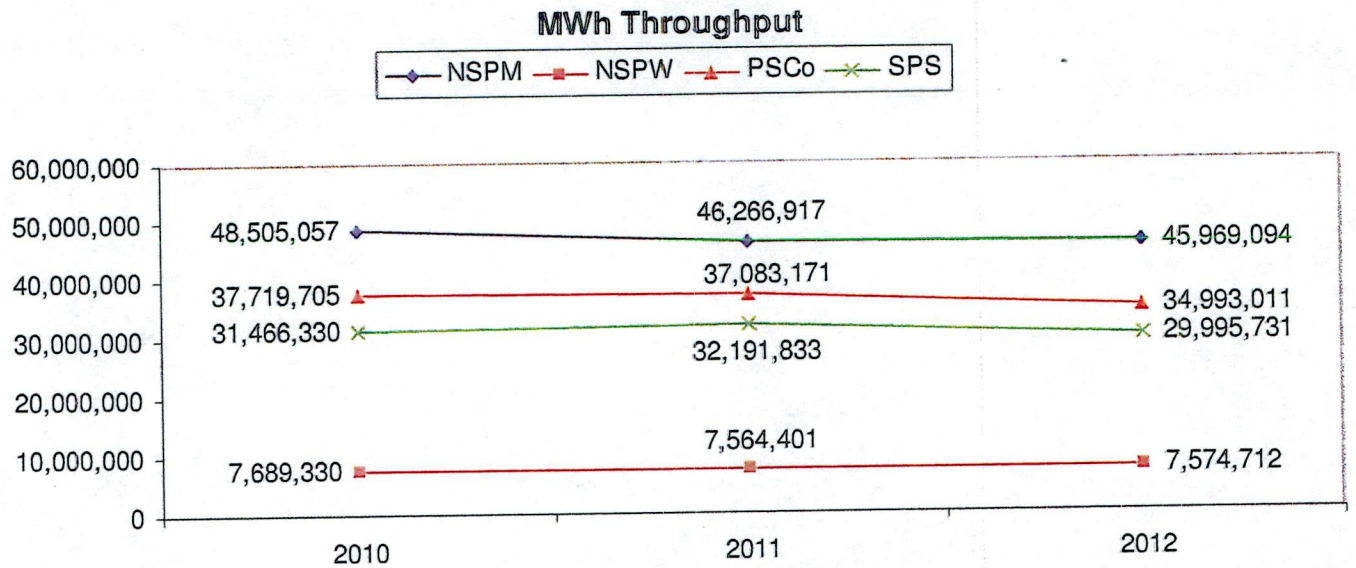
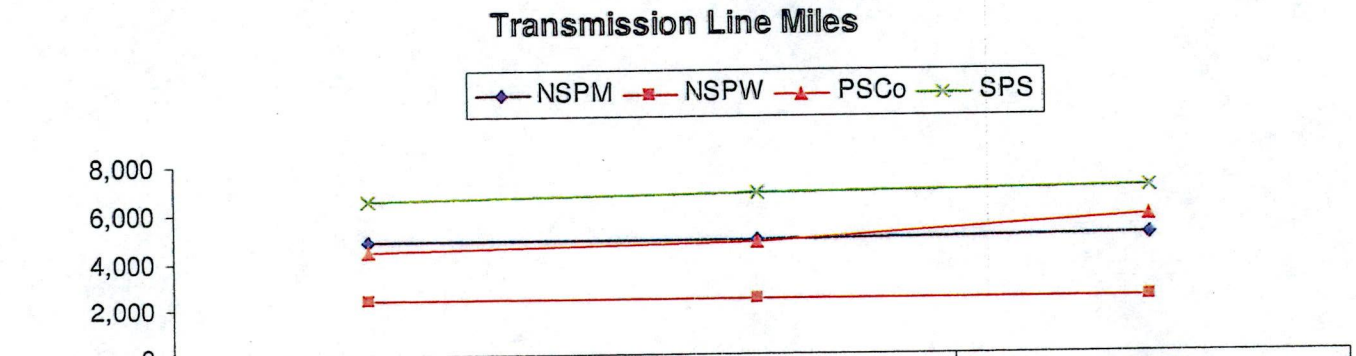
RESPONSIBLE BY NATURE™

# Transmission MWh Throughput and Line Miles




| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | 4,789 | 4,825 | 4,955 |
| NSPW | 2,396 | 2,364 | 2,375 |
| PSCo | 4,393 | 4,717 | 5,701 |
| SPS | 6,516 | 6,702 | 6,904 |

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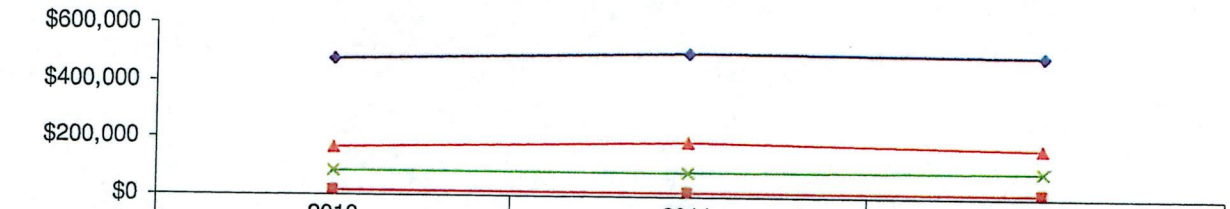
# Production Non-Fuel O&M Costs

## Non-Fuel Production O&M (All Generation)

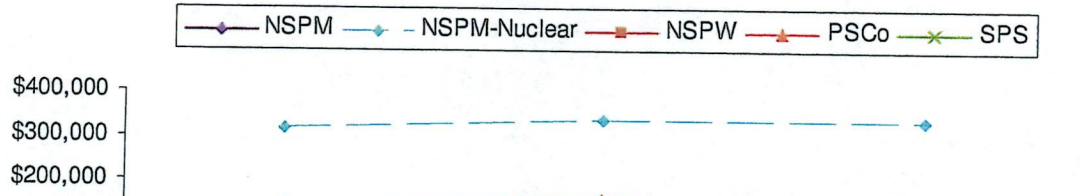
**$ in Thousands**




| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | $481,848 | $504,458 | $501,447 |
| NSPW | $21,988 | $21,254 | $19,244 |
| PSCo | $171,749 | $195,991 | $178,956 |
| SPS | $90,931 | $89,661 | $92,893 |

## Steam and Nuclear O&M

**$ in Thousands**




| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | $127,273 | $131,787 | $127,411 |
| NSPM-Nuclear | $319,069 | $337,559 | $340,009 |
| NSPW | $10,350 | $8,370 | $8,380 |
| PSCo | $143,489 | $158,411 | $137,676 |

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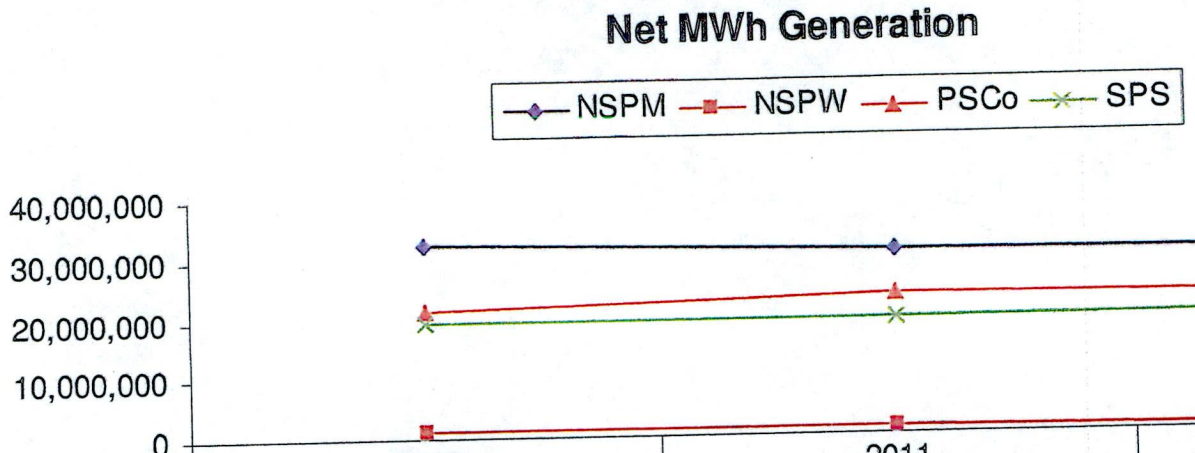
# Net MWh Generation




| | 2010 | 2011 | 2012 |
|---|---|---|---|
| NSPM | 32,465,850 | 30,793,266 | 30,382,911 |
| NSPW | 1,245,583 | 1,191,384 | 935,033 |
| PSCo | 21,258,200 | 23,247,462 | 23,189,340 |
| SPS | 19,303,403 | 19,327,229 | 19,940,523 |

EXHIBIT
tabbies
PSC-10



## ABOUT


- Overview
- Staff
- Board of Directors
- Committees


/// MEMBERSHIP BENEFITS

### Doing Business in North Dakota?

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### @nodakchamber

RT @kxmb: North Dakota oil production at 821,415 barrels per day in June-another new all-time high. #NDoil #NorthDakota #oil #kxnews #bakken

via Greater ND Chamber

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# Board of Directors

| NAME | BOARD POSITION | COMPANY | TITLE |
|---|---|---|---|
| Sort | Sort | Sort | Sort |
| Barbara Aasen | Chair-Elect | Eide Bailly LLP | Partner |
| Debra Anderson | | Summers Manufacturing Co., Inc. | President |
| Lori Berentson | | DEVA Lifewear, Inc. | President |
| Steven Britsch | | Britsch & Associates, PC | President |
| Tim Brumfield | | Gate City Bank - Dickinson | |
| Wendy Howe | | Minot Convention & Visitor's Bureau | Director |
| Niles Hushka | | Kadrmas, Lee & Jackson, Inc. | CEO & President |

| NAME | BOARD POSITION | COMPANY | TITLE |
|---|---|---|---|
| Sort | Sort | Sort | Sort |
| Ed Irion | | Dakota Growers Pasta Co. | President |
| Brian Johnson | | Tecton Products-Marvin Windows, Marvin Windows | Interim VP of Operations |
| Cathy Kruse | | Halcon Resources | Production Analyst |
| L. John MacMartin | | Minot Chamber of Commerce | President |
| Shannon McQuade-Ely | Chair | McQuade Distributing Co., Inc. | President |
| David Molmen | | Altru Health System | CEO |
| Jeremy Neuharth | | Sycorr | Co-Founder |
| Mark Nisbet | | Xcel Energy | Principal Manager, North Dakota |
| Wade Pearson | | Home of Economy | CEO |
| Andy Peterson | | Greater North Dakota Chamber | President/CEO |
| John Phillips | | Lutheran Social Services of North Dakota | |
| Tim Priebe | | Fisher Industries | Chief Adminstrative Officer |
| David Reiten | | Reiten Television Co. | Chairman |
| Debbie Richter | | American State Bank & Trust Co. | Marketing Officer |
| Joseph Rothschiller | Immediate Past Chair | Steffes Corporation | President |
| Brad Schlossman | Financial Vice Chair | West Acres Development, LLP | CEO |
| Gene Schmidt | | The SIA Companies | CEO |
| Steve Schmitz | | First Community Credit Union | President |
| Kris Sheridan | | Park Co. Realtors | President |
| Jay Skabo | | MDU Resources Group, Inc. | Vice President of Operations |
| John Stern | | Straus Company | President |

*GREATER NORTH DAKOTA CHAMBER*

2000 Schafer Street, Box 2639 Bismarck, ND 58502 | Map It

Phone:701-222-0929
Fax: 701-222-1611

Contact Us »

# Bill Tracker

The Greater North Dakota Chamber tracks legislation that may affect the state's business community.

Here you'll find a list of specific bills, the Chamber's position on each, updates on bill language, and links to testimony and voting records.

Check back daily throughout the legislative session for updates.

| BILL # Sort | DESCRIPTION Sort | WHERE WE STAND Sort | RESOURCES |
|---|---|---|---|
| 1020 | Provide an appropriation for defraying the expenses of the state water commission; to provide exemptions; to provide legislative intent; to amend and reenact section 6-09.5-03 of the North Dakota Century Code, relating to the community water facility loan fund; to provide for legislative management reports; to provide for a loan from the Bank of North Dakota; and to declare an emergency. |  | Bill Text<br>Bill Actions |
| 1021 | Provide an appropriation for defraying the expenses of workforce safety and insurance. | --- | Bill Text<br>Bill Actions |
| 1029 | Relating to a tax credit for contributions to the housing incentive fund and relating to a multifamily housing finance program and to the housing incentive fund and tax credits |  | Bill Text<br>Bill Actions |
| 1031 | Relating to the bonding authority of the North Dakota pipeline authority for refineries. | --- | Bill Text<br>Bill Actions |
| 1032 | Relating to an exemption from the oil extraction tax |  | Bill Text<br>Bill Actions |
| 1034 | Provide for a legislative management study of health care reform. | --- | Bill Text<br>Bill Actions |
| 1042 | Relating to actions having venue where the defendant resides. |  | Bill Text<br>Bill Actions |
| 1044 TESTIMONY | Provide a residential property tax credit for an individual's primary residence. The bill provides for state payment of property taxes on the first $75,000 of true and full evaluation of the residence. For an individual 65 years of age or older, the credit is increased to cover taxes on the first $125,000 of true and full valuation of the residence. The credits provided are in addition to any homestead or disabled veterans credit. The bill appropriates $384 million for allocation of residential property tax credit funds to counties for the 2013-15 biennium |  | Bill Text<br>Bill Actions |
| 1045 TESTIMONY | Provide property tax relief by appropriating $200 million for the 2013-15 biennium for allocation to counties to provide a 10 percent reduction in property taxes levied against all property by all taxing districts |  | Bill Text<br>Bill Actions |
| 1046 | Relating to city or county authority to reduce or revoke a previously granted property tax exemption or option to make payments in lieu of taxes | --- | Bill Text<br>Bill Actions |
| 1051 | Provide for a workers' compensation review committee study of the workers' compensation preferred provider program. |  | Bill Text<br>Bill Actions |
| 1052 TESTIMONY | relating to the workers' compensation preferred provider program |  | Bill Text<br>Bill Actions |
| 1053 | Requires medical providers that have entered into a professional relationship with WSI to inform injured workers they may treat of the relationship with WSI. |  | Bill Text<br>Bill Actions |
| 1055 | Relating to traffic citations on the capitol grounds during a legislative session. | --- | Bill Text<br>Bill Actions |
| 1064 | Relating to the maximum penalty for a violation of pipeline safety standards. |  | Bill Text<br>Bill Actions |
| 1071 | Relating to licensing procedures to obtain a registration under the Uniform Controlled Substances Act; relating to controlled substances; and to provide a penalty. |  | Bill Text<br>Bill Actions |
| 1079 | Relating to the partnership in assisting community expansion program at the Bank of North Dakota and the definition of business incentive. |  | Bill Text<br>Bill Actions |
| 1080 | Relating to definition of wages and federal wages for national guard employees, biennial report | | Bill Text |

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document


Xcel Energy
Case No.: PU-12-813
Response To: North Dakota Public Service Commission
Requestor: Snavely King
Date Received: April 4, 2013

Data Request No. NDPSC-8-068

SUPPLEMENT

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Question:

Subject: ASC No. 410 and FIN 47

Please refer to page 38 of the parent Company's 2011 10-K filing to the SEC. If not provided elsewhere, please provide the workpapers supporting the calculation of the asset retirement obligation of $875 million as of December 31, 2010 and $1.5 billion as of December 31, 2011. Please provide these workpapers in electronic format (Excel), with all formulae intact. Provide the calculations on a plant account-by-plant account basis. Also provide the workpapers in electronic format (Excel), with all formulae intact that support the calculation of the regulatory liability of $463 million at 12/31/10 and $439 million at 12/31/11.

Response:

The Company respectfully objects that this request is not reasonably calculated to lead to the discovery of relevant evidence, because the requested information is irrelevant to determining the North Dakota depreciation expense included in the test year revenue requirement. Asset Retirement Obligations relate to the required financial presentation necessary for every public trading entity. However, this Commission undertakes a regulatory review of removal in the depreciation expense developed through the depreciation study process. The creation of financial reporting standards does not supplant the regulatory process; in fact, the financial requirements accounted for only a portion of what regulators review. Subject to this objection and discussion, the Company notes that the amounts related to the regulatory liabilities are based on regulatory orders and/or approved rates, and the detail underlying these amounts can be seen on page 82 of our 2011 SEC Report 10-K.

SUPPLEMENT:

The Company records an asset retirement obligation (ARO) for all known and estimable legal obligations related to the retirement of assets. Upon recognition of an

ARO, a corresponding asset retirement cost (ARC) asset is recorded to reflect the net present value of the expected future value of related removal costs. Refer to Attachment A to this supplemental response for a listing of all the recorded AROs as of December 31, 2010 and 2011.

Once established, an ARO is accreted through the expected expenditure date up to the future estimated removal cost, and the related ARC is depreciated over the life of the underlying asset. As a regulated entity, on a monthly basis, the Company reclassifies the accretion and depreciation expense related to its AROs to a regulatory asset to meet the requirements of ASC 410. However, the financial reporting requirements of ASC 410 neglect to account for the recovery of non-legal removal costs associated with standard utility industry ratemaking procedures. For ratemaking purposes, the total expected removal costs for all legal and non-legal obligations are accrued through depreciation expense and recorded as accrued costs of removal, an offset to rate base. Since the recovery of all legal and non-legal costs are accrued through this process, all ARO liabilities, ARC assets, and related regulatory assets are not presented in ratemaking, as doing so would lead to over-recovery of the expected legal removal costs. Therefore, all ARO-related amounts presented in the Company's Annuals SEC Form 10-K are identified solely for presentation purposes to meet the reporting requirements of ASC 410.

The accrued costs of removal (both legal and non-legal) described above are recovered through the Commission-approved depreciation expense. The Company records these accrued costs of removal as an offset to rate base and included within accumulated depreciation FERC Account 108. For SEC reporting, the Company reclassifies these accrued costs to a regulatory liability in compliance with SEC reporting requirements. Per page 82 of the Company's 2011 SEC Annual Form 10-K, the Company has accrued costs of removal of $400.2 million and $382.1 million as of December 31, 2010 and 2011, respectively. Please refer to Attachment B to this supplemental response for a listing of the amounts at each period by functional class.

The Company's recovery of all asset retirement obligations (ARO) costs – both legal obligations as required under ASC 410 and FIN 47 (legal obligations) and asset removal (non-legal obligations) – is consistent with longstanding practice in North Dakota.

The North Dakota Public Service Commission has adopted Minnesota's depreciation parameters as a baseline by which it will prospectively determine appropriate depreciation methodologies. *In Re Otter Rail Power Company*, Case No. PU-401-93-520, ORDER APPROVING SETTLEMENT (Sept. 22, 1993) ("[t]he second reduction related to a decrease in depreciation expense when the Commission adopted the Minnesota depreciation parameters for North Dakota operations"). In Minnesota, the Company includes both legal obligations and non-legal obligations in its depreciation.

In Case No. PU-06-525, the Commission approved the following regulatory treatment for plant retirements:

> First, the Company shall continue to recover the estimated net present value of the cost of retirement over the useful life of an asset. Second, for regulatory purposes, the Company shall continue to include all retirements as part of accumulated depreciation, which in turn results in an offset to rate base equal to the amount of the accumulated depreciation. Should at any future date, there be change in regulation or other event that would result in a change in the above-described process, the Company agrees to work with the Commission to ensure that any accumulated depreciation amounts for retirement purposes are considered and appropriately addressed as part of the change.

*Re Northern States Power Company*, Case No. PU-06-525, ORDER ADOPTING SETTLEMENT (June 13, 2007).

In Case No. PU-07-776, the ability of the Company to include non-legal obligations in its depreciation recovery was fully litigated. *See In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in North Dakota*, Case No. PU-07-776, Direct Testimony of Michael J. Majoros, JR at pp. 9-21 (May 2008); Rebuttal Testimony of Dane A. Watson at pp. 16-28 (June 13, 2008). In settlement of these issues, the Commission approved the agreement between the Company and Advocacy Staff:

> Both Parties agree that, unless directed otherwise by the Commission, rate recovery – past, present, and future – for the removal and retirement of Company utility property will be used solely for the retirement of the Company's utility property and recognized as a regulatory liability.

ORDER ADOPTING SETTLEMENT, Settlement Agreement at p. 8 (Jan. 14, 2009).

Although such settlement agreements are not binding future precedent, the Company believes that the accounting in the settlement is reasonable, that the issues have been fully addressed multiple times including as recently as 2009, and have been historically accepted by the Commission. Consequently, the Company has accounted for both legal obligations and non-legal obligations in a manner consistent with the approach that has been accepted by the Commission. The Company recognizes that the

Commission may change this methodology, but believes it has adopted a historically-acceptable method and mitigated any concerns with respect to the accumulation of non-legal obligations by recognizing the accrued non-legal obligations as a regulatory liability and agreeing to utilize these funds for the retirement of the Company's utility property.

---

| | |
|---|---|
| Witness: | Lisa Perkett |
| Preparer: | Andy Sawyer |
| Title: | Senior Analyst |
| Department: | Capital Asset Accounting |
| Telephone: | (612) 215-4649 |
| Date: | May 9, 2013 |

Northern States Power Company
Electric Utility - State of North Dakota

Case No. PU-12-813
NDPSC Data Request 8-068 Supplement
Attachment A - Page 1 of 2

**Recorded Asset Retirement Obligations (ARO) as of December 31, 2011**

| Plant Account | ARO Liability | ARC Asset | ARC Reserve | Regulatory Asset | Description |
|---|---|---|---|---|---|
| 317 - Steam Production | $ 42,964.39 | $ (21,184.24) | $ 3,294.93 | $ 67,443.56 | Steam production radiation sources |
| 317 - Steam Production | 3,456,662.17 | 2,189,400.86 | 174,074.84 | 1,441,336.15 | Steam production asbestos removal - Black Dog |
| 317 - Steam Production | 2,787,025.82 | (576,933.08) | 26,819.64 | 3,390,778.54 | Steam production asbestos removal - MN Valley |
| 317 - Steam Production | 1,205,921.38 | 490,432.39 | 423,680.39 | 1,139,169.38 | Steam production asbestos removal - Red Wing |
| 317 - Steam Production | 1,483,565.94 | 283,838.80 | 165,452.28 | 1,365,179.42 | Steam production asbestos removal - Riverside |
| 317 - Steam Production | 338,842.57 | (5,784,865.84) | 406,632.22 | 6,530,340.63 | Steam production asbestos removal - Sherco |
| 317 - Steam Production | 1,205,921.38 | 490,432.39 | 423,680.39 | 1,139,169.38 | Steam production asbestos removal - Wilmarth |
| 317 - Steam Production | 30,989,257.85 | 13,240,331.83 | 1,269,165.62 | 19,018,091.64 | Steam production ash containment |
| | 41,510,161.50 | 10,311,453.11 | 2,892,800.31 | 34,091,508.70 | |
| 326 - Nuclear Production | 631,703,079.10 | 168,982,167.71 | 37,662,447.91 | 500,383,359.30 | Nuclear decommissioning - Monticello |
| 326 - Nuclear Production | 377,961,363.53 | (16,872,254.61) | 31,497,981.52 | 426,331,599.66 | Nuclear decommissioning - Prairie Island Unit 1 |
| 326 - Nuclear Production | 473,076,437.64 | 18,879,787.24 | 28,975,197.15 | 483,171,847.55 | Nuclear decommissioning - Prairie Island Unit 2 |
| | 1,482,740,880.27 | 170,989,700.34 | 98,135,626.58 | 1,409,886,806.51 | |
| | | | | (1,315,124,603.62) | Contra regulatory asset for decommissioning trust fund investments |
| | | | | 94,762,202.89 | Net Nuclear Regulatory Asset |
| 347 - Other Production | 13,654,296.29 | 11,767,446.38 | 1,111,894.25 | 2,998,744.16 | Wind Farm Removal - Grand Meadow |
| 347 - Other Production | 26,861,201.42 | 25,671,214.81 | 1,108,723.62 | 2,298,710.23 | Wind Farm Removal - Nobles |
| | 40,515,497.71 | 37,438,661.19 | 2,220,617.87 | 5,297,454.39 | |
| 374 - Electric Distribution | 15,699,780.22 | 15,474,098.59 | 129,036.15 | 354,717.78 | Electric distribution |
| 388 - Gas Distribution | 295,246.73 | (675,009.57) | 329,774.62 | 1,300,030.92 | Gas distribution |
| 399.1 - Common | 1,134,825.62 | (1,829,331.13) | (1,829,331.13) | 1,134,825.62 | Common general plant asbestos removal |
| Total | $ 1,581,896,392.05 | $ 231,709,572.53 | $ 101,878,524.40 | $ 136,940,740.30 | |

**Recorded Asset Retirement Obligations (ARO) as of December 31, 2010**

| Plant Account | ARO Liability | ARC Asset | ARC Reserve | Regulatory Asset | Description |
|---|---|---|---|---|---|
| 317 - Steam Production | $ 38,471.82 | $ (23,079.86) | $ 4,534.55 | $ 66,086.23 | Steam production radiation sources |
| 317 - Steam Production | 3,307,302.31 | 2,189,400.86 | 72,886.93 | 1,190,788.38 | Steam production asbestos removal - Black Dog |
| 317 - Steam Production | 2,636,372.40 | (576,933.08) | 138,281.66 | 3,351,587.14 | Steam production asbestos removal - MN Valley |
| 317 - Steam Production | 1,177,704.59 | 490,432.39 | 412,555.07 | 1,099,827.27 | Steam production asbestos removal - Red Wing |
| 317 - Steam Production | 1,420,384.52 | 283,838.80 | 161,107.80 | 1,297,653.52 | Steam production asbestos removal - Riverside |
| 317 - Steam Production | 320,016.29 | (5,784,865.84) | 702,640.04 | 6,807,522.17 | Steam production asbestos removal - Sherco |
| 317 - Steam Production | 1,177,704.59 | 490,432.39 | 412,555.07 | 1,099,827.27 | Steam production asbestos removal - Wilmarth |
| 317 - Steam Production | 12,814,572.99 | (4,426,881.85) | 1,472,370.87 | 18,713,825.71 | Steam production ash containment |
| | 22,892,529.51 | (7,357,656.19) | 3,376,931.99 | 33,627,117.69 | |
| 326 - Nuclear Production | 289,891,288.57 | (155,272,794.37) | 43,845,789.78 | 489,009,872.72 | Nuclear decommissioning - Monticello |
| 326 - Nuclear Production | 253,760,361.25 | (121,869,100.37) | 38,682,424.10 | 414,311,885.72 | Nuclear decommissioning - Prairie Island Unit 1 |
| 326 - Nuclear Production | 265,822,689.20 | (167,494,535.38) | 35,266,549.33 | 468,583,773.91 | Nuclear decommissioning - Prairie Island Unit 2 |
| | 809,474,339.02 | (444,636,430.12) | 117,794,763.21 | 1,371,905,532.35 | |
| | | | | (1,321,042,411.79) | Contra regulatory asset for decommissioning trust fund investments |
| | | | | 50,863,120.56 | Net Nuclear Regulatory Asset |
| 347 - Other Production | 12,791,838.35 | 11,767,446.38 | 623,853.78 | 1,648,245.75 | Wind Farm Removal - Grand Meadow |
| 347 - Other Production | 25,760,850.14 | 25,671,214.81 | 85,286.45 | 174,921.78 | Wind Farm Removal - Nobles |
| | 38,552,688.49 | 37,438,661.19 | 709,140.23 | 1,823,167.53 | |
| 374 - Electric Distribution | 3,088,381.48 | 3,014,892.82 | 48,951.96 | 122,440.62 | Electric distribution |
| 388 - Gas Distribution | 277,541.62 | (675,009.57) | 340,133.20 | 1,292,684.39 | Gas distribution |
| 399.1 - Common | 1,075,942.98 | (1,829,331.13) | (1,829,331.13) | 1,075,942.98 | Common general plant asbestos removal |
| Total | $ 875,361,423.10 | $ (414,044,873.00) | $ 120,440,589.46 | $ 88,804,473.77 | |

Northern States Power Company
Electric Utility - State of North Dakota

Case No. PU-12-813
NDPSC Data Request 8-068 Supplement
Attachment B - Page 1 of 1

Accrued Costs of Removal by Functional Class

| | 12/31/10 Balance | 12/31/11 Balance |
|---|---|---|
| Common General | $ (4,105,501.56) | $ (5,225,010.67) |
| Electric Distribution | 216,044,360.85 | 223,522,024.80 |
| Electric General | (152,465.91) | (444,052.78) |
| Electric Production | 35,352,048.62 | 5,301,959.88 |
| Electric Transmission | 73,930,883.01 | 76,842,323.76 |
| Gas Distribution | 72,037,693.27 | 74,766,170.96 |
| Gas General | 28,702.09 | 10,813.46 |
| Gas Production | 174,852.85 | 180,518.48 |
| Gas Storage | 383,380.71 | 395,767.11 |
| Gas Transmission | 6,538,903.42 | 6,738,529.03 |
| | $ 400,232,857.35 | $ 382,089,044.03 |

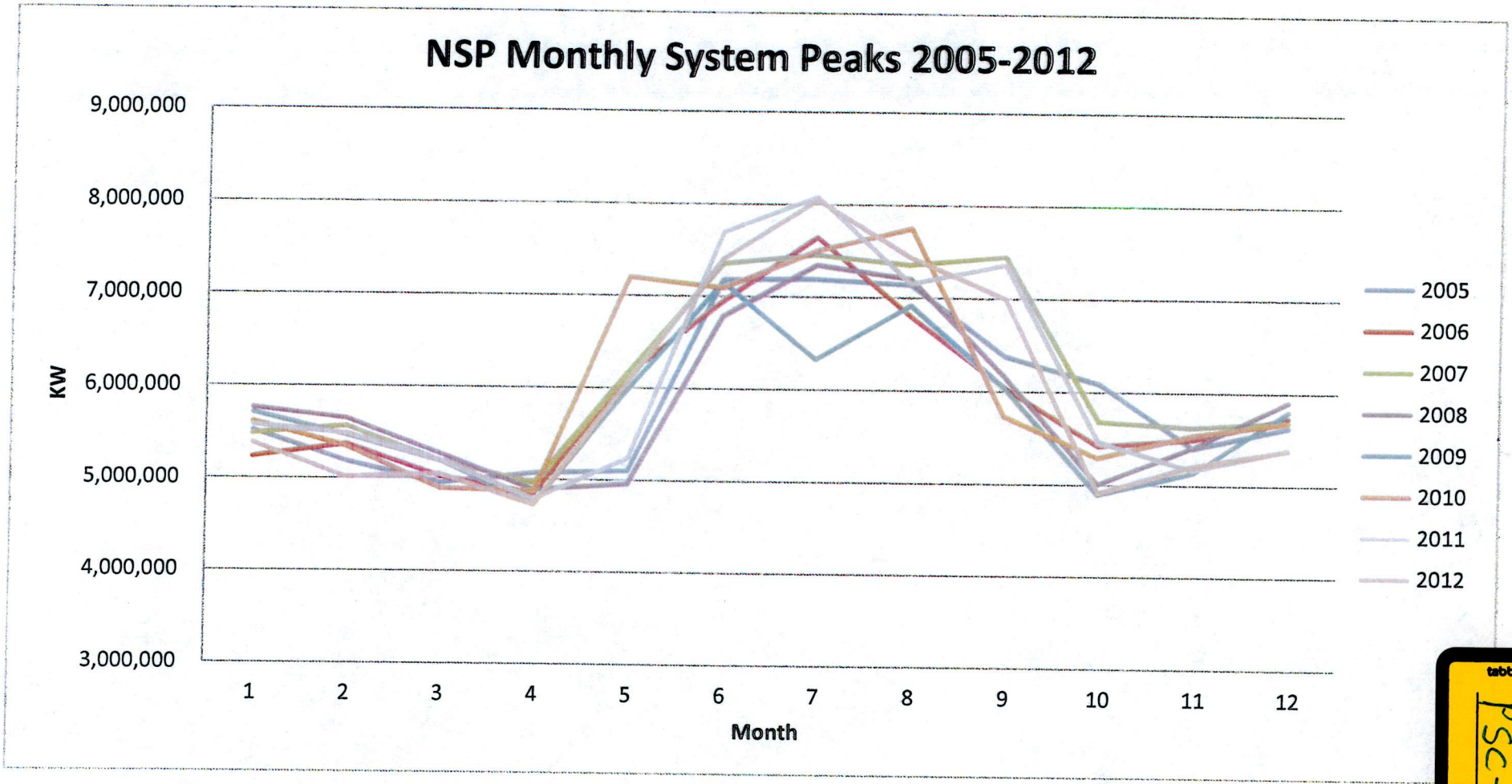


EXHIBIT
PSC-12

EXHIBIT
tabbies
PSC-13

# EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 21.85 | P/E RATIO 15.6 (Trailing: 15.8 Median: 16.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.6%

TIMELINESS 2 Raised 6/14/13
SAFETY 2 Raised 3/23/12
TECHNICAL 3 Raised 3/22/13
BETA .65 (1.00 = Market)

2016-18 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+15%) | 8% |
| Low | 19 | (-15%) | 2% |

Insider Decisions

| | J | A | S | O | N | D | J | F | M |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | |

Institutional Decisions

| | 3Q2012 | 4Q2012 | 1Q2013 |
|---|---|---|---|
| to Buy | 56 | 53 | 56 |
| to Sell | 42 | 44 | 54 |
| Hld's(000) | 19355 | 19863 | 20020 |

| High: | 22.0 | 22.5 | 23.5 | 25.0 | 25.1 | 26.1 | 23.5 | 19.4 | 22.5 | 23.3 | 22.0 | 23.3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Low: | 15.1 | 17.0 | 19.5 | 19.3 | 20.3 | 21.1 | 14.9 | 11.9 | 17.6 | 18.0 | 19.5 | 20.6 |

LEGENDS
— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
*Shaded areas indicate recessions*

Target Price Range 2016 | 2017 | 2018

% TOT. RETURN 5/13

| | THIS STOCK | VL ARITH.* INDEX |
|---|---|---|
| 1 yr. | 13.6 | 33.2 |
| 3 yr. | 36.3 | 55.0 |
| 5 yr. | 39.0 | 67.0 |

| 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | © VALUE LINE PUB. LLC | 16-18 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12.83 | 14.02 | 13.94 | 14.78 | 13.37 | 13.56 | 13.03 | 12.67 | 14.80 | 13.67 | 14.59 | 15.25 | 13.04 | 13.02 | 13.74 | 13.11 | *13.70* | *14.10* | Revenues per sh | *16.25* |
| 2.67 | 2.97 | 2.89 | 3.12 | 2.19 | 2.43 | 2.48 | 2.22 | 2.45 | 2.75 | 2.69 | 2.91 | 2.72 | 2.85 | 3.21 | 2.99 | *3.15* | *3.25* | "Cash Flow" per sh | *4.00* |
| 1.29 | 1.53 | 1.13 | 1.35 | .59 | 1.19 | 1.29 | .86 | .92 | 1.41 | 1.09 | 1.17 | 1.18 | 1.17 | 1.31 | 1.32 | *1.40* | *1.45* | Earnings per sh [A] | *1.70* |
| 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | 1.28 | .64 | 1.00 | *1.00* | *1.00* | Div'd Decl'd per sh [B] ■ † | *1.20* |
| 3.38 | 3.03 | 4.14 | 7.61 | 4.02 | 3.43 | 2.65 | 1.64 | 2.83 | 3.97 | 5.46 | 6.28 | 4.07 | 2.63 | 2.44 | 3.22 | *3.85* | *3.75* | Cap'l Spending per sh | *2.25* |
| 13.06 | 13.43 | 13.48 | 13.65 | 13.58 | 14.59 | 15.17 | 14.76 | 15.08 | 15.49 | 16.04 | 15.56 | 15.75 | 15.82 | 16.53 | 16.90 | *17.25* | *17.80* | Book Value per sh [C] | *19.25* |
| 16.78 | 17.11 | 17.37 | 17.60 | 19.76 | 22.57 | 24.98 | 25.70 | 26.08 | 30.25 | 33.61 | 33.98 | 38.11 | 41.58 | 41.98 | 42.48 | *43.00* | *44.75* | Common Shs Outst'g [D] | *46.25* |
| 13.9 | 14.0 | 21.7 | 17.7 | 33.9 | 16.2 | 15.8 | 24.8 | 24.5 | 15.9 | 21.7 | 17.3 | 14.3 | 16.8 | 15.8 | 15.8 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | *13.0* |
| .80 | .73 | 1.24 | 1.15 | 1.74 | .88 | .90 | 1.31 | 1.30 | .86 | 1.15 | 1.04 | .95 | 1.07 | .99 | 1.01 | | | Relative P/E Ratio | *.85* |
| 7.1% | 6.0% | 5.2% | 5.4% | 6.4% | 6.6% | 6.3% | 6.0% | 5.7% | 5.7% | 5.4% | 6.3% | 7.6% | 6.5% | 3.1% | 4.8% | | | Avg Ann'l Div'd Yield | *5.5%* |
| 325.5 | 325.5 | 386.2 | 413.5 | 490.2 | 518.2 | 497.2 | 541.3 | 576.9 | 557.1 | *590* | *630* | Revenues ($mill) | *750* |
| 29.5 | 21.8 | 23.8 | 39.9 | 33.2 | 39.7 | 41.3 | 47.4 | 55.0 | 55.7 | *60.0* | *65.0* | Net Profit ($mill) | *80.0* |
| 34.5% | 34.1% | 33.4% | 35.4% | 30.3% | 32.5% | 32.5% | 39.2% | 38.4% | 38.0% | *38.0%* | *38.0%* | Income Tax Rate | *38.0%* |
| 1.0% | 1.0% | 2.4% | 10.7% | 23.1% | 31.5% | 34.2% | 21.5% | .9% | 3.5% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *1.0%* |
| 52.0% | 51.3% | 51.0% | 49.7% | 50.1% | 53.6% | 51.6% | 51.3% | 49.9% | 49.1% | *53.0%* | *51.5%* | Long-Term Debt Ratio | *51.5%* |
| 48.0% | 48.7% | 49.0% | 50.3% | 49.9% | 46.4% | 48.4% | 48.7% | 50.1% | 50.9% | *47.0%* | *48.5%* | Common Equity Ratio | *48.5%* |
| 789.2 | 779.1 | 803.3 | 931.0 | 1081.1 | 1140.4 | 1240.3 | 1350.7 | 1386.2 | 1409.4 | *1585* | *1640* | Total Capital ($mill) | *1825* |
| 833.9 | 857.0 | 896.0 | 1031.0 | 1178.9 | 1342.8 | 1459.0 | 1519.1 | 1563.7 | 1657.6 | *1745* | *1835* | Net Plant ($mill) | *1950* |
| 5.7% | 4.7% | 4.7% | 5.9% | 4.7% | 5.2% | 5.2% | 5.1% | 5.5% | 5.4% | *5.0%* | *5.0%* | Return on Total Cap'l | *5.5%* |
| 7.8% | 5.8% | 6.0% | 8.5% | 6.2% | 7.5% | 6.9% | 7.2% | 7.9% | 7.8% | *8.0%* | *8.0%* | Return on Shr. Equity | *8.5%* |
| 7.8% | 5.8% | 6.0% | 8.5% | 6.2% | 7.5% | 6.9% | 7.2% | 7.9% | 7.8% | *8.0%* | *8.0%* | Return on Com Equity [E] | *8.5%* |
| .1% | NMF | NMF | .8% | NMF | NMF | NMF | NMF | 4.1% | 1.9% | *2.5%* | *2.5%* | Retained to Com Eq | *2.5%* |
| 99% | NMF | NMF | 90% | 117% | 109% | 109% | 110% | 49% | 76% | *72%* | *69%* | All Div'ds to Net Prof | *71%* |

CAPITAL STRUCTURE as of 3/31/13
Total Debt $715.1 mill. Due in 5 Yrs $49.9 mill.
LT Debt $691.6 mill. LT Interest $39.8 mill.
Incl. $4.4 mill. capitalized leases.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $.8 mill.
Pension Assets-12/12 $160.2 mill.
Oblig. $248.0 mill.
Pfd Stock None

Common Stock 42,668,138 shs.
as of 4/30/13

MARKET CAP: $925 million (Small Cap)

ELECTRIC OPERATING STATISTICS

| | 2010 | 2011 | 2012 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +6.1 | -2.3 | -3.2 |
| Avg. Industrial Use (MWH) | 2813 | 2865 | 2913 |
| Avg. Industrial Rev/KWH (¢) | 6.92 | 7.72 | 7.66 |
| Capacity at Peak (Mw) | 1409 | 1392 | 1391 |
| Peak Load, Summer (Mw) | 1199 | 1198 | 1142 |
| Annual Load Factor (%) | 53.2 | 52.0 | 52.2 |
| % Change Customers (avg.) | +.4 | -1.5 | +.6 |
| Fixed Charge Cov. (%) | 248 | 307 | 314 |

ANNUAL RATES of change (per sh)

| | Past 10 Yrs. | Past 5 Yrs. | Est'd '10-'12 to '16-'18 |
|---|---|---|---|
| Revenues | -.5% | -1.5% | *3.5%* |
| "Cash Flow" | 1.5% | 3.0% | *5.0%* |
| Earnings | 2.0% | 2.0% | *5.0%* |
| Dividends | -2.5% | -5.5% | *3.5%* |
| Book Value | 1.5% | 1.0% | *2.5%* |

QUARTERLY REVENUES ($ mill.)

| Calendar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2010 | 139.9 | 114.5 | 154.1 | 132.8 | 541.3 |
| 2011 | 150.7 | 129.1 | 164.3 | 132.8 | 576.9 |
| 2012 | 137.2 | 131.6 | 159.2 | 129.1 | 557.1 |
| 2013 | 151.1 | *130* | *165* | *143.9* | *590* |
| 2014 | *160* | *140* | *175* | *155* | *630* |

EARNINGS PER SHARE [A]

| Calendar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2010 | .22 | .18 | .55 | .20 | 1.17 |
| 2011 | .29 | .22 | .60 | .21 | 1.31 |
| 2012 | .23 | .25 | .60 | .23 | 1.32 |
| 2013 | .30 | *.26* | *.62* | *.22* | *1.40* |
| 2014 | *.32* | *.28* | *.63* | *.22* | *1.45* |

QUARTERLY DIVIDENDS PAID [B] ■ †

| Calendar | Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2009 | .32 | .32 | .32 | .32 | 1.28 |
| 2010 | .32 | .32 | .32 | .32 | 1.28 |
| 2011 | .32 | .32 | -- | -- | .64 |
| 2012 | .25 | .25 | .25 | .25 | 1.00 |
| 2013 | .25 | .25 | | | |

**BUSINESS:** The Empire District Electric Company supplies electricity to 167,000 customers in a 10,000 sq. mi. area in Missouri (89% of '12 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acquired Missouri Gas (43,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Electric revenue breakdown: residential, 43%; commercial, 30%; industrial, 15%; other, 12%. Generating sources: coal, 48%; gas, 25%; hydro, 1%; purchased, 26%. Fuel costs: 35% of revenues. '12 reported deprec. rate: 2.9%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

**Empire District Electric's earnings are likely to advance solidly in 2013.** The primary reason is the $27.5 million (6.8%) electric rate increase in Missouri, which took effect at the start of April. The recovery in the utility's service area (see below) is another plus. And the company will reap a full year's benefit from the $450,000 water tariff hike that took effect last November. All told, the bottom line should climb nicely, despite the pretax writedown of $2.4 million that Empire District took in the March quarter. Our earnings estimate is near the high end of the company's targeted range of $1.26-$1.43 a share, which we regard as conservative. The stock is ranked 2 (Above Average) for Timeliness.

**The recovery in the company's service territory is continuing.** Joplin, Missouri was devastated by a tornado in May of 2011. Thousands of homes and businesses were destroyed, as well as the city's high school and one of its hospitals. As of the end of the first quarter, thanks to rebuilding and growth in other parts of Empire District's service area, the customer count was only about 100 less than the figure at the time of the tornado. There is still a way to go, however. The high school won't be completed until next year, and the hospital until early 2015.

**We estimate modest earnings growth in 2014.** A full year of the aforementioned electric rate increase and the service area's recovery should be the key factors. We forecast a profit increase of 4%.

**Financing needs are moderate.** In the second quarter, Empire District issued $150 million of long-term debt. Most of this was for the retirement of debt that was due in June. The company's next financing move probably won't come until late 2014; we are estimating an equity offering. Management's goal is to maintain roughly a 50/50 split between debt and equity.

**Empire District offers a dividend yield that is above average, even by utility standards.** However, because the payout ratio is on the high side for a utility, we look for no dividend increase until 2015. Total return potential to 2016-2018 is low, but about average for the electric utility industry.

*Paul E. Debbas, CFA* *June 21, 2013*

(A) Diluted earnings. Excl. loss from disc. ops.: '06, 2¢. '10 EPS don't add due to change in shs., '11 & '12 due to rounding. Next earnings report due late July. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% disc.). † Shareholder investment plan avail. (C) Incl. intang. In '12: $6.85/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '13: none specified; earned on avg. com. eq., '12: 7.9%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 85 |

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document

Xcel Energy
Case No.: PU-12-813
Response To: North Dakota Public Service Commission
Data Request No. NDPSC-5-014
Requestor: Snavely King
Date Received: March 29, 2013

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Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Provide monthly balances beginning in January 2013, of NSP-NDO Balance Sheets and Income Statements; continue to update throughout the rate proceeding.

Response:

The Company respectfully objects to this request as unduly burdensome as the Company does not prepare monthly balance sheets and income statements for individual jurisdictions such as North Dakota. Preparation of such information on a monthly basis is unduly burdensome.

The NSPM FERC Form 1 will be provided as part of our response to NDPSC-5-2 and the NSPM FERC Form 3 for the first quarter of 2013 will be provided after its submission to FERC. Also please see the Company's response to NDSPC-5-13 for the North Dakota jurisdictional reports.

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Preparer: Karen Everson
Title: Director Utility Accounting
Department: NSP Utility Accounting
Telephone: 715-737-2417
Date: April 12, 2013

☐ Non Public Document – Contains Trade Secret Data
☐ Public Document – Trade Secret Data Excised
☒ Public Document


Xcel Energy
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Data Request No. NDPSC-5-065
Requestor: Snavely King
Date Received: March 29, 2013

---

Question:

Witness: Anne E. Heuer-Revenue Requirement (Exhibit AEH-1)

Please refer to the Interim Rate increase approved by the NDPSC on January 30, 2013, in the amount of $14,704,000 (8.05%), and provide the monthly incremental sales revenues collected from customers beginning on February 16, 2013, and continuing throughout the rate proceeding. Please also provide the breakdown of the incremental sales revenues by class of customer and by fixed cost/usage, and any other approved charges.

Response:

Attachment A identifies the monthly billed, net unbilled, and calendar interim rate revenues in February 2013 and March 2013. The revenues are broken down by customer class; however, since the interim rate revenues are computed as a percentage of total non-fuel charges and appear as a single line on the customers' bills, no further breakdown is available. Consistent with other requests for monthly updates, the Company is willing to supplement this response in June with April and May data.

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Preparer: Karen Everson
Title: Director, Utility Accounting
Department: NSPM Utility Accounting
Telephone: 715-737-2417
Date: May 9, 2013

**NSP-Minnesota**
**North Dakota Interim Electric Revenues**

**Case No. PU-12-813**
**Data Request NDPSC 5-65**
**Attachment A, Page 1 of 1**

**Billed Interim Rate Revenues**

| | Feb-13 | Mar-13 | YTD 2013 |
|---|---|---|---|
| Residential | $ 51,892 | $ 418,250 | $ 470,142 |
| Commercial and Industrial | 57,382 | 499,525 | 556,907 |
| Public Street and Highway Lighting | 777 | 7,432 | 8,209 |
| Sales to Public Authorities | 123 | 3,999 | 4,122 |
| | $110,174 | $929,206 | $1,039,380 |

**Net Unbilled Interim Rate Revenues**

| | Feb-13 | Mar-13 | YTD 2013 |
|---|---|---|---|
| Residential | $ 270,937 | $ 21,075 | $ 292,012 |
| Commercial and Industrial | 402,173 | 572 | 402,745 |
| Public Street and Highway Lighting | 11,093 | (1,704) | 9,389 |
| Sales to Public Authorities | 7,093 | 556 | 7,649 |
| | $691,296 | $20,499 | $711,795 |

**Calendar Interim Rate Revenues**

| | Feb-13 | Mar-13 | YTD 2013 |
|---|---|---|---|
| Residential | $ 322,829 | $ 439,325 | $ 762,154 |
| Commercial and Industrial | 459,555 | 500,097 | 959,652 |
| Public Street and Highway Lighting | 11,870 | 5,728 | 17,598 |
| Sales to Public Authorities | 7,216 | 4,555 | 11,771 |
| | $801,470 | $949,705 | $1,751,175 |


**Case No. PU-12-813**
**Michael J. Majoros, Jr.**
**Opening Statement**
**August 29, 2013**

My name is Michael J. Majoros, Jr. I am the advocacy staff's witness on depreciation. I have testified before this Commission on several occasions, the last time in Case No. PU-07-776. I was the staff's revenue requirement witness in that case which included a discussion of depreciation. Depreciation was one of the primary issues in case No. PU-07-776.

The thrust of my direct and supplemental testimony in this case is to obtain the transparency and accountability North Dakota ratepayers deserve regarding the cash flow they provide to NSPM thru depreciation charges.

Depreciation is a ratemaking mechanism used to transfer cash from ratepayers to a utility to pay for the investment it made in property plant and equipment. Depreciation is an after the fact return of capital, accomplished using a constant depreciation rate over the life of the property plant and equipment.

When a utility includes depreciation in its revenue requirement, it provides cash flow to the utility, since there it is a non-cash expense, i.e. a return of a previous expenditure. The higher the depreciation rate, the greater the cash flow. Yesterday, Mr. Tyson discussed investor expectations. He explained that cash flow is an important factor to investors, since the greater the cash flow the less the future dilution of stock prices.

I have prepared an example to show the difference between the Company's accrual basis return, which Ms. Heuer discussed, and its cash basis rates of return for 2011 and 2012. The cash basis rates of return far exceed the accrual basis returns. Depreciation is one of the primary contributors to this cash flow.

Getting back to depreciation rates, somewhere along the line, utilities were successful in increasing the depreciation rate to account for future cost of removal on the grounds of intergenerational equity. That is, current ratepayers should pay more now to protect future ratepayers from overpaying.

As a result, depreciation rates were increased to account for future costs and then increased again by using inflated future costs thus further increasing the cash transfer from ratepayers to the utility.

In 2002, the professional accounting community and the SEC expressed their displeasure with this practice. Normal companies are not allowed to include future cost estimates in current depreciation rates, inflated or otherwise. The professional accountants determined that it was folly to charge current periods for future costs that would not be incurred. Thus, if a company has a legal obligation to incur a future removal cost, it is required to capitalize that cost at its present value and charge it to expense over the life of the asset, just as any other capital expenditure.

Not only did professional accountants reaffirm that normal businesses were not allowed to include future cost estimates in current depreciation rates, it demonstrated its disdain for the practice by requiring regulated utilities to report the excess non-legal collections as regulatory liabilities. Specifically, as amounts owed to ratepayers if they were not spent on their intended purpose.

As a result of these GAAP changes, NSPM reported a $432 million regulatory liability in its 2012 SEC form 10K, and its annual report to shareholders. NSPM owes its ratepayers $432 million for cash it has collected for cost of removal that it has not incurred. That is, $432 million over and above the actual money it has spent for cost of removal. The excess $432 million is not in a bank account somewhere as is the case with the nuclear fund, instead, it went somewhere else, and we do not know where. It is part of the free cash flow embedded in ratemaking service rates as explained earlier.

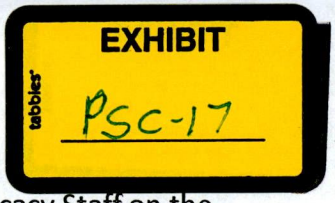
The only thing ratepayers have by way of transparency and accountability is the regulatory liability reported in GAAP financial statements, but not in the reports to this Commission.

In Case No. PU-07-776, the staff and the Company reached an agreement which staff thought would provide such accountability and transparency. We believe the Company has failed to comply with the Case No. 07-776 stipulation.

So, the primary thrust of my current testimony is to obtain, by Commission recognition and Order, the transparency and accountability that North Dakota ratepayers deserve regarding the additional free cash flow they have provided to the Company for unincurred future costs.

Ms. Perkett's testimony concerns me as she asserts that NSPM reports the $432 million regulatory liability in its GAAP financial statements as a result of the settlement in Case No. 07-776. That is not true. NSPM reports a $432 million regulatory liability in its GAAP financial statements because the professional accounting community and the SEC recognize that NSPM owes that money back to its ratepayers. It has nothing to do with net versus gross plant.

So, my bottom line is that, given these facts, the least North Dakota ratepayers should be able to expect is that the Company identify the rates and amounts involved and properly report its regulatory liability to this Commission for further scrutiny.




Good Morning. My name is Charles King. I am here representing Advocacy Staff on the subject of rate of return.

I recommend a rate of return on equity for NSP's North Dakota rate base of 9.0 percent. The basis of this recommendation is set forth in my testimony and exhibits. The reasons why I arrive at 9.0 percent while Ms. Bulkley comes up with 10.25 percent are listed in the last pages of my testimony. I will not repeat them here.

The Company's response to my recommendation essentially boils down to two points: first, that interest rates are increasing and second, that 9.0 percent is way below the return awards being granted to other utilities.

Ms. Bulkley would have you believe that interest rates are skyrocketing. That's something of an exaggeration. Here are the numbers: In July, the average yield on 30 year Treasury bonds was 3.61 percent, last week it was 3.87 percent, higher but hardly skyrocketing. In July Baa rated corporate bonds were yielding 5.32 percent; last week they at 5.55 percent, again hardly a skyrocketing increase. Ms. Bulkely admits that as interest rates increase, the spread between bond yields and stock returns narrows. If that is the case, then the 20 point increase in interest rates translates to a much smaller increase in ROE requirements.

Ms. Bulkley also points to forecasts of much higher interest rates, with long-term Treasuries over five percent in few years. The problem here is that analysts have been forecasting the interest rate increases for years, and they have yet to materialize. The Federal

Reserve has made clear that it will not allow interest rates to increase significantly until the unemployment rate falls below six percent. Sadly, we are still a long way from that goal.

The Company has placed its greatest emphasis on its second objection, that a 9.0 percent return would be lower than all but one return awarded in the last year and a half.

In my testimony, I guard against relying on other commissions' returns on the grounds that it makes regulation circular: decisions based on other decisions do not allow for objective evidence that departs from the conventional wisdom of the regulatory community.

My response to NSP's complaint is two-fold: first, objective evidence does indicate that the appropriate return is well below the average of allowed returns during the past year, and second, objective evidence suggests that the average awarded return is too high.

The objective evidence supporting a lower return is in my testimony. I did not invent a single number in that testimony and exhibit. Every number came from an outside, objective source that has no particular interest in skewing equity returns up or down. Those numbers show quite clearly that a return of approximately 9.0 percent is all that investors require at this time.

The objective evidence that currently allowed returns are unnecessarily high is found in my exhibit CWK-2, Schedule 4, page 2, column C. That column shows the ratios of the market price of each company's stock to the book value of that stock. ROE awards are applied to the book value of each utility's plant. If regulators are granting the exact return on book value that investors require, then the amount they are willing for the company's stock should equal that

book value. But it does not. In every case, the returns on book value are such that investors are bidding the market value of utility stocks will over the book value. In Xcel's case the market value of its stock is 153 percent of its book value, but they run as high as 225 percent. That persistent excess of market over book value indicates fairly clearly that the utility returns exceed considerably the minimum requirements of investors. The 10 percent that regulators have been granting is clearly excessive.

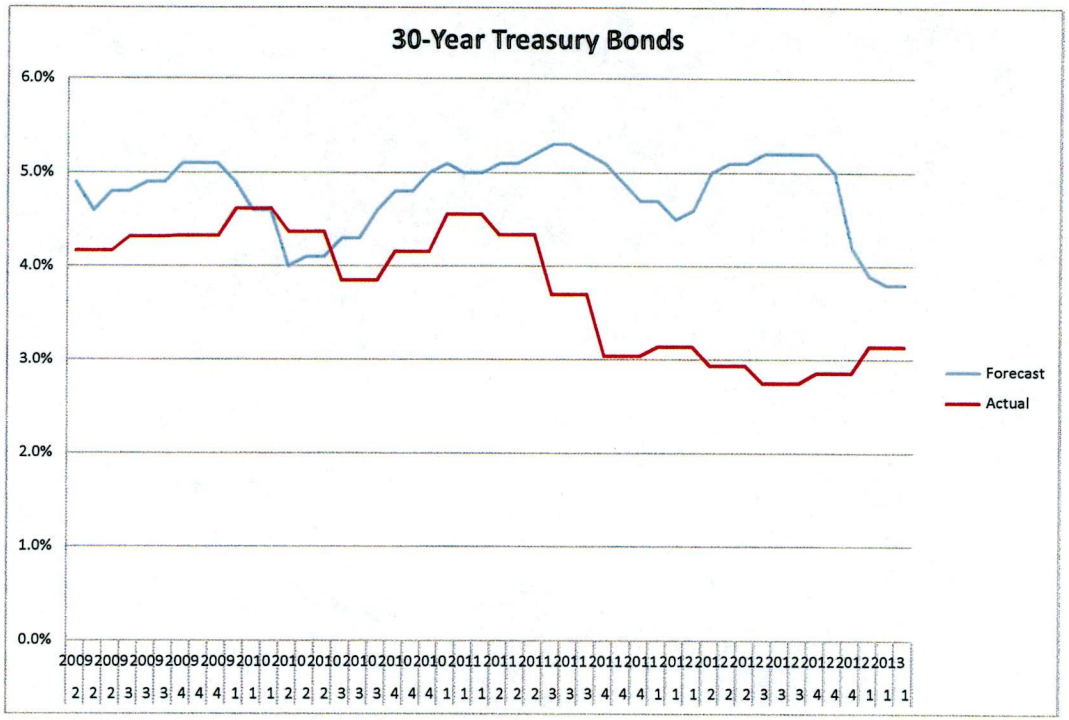
You have been told that a nine percent return award will result in North Dakota being downgraded as an investor unfriendly regulatory environment. This challenge raises the question of your responsibility. Are you responsible to the investor community to provide an ROE award you make pleases them? Or, are you responsible to the citizens of North Dakota to ensure that they pay rates sufficient, but no more than sufficient, to allow the Company attract capital and maintain credit? If your responsibility is to the citizens of North Dakota, then you will award a 9.0 percent regardless of what the investment community thinks.

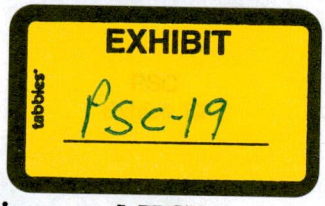



**Blue Chip Financial Forecasts**
**30 Year Treasury Bonds Forecast vs. Actual**

Fed Res historical record

| Foreecast Made in | | | For Quarter | | Actual | Error |
|---|---|---|---|---|---|---|
| Jan | 2008 | 2 | 2009 | 4.9% | 4.17% | 0.73% |
| Feb | 2008 | 2 | 2009 | 4.6% | 4.17% | 0.43% |
| Mar | 2008 | 2 | 2009 | 4.8% | 4.17% | 0.63% |
| Apr | 2008 | 3 | 2009 | 4.8% | 4.32% | 0.48% |
| May | 2008 | 3 | 2009 | 4.9% | 4.32% | 0.58% |
| June | 2008 | 3 | 2009 | 4.9% | 4.32% | 0.58% |
| July | 2008 | 4 | 2009 | 5.1% | 4.33% | 0.77% |
| Aug | 2008 | 4 | 2009 | 5.1% | 4.33% | 0.77% |
| Sept | 2008 | 4 | 2009 | 5.1% | 4.33% | 0.77% |
| Oct | 2008 | 1 | 2010 | 4.9% | 4.62% | 0.28% |
| Nov | 2008 | 1 | 2010 | 4.6% | 4.62% | -0.02% |
| Dec | 2008 | 1 | 2010 | 4.6% | 4.62% | -0.02% |
| Jan | 2009 | 2 | 2010 | 4.0% | 4.37% | -0.37% |
| Feb | 2009 | 2 | 2010 | *4.1%* | 4.37% | -0.27% |
| Mar | 2009 | 2 | 2010 | 4.1% | 4.37% | -0.27% |
| Apr | 2009 | 3 | 2010 | 4.3% | 3.85% | 0.45% |
| May | 2009 | 3 | 2010 | 4.3% | 3.85% | 0.45% |
| June | 2009 | 3 | 2010 | 4.6% | 3.85% | 0.75% |
| July | 2009 | 4 | 2010 | *4.8%* | 4.16% | 0.64% |
| Aug | 2009 | 4 | 2010 | *4.8%* | 4.16% | 0.64% |
| Sept | 2009 | 4 | 2010 | 5.0% | 4.16% | 0.84% |
| Oct | 2009 | 1 | 2011 | 5.1% | 4.56% | 0.54% |
| Nov | 2009 | 1 | 2011 | 5.0% | 4.56% | 0.44% |
| Dec | 2009 | 1 | 2011 | 5.0% | 4.56% | 0.44% |
| Jan | 2010 | 2 | 2011 | *5.1%* | 4.34% | 0.76% |
| Feb | 2010 | 2 | 2011 | *5.1%* | 4.34% | 0.76% |
| Mar | 2010 | 2 | 2011 | 5.2% | 4.34% | 0.86% |
| Apr | 2010 | 3 | 2011 | 5.3% | 3.70% | 1.60% |
| May | 2010 | 3 | 2011 | 5.3% | 3.70% | 1.60% |
| June | 2010 | 3 | 2011 | 5.2% | 3.70% | 1.50% |
| July | 2010 | 4 | 2011 | 5.1% | 3.04% | 2.06% |
| Aug | 2010 | 4 | 2011 | 4.9% | 3.04% | 1.86% |
| Sept | 2010 | 4 | 2011 | 4.7% | 3.04% | 1.66% |
| Oct | 2010 | 1 | 2012 | 4.7% | 3.14% | 1.56% |
| Nov | 2010 | 1 | 2012 | 4.5% | 3.14% | 1.36% |
| Dec | 2010 | 1 | 2012 | 4.6% | 3.14% | 1.46% |
| Jan | 2011 | 2 | 2012 | 5.0% | 2.94% | 2.06% |
| Feb | 2011 | 2 | 2012 | *5.1%* | 2.94% | 2.16% |
| Mar | 2011 | 2 | 2012 | *5.1%* | 2.94% | 2.16% |
| Apr | 2011 | 3 | 2012 | 5.2% | 2.75% | 2.45% |
| May | 2011 | 3 | 2012 | 5.2% | 2.75% | 2.45% |
| June | 2011 | 3 | 2012 | 5.2% | 2.75% | 2.45% |
| July | 2011 | 4 | 2012 | 5.2% | 2.86% | 2.34% |
| Aug | 2011 | 4 | 2012 | 5.0% | 2.86% | 2.14% |
| Sept | 2011 | 4 | 2012 | 4.2% | 2.86% | 1.34% |
| Oct | 2011 | 1 | 2013 | 3.9% | 3.14% | 0.76% |
| Nov | 2011 | 1 | 2013 | 3.8% | 3.14% | 0.66% |
| Dec | 2011 | 1 | 2013 | 3.8% | 3.14% | 0.66% |






**Karl Richard Pavlovic**
**Jurisdictional and Class Cost Allocation, Rate Design, and TCR**
**Evidentiary Hearing Opening Statement**
**Case No. PU-12-813**

My name is Karl Richard Pavlovic. My testimony addresses, on behalf of the Commission's Advocacy Staff, the assertions and proposals in this proceeding by Northern States Power regarding its North Dakota jurisdictional and class costs of service, rate design, and proposed Transmission Cost Recovery (TCR) tracker.

In my testimony I conclude that NSP's jurisdictional cost assignment methods and procedures are, with the exception of the use of a 12 coincident peak demand allocator, appropriate and in accordance with the principles enunciated in the NARUC Cost Allocation Manual. The 12 coincident peak demand over-allocates system costs to the North Dakota jurisdiction. I also conclude that NSP's class cost assignment methods and procedures are appropriate and consistent with the NARUC cost allocation principles and that NSP's proposed customer class revenue distribution is cost based and reasonable. While the class cost study does not directly support the current rate structure, NSP's proposed modifications to the rate components, moving customer and demand charges towards full cost recovery, are appropriate and reasonable. NSP's rate structure, however, is overly complex and the tariff is virtually incomprehensible. Finally, I conclude that NSP's application for a Transmission Cost Recovery rider does not comport with the statutory requirements for Commission consideration and lacks a demonstration that the costs proposed for the tracker meet the criteria for inclusion in a tracker.

There are 13 generally accepted methods for the allocation of electric production costs and 6 generally accepted methods for the allocation of electric transmission costs. The primary factor considered in selection of an allocation method is cost causation as reflected in the planning and

operation of an electric utility's production and transmission facilities. The primary drivers/metrics of cost causation on electric production and transmission facilities are demand and energy. Selection of an allocation method consists of determining which method best reflects the utility's actual system planning and operation. My testimony provides explanations and illustrations of each of these points drawn from the NARUC Manual.

In my testimony I assess the 12 Coincident Peak (12CP) demand allocator that Northern States Power uses to effect its jurisdictional allocation of production and transmission costs and recommended that NSP use a Single Coincident Peak (1CP) demand allocator. My assess is based on my review of cost allocation and system planning documents and other information provided by NSP in testimony and discovery.

The 12CP method is considered appropriate where system monthly peak demand does not vary significantly or where the utility plans and operates its facilities so as to maintain equal reserve margins, LOLPs or other reliability index values in all months. As regards variation in monthly peak demand, NSP is a strongly summer peaking system and there is considerable variation in its monthly peak demand. As regards equal monthly reliability indexes, there is in the documents and information I reviewed no indication or explanation that NSP plans and operates its system to maintain equal monthly reliability indexes.

In fact, other than statements that NSP uses the 12CP method to allocate production and transmission, there is in the documents and information that I reviewed no indication or explanation that NSP plans and operates its production and transmission facilities to anything other than its annual system peak demand. In addition there are allocation methods explained in the NARUC Manual that are designed to account for timing and cost differences among baseload, intermediate, and peaking production facilities. NSP does not use any of these other allocation methods. For

these reasons I conclude that 1CP is the appropriate method for allocation of NSP's production and transmission costs to the North Dakota jurisdiction.


I/M/O the Application of the Northern States Power Company
For Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-12-813

Opening Statement

My name is Dante Mugrace. I am a Senior Consultant with the Economic and Management Consulting Firm of Snavely-King Majoros and Associates, Inc. Our Offices is located in Landover MD. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service Commission. I have provided testimony with respect to the Company, Northern States Power Company's, Revenue Requirement for its Electric Service operations in North Dakota.

My approach in calculating the recommended revenue requirement is based upon the use of a three year historical average (2010, 2011, and 2012, for the Company's Other Operating Revenues and its Operating Expenses. The use of a three year average provides for:

- A normalized level of its Other Operating Revenues which takes into consideration the variations and fluctuations occurring year to year, and operating cycle to operating cycle, and provides for a smoothening of Other Operating Revenues going forward.

- A normalized level of Operating Expenses which takes into consideration the variations and fluctuations occurring year to year, and operating cycle to operating cycle, and provides for a smoothening of expenses going forward.

- The results of a three year historical average approach provides the basis to set a foundational level related to the Company's Other Operating Revenues and Operating Expenses instead of the Company's 2013, fully forecasted test approach for its financial data. The main factor for the use of a three year historical average is that the Company does not produce interim or semi-annual financial statements. It is therefore difficult to test whether the Company's projections are comparable and reliable with known actual results. I also have taken into consideration and made

recommendations regarding the Company's forecasted and individual 2013 adjustments to its Other Operating Revenues and its Operating Expenses.

- For the setting of the Company's Retail Operating Revenues I've relied on the Company's Notice (Schedule 2) which the Company has projected total MWH Sales of 2,270,721. Based upon Company data requests (ND-PSC 5-025, which shows 5 months of usage as of May 2013 and annualized at 2,436,000 MWH) it is clear that MWH Sales have increased since the Company filed its Rate Case proceeding in December 2012. I have used a percentage factor of a 1.54% increase as described in my testimony to set projected MWH Sales in 2013 along with an historical average of three years of Kwh costs at 7.68 cents to compute my recommended Sales Revenues of $177,077,000.

My approach to the Company's proposed Rate Base is the use of the Company as filed 2012 Earnings Report for the North Dakota Jurisdiction, which shows the Plant in Service Average Balance. I've taken into account the Company's various proposed and forecasted adjustments expected to occur in 2013 as shown on Company Exhibit AEH-1 Schedule 5 I have also taken into account and have accepted the Company's various data responses with regard to its North Dakota Jurisdictional capital additions for 2013 and applied the Company's allocation factor applicable to the North Dakota Operations to compute a projected capital plant addition balance that is expected to be placed in service for 2013.

Based upon this approach, my recommendation is a Rate Base balance of $326,528,000 and a Rate of Return as recommended by Witness Charles King, of 7.138% which calculates to a Utility Operating Income of $23,307,000. The recommended ratemaking components calculates to an overall revenue requirement decrease of $9,999,000, as opposed to the Company's revenue requirement increase of $14,884,000 as calculated by Company Witness Ms. Heuer in her Rebuttal Testimony.

I have relied on the testimony of Michael Majoros regarding the recommended Depreciation Expense to include in my revenue requirement calculation and on the testimony of Dr. Karl Pavlovic regarding the various

jurisdictional allocators to the Company's Rate Base Components and certain of the Company's Operating Expenses.


Sara Cardwell
Evidentiary Hearing Opening Statement
Case No. PU-12-813

I am a Public Utility Analyst with the North Dakota Public Service Commission and am appearing on behalf of advocacy staff. The purpose of my testimony is to express concerns on the part of the advocacy staff as to NSP's spending that has caused the Company to ask for increases from customers for a 2008, 2011, 2012 and now a 2013 test period.

In the Company's rebuttal, Vice President McCarten states that the Company is considering the ratepayer and points to their offer to spread the 2008 market losses in their pension plan over multiple years. Yet this is a very small component of the rate case and we don't know how postponing this small amount may affect a future increase. She also points to two projects, the Black Dog Repowering and the Prairie Island uprate that the Company cancelled as cost reduction programs. However, the primary reason the Company cancelled these projects was because the load growth that necessitated them didn't materialize.

And, when questioned by Commissioner Fedorchak Ms. McCarten indicated that the Company will have at least two more years of significant spending as they complete their nuclear projects and the CAPX2020 projects. In summary, the Company has not alleviated our concerns regarding cost control.