# BOMA INTERROGATORY 2

2.0 Usage Fee

## INTERROGATORY

Ref Business Plan, Page 1

Please confirm that the nine percent reduction is from the combined usage fees of the IESO and OPA in 2015.

## RESPONSE

The table below shows the calculation of the nine percent reduction of 2016 usage fees from the combined usage fees of the IESO and OPA in 2015:

| | **2015** | | | **2016** | |
|---|---|---|---|---|---|
| | OPA | IESO | Combined | RRS | Savings in % |
| Usage Fee | 0.438 | 0.803 | 1.241 | 1.13 | 9% |

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# BOMA INTERROGATORY 28

2.0 Usage Fee

## INTERROGATORY

Ref. Exhibit B, Tab 1, Schedule 1, Page 3, Line 9

(a) Why does the IESO think that changing its fee including the "OPA component" of its fee to all customers irrespective of the proportion of distributed generation within the distribution company service territory will treat customers more equitably than the "current regime"?

(b) Would not the current practice under which the OPA charged its usage fee to distributors on a net basis? That is net of volumes produced by embedded generation, coupled with a requirement that distributors pass the savings (or a part thereof along pro rata to its customers that have embedded generation provide an incentive for customers to invest in distributed generation, including renewable distributed generation, a result which is consistent with the government's renewable energy/GHG policies, and provides benefits to the grid.

## RESPONSE

a) When the IESO sought and was granted approval to charge its fee to embedded generation in its 2014 fee application (EB-2013-0381), its evidence and interrogatory responses included the following points which continue to be relevant to the current proposal to charge the new IESO fee to embedded generation:

- The IESO is not only responsible for administering the transmission grid and wholesale market, but also for facilitating the incorporation of large amounts of distribution-connected embedded generation into the IESO's reliable operation of the provincial electricity system and managing contracts with embedded generators.

- There is no distinguishable difference between the IESO costs caused by customers served by distributors with embedded generation as compared to those without embedded generation.

- All LDC customers will be treated equally by paying the IESO fee based on the same charge determinant – i.e. their total consumption — irrespective of what portion is supplied by embedded vis-à-vis directly-connected generation.

- Customers of LDCs with large amounts of embedded generation will no longer receive a discount in the amount of usage fee that they pay.

- The amount of embedded generation in Ontario is expected to continue to increase in materiality. The IESO believes the proposed change in methodology more fairly reflects the changing nature of the grid.

- Also it should be noted that customers of an LDC with embedded generation do not pay transmission charges for energy generated within the LDC; the IESO's proposal will not change this.

b) The IESO believes that to the extent possible, parties should bear the costs they cause. Although the IESO is supportive of distributed generation, the IESO considers it appropriate for the business case for such a facility to be based on the actual costs incurred or avoided by that facility. As such, the IESO considers it appropriate for customers of LDCs with embedded generation to no longer receive a discount in the amount of usage fee that they pay, given that this discount does not reflect any cost reductions to the IESO for these customers. Please also see the response to part a) above. In addition, it should be noted that with the current regime, the subsidy is received by all customers of the LDC rather than the LDC itself or the embedded generator. If an incentive is desired, this is an ineffective design.

# ENERGY PROBE INTERROGATORY 8

2.0 Usage Fee

## INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Page 6, Table 2

a) IESO is proposing to charge a Single fee of $1.13. Can IESO provide a breakdown of what the fee would be if the OPA portion of costs was still billed on a net rather than a gross basis?

b) Please provide in a single table, the historic forecast and actual (2011-2015) and 2016 forecast TWH for the three user classes.

c) Based on historic experience provide a sensitivity analysis for 2016 for the three components and discuss the result.

d) How will IESO "true up" its 2016 Fees if one or more of the TWH forecasts is in error?

## RESPONSE

a) The IESO is unable to split out the OPA portion of costs, as since the merger of the IESO and OPA on January 1, 2015, the organization has operated as a single entity with one set of books. As stated in Exhibit A-1-1, page 3, "As the merger of the IESO and OPA took effect on January 1, 2015... the IESO only recorded IESO expenses in 2015, no expenses in 2015 were recorded as OPA expenses." Therefore, the OPA portion of costs cannot be broken out as requested.

b) In this answer the IESO assumes that the three "user classes" referred to in question (b) are Ontario demand, exports and embedded generation.

| Year | Source | Ontario Demand (TWh) | Exports (TWh) | Embedded Generation (TWh) |
|---|---|---|---|---|
| **2010** | Forecast (18-Month Outlook released 2009/08/25) | 141.1 | 10.0 | N/A |
| | Actual | 142.2 | 15.2 | 2.3 |
| **2011** | Forecast (18-Month Outlook released 2010/08/23) | 142.9 | 12.9 | N/A |
| | Actual | 141.5 | 12.8 | 2.9 |
| **2012** | Forecast (18-Month Outlook released 2011/08/24) | 144.5 | 156.4 | N/A |
| | Actual | 141.3 | 14.6 | 3.3 |
| **2013** | Forecast (18-Month Outlook released 2012/09/12) | 141.1 | 152.2 | 4.8 |
| | Actual | 140.7 | 18.3 | 4.3 |
| **2014** | Forecast (18-Month Outlook released 2013/09/03) | 141.0 | 152.4 | 5.6 |
| | Actual | 139.8 | 19.1 | 5.2 |
| **2015** | Forecast (18-Month Outlook released 2014/09/04) | 138.8 | 149.4 | 6.7 |
| | Actual | 137.0 | 22.6 | 6.2 |
| **2016** | Forecast (18-Month Outlook released 2015/09/21) | 138.7 | 153.5 | 6.6 |

*Note: The forecast of export volumes is created by the IESO for the purpose of our revenue requirement submission.*

c) The three components are added together to form the denominator of the IESO fee. Any change in the components will have an equal impact on the denominator.

d) The IESO utilizes the $10 million contingency fund and/or tracks the amounts and any associated borrowing costs in the Forecast Variance Deferral Account ("FVDA"). Please see the response to Energy Probe Interrogatory 11, at Exhibit I, Tab 4, Schedule 5.11 for the process associated with truing up FVDA balances.

# ENERGY PROBE INTERROGATORY 9

2.0 Usage Fee

## INTERROGATORY

Reference: Business Plan Exhibit A-2-2, Business Plan Page 10

a) Does IESO have any evidence that breaks down the cost to the Agency's Operations by class of generators and the Supply Mix (gas, solar, wind, nuclear and hydro)?

b) Does IESO have any studies that delineate operating costs based on more (or less) embedded generation? If so, please provide these.

## RESPONSE

a) The IESO does not track operational costs in a manner that would allow for breakdowns as requested.

b) The IESO has not conducted any studies that delineate IESO operating costs based on more (or less) embedded generation.

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*Report for*

# American Public Power Association (APPA)

# Electric Market Reform Initiative (EMRI) Task 2 Analysis of Operational and Administrative Cost of RTOs

*February 5, 2007*

*Prepared by:*

GDS Associates, Inc.
Engineers and Consultants

**Contact Person:**

*William M. Bateman*
Project Manager, Transmission Services
770-425-8100

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D1 - California ISO
D2 - ISO New England
D3 - Midwest ISO
D4 - New York ISO
D5 - PJM
D6 - Southwest Power Pool

## Appendix E - Data Sources

# 1.0 Executive Summary

This report serves as an examination of the costs incurred by the nation's Regional Transmission Organizations ("RTOs"). These costs, which include operational and administrative costs, are recovered from users of the transmission system and participants in electricity markets. RTOs typically go through three major stages of development: Pre-Day 1, Day 1, and Day 2. The costs examined in this report will be those associated with the Day 1 and Day 2 RTOs. Specifically, the following six RTOs were examined:

- California ISO
- ISO New England
- Midwest ISO
- New York ISO
- PJM Interconnection
- Southwest Power Pool

The RTOs shown above ("the study group") currently operate as Day 2 RTOs, with the exception of the Southwest Power Pool, which operates as a Day 1 RTO. In the course of preparing this analysis, a timeline was developed to track major milestones since the RTO formation process began in 1996. Milestones include identification of years when RTOs were formed and important issuances of FERC Orders affecting RTOs. In reviewing the costs, the latest five years of available data was examined for each RTO.

In 2005, RTO participants paid just over $1 billion in total costs. The costs associated with the RTOs are broken down into two major categories: 1) operational costs and 2) administrative costs. *FERC Form Nos. 1: Annual Reports of Major Electric Utilities, Licensees, and Others* ("FERC Form 1" or "Form 1") were used as the primary data source of cost information for each RTO. Examples of major operational costs include load dispatching and maintenance of plant. Examples of administrative costs include administrative and general salaries, consulting fees, and regulatory costs.

Overall, RTOs had significantly higher administrative than operational costs. There was on average a 75/25 split between administrative and operational costs. In 2005, administrative share ranged from 63 percent of California ISO's total costs to 99 percent of MISO total costs. These costs are broken down into greater detail in this report. There is a significant variation in costs between the RTOs. As a result of FERC Order No. 668[1], *Accounting and Financial Reporting for Public Utilities Including RTOs*, RTOs will be required to report their cost data in more detail beginning with 2006 data. This will bring more consistency to costs reported by RTOs and make it easier to compare costs between them. Table 1 on the following page shows a summary of the study group's total costs for 2005.

[1] Docket No. RM04-12-000, Issued December 16, 2005.

**Table 1 – 2005 Study Group Costs**

| RTO | Operational | Percent of Total | Administrative | Percent of Total | Total | $/MWh |
|---|---|---|---|---|---|---|
| **Day 2 RTOs** | | | | | | |
| California ISO | $ 63,719,381 | 37% | $ 107,892,132 | 63% | $ 171,611,513 | $ 0.724 |
| ISO New England | $ 25,379,347 | 20% | $ 99,041,681 | 80% | $ 124,421,028 | $ 0.912 |
| Midwest ISO | $ 2,544,847 | 1% | $ 270,876,399 | 99% | $ 273,421,246 | $ 0.419 |
| New York ISO | $ 12,246,311 | 8% | $ 136,924,551 | 92% | $ 149,170,862 | $ 0.892 |
| PJM Interconnection | $ 79,932,444 | 30% | $ 187,926,950 | 70% | $ 267,859,394 | $ 0.393 |
| **Day 2 RTO Total** | **$ 183,822,330** | **19%** | **$ 802,661,713** | **81%** | **$ 986,484,043** | **$ 0.526** |
| **Day 1 RTO** | | | | | | |
| Southwest Power Pool | $ 1,942,496 | 4% | $ 46,449,908 | 96% | $ 48,392,404 | $ 0.240 |
| **Day 1 RTO Total** | **$ 1,942,496** | **4%** | **$ 46,449,908** | **96%** | **$ 48,392,404** | **$ 0.240** |
| **All RTOs** | **$ 185,764,826** | **18%** | **$ 849,111,621** | **82%** | **$ 1,034,876,447** | **$ 0.498** |

Over the five year study period 2001-2005, total aggregate costs increased for ISO-NE by 98 percent, for MISO by 228 percent, for NYISO by 66 percent, and for PJM by 94 percent. Costs for CAISO declined.

As measured on a $/MWh basis, total costs increased for ISO-NE, NYISO, and MISO. Total costs in $/MWh for CAISO and PJM fluctuated over the past five years, but overall have seen a decrease. All six RTOs have shown wide variations in terms of how costs are reported and the magnitude of these costs.

As RTOs expand their services and as their systems age and must be replaced, the administrative and operational costs are likely to increase. For example, PJM is planning on developing a second control center, the cost of which will eventually be included in operational costs of PJM, and therefore recovered from the PJM customers.

This report also explains how RTOs recover their costs from their customers pursuant to the individual RTO tariffs[2]. In general, for both Day 1 and Day 2 RTOs, many costs are charged using FERC approved rates included in the various RTO tariffs. Day 2 RTOs also tend to have additional tariff schedules used to recover the costs associated with the administration of their energy markets. Cost recovery methodologies are often quite complex and vary widely among the Day 2 RTOs because of these additional schedules. As RTOs expand their services and as settlements and their related costs become more complicated and labor intensive, it is likely that the recovery mechanisms could become even more complex and numerous.

[2] RTO tariffs are FERC approved documents that explain all the rates and charges assessed by the RTO for recovery of the RTO's costs.

# 2.0 Introduction

In Order 2000, the Federal Energy Regulatory Commission ("FERC") found that in spite of its prior actions to promote competitive wholesale electricity markets, there still existed barriers and impediments to the creation of such markets. FERC also found that Regional Transmission Organizations ("RTO") would provide benefits that address those barriers and impediments and would further the commission's goal of achieving viable and competitive wholesale electricity markets.

RTOs are independent organizations that are responsible for the operation and short term reliability of the grid. Congestion management, transmission planning, and tariff administration are among the many services that RTOs provide. RTOs have their own staff and management. Governance is usually provided by an independent board of directors whose members are elected by the grid owners and grid users. RTOs typically have a well defined Stakeholder process where major issues are raised and discussed by grid owners and grid users. In some cases the RTO Board is elected trough the Stakeholder process and cost recovery decisions are presented and voted on by the Stakeholders.

Unlike RTOs, Independent System Operators ("ISOs") have been around many for years. ISOs were originally set up to manage power pools. Over time they have evolved into RTOs or organizations similar to RTOs.

A major portion of the United States transmission system is covered by an RTO or ISO entity in some form of development as shown in Figure 1. The only major exceptions are in the Southeast and the West where, with the exception of California, RTO development has been suspended.

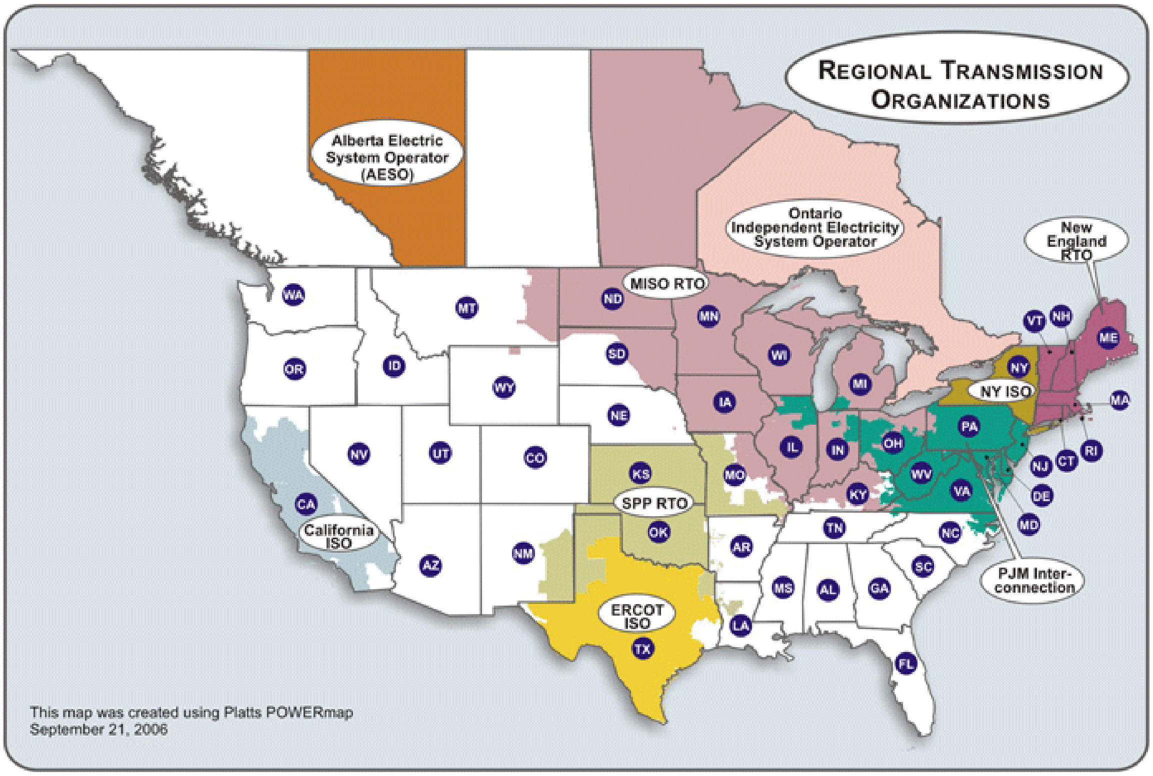



**Figure 1 - RTO Development (http://www.ferc.gov)**

In general, there are three major stages of RTO development: Pre-Day 1, Day 1, and Day 2. A Pre-Day 1 RTO is an RTO that is considered to be in an embryonic or developmental stage in which the entity may or may not have received initial FERC approval. Entities involved in a Pre-Day 1 RTO may have considered establishing a common OASIS[3] and have organized some type of Stakeholder process; however, they do not operate any energy markets or perform any congestion management functions.

Operational RTOs fall into two market categories: Day 1 and Day 2. In the Day 1 stage, the RTO manages the administration of real-time energy markets plus some form of congestion management. Unlike the Pre-Day 1 RTOs, Day 1 RTOs have fully developed Stakeholder processes. Currently, SPP is considered to be a Day 1 RTO. The final stage of RTO development, known as Day 2, offers a fully functioning market for day-ahead and real-time capacity[4], energy[5], ancillary services[6], and market-based congestion management[7]. PJM, MISO[8], NYISO, CAISO, and ISO-NE are considered Day 2 RTOs.

[3] OASIS stands for "Open Access Same-Time Information System," a system created by FERC Order 888, which is Internet based and allows transmission customers to request and reserve transmission service.
[4] Capacity refers to the ability to produce electric power.
[5] Energy refers to the actual production of electric power.
[6] Ancillary services are services that are not related to the production of electric power, but are required for the reliable operation of the grid (e.g. voltage support).
[7] Market based congestion management refers to the buying and selling of the rights to cause congestion on the grid and is generally associated with Financial Transmission Rights.
[8] MISO currently does not have a capacity market or ancillary service market. These are currently being developed.

This report will focus on the cost associated with RTOs in Day 1 and Day 2 stages of development. It will also provide more specific information on the operational and administrative costs that are involved in Day 1 and Day 2 RTOs. Detailed cost information is provided for the following study group:

- California ISO ("CAISO")
- ISO New England ("ISO-NE")
- Midwest ISO ("MISO")
- New York ISO ("NYISO")
- PJM Interconnection ("PJM")
- Southwest Power Pool ("SPP")

# 3.0 Timeline of RTO Formation

The timeline below lists the major milestones that have occurred in RTO Formation since 1996. RTO formation began in earnest after the December 20, 1999 issuance of FERC Order 2000, which encouraged RTO formation and established specific characteristics and functions of an RTO. The items in bold italics represent the key dates when the ISOs and RTOs started operation.

- 1996
  - FERC issues Order 888, requiring FERC-regulated utilities to provide nondiscriminatory "open access" to their transmission systems by other parties.
- 1997
  - FERC approves PJM as an ISO
  - FERC approves ISO-NE as an ISO
- 1998
  - ***CAISO created.*** CAISO assumes control of California wholesale power grid
  - FERC conditionally approves MISO formation
- 1999
  - ***FERC issues Order 2000***
  - NYISO takes over New York State's grid and launches energy markets
  - ISO-NE launches wholesale markets
- 2000
  - Western Energy Crisis begins
- 2001
  - Western Energy Crisis ends
  - GridSouth granted provisional RTO status[9]
  - GridFlorida granted provisional RTO status[10]
  - ***MISO granted RTO status***
  - ***PJM granted RTO status***
  - SPP and MISO contemplate merging
  - FERC finds that California wholesale markets are flawed
  - Enron declares bankruptcy
- 2002
  - FERC issues Standard Market Design ("SMD") NOPR
  - Allegheny Power integrated into PJM
- 2003
  - FERC issues Order 2003 (Standardization of Generator Interconnection Agreements and Procedures)
  - FERC issues Order 2004 (Standards of Conduct for Transmission Providers)
  - ISO-NE adopts SMD
  - SPP and MISO terminate merger
  - Northeast blackout
  - FERC approves NYISO capacity market (ICAP)

[9] GridSouth was instructed by FERC to make additional filings before it could be certified as an RTO.
[10] GridFlorida was instructed by FERC to make additional filings before it could be certified as an RTO.

- 2004
  - ***SPP granted RTO status***
  - ISO-NE granted provisional RTO status[11]
- 2005
  - FERC terminates SeTrans[12] RTO proceedings
  - FERC terminates SMD proceedings
  - PJM files initial Reliability Pricing Model (“RPM”) proposal
  - ***ISO-NE begins RTO operations***
  - MISO launches wholesale energy markets
  - FERC issues Order 2006 (Standardization of Small Generator Interconnection Agreements and Procedures)
  - FERC adopts remedies pertaining to California’s electricity market
- 2006
  - FERC approves ISO-NE capacity market (LICAP).
  - PJM files initial Long Term Transmission Rights proposal
  - FERC conditionally approves CAISO Market Redesign & Technology Upgrade (MRTU) program
  - FERC issues Order 671-A (Long-Term Firm Transmission Rights in Organized Electricity Markets)
  - FERC issues Order 888 Reform NOPR: Preventing Undue Discrimination and Preference in Transmission Service (*Docket Nos. RM05-25-000, RM05-17-000*)
  - FERC institutes inquiries into gas-electric coordination with respect to the scheduling practices of ISOs and RTOs

RTO development is continuing to progress in the present environment. For example, SPP is working towards becoming a Day 2 RTO by starting an energy imbalance market in 2007. Other RTOs continue to add services and additional markets, such as Ancillary Services and Capacity Markets.

[11] ISO-NE was instructed by FERC to make additional filings before it could be certified as an RTO.
[12] SeTrans was an attempt by utilities in the southeast to form an RTO. The participants included Southern Company and Entergy, as well as several cooperatives and municipals.

# 4.0 Cost Structure

## *4.1 General Cost Information*

Total operational and administrative costs vary widely by ISO/RTO. Figure 2 below shows the costs in dollars per MWh ($/MWh) [13] for the study group examined over the five year period, 2001-2005.

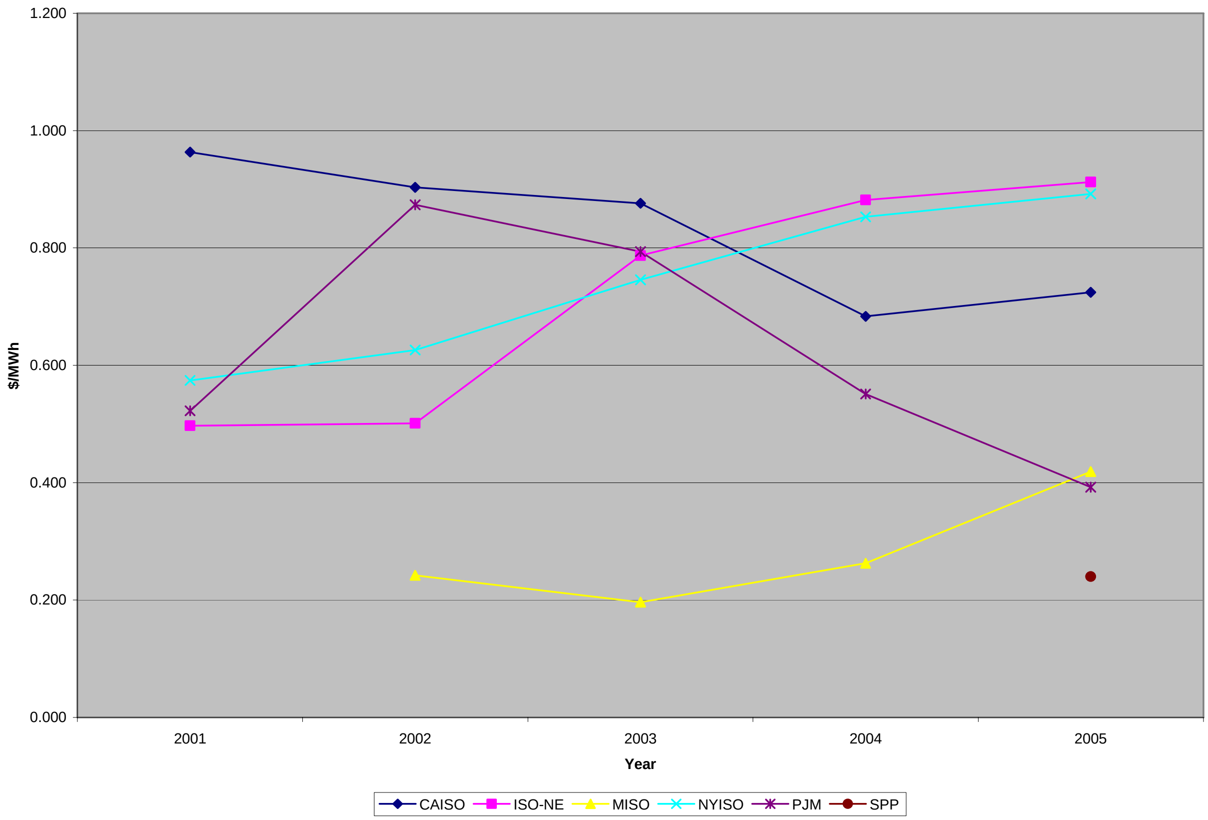



**Figure 2 - RTO Costs in $/MWh (2001 to 2005)**

A review of the operational and administrative costs of the RTOs identified several cost classifications that were common to all. The common costs categories are:

- Office Supplies and Expense
- Regulatory Costs[14]
- Consulting Fees/Outside Services
- Depreciation Expense
- Interest Expense
- Employee Pensions and Benefits

[13] Load information to determine the dollars per MWh is taken directly from FERC Forms 714 and 582 as filed by the RTOs (see Appendix E for details). For PJM this information was found on the PJM website.
[14] Regulatory costs include lobbying and public relations expenses.

The common cost categories used by the RTOs in their FERC Form 1 filings have been classified for this report as either "operational" or "administrative." Operational costs were defined as costs that directly relate to the reliable operation of the transmission system or efficient operation of the energy market. Administrative costs were determined to be any other costs associated with the services provided by the RTO. The classifications are shown in Table 2 below.

**Table 2 – RTO Cost Classifications – Common Categories**

| Administrative | Operational |
|---|---|
| Customer Assistance Expense | Load Dispatching |
| Office Supplies and Expense | Maintenance Supervision and Engineering |
| Regulatory Costs | Maintenance of General Plant |
| Administrative and General Salaries | Operation Supervision & Engineering |
| Consulting Fees/Outside Services | |
| Employee Pension and Benefits | |
| Depreciation Expense | |
| Interest Expense | |

Research showed that the RTOs studied for this report had, at times, exhibited different methods for allocating their total cost into categories that would typically be considered administrative and what would typically be considered operational. Beginning in 2006, ISOs and RTOs will have a new set of accounting codes to use in their Form 1 filing as a result of FERC Order 668. These new codes should expand and clarify the breakdown between operational and administrative costs. A table of the new FERC ISO and RTO Accounting Codes from Order 668 is included as *Appendix A.*

Overall, the RTOs studied had much higher administrative related costs than operational costs as shown in Figure 3 on the following page.

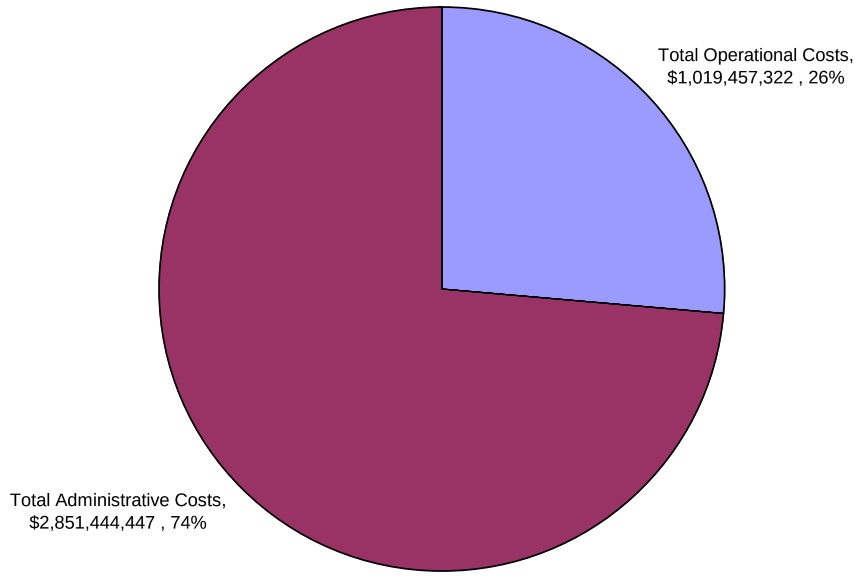



**Figure 3 – RTO Total Operational vs. Total Administrative Costs (Cumulative 2001-2005)**

ISOs and RTOs generally recover administrative and operational costs from their customers based on their use of the transmission system or use of a specific service offered by the ISO or RTO. For example, charges such as Control Area Administration may be based on the customer's monthly MWh delivered over the transmission system, while certain charges are only allocated to specific customers that use that service. Because of the variation in the methods for allocating costs, a dollar per MWh ($/MWh) measure is not necessarily a clear indication of how individual participants are impacted by RTO costs. Section 4.2, 4.3, and Appendix D provide a more detailed explanation of how the study group charges its customers to recover its costs.

A large portion of the operational costs are recovered using Ancillary Schedule 1, Scheduling, System Control and Dispatch Service, which is offered in all RTO transmission tariffs. Schedule 1 is the portion of the tariff that contains the rates and charges assessed by the RTO to recover its costs. Generally speaking, the rates and charges contained in Schedule 1 are related operational costs. Administrative costs are typically recovered using a different schedule included in the transmission or market tariffs. Administrative schedules vary by RTO in both the number of schedules offered and type of schedules.

Day 2 RTOs tend to have a fairly complicated cost recovery structure. For example, PJM has thirteen (13) tariff or operating agreement schedules that are used to recover administrative and operational costs. In contrast, SPP, a Day 1 RTO, uses only two (2) schedules from its tariff to recover costs.

In order to recover costs through a tariff or operating agreement schedule, RTO's are typically required to present the cost and recovery mechanism to their Stakeholders. The Stakeholders usually have the opportunity to question the RTO staff about the new cost and vote on the new cost recovery mechanism. The mechanisms are then filed at FERC for approval.

### *4.2 Day 1 RTO Costs*

The Southwest Power Pool operates as a Day 1 RTO. Day 1 RTOs provide at least the following services[15]:

- Tariff Administration and Design
- Congestion Management – Redispatch
- Parallel Path Flow
- Ancillary Services
- OASIS
- Market Monitoring
- Transmission Planning
- Interregional Coordination

In addition to reviewing SPP's operational and administrative costs as reported in the FERC Form 1, this section of the report provides the costs associated with PJM and the Midwest ISO when they were functioning as Day 1 RTOs.

**Table 3 – Day One RTO Costs in a Typical Year**

| Item | MISO (FERC Estimate) | Percent of Total | PJM (FERC Estimate) | Percent of Total | SPP (2005 Actual) | Percent of Total |
|---|---|---|---|---|---|---|
| Salaries/Benefits | $ 26,596,956 | **30%** | $ 34,852,639 | **45%** | $ 12,704,051 | **26%** |
| Outside Services | $ 8,910,654 | **10%** | $ 16,025,950 | **21%** | $ 10,412,326 | **22%** |
| Occupancy | $ 3,552,012 | 4% | | 0% | | 0% |
| Insurance | $ 2,982,254 | 3% | | 0% | | 0% |
| Supplies/Other | $ 9,487,711 | **11%** | $ 6,619,453 | 9% | $ 3,943,730 | 8% |
| Taxes | $ 1,248,418 | 1% | | 0% | $ 993,358 | 2% |
| Depreciation | $ 15,886,992 | **18%** | $ 12,722,689 | **16%** | $ 2,805,300 | 6% |
| Amortization | $ 9,819,026 | **11%** | | 0% | | 0% |
| Interest | $ 9,399,340 | **11%** | $ 4,431,897 | 6% | $ 1,374,356 | 3% |
| Hardware Lease Expense | | 0% | $ 3,149,064 | 4% | | 0% |
| Maintenance of General Plant | | 0% | | 0% | $ 1,942,496 | 4% |
| Employee Pension and Benefits | | 0% | | 0% | $ 4,512,354 | 9% |
| Regulatory Costs | | 0% | | 0% | $ 9,196,078 | **19%** |
| Misc. General Expense | | 0% | | 0% | $ 427,403 | 1% |
| Amort. Of Debt Disc. And Expense | | 0% | | 0% | $ 80,952 | 0% |
| **Total** | **$ 87,883,363** | **100%** | **$ 77,801,692** | **100%** | **$ 48,392,404** | **100%** |

Table 3 above shows a typical year's expenses for the Day 1 RTOs. The costs for each of these RTOs were reported differently depending on the source of the data. Therefore, the cost items

[15] "Staff Report on Cost Ranges for the Development of Operation of a Day One Regional Transmission Organization" Federal Energy Regulatory Commission, Docket PL04-14-000, October 2004, page 3.

shown above are not uniform across all the RTOs. For example, insurance costs were reported for MISO, but not for PJM or SPP.

Day 1 RTO cost information for MISO and PJM was obtained from the Federal Energy Regulatory Commission *Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization*[16]. The costs provided in this FERC Staff report represented a typical Day 1 operating year for MISO and PJM. Cost information for SPP was obtained from SPP's 2005 FERC Form 1. SPP began RTO operations in 2005 and is currently operating as a Day 1 RTO.[17]

Salaries and benefits were the largest expense item for all three Day 1 RTOs. For PJM, salaries and benefits made up nearly half of its total expenses for the year. Outside services (e.g. consulting fees) was also significant, accounting for over 20% of the total costs for PJM and SPP and about 10% of the total costs for MISO. Depreciation accounted for 18% of MISO's total expenses and 16% of PJM's total expenses. Regulatory costs were a large expense item for SPP, accounting for nearly 20% of its annual expenses.

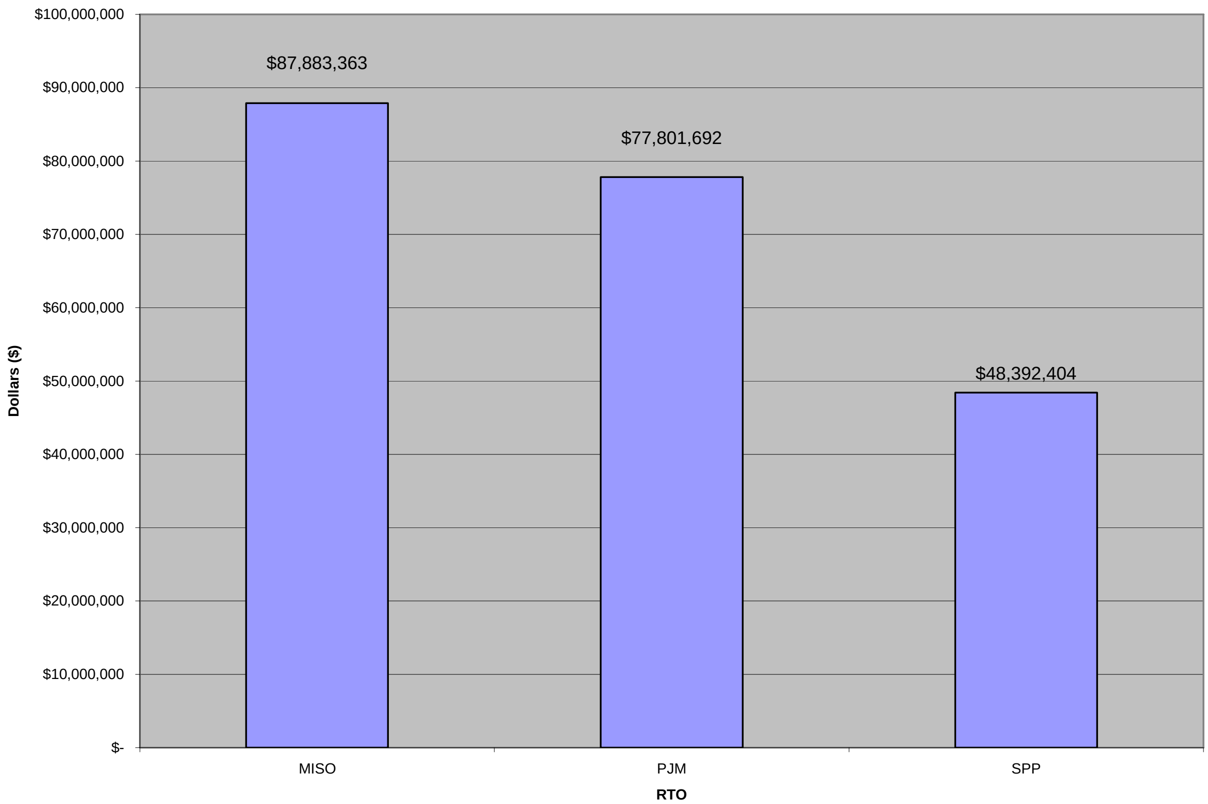



**Figure 4 – Day One RTO Costs in a Typical Year**

As shown in Figure 4 above, MISO had the highest expenses in a typical year among the three Day 1 RTOs, totaling $87,883,363. PJM and SPP expenses totaled $77,801,692 and $48,392,404 respectively. One possible explanation for the large difference in costs between the

[16] Docket No. PL04-16-000, October 2004.
[17] Prior to 2004, SPP operated as an Independent Transmission Provider and Reliability Coordinator.

two Day 1 RTO estimates and SPP is the size of the region. In terms of load, SPP is the smallest of the three RTOs and MISO is the largest.

## Southwest Power Pool

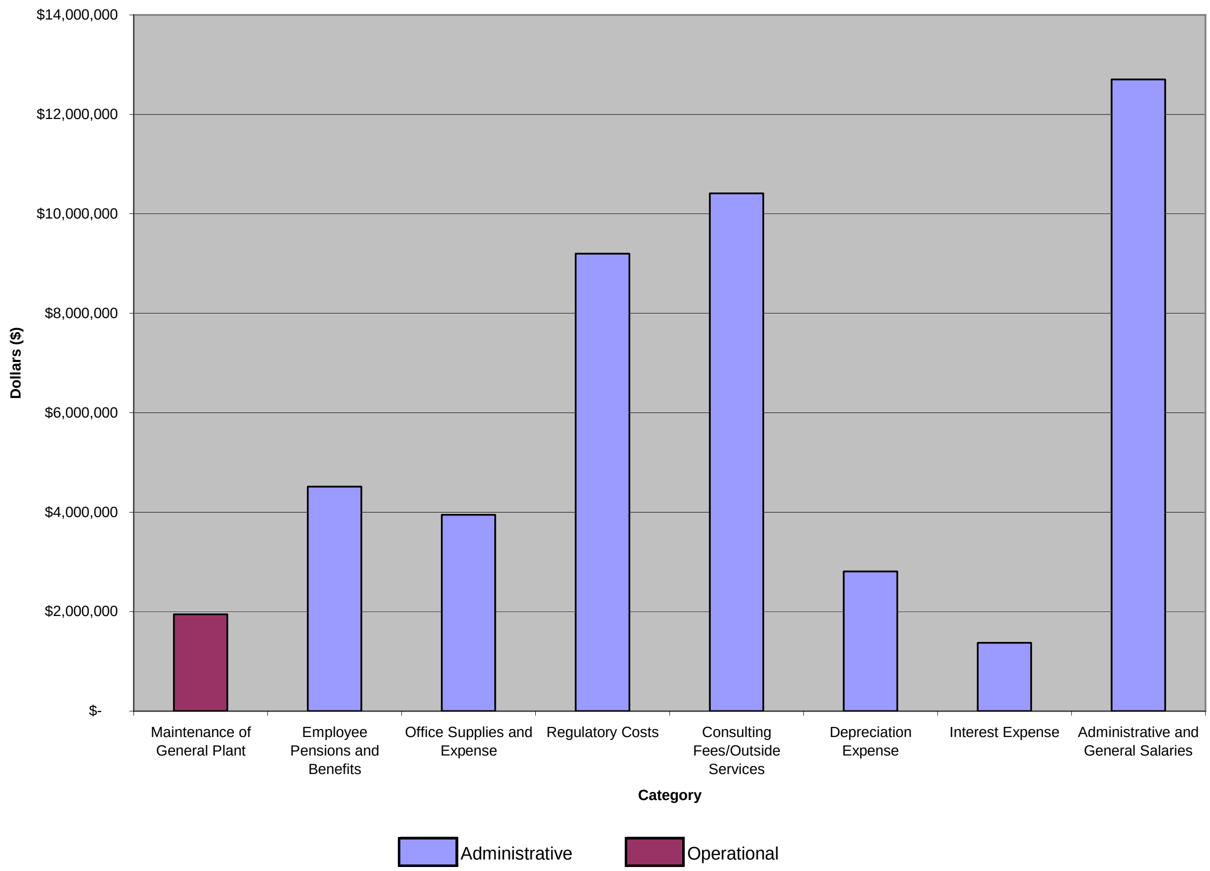



**Figure 5 – Southwest Power Pool Major Cost Categories (2005)**

Year 2005 data is the only complete year of data available for SPP since it was granted RTO status in 2004. As mentioned previously, SPP is currently operating as a Day 1 RTO and has relatively low costs in terms of total dollars when compared to FERC Staff's estimates of Day 1 expenses for MISO and PJM. However, it should be noted that on a dollars per MWh basis ($/MWh), SPP's total costs equate to $0.240/MWh. This is slightly above FERC Staff's estimates of $0.160 to $0.220 per MWh for typical Day 1 RTO expenses[18]. The majority of SPP's costs are administrative costs as these make up 96% of the RTO's total costs[19]. Total costs for SPP in calendar year 2005 were $48,392,404. As shown in Figure 5 above, the three largest cost categories (administrative costs) for SPP are administrative and general salaries, regulatory costs, and consulting fees/outside services. Detailed annual cost data for SPP can be found in Appendix C6.

SPP recovers its operational and administrative costs using two (2) schedules included in its Tariff. For more details on SPP's cost recovery, please see Appendix D6.

[18] "Staff Report on Cost Ranges for the Development of Operation of a Day One Regional Transmission Organization" Federal Energy Regulatory Commission, Docket PL04-14-000, October 2004, pages 14-19.
[19] SPP's administrative costs totaled $46,449,908 in calendar year 2005, while operational costs totaled $1,942,496.

## *4.3 Day 2 RTO Costs*

The Day 2 RTOs that were examined for this report are the California ISO, ISO New England, Midwest ISO, New York ISO, and PJM. Day 2 RTOs provide at least the following services[20]:

- Tariff Administration and Design
- Congestion Management – Market-Based
- Parallel Path Flow
- Ancillary Services
- OASIS
- Market Monitoring
- Transmission Planning
- Interregional Coordination
- Day-Ahead Energy Market
- Same-Day Energy Market
- Ancillary Services Market
- Capacity Market

## California ISO

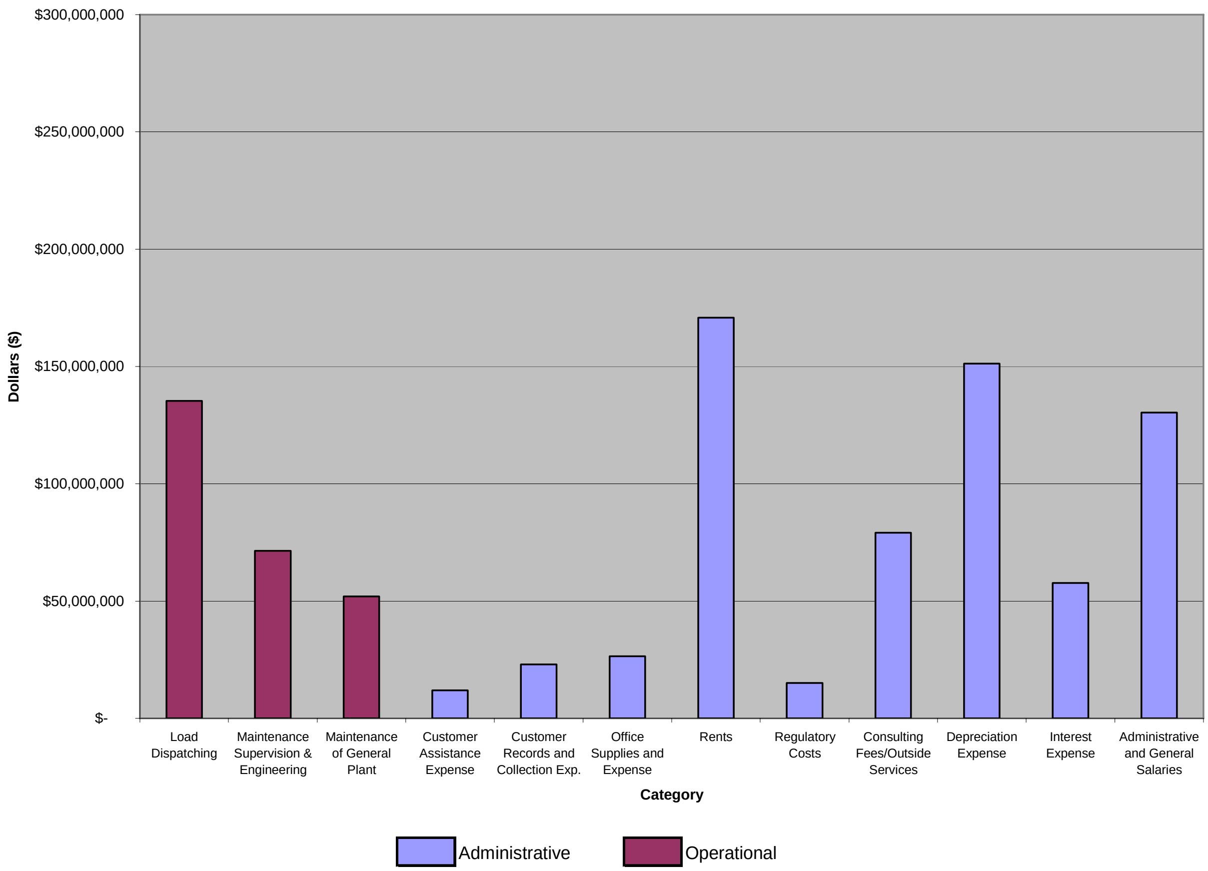
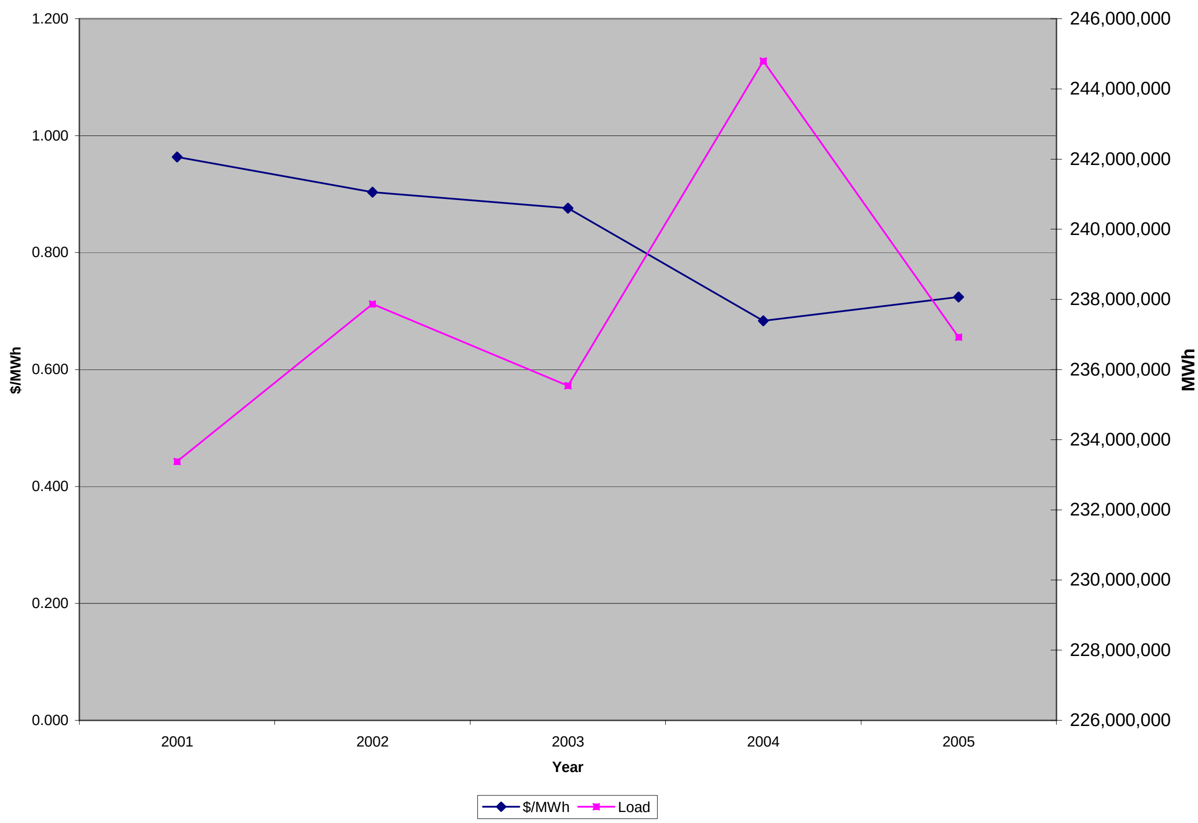



**Figure 6 – California ISO Major Cost Categories (Total Cumulative Costs 2001-2005)**

[20] "Staff Report on Cost Ranges for the Development of Operation of a Day One Regional Transmission Organization" Federal Energy Regulatory Commission, Docket PL04-14-000, October 2004, page 3.

Over the past five years, administrative costs have accounted for 71% of CAISO's total expenses, while operational costs accounted for 29%. As shown in Figure 6 on the previous page, during this time period, rents, depreciation expense, administrative and general salaries, and load dispatching have been CAISO's largest expenses. Operational costs have increased from $54,605,595 in 2001 to $63,719,381 in 2005. Administrative costs have decreased from $170,245,671 in 2001 to $107,892,132 in 2005. Overall, total costs have decreased from $224,851,266 in 2001 to $171,611,513 in 2005. The largest decline in costs was between 2003 and 2004, and the main factor was a large decrease in rents. As shown in Figure 7 below, on a dollars per MWh basis ($/MWh), CAISO's costs decreased from $0.963 per MWh in 2001 to $0.724 per MWh in 2005. Detailed annual cost data for CAISO can be found in Appendix C1.




| Year | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| Costs | $ 224,851,266 | $ 214,850,342 | $ 206,343,863 | $ 167,313,598 | $ 171,611,513 |
| MWh | 233,378,803 | 237,870,367 | 235,540,579 | 244,794,546 | 236,925,183 |
| **$/MWh** | **$ 0.963** | **$ 0.903** | **$ 0.876** | **$ 0.683** | **$ 0.724** |

**Figure 7 – California ISO Total Annual Costs, MWh, and $/MWh**

CAISO uses a Grid Management Charge ("GMC") to recover its costs. The GMC is divided into eight (8) separate cost recovery components. Appendix D1 provides more details on the CAISO GMC.

## ISO New England

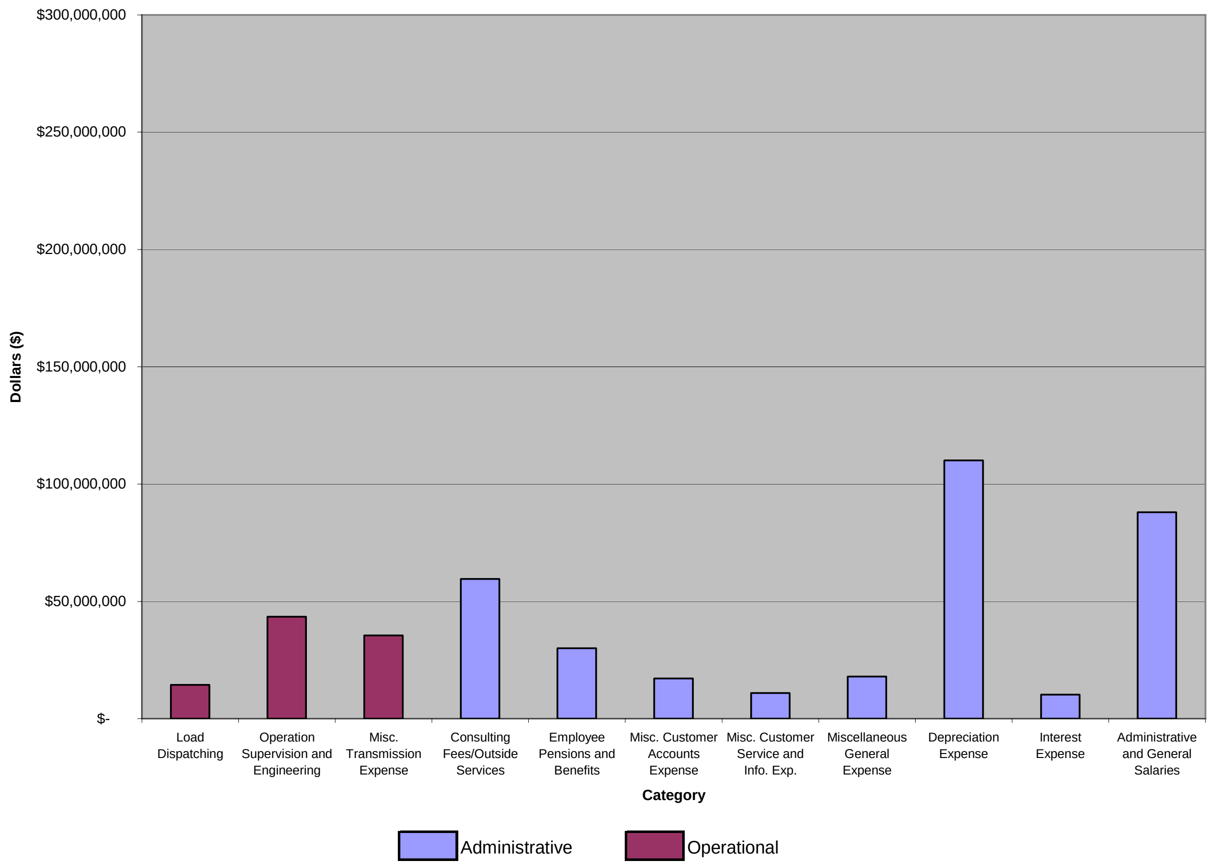
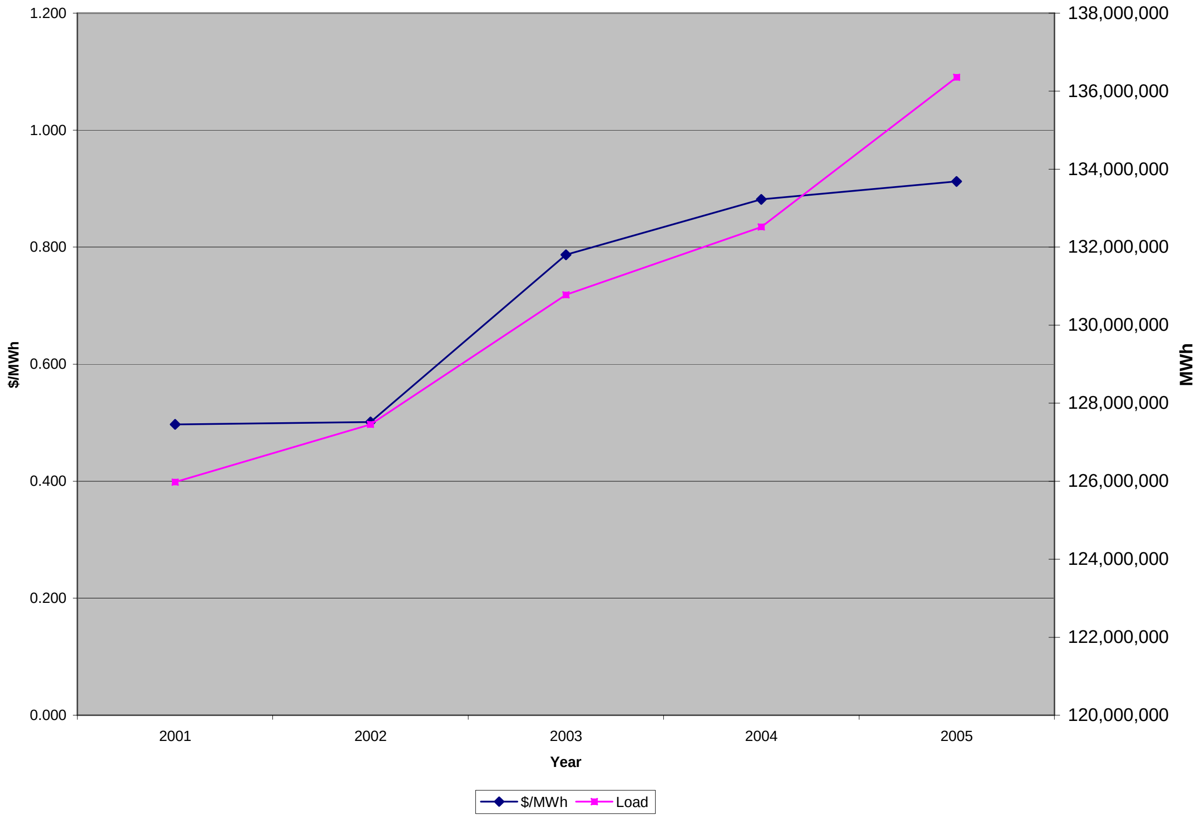



**Figure 8 – ISO New England Major Cost Categories (Total Cumulative Costs 2001-2005)**

Over the five year period 2001-2005, administrative costs have accounted for 77% of ISO-NE's total expenses, while operational costs accounted for 23%. As shown in Figure 8 above, during this 5-year time period, administrative and general salaries, depreciation expense, and consulting fees/outside services have been ISO-NE's largest expenses. Operational costs have increased from $16,764,265 in 2001 to $25,379,347 in 2005. Administrative costs have increased from $45,867,293 in 2001 to $99,041,681 in 2005. The largest increase in costs was between 2002 and 2003, and the main factor was a $24 million increase in depreciation expense. Overall, total costs have increased by 98% from $62,631,558 in 2001 to $124,421,028 in 2005. As shown in Figure 9 on the following page, on a dollars per MWh basis ($/MWh), ISO-NE increased from $0.497 per MWh in 2001 to $0.912 per MWh in 2005. Detailed annual cost data for ISO-NE can be found in Appendix C2.




| Year | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| Costs | $ 62,631,558 | $ 63,869,435 | $ 102,924,027 | $ 116,842,065 | $ 124,421,028 |
| MWh | 125,976,457 | 127,455,232 | 130,777,995 | 132,518,126 | 136,355,309 |
| **$/MWh** | **$ 0.497** | **$ 0.501** | **$ 0.787** | **$ 0.882** | **$ 0.912** |

**Figure 9 – ISO New England Total Annual Costs, MWh, and $/MWh**

ISO-NE uses four (4) schedules filed with FERC as part of its Tariff to recover its costs. Detailed information on these schedules is contained in Appendix D2.

## Midwest ISO

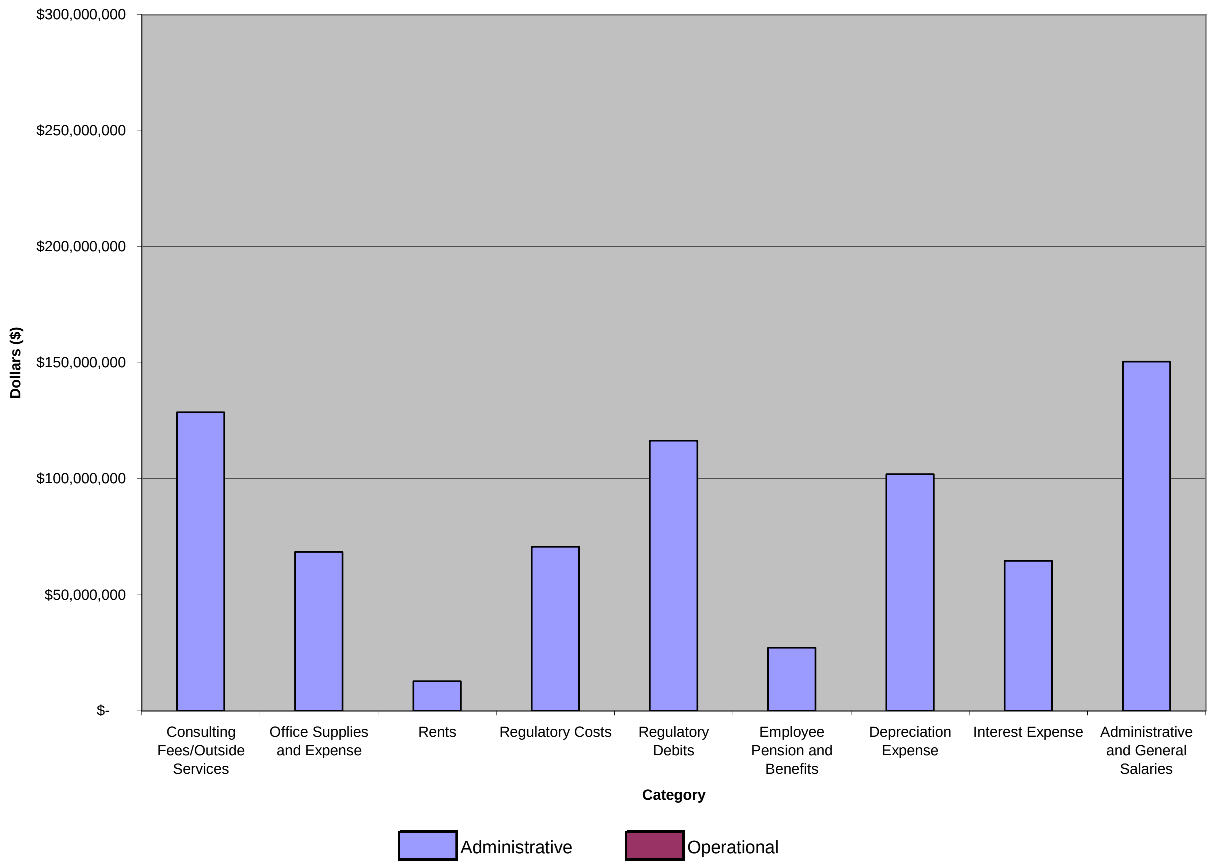
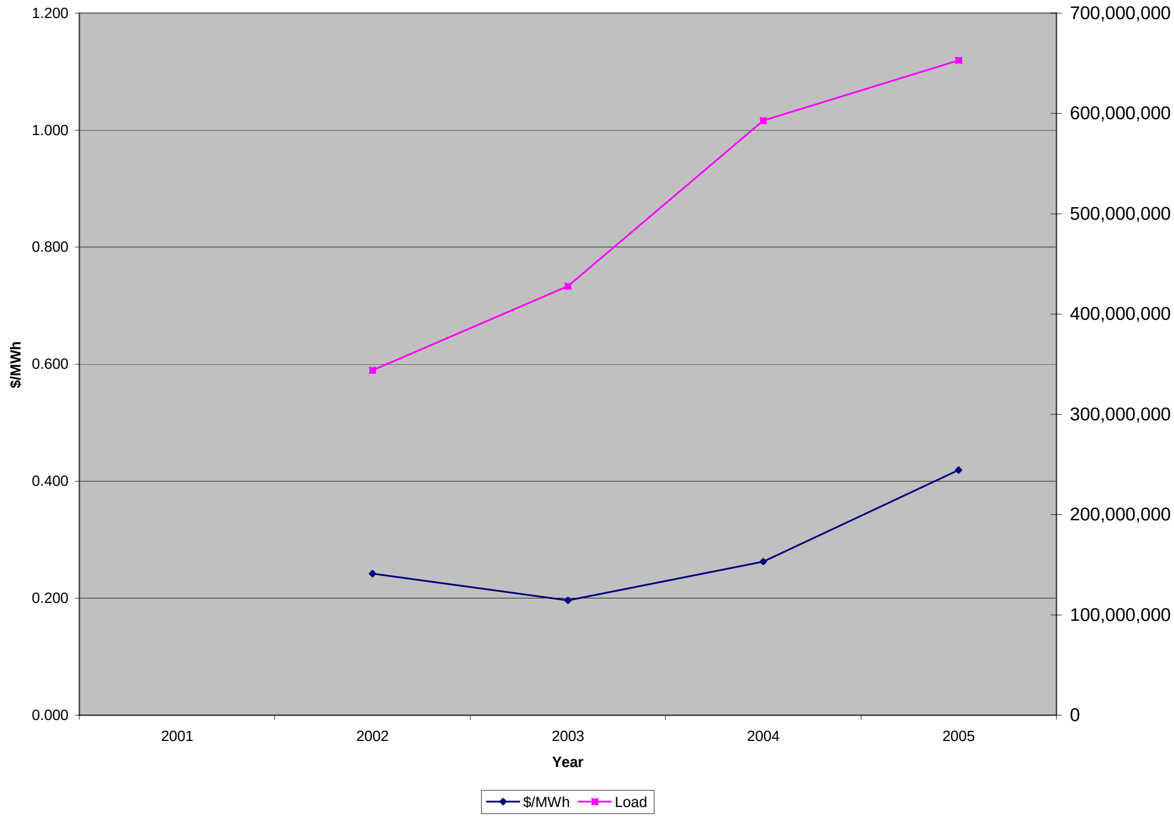



**Figure 10 – Midwest ISO Major Cost Categories (Total Cumulative Costs 2002-2005)**

MISO began coordination of transmission service in 2002. Over the four year period 2002-2005, MISO's total expenses have been made up almost entirely of administrative costs (99% of total costs). As shown in Figure 10 above, during this time period, administrative and general salaries, consulting fees/outside services, regulatory debits, and depreciation expense have been MISO's largest expenses. Operational costs have increased from $1,164,637 in 2002 to $2,544,847 in 2005. Administrative costs have increased from $82,075,753 in 2002 to $270,876,399 in 2005. Overall, total costs have increased by 228% from $83,240,390 in 2002 to $273,421,246 in 2005. As shown in Figure 11 on the following page, on a dollars per MWh basis ($/MWh), MISO increased from $0.242 per MWh in 2002 to $0.419 per MWh in 2005. Detailed annual cost data for MISO can be found in Appendix C3.

The main reason for the dramatic increase in costs from 2003 to 2004 and 2004 to 2005 is the start-up of the MISO energy market in 2005. Prior to the energy market start-up, MISO had to invest in new systems and additional staff to support the new market. These additional resources would result in a significant increase in costs for MISO.




| Year | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|
| Costs | $ 83,240,390 | $ 84,050,582 | $ 155,669,224 | $ 273,421,246 |
| MWh | 343,816,582 | 427,998,509 | 592,780,417 | 652,763,614 |
| **$/MWh** | **$ 0.242** | **$ 0.196** | **$ 0.263** | **$ 0.419** |

**Figure 11 – Midwest ISO Total Annual Costs, MWh, and $/MWh**

MISO's costs are recovered from its customers through four (4) separate schedules in its Electric Tariff. Detailed information on these schedules is included as Appendix D3.

## New York ISO

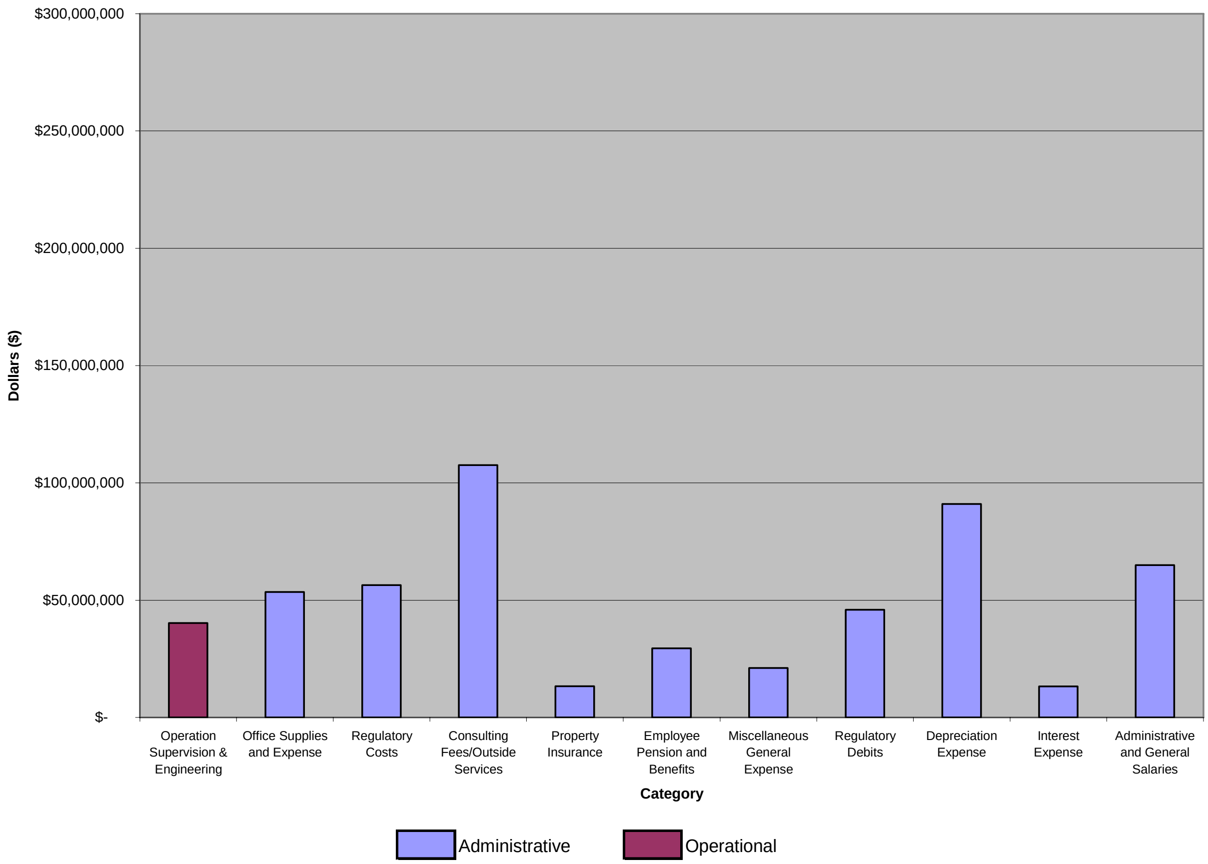
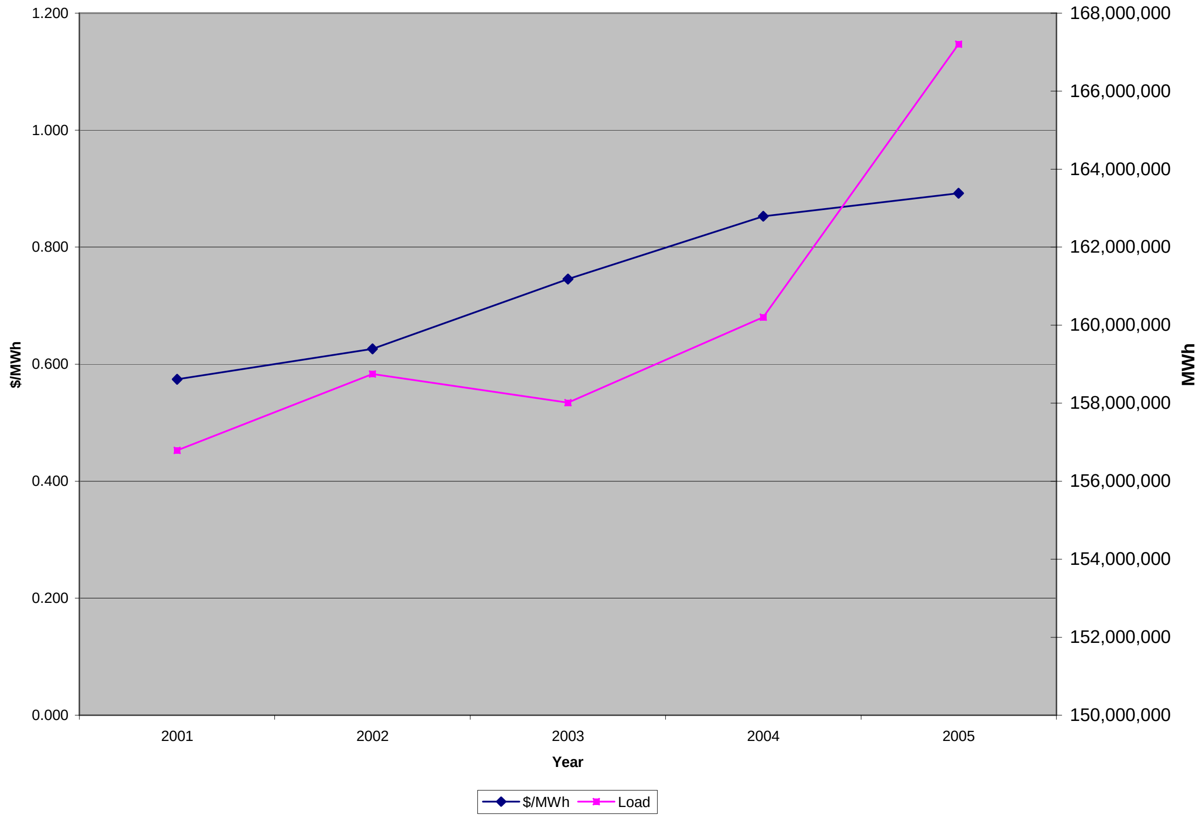



**Figure 12 – New York ISO Major Cost Categories (Total Cumulative Costs 2001-2005)**

Over the past five years, administrative costs have accounted for 91% of NYISO's total expenses, while operational costs accounted for only 9%. As shown in Figure 12 above, during this time period, consulting fees/outside services, depreciation expense, and administrative and general salaries have been NYISO's largest expenses. Operational costs have increased from $8,479,312 in 2001 to $12,246,311 in 2005. Administrative costs have increased from $81,564,644 in 2001 to $136,924,551 in 2005. The largest cost increases were in the depreciation and salaries and wages categories. Overall, total costs have increased by 66% from $90,043,956 in 2001 to $149,170,862 in 2005. As shown in Figure 13 on the following page, on a dollars per MWh basis ($/MWh), NYISO increased from $0.574 per MWh in 2001 to $0.892 per MWh in 2005. Detailed annual cost data for NYISO can be found in Appendix C4.




| Year | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| Costs | $ 90,043,956 | $ 99,410,931 | $ 117,819,269 | $ 136,661,595 | $ 149,170,862 |
| MWh | 156,787,408 | 158,744,782 | 158,013,534 | 160,209,093 | 167,204,055 |
| **$/MWh** | **$ 0.574** | **$ 0.626** | **$ 0.746** | **$ 0.853** | **$ 0.892** |

**Figure 13 – New York ISO Total Annual Costs, MWh, and $/MWh**

NYISO recovers its cost using Schedule 1, Scheduling, System Control, and Dispatch Service of its Transmission Tariff. There are four (4) components of this schedule that are billed out to customers. The details of these components are included as Appendix D4.

## PJM

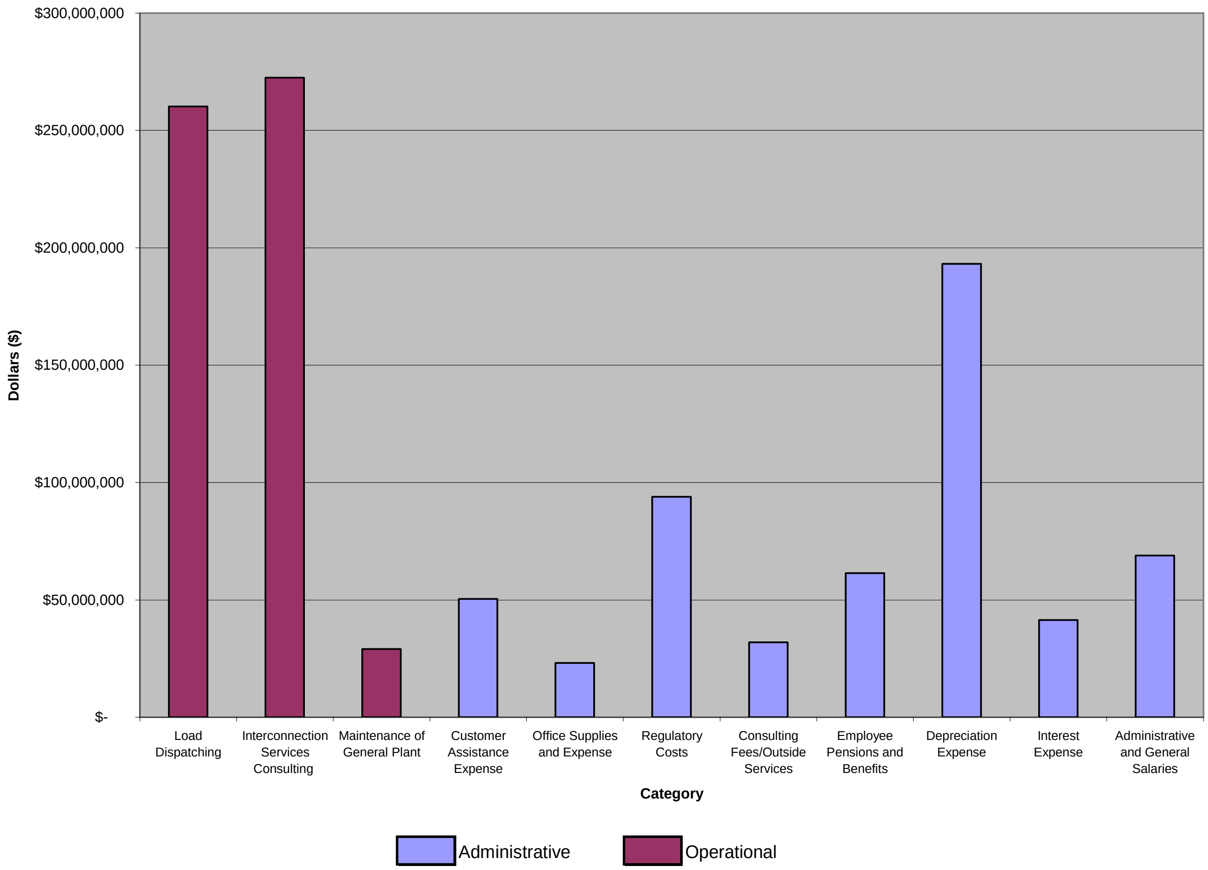
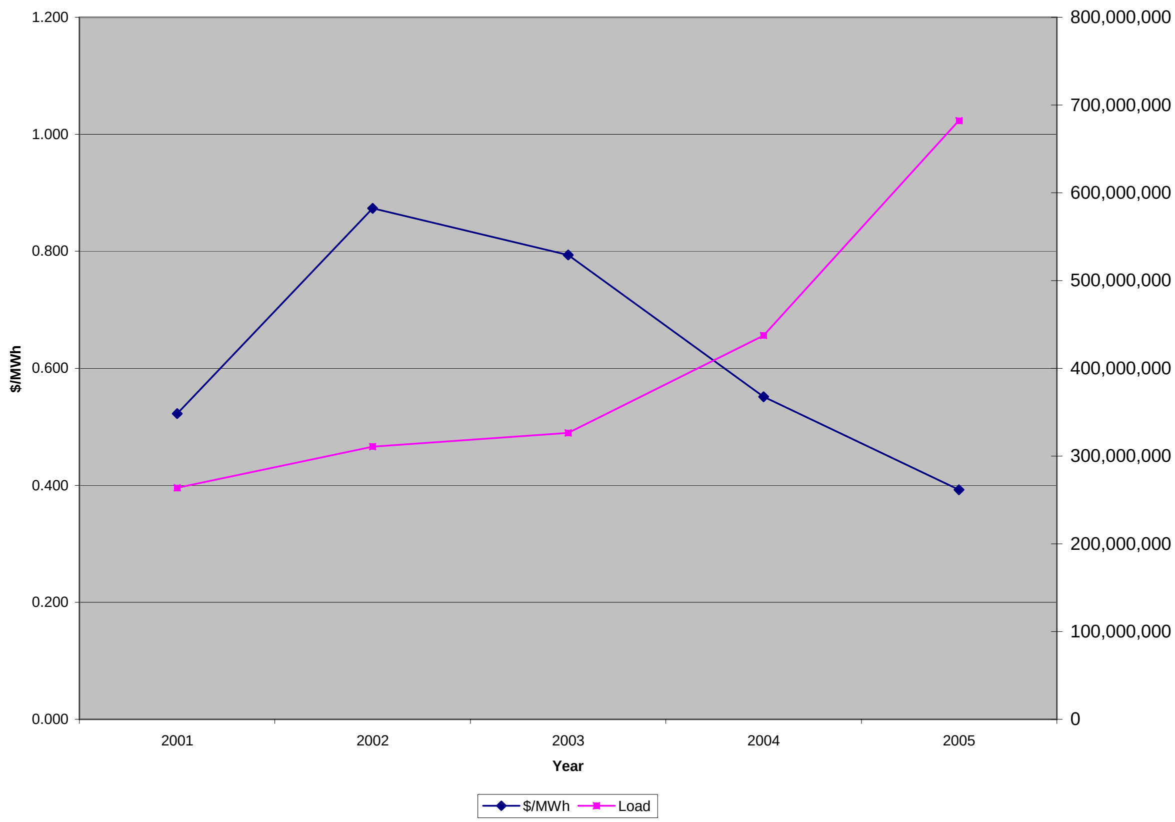



**Figure 14 – PJM Major Cost Categories (Total Cumulative Costs 2001-2005)**

From 2001-2005, PJM's total costs were almost evenly split between administrative and operational costs. Administrative costs made up 52% of PJM's total cost, while operational costs made up 48%. As shown in Figure 14 above, during this time period, interconnection services consulting, load dispatching, depreciation expense, and regulatory costs have been PJM's largest expenses. PJM's operational costs of $79,662,974 in 2001 are similar to its operational costs of $79,932,444 in 2005. However, operational costs have fluctuated over the years, reaching a high of $175,407,304 in 2002. Administrative costs increased from $58,196,561 in 2001 to $187,926,950 in 2005 while overall, total costs have increased by 94% from $137,859,535 in 2001 to $267,859,394 in 2005. As shown in Figure 15 on the following page, on a dollars per MWh basis ($/MWh), PJM's costs decreased from $0.523 per MWh in 2001 to $0.393 per MWh in 2005. Detailed annual cost data for PJM can be found in Appendix C5.

The decrease in PJM's costs on a $/MWh basis is due to the increased load in PJM. In 2002, 2004, and 2005, new members joined PJM, thus increasing the RTO's total load. Allegheny Power integrated into PJM in 2002, AEP and Dayton Power integrated into PJM in 2004, and Dominion and Duquesne Power integrated into PJM in 2005. PJM is also a well established

RTO with most of its market and settlement systems already in place. There is potential for an increase in costs in 2006 due to a new settlement system that PJM is currently developing.




| Year | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| Costs | $ 137,859,535 | $ 271,411,002 | $ 259,103,173 | $ 241,129,511 | $ 267,859,394 |
| MWh | 263,811,916 | 310,721,075 | 326,401,266 | 437,342,067 | 682,317,607 |
| **$/MWh** | **$ 0.523** | **$ 0.873** | **$ 0.794** | **$ 0.551** | **$ 0.393** |

**Figure 15 – PJM Total Annual Costs, MWh, and $/MWh**

Of all of the RTO's reviewed PJM seems to have the most complex recovery mechanism, involving thirteen (13) separate schedules and sub schedules in the PJM Tariff and Operating Agreement. PJM recently changed to a fixed rate for its operational and administrative costs recovery, which makes it easier to reconcile these charges. The detailed information on the PJM schedules and rates is included as Appendix D5.

# 5.0 Conclusions

Total operational and administrative costs vary widely by RTO. One of the reasons for this is the lack of a uniform and more detailed set of accounting codes that would better define these costs. While the FERC Form 1 includes all costs associated with the administration and operation of an RTO, more accounting detail is needed in order to better understand the nature and classification of all underlying costs.

Beginning with the 2006 reporting year, RTOs will be required to report more detailed financial information as directed by new accounting standards set forth in FERC's *Accounting and Financial Reporting for Public Utilities Including RTOs*[21]. These new codes should provide greater transparency of RTO costs in the future because they will help expand and clarify the nature of all classes of RTO costs.

Overall, as would be expected, the six RTOs examined in this report had much higher administrative costs than operational costs. There was approximately a 75/25 split between administrative and operational costs. The largest operational cost was load dispatching. The largest administrative costs were administrative and general salaries, consulting fees/outside services, depreciation expense, and regulatory costs.

**Table 4 – RTO Total Cost Summary on a $/MWh Basis**

| Year | CAISO | ISO-NE | MISO | NYISO | PJM | SPP |
|---|---|---|---|---|---|---|
| **2001** | 0.963 | 0.497 | | 0.574 | 0.523 | |
| **2002** | 0.903 | 0.501 | 0.242 | 0.626 | 0.873 | |
| **2003** | 0.876 | 0.787 | 0.196 | 0.746 | 0.794 | |
| **2004** | 0.683 | 0.882 | 0.263 | 0.853 | 0.551 | |
| **2005** | 0.724 | 0.912 | 0.419 | 0.892 | 0.393 | 0.240 |

Table 4 above shows an overview of the study group's costs over the five years, 2001-2005. ISO-NE, NYISO, and MISO saw increases in costs in $/MWh over the period. Costs in $/MWh for CAISO and PJM fluctuated over the past five years, but overall have seen a decrease. As RTOs mature, their costs on a $/MWh basis tend to decrease. This is usually a result of having all the necessary systems and resources already in place (and thus having incurred all of its associated costs), while load continues to increase.

As RTOs expand their services and as their systems age and must be replaced, the administrative and operational cost will increase. For example, PJM is planning on developing a second control center, the cost of which will eventually be included in operational costs of PJM, and therefore recovered from the PJM customers.

RTOs recover costs from their customers according to the schedules in each of their respective tariffs. Many costs are typically recovered through Schedule 1, Scheduling, System Control and Dispatch Service. Due to an increase in the number of functions associated with the energy

[21] 18 CFR Part 101, Docket No. RM04-12-000; Order No. 668, Issued December 16, 2005.

markets, Day 2 RTOs incur more costs and typically recover those costs through additional schedules, or sub-schedules, in their respective tariffs.

RTO cost recovery mechanisms can be complicated, involving multiple adders depending on the nature of the costs being recovered from customers. As RTOs expand their services and as settlements and their related cost become more complicated and labor intensive, it is likely that the recovery mechanisms could become even more complex and numerous.

# 6.0 Appendices

# Appendix A - Table of New FERC Accounts for RTOs (Order 668)

# Table of New FERC Accounts for RTOs
# From Order 668

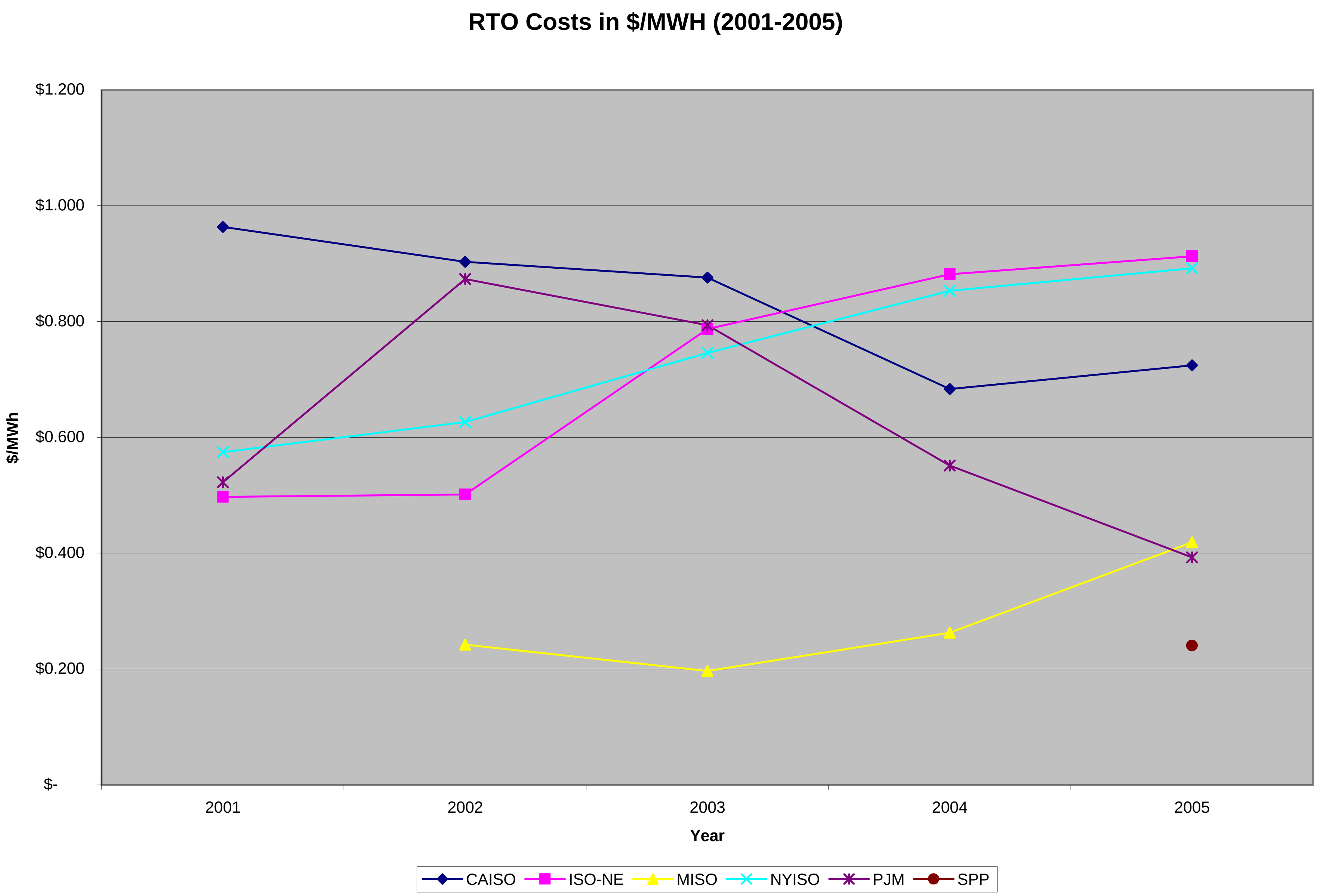
| Account Number | Description |
|---|---|
| ***Electric Plant*** | |
| **5. Regional Transmission and Market Operation Plant** | |
| 380 | Land and land rights |
| 381 | Structures and improvements |
| 382 | Computer hardware |
| 383 | Computer software |
| 384 | Communication equipment |
| 385 | Miscellaneous Regional Transmission and Market Operation Plant |
| 386 | Asset Retirement Costs for Regional Transmission and Market Operation Plant |
| 387 | [Reserved] |
| ***Operations and Maintenance Expense Chart of Accounts*** | |
| **3. Regional Market Expenses** | |
| Operation | |
| 575.1 | Operation Supervision |
| 575.2 | Day-ahead and real-time market facilitation |
| 575.3 | Transmission rights market facilitation |
| 575.4 | Capacity market facilitation |
| 575.5 | Ancillary services market facilitation |
| 575.6 | Market monitoring and compliance |
| 575.7 | Market facilitation, monitoring, and compliance services |
| 578.8 | Rents |
| Maintenance | |
| 576.1 | Maintenance of structures and improvements |
| 576.2 | Maintenance of computer hardware |
| 576.3 | Maintenance of computer software |
| 567.4 | Maintenance of communication equipment |
| 567.5 | Maintenance of miscellaneous market operation plant |

# Table of New FERC Accounts for RTOs
# From Order 668

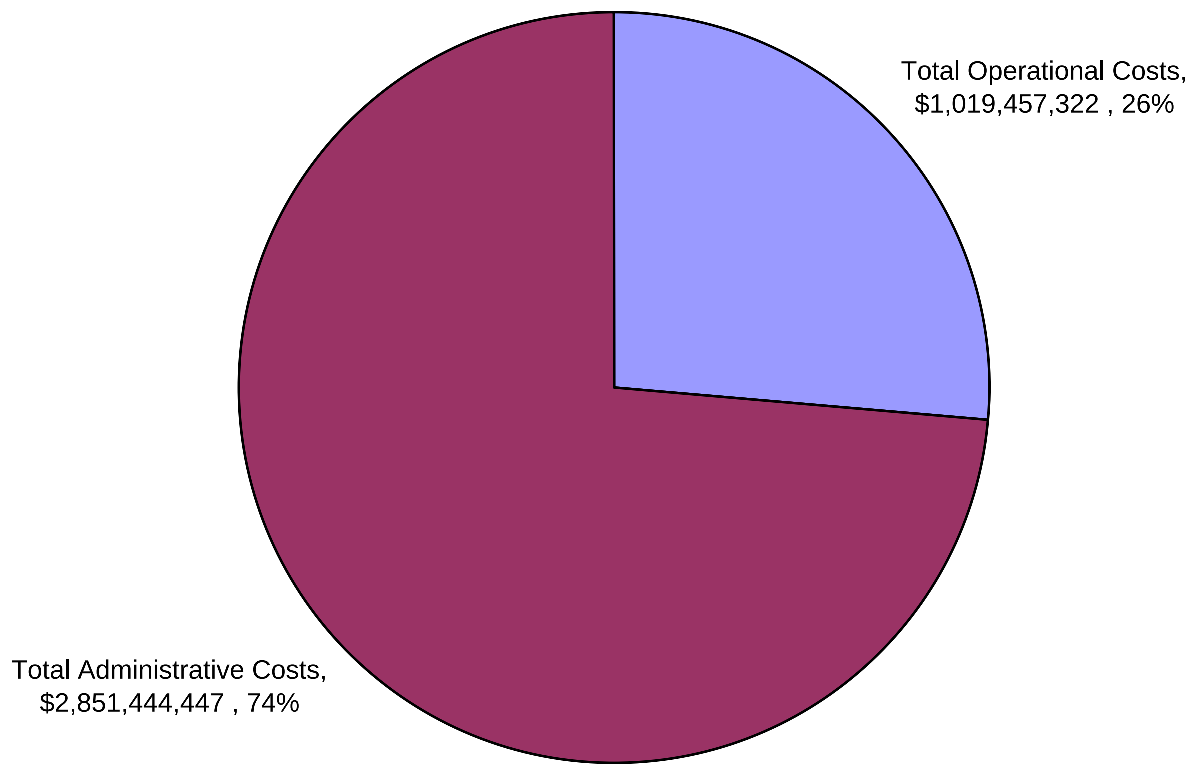
| Account Number | Description |
|---|---|
| **2. Transmission Expenses** | |
| Operation | |
| 560 | Operation supervision and engineering |
| 561.1 | Load dispatch-Reliability |
| 561.2 | Load dispatch-Monitor and operate transmission system |
| 561.3 | Scheduling, system control and dispatch services |
| 561.4 | Load dispatch-Transmission service and scheduling |
| 561.5 | Reliability planning and standards development |
| 561.6 | Transmission service studies |
| 561.7 | Generation interconnection studies |
| 561.8 | Reliability planning and standards development services |
| 562 | Station expenses (Major only) |
| 563 | Overhead line expenses (Major only) |
| 564 | Underground line expenses (Major only) |
| 565 | Transmission of electricity by others (Major only) |
| 566 | Miscellaneous transmission expenses (Major only) |
| 567 | Rents |
| 567.1 | Operation supplies and expenses (Nonmajor only) |
| Maintenance | |
| 568 | Maintenance supervision and engineering (Major only) |
| 569 | Maintenance of structures (Major only) |
| 569.1 | Maintenance of computer hardware |
| 569.2 | Maintenance of computer software |
| 569.3 | Maintenance of communication equipment |
| 569.4 | Maintenance of miscellaneous regional transmission plant |
| 570 | Maintenance of station equipment (Major only) |
| 571 | Maintenance of overhead lines (Major only) |
| 572 | Maintenance of underground lines (Major only) |
| 573 | Maintenance of miscellaneous transmission plant (Major only) |
| 574 | Maintenance of transmission plant (Nonmajor only) |

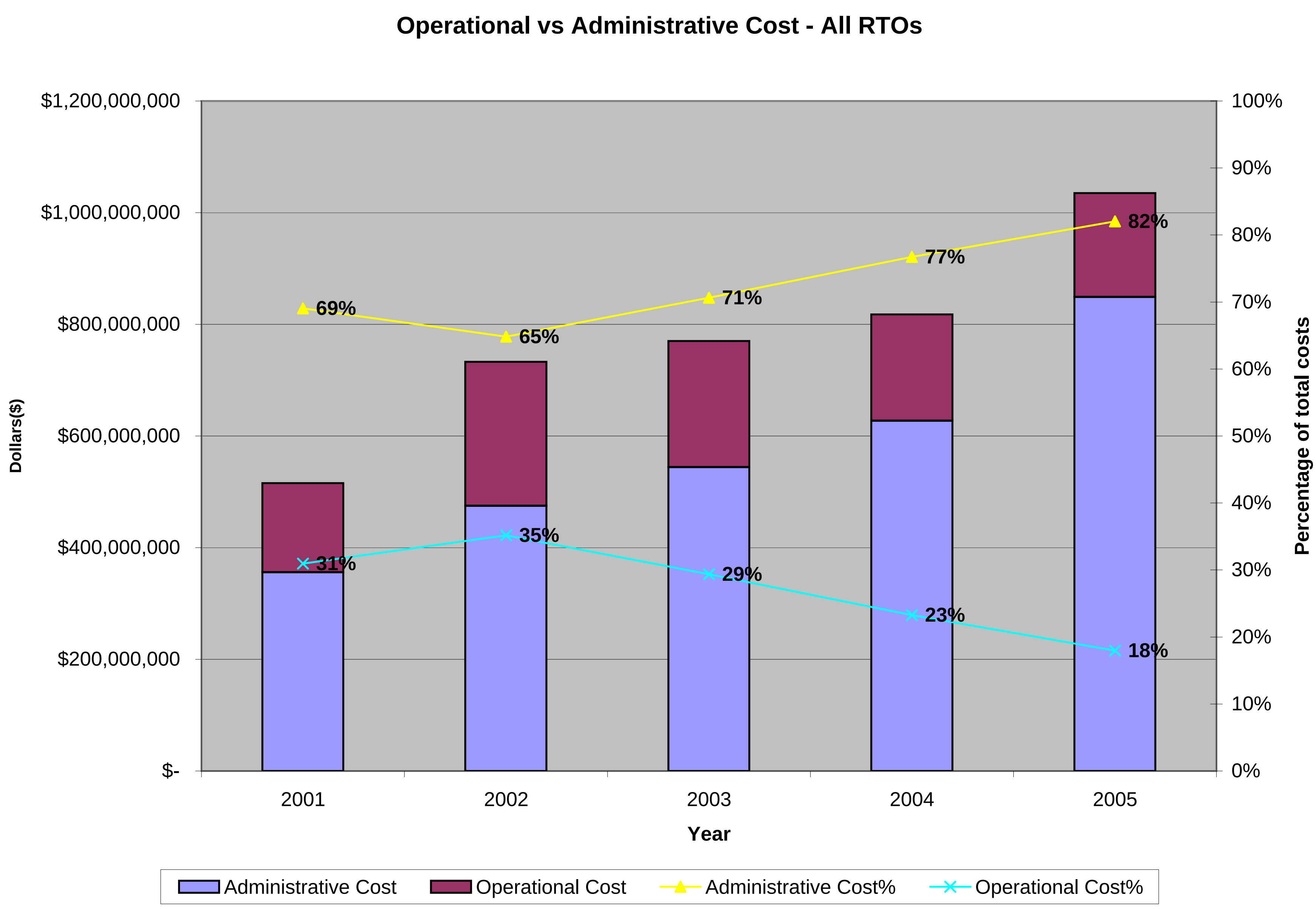
# Appendix B - Graphs of RTO Administrative and Operational Costs

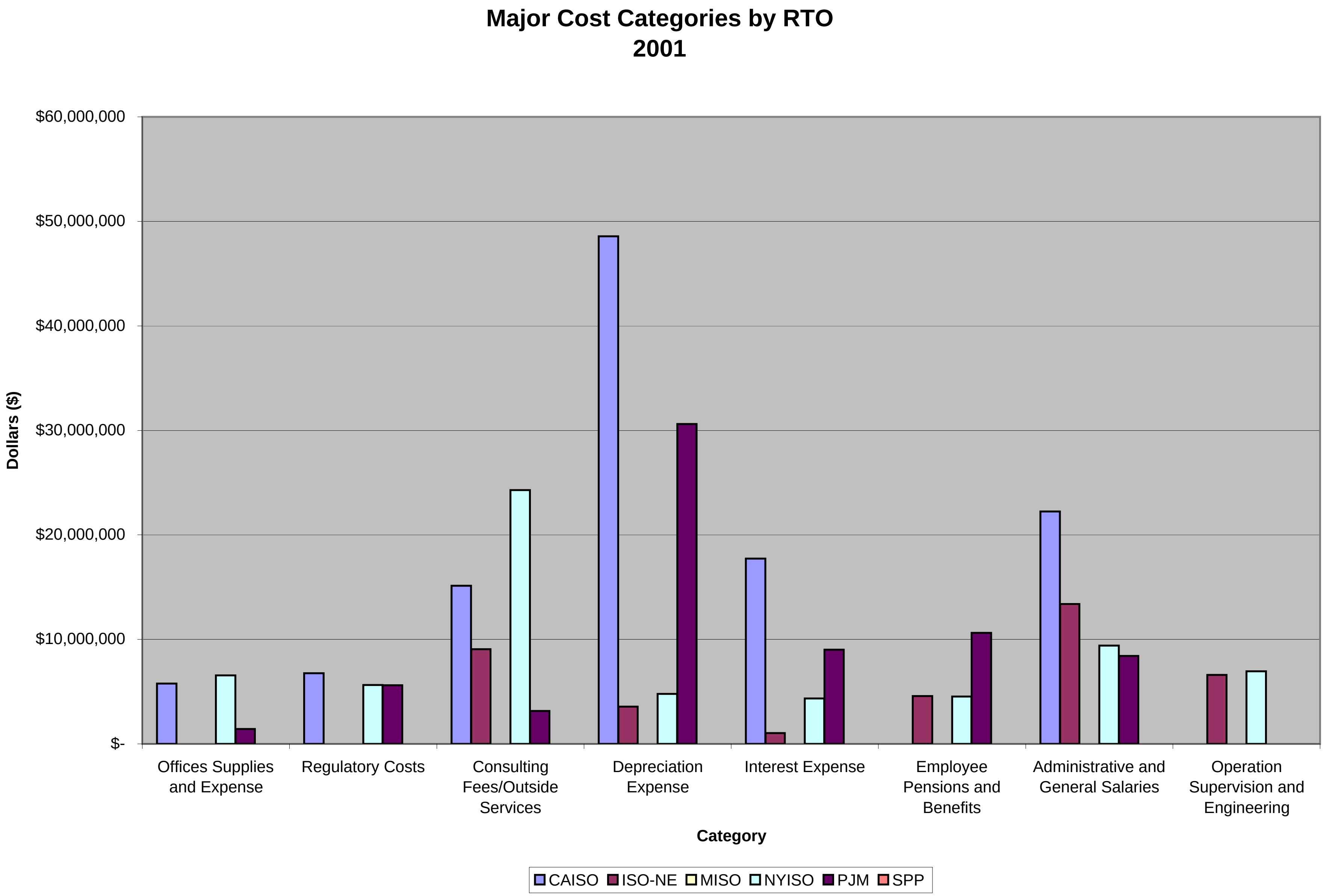
# B1 - Overview

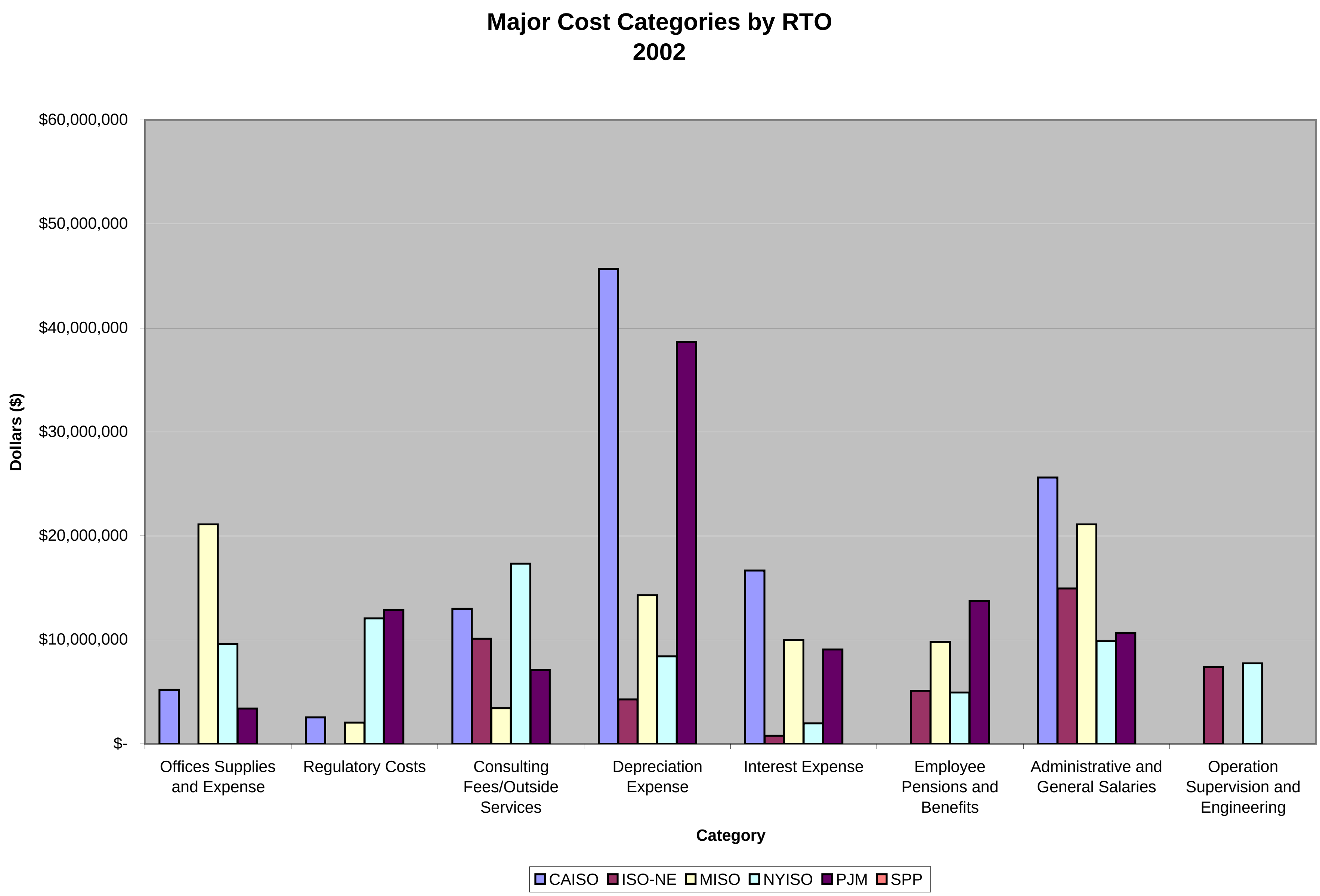

RTO Costs in $/MWH (2001-2005)
$1.200
$1.000
$0.800
$0.600
$0.400
$0.200
$-
$/MWh
2001
2002
2003
2004
2005
Year
CAISO
ISO-NE
MISO
NYISO
PJM
SPP

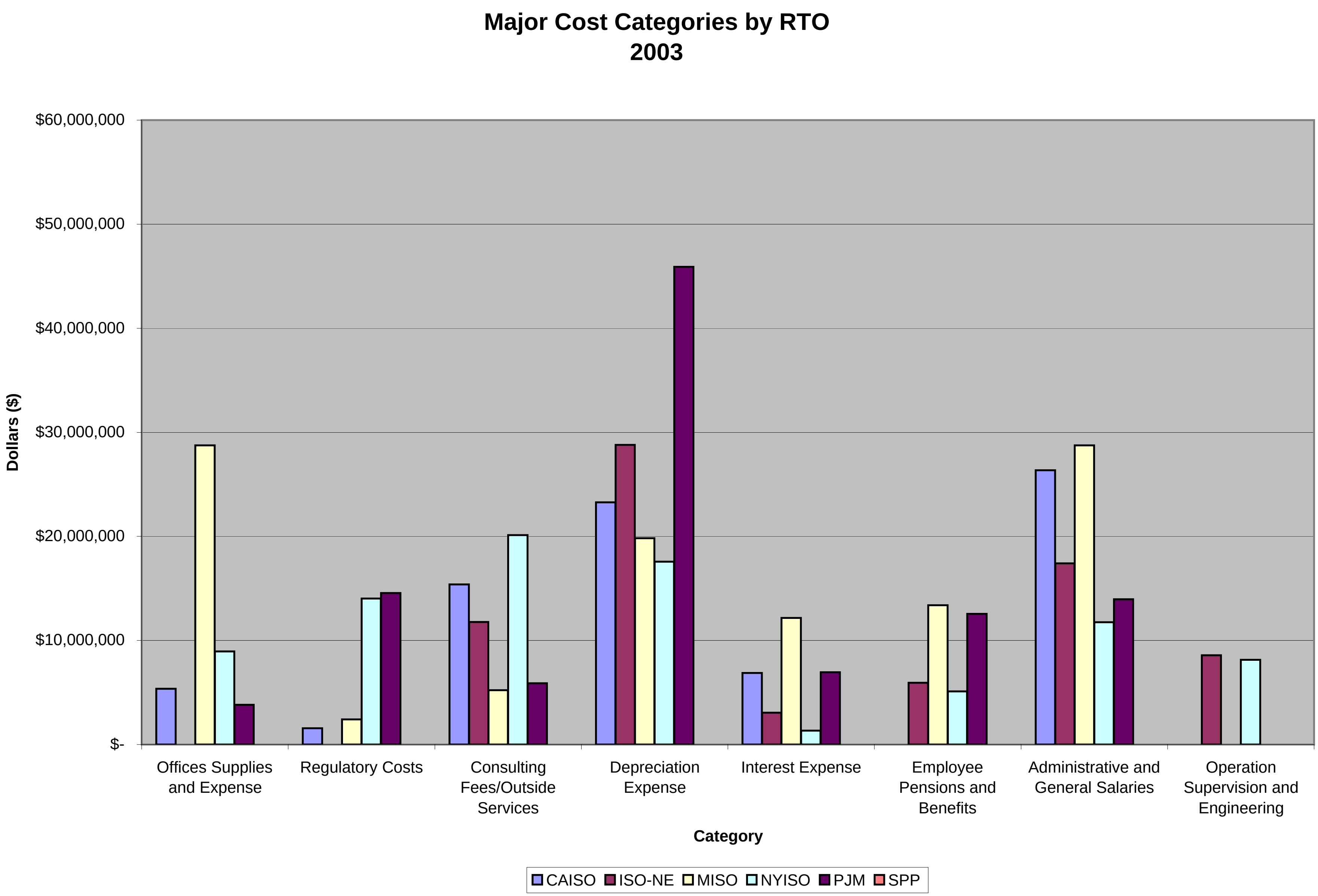
## RTO Total Operational vs. Total Administrative Costs (2001-2005)

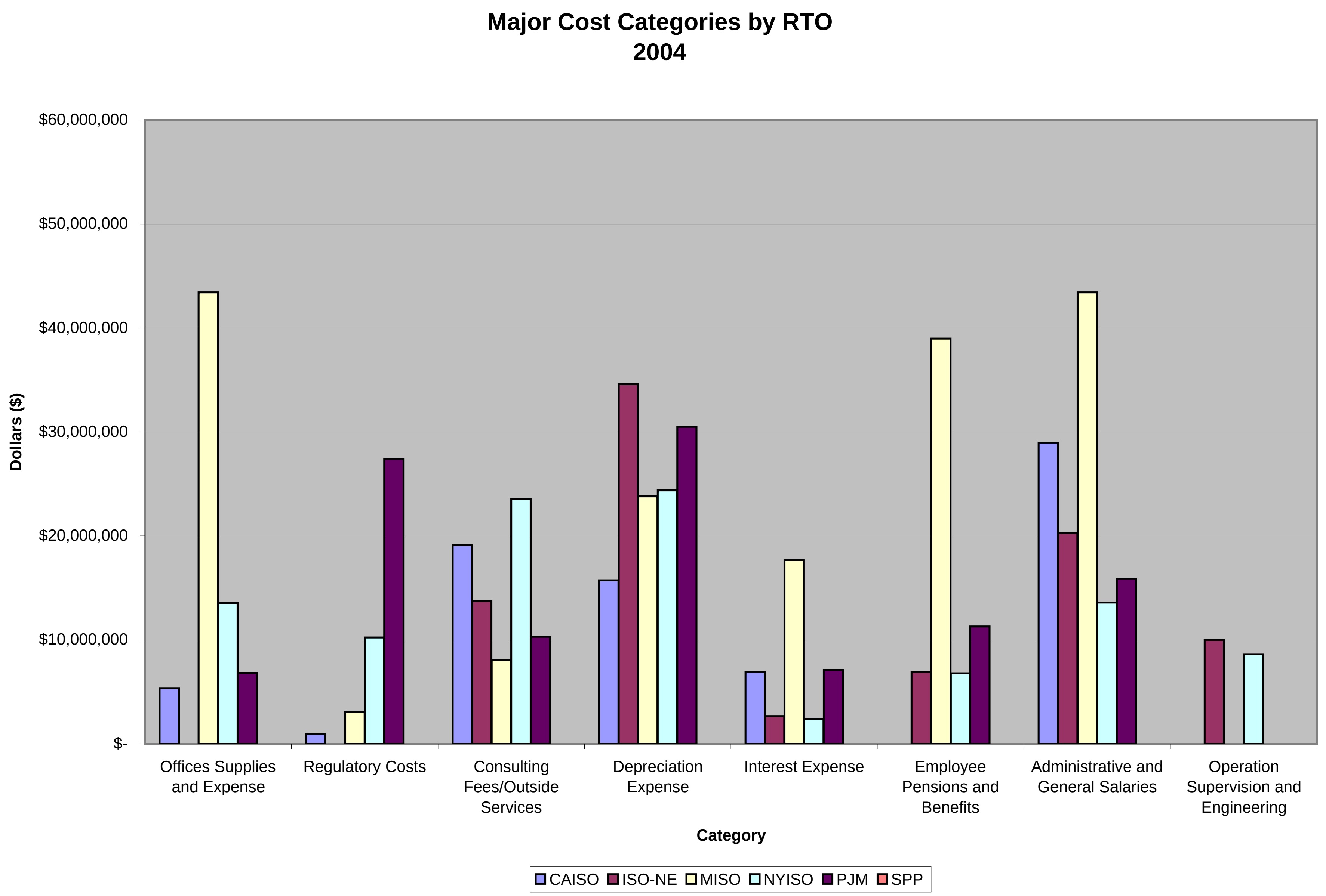


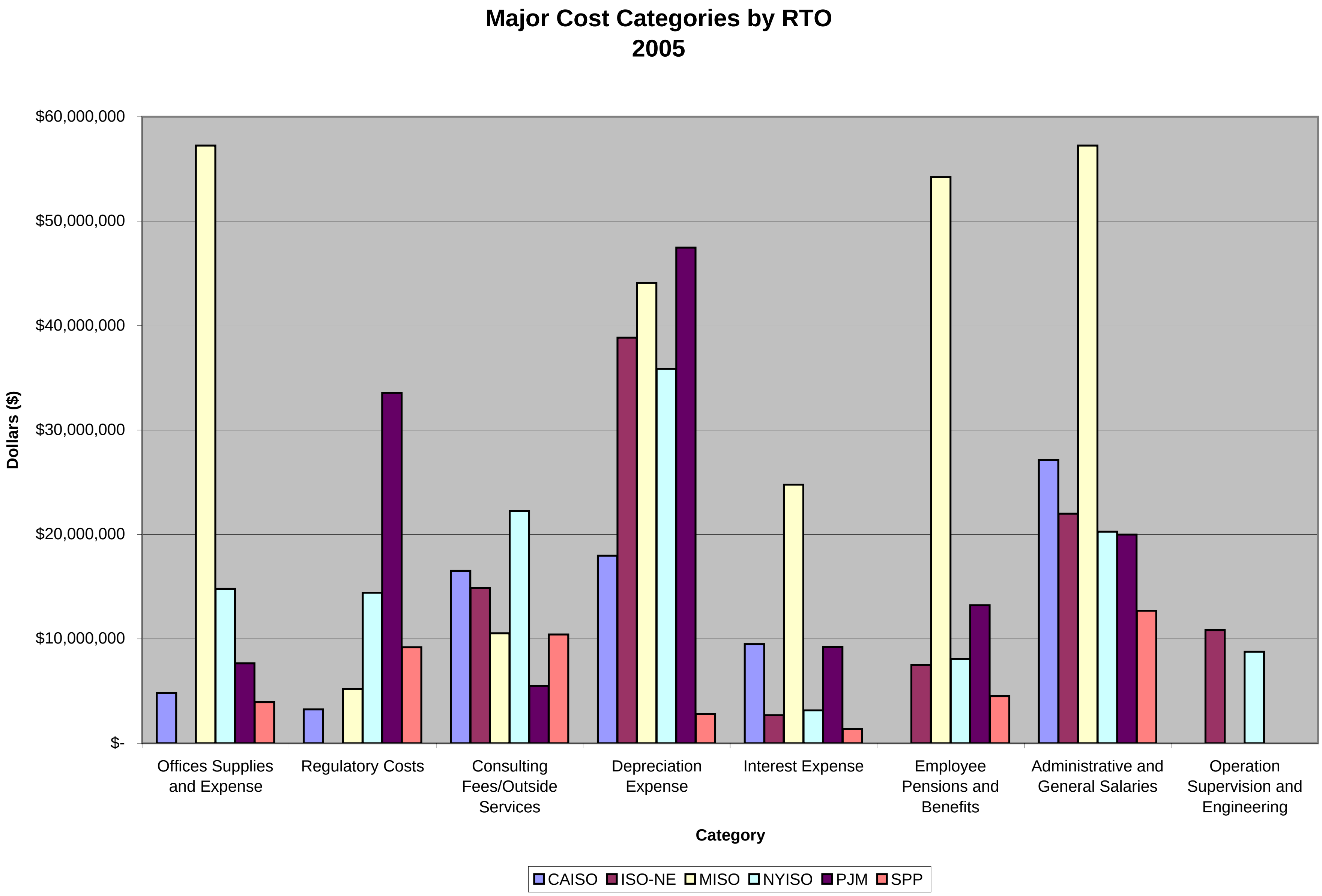

Operational vs Administrative Cost - All RTOs
$1,200,000,000
$1,000,000,000
$800,000,000
$600,000,000
$400,000,000
$200,000,000
$-
Dollars($)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of total costs
69%
65%
71%
77%
82%
31%
35%
29%
23%
18%
2001
2002
2003
2004
2005
Year
Administrative Cost
Operational Cost
Administrative Cost%
Operational Cost%


Major Cost Categories by RTO
2001
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
Dollars ($)
Offices Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Depreciation Expense
Interest Expense
Employee Pensions and Benefits
Administrative and General Salaries
Operation Supervision and Engineering
Category
CAISO
ISO-NE
MISO
NYISO
PJM
SPP


Major Cost Categories by RTO
2002
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
Dollars ($)
Offices Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Depreciation Expense
Interest Expense
Employee Pensions and Benefits
Administrative and General Salaries
Operation Supervision and Engineering
Category
CAISO
ISO-NE
MISO
NYISO
PJM
SPP

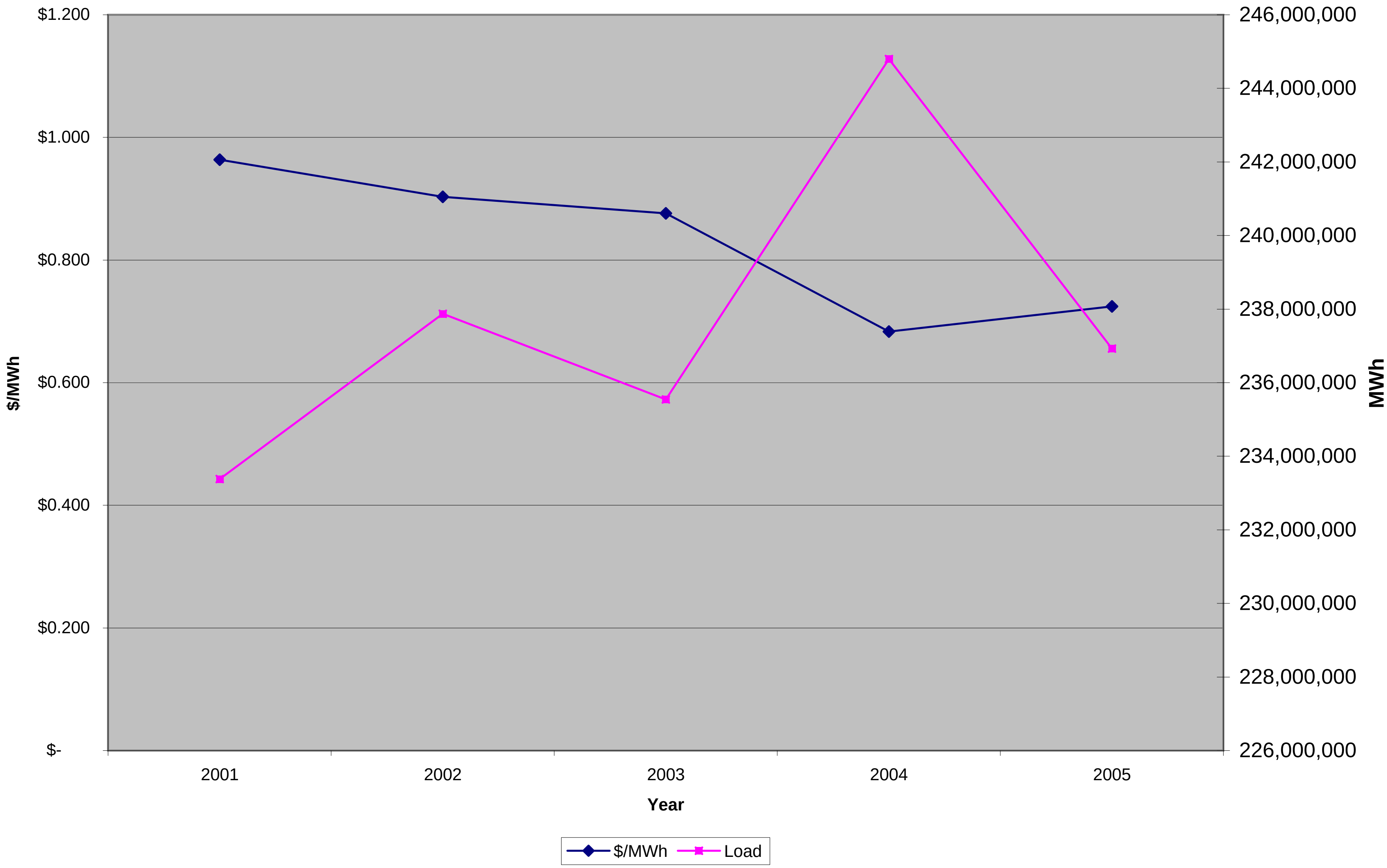

Major Cost Categories by RTO
2003
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
Dollars ($)
Offices Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Depreciation Expense
Interest Expense
Employee Pensions and Benefits
Administrative and General Salaries
Operation Supervision and Engineering
Category
CAISO
ISO-NE
MISO
NYISO
PJM
SPP

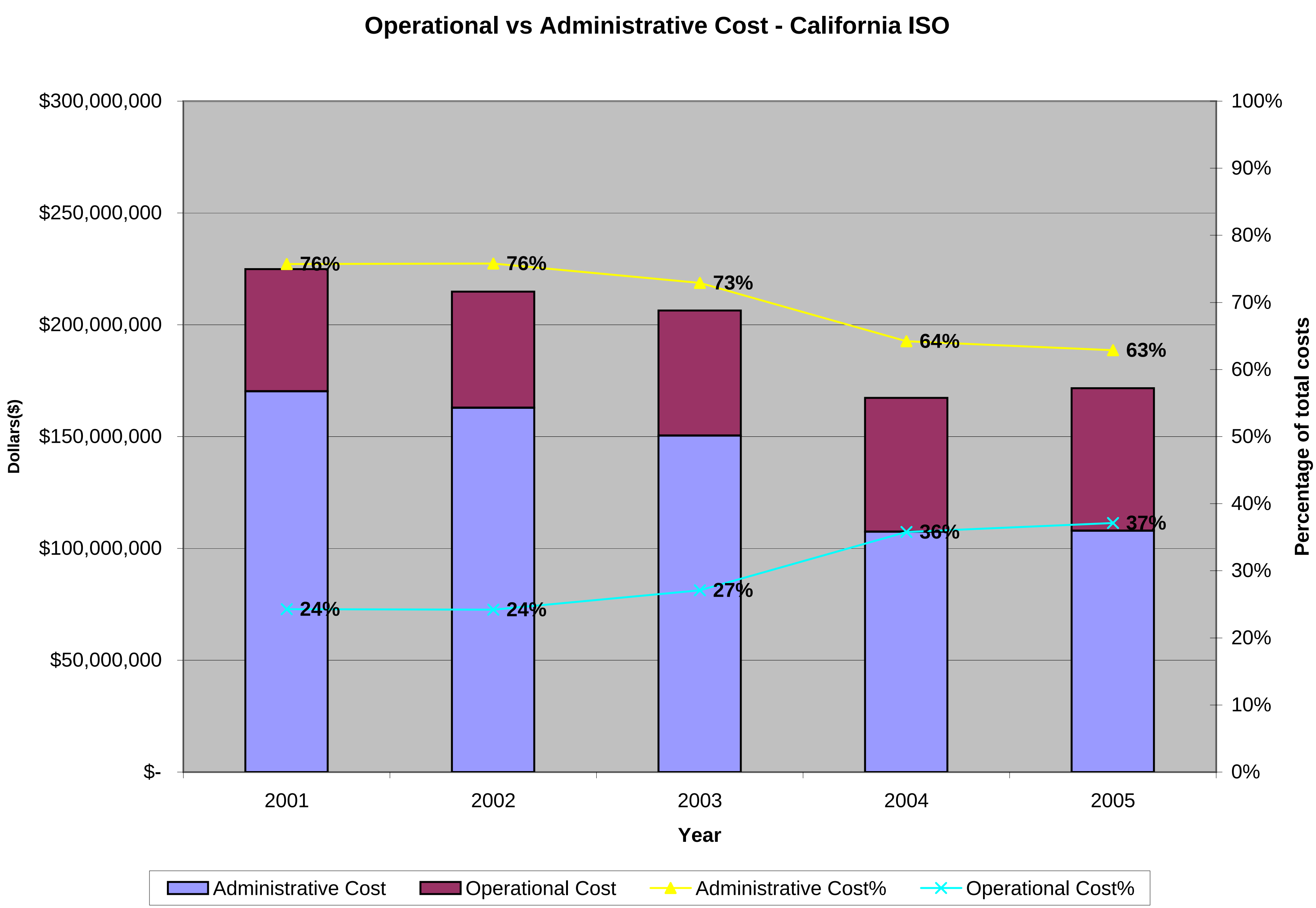

Major Cost Categories by RTO
2004
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
Dollars ($)
Offices Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Depreciation Expense
Interest Expense
Employee Pensions and Benefits
Administrative and General Salaries
Operation Supervision and Engineering
Category
CAISO
ISO-NE
MISO
NYISO
PJM
SPP


Major Cost Categories by RTO
2005
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
Dollars ($)
Offices Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Depreciation Expense
Interest Expense
Employee Pensions and Benefits
Administrative and General Salaries
Operation Supervision and Engineering
Category
CAISO
ISO-NE
MISO
NYISO
PJM
SPP

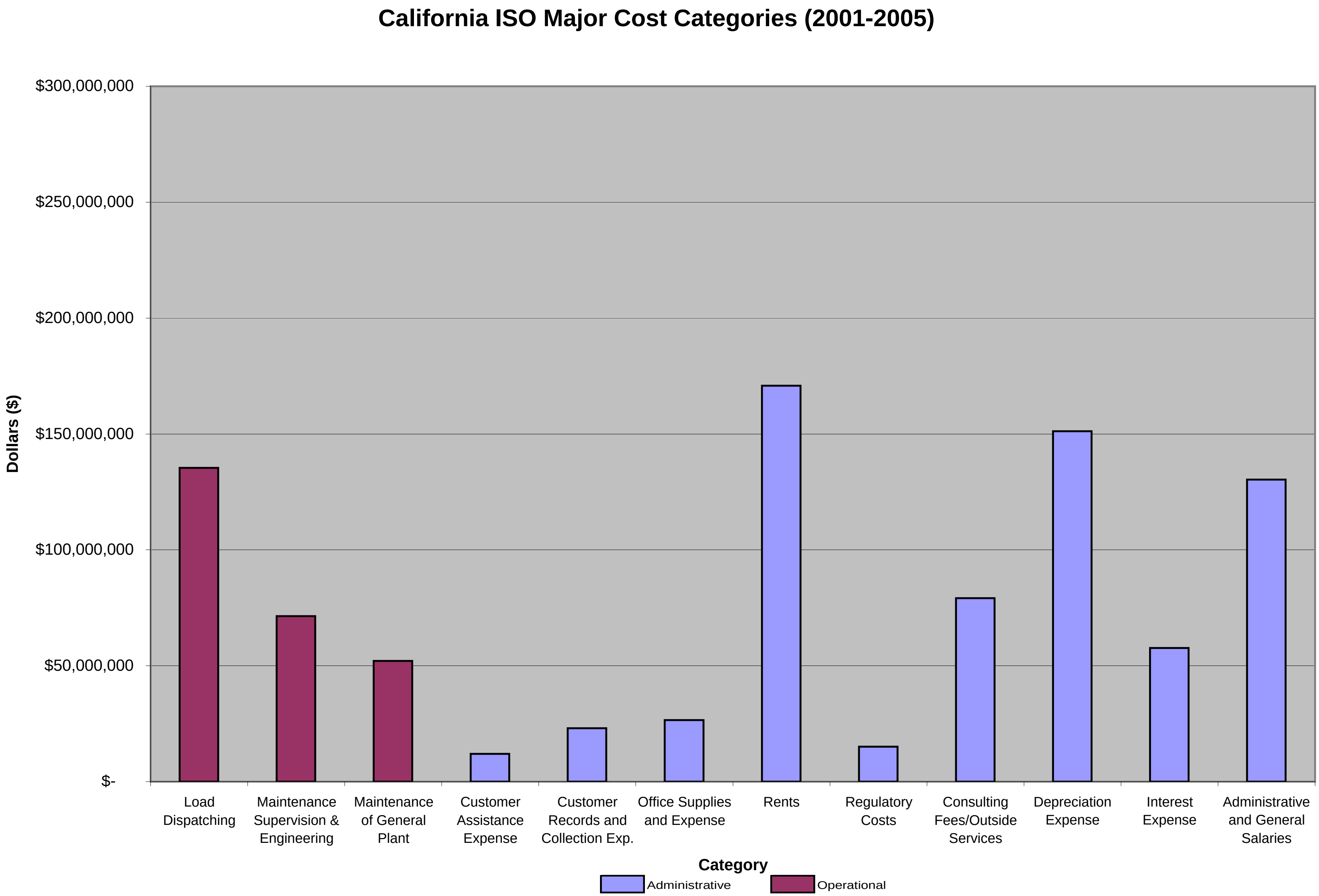
# B2 - California ISO

**California ISO MWh and $/MWh**

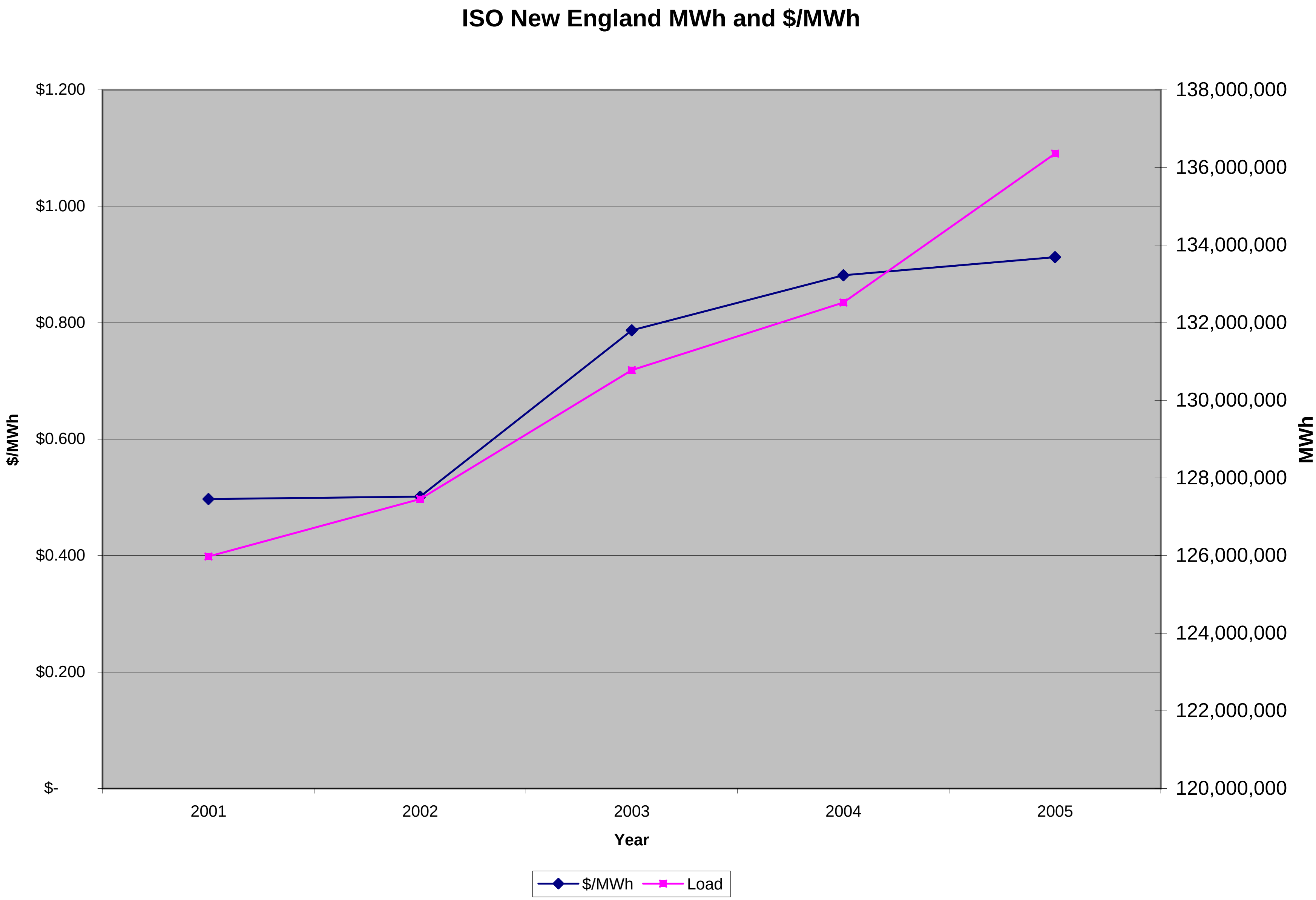


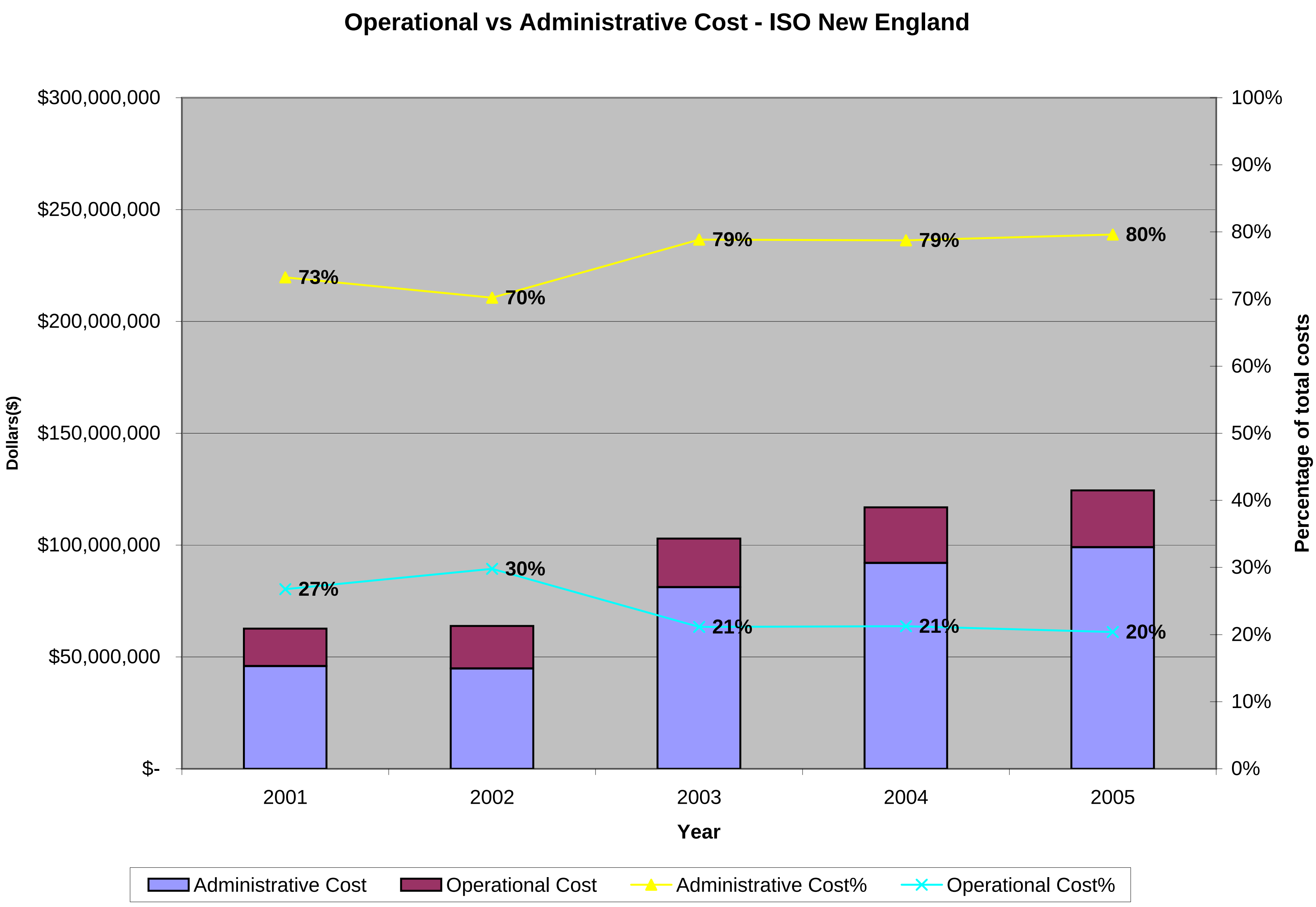


Operational vs Administrative Cost - California ISO
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Dollars($)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of total costs
76%
76%
73%
64%
63%
24%
24%
27%
36%
37%
2001
2002
2003
2004
2005
Year
Administrative Cost
Operational Cost
Administrative Cost%
Operational Cost%

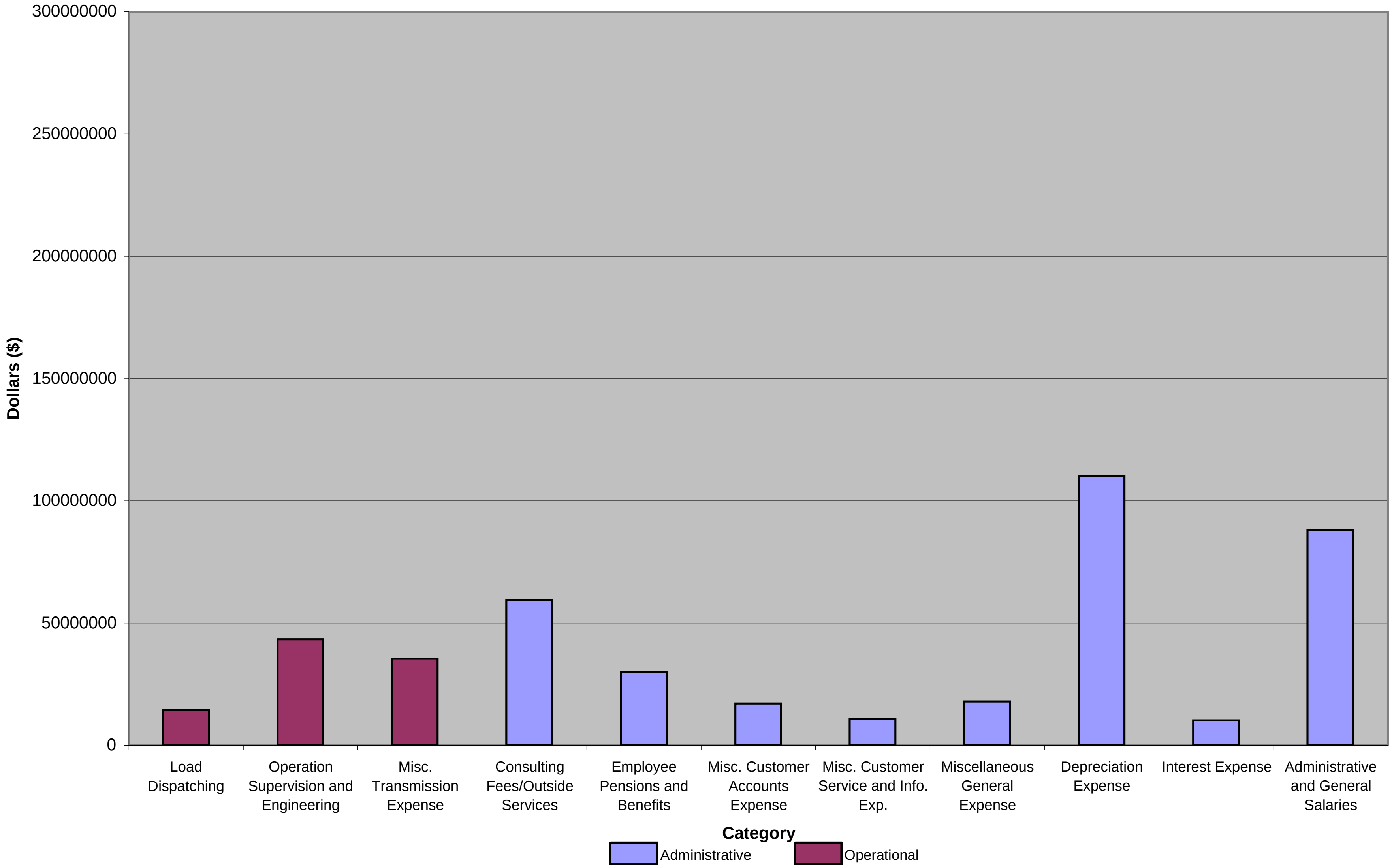

California ISO Major Cost Categories (2001-2005)
Dollars ($)
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Load Dispatching
Maintenance Supervision & Engineering
Maintenance of General Plant
Customer Assistance Expense
Customer Records and Collection Exp.
Office Supplies and Expense
Rents
Regulatory Costs
Consulting Fees/Outside Services
Depreciation Expense
Interest Expense
Administrative and General Salaries
Category
Administrative
Operational

# B3 - ISO New England


ISO New England MWh and $/MWh
$1.200
$1.000
$0.800
$0.600
$0.400
$0.200
$-
$/MWh
138,000,000
136,000,000
134,000,000
132,000,000
130,000,000
128,000,000
126,000,000
124,000,000
122,000,000
120,000,000
MWh
2001
2002
2003
2004
2005
Year
$/MWh
Load

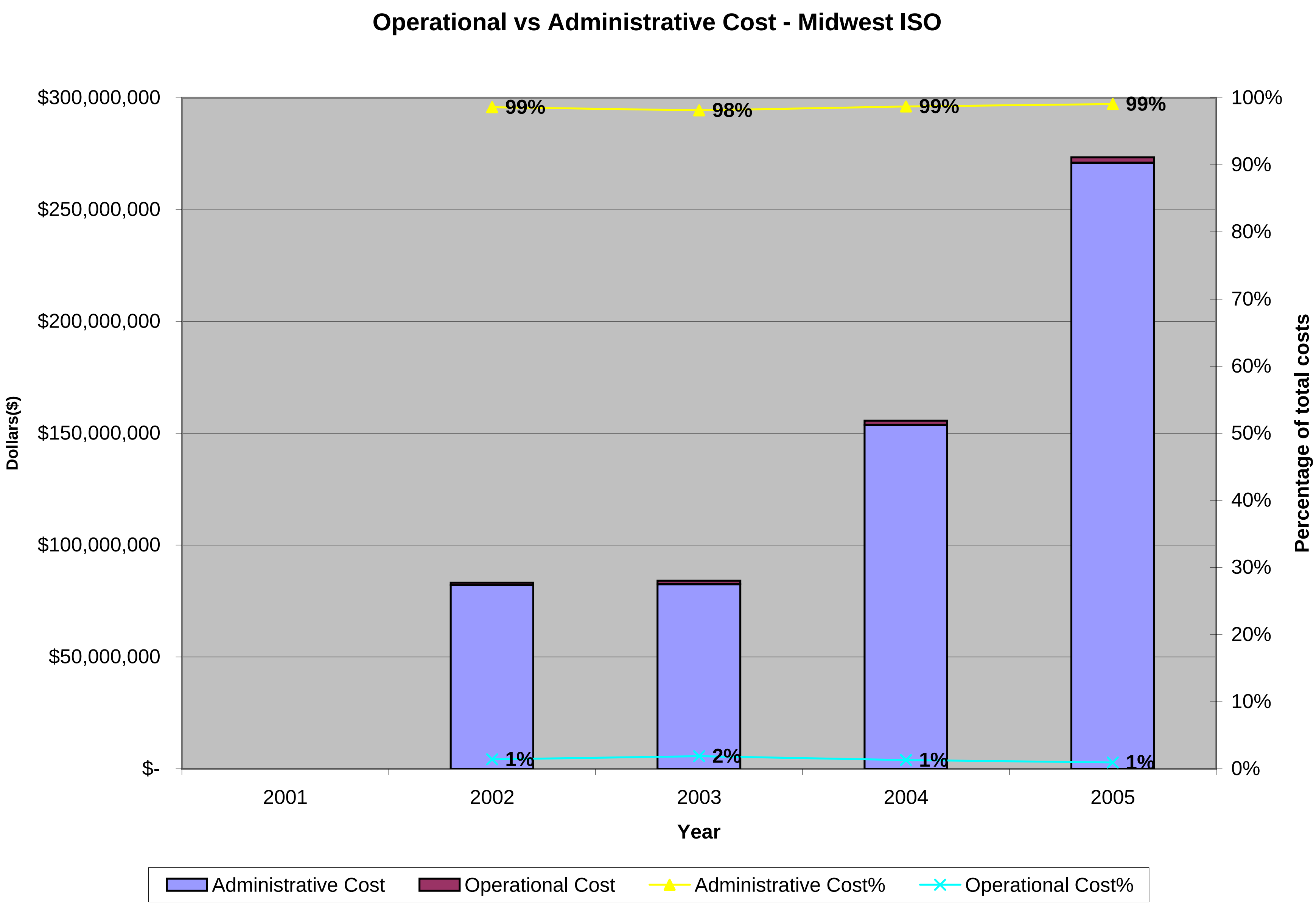

Operational vs Administrative Cost - ISO New England
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Dollars($)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of total costs
73%
70%
79%
79%
80%
27%
30%
21%
21%
20%
2001
2002
2003
2004
2005
Year
Administrative Cost
Operational Cost
Administrative Cost%
Operational Cost%

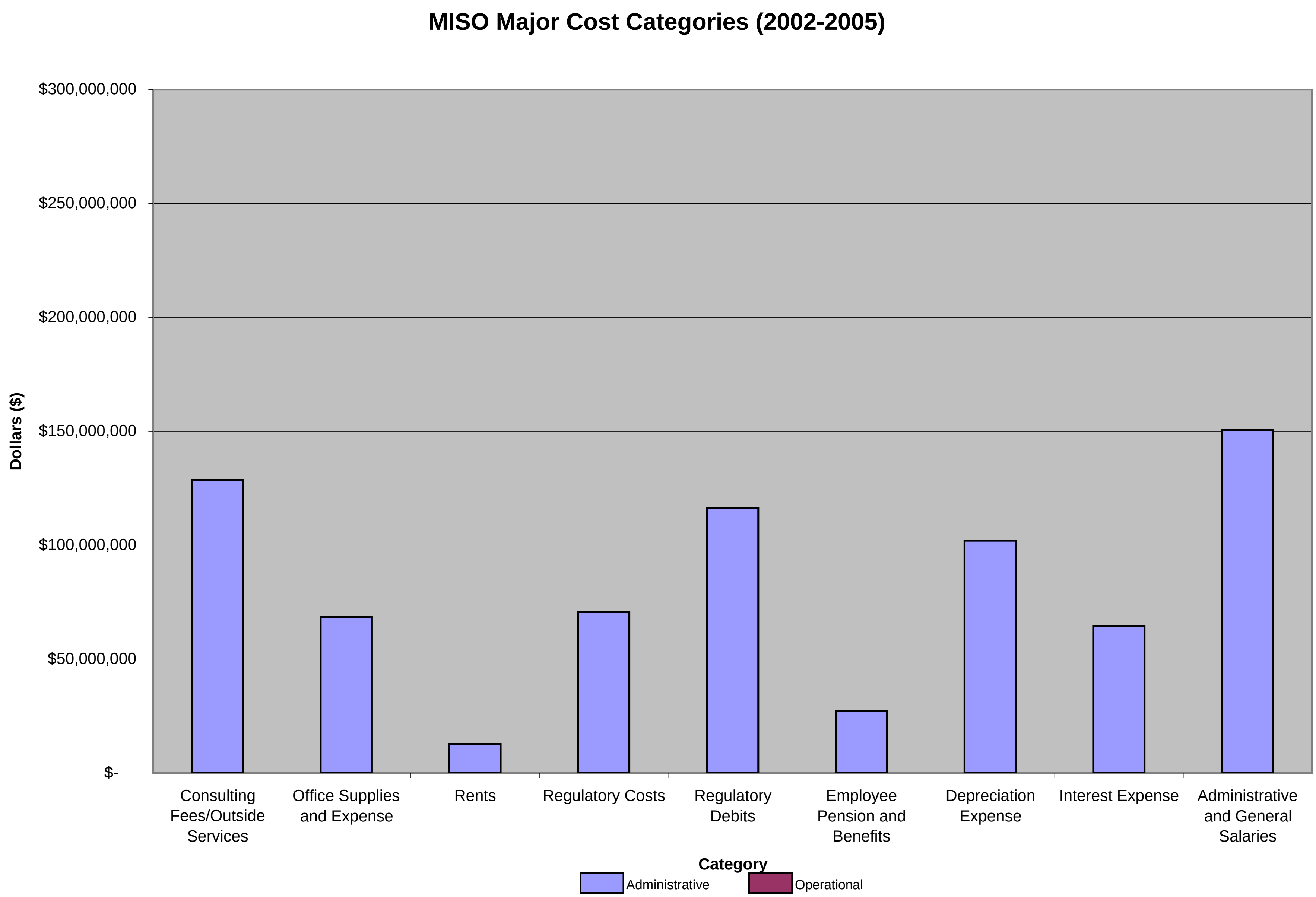
## ISO New England Major Cost Categories (2001-2005)



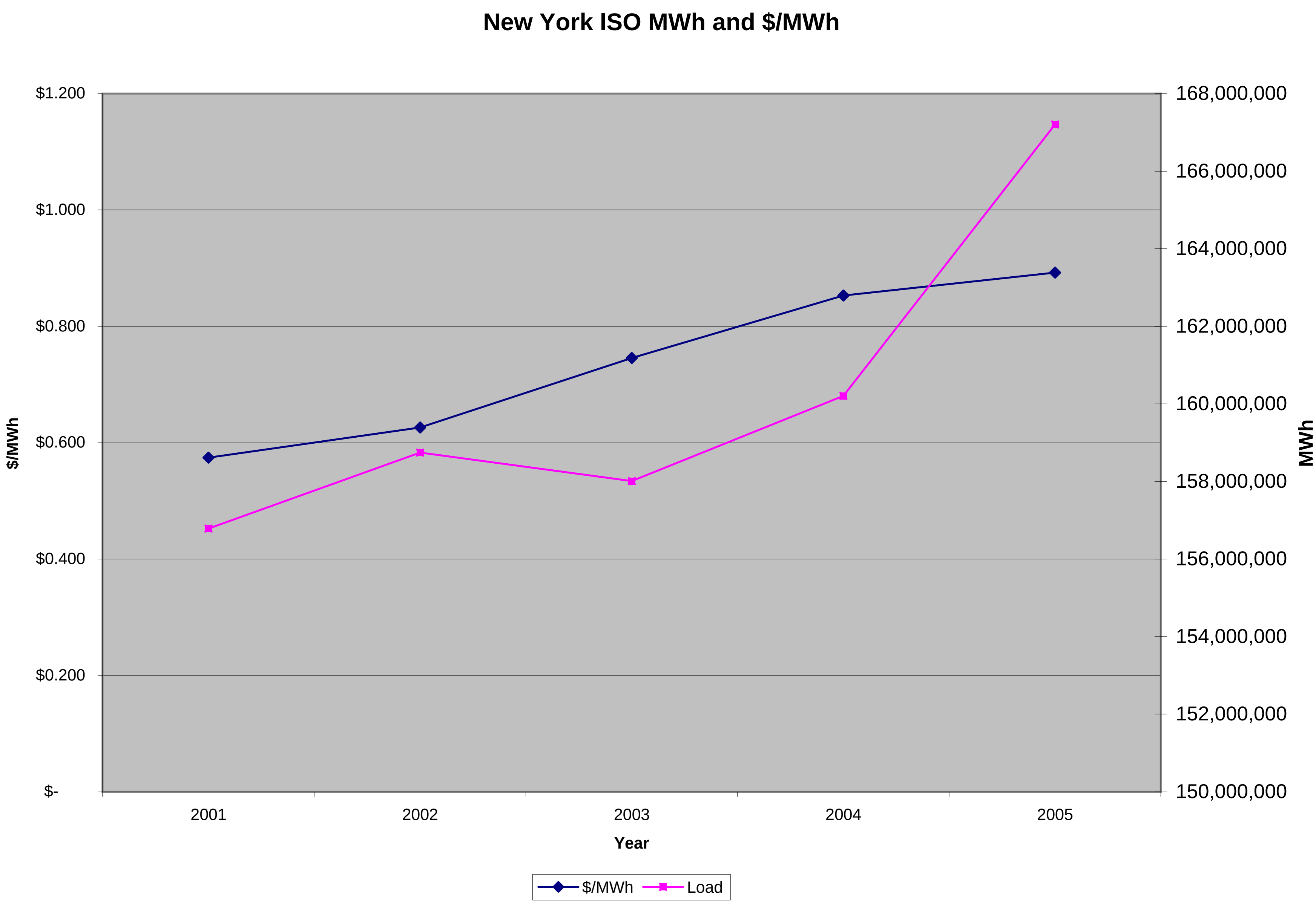
# B4 - Midwest ISO

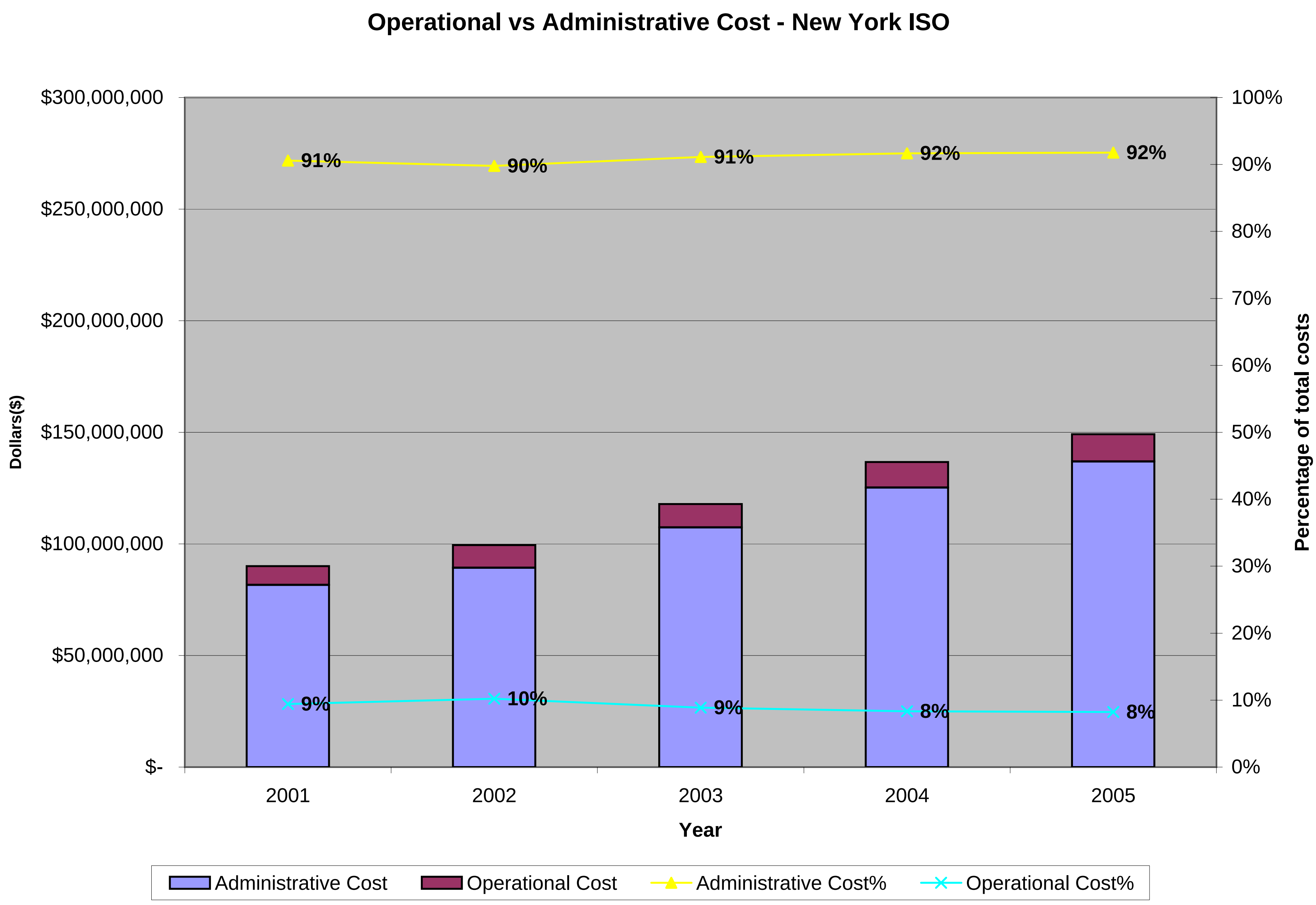

Midwest ISO MWh and $/MWh
$1.200
$1.000
$0.800
$0.600
$0.400
$0.200
$-
$/MWh
700,000,000
600,000,000
500,000,000
400,000,000
300,000,000
200,000,000
100,000,000
0
MWh
2001
2002
2003
2004
2005
Year
$/MWh
Load

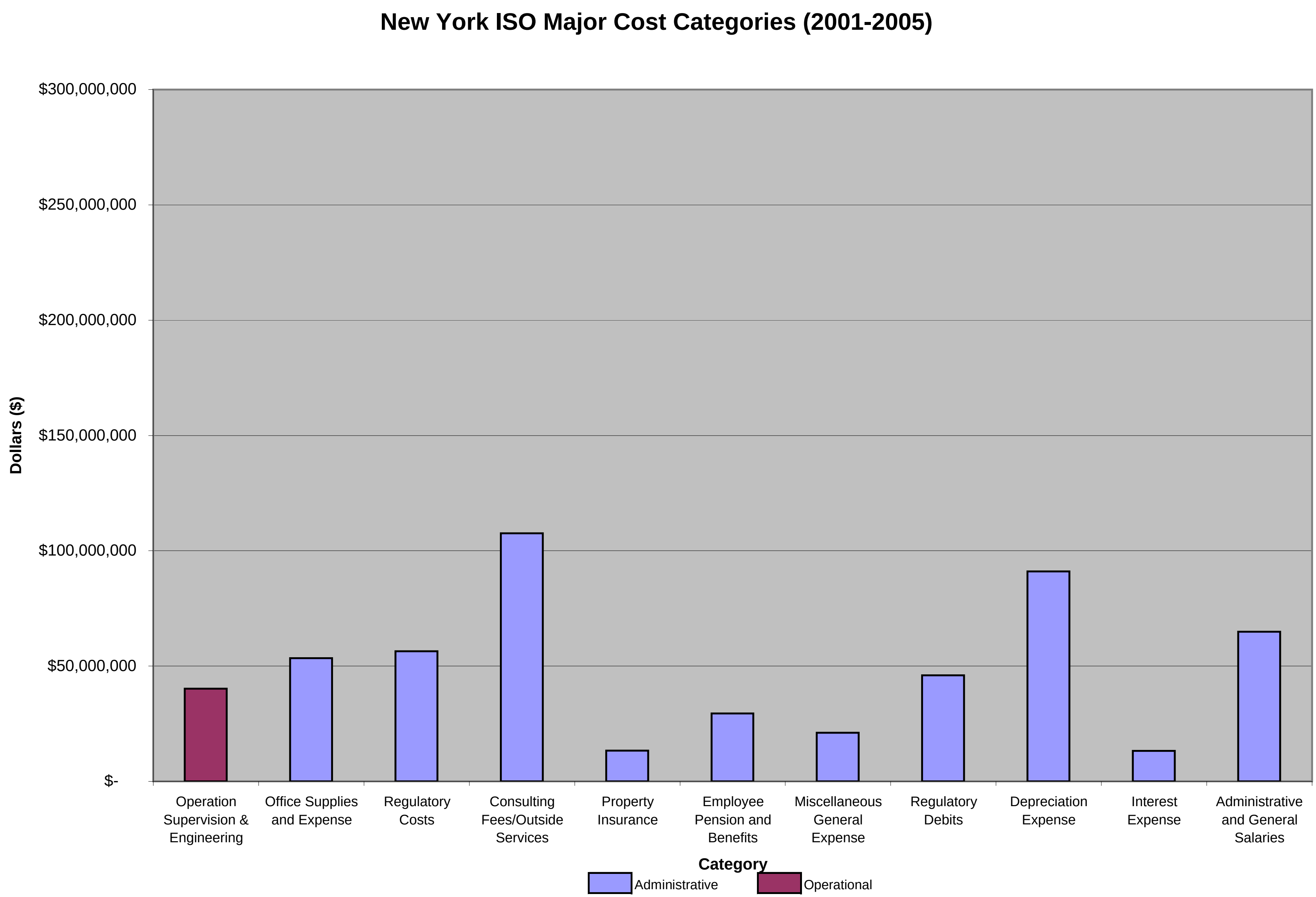

Operational vs Administrative Cost - Midwest ISO
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Dollars($)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of total costs
99%
98%
99%
99%
1%
2%
1%
1%
2001
2002
2003
2004
2005
Year
Administrative Cost
Operational Cost
Administrative Cost%
Operational Cost%


MISO Major Cost Categories (2002-2005)
Dollars ($)
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Consulting Fees/Outside Services
Office Supplies and Expense
Rents
Regulatory Costs
Regulatory Debits
Employee Pension and Benefits
Depreciation Expense
Interest Expense
Administrative and General Salaries
Category
Administrative
Operational

# B5 - New York ISO

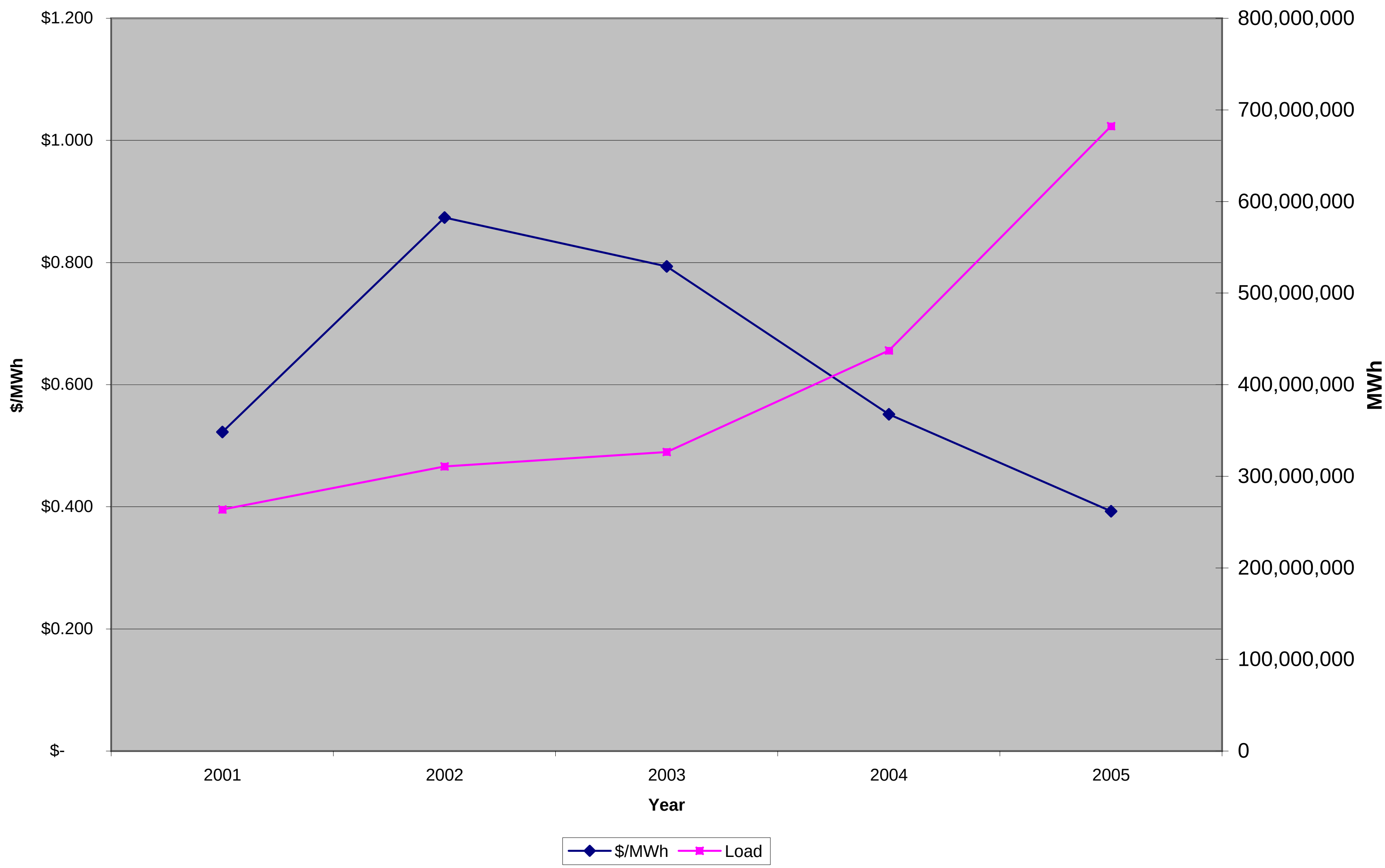

New York ISO MWh and $/MWh
$1.200
$1.000
$0.800
$0.600
$0.400
$0.200
$-
$/MWh
168,000,000
166,000,000
164,000,000
162,000,000
160,000,000
158,000,000
156,000,000
154,000,000
152,000,000
150,000,000
MWh
2001
2002
2003
2004
2005
Year
$/MWh
Load

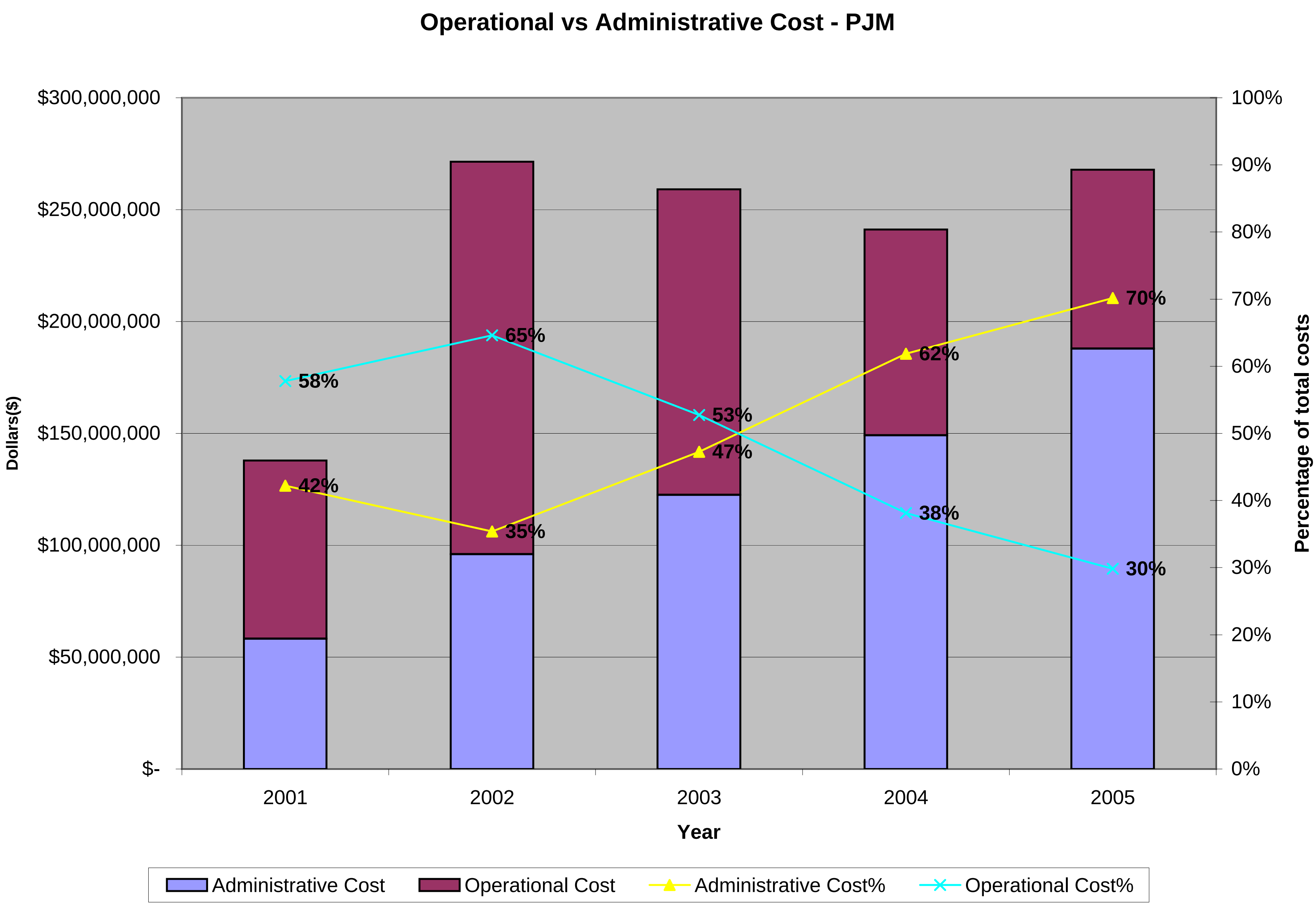

Operational vs Administrative Cost - New York ISO
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Dollars($)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of total costs
91%
90%
91%
92%
92%
9%
10%
9%
8%
8%
2001
2002
2003
2004
2005
Year
Administrative Cost
Operational Cost
Administrative Cost%
Operational Cost%

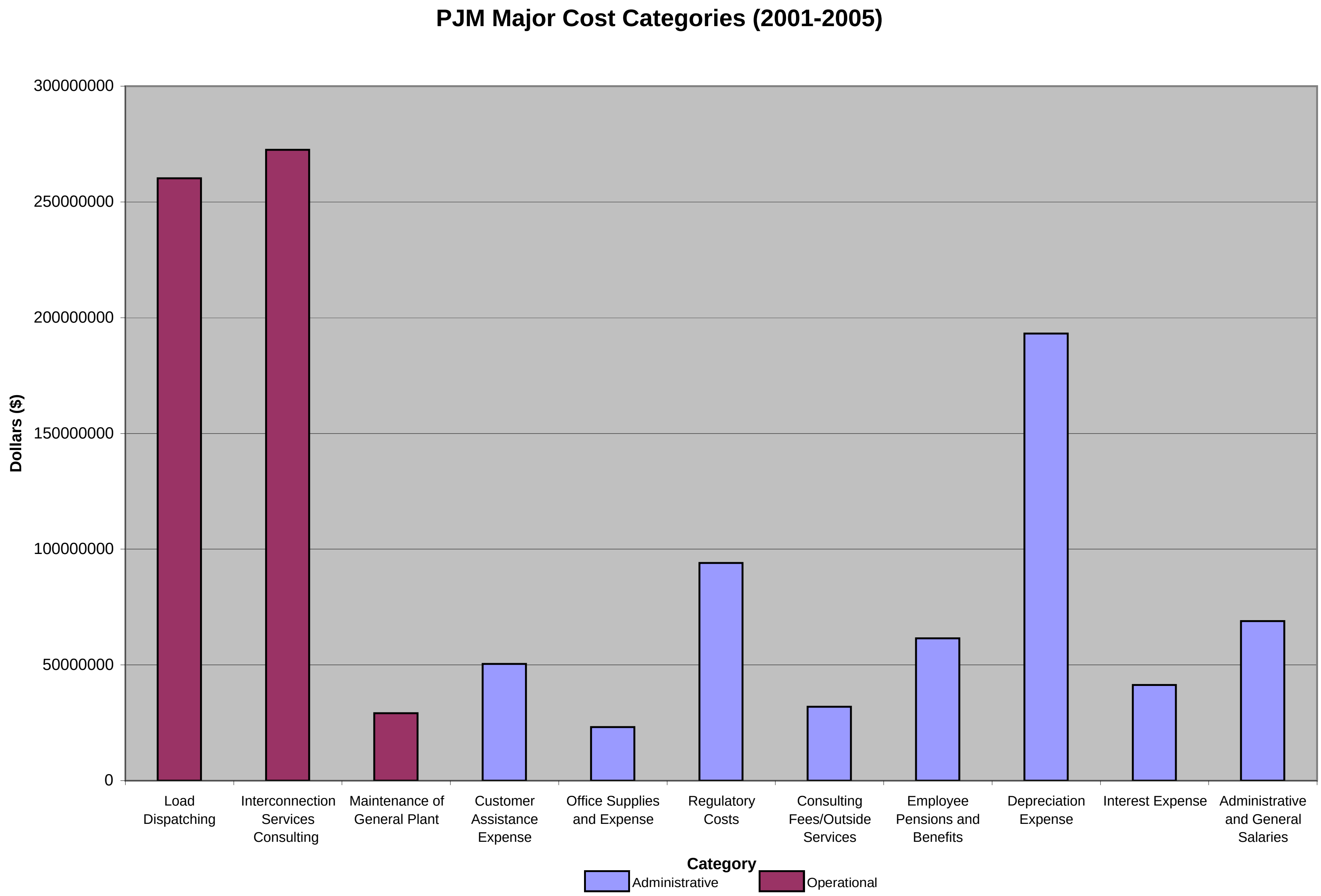

New York ISO Major Cost Categories (2001-2005)
Dollars ($)
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Operation Supervision & Engineering
Office Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Property Insurance
Employee Pension and Benefits
Miscellaneous General Expense
Regulatory Debits
Depreciation Expense
Interest Expense
Administrative and General Salaries
Category
Administrative
Operational

# B6 – PJM

## PJM MWh and $/MWh

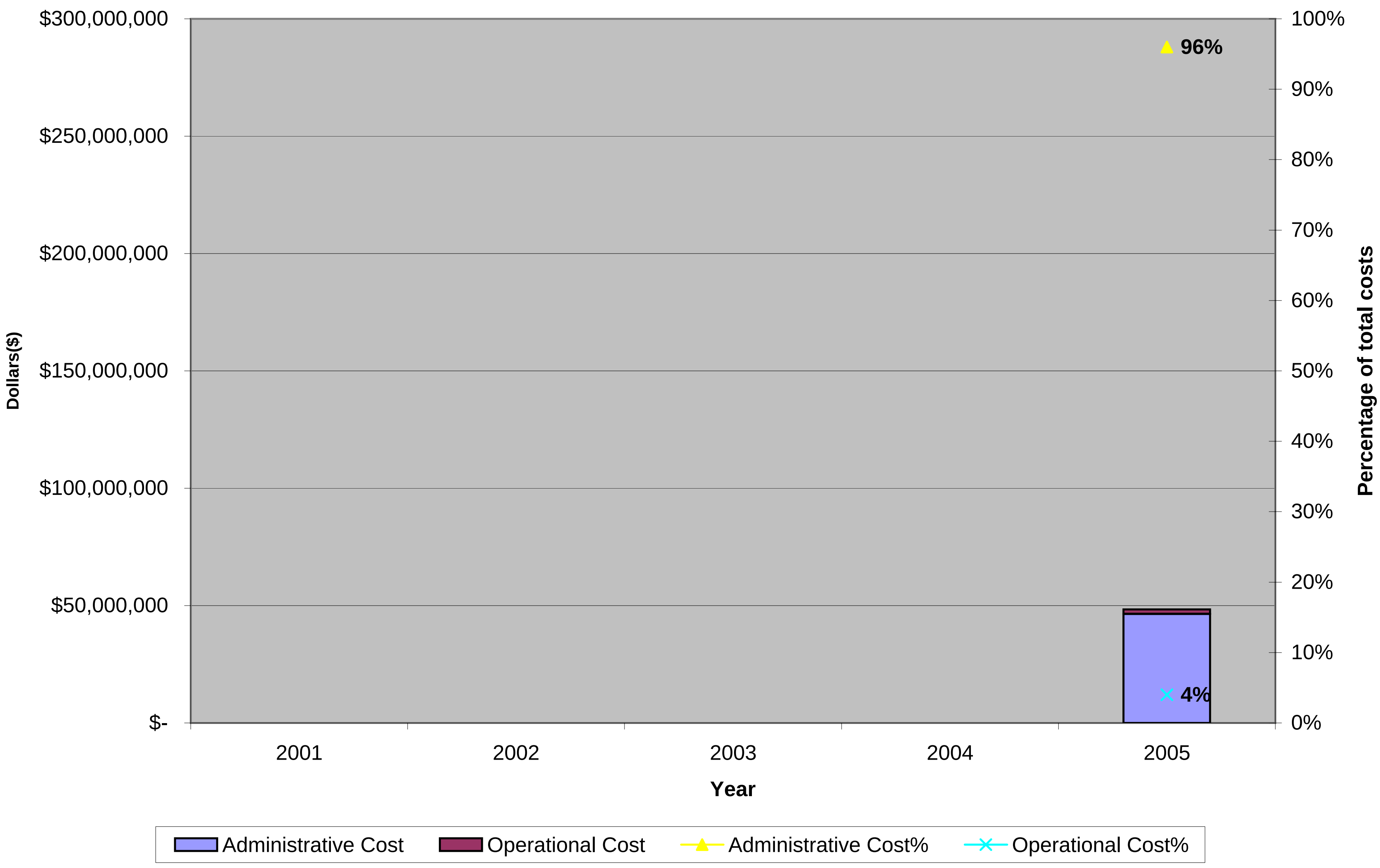



Operational vs Administrative Cost - PJM
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
Dollars($)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percentage of total costs
58%
65%
53%
38%
30%
42%
35%
47%
62%
70%
2001
2002
2003
2004
2005
Year
Administrative Cost
Operational Cost
Administrative Cost%
Operational Cost%

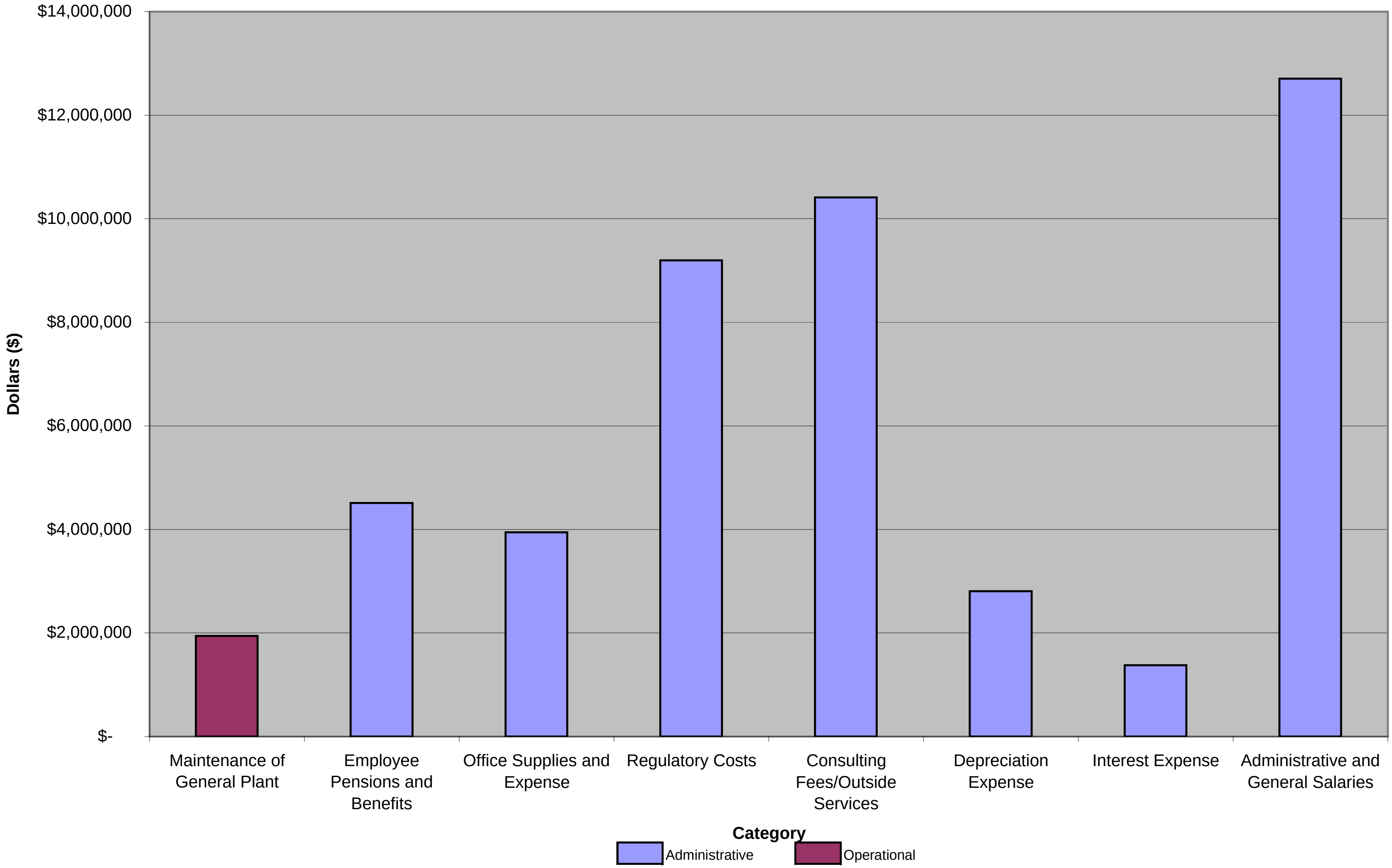

PJM Major Cost Categories (2001-2005)
Dollars ($)
300000000
250000000
200000000
150000000
100000000
50000000
0
Load Dispatching
Interconnection Services Consulting
Maintenance of General Plant
Customer Assistance Expense
Office Supplies and Expense
Regulatory Costs
Consulting Fees/Outside Services
Employee Pensions and Benefits
Depreciation Expense
Interest Expense
Administrative and General Salaries
Category
Administrative
Operational

# B7 - Southwest Power Pool

## Operational vs Administrative Cost - Southwest Power Pool



## SPP Major Cost Categories (2005)



# Appendix C - Detailed Tables of RTO Administrative and Operational Costs

# C1 - California ISO

**Summary Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**California ISO**

**Major Cost Breakdown**

**Note: RTO Major Costs are those that are typically over 2% of the Total Cost for a year.**

| | 2001 | 2002 | 2003 | 2004 | 2005 | Survey Period Total | % of Total Cost |
|---|---|---|---|---|---|---|---|
| **CAISO Annual Load (MWh)** | 233,378,803 | 237,870,367 | 235,540,579 | 244,794,546 | 236,925,183 | 1,188,509,478 | N/A |
| **Total Costs** | $ 224,851,266 | $ 214,850,342 | $ 206,343,863 | $ 167,313,598 | $ 171,611,513 | **$ 984,970,582** | 100.0% |
| $/MWh | $ 0.963 | $ 0.903 | $ 0.876 | $ 0.683 | $ 0.724 | $ 0.829 | |
| **Operational** | | | | | | | |
| **Total Operational Costs** | $ 54,605,595 | $ 52,007,237 | $ 55,884,977 | $ 59,887,060 | $ 63,719,381 | **$ 286,104,250** | 29.0% |
| $/MWh | $ 0.234 | $ 0.219 | $ 0.237 | $ 0.245 | $ 0.269 | $ 0.241 | |
| **Load Dispatching** | $ 23,553,659 | $ 24,334,773 | $ 28,510,876 | $ 27,783,431 | $ 31,157,011 | **$ 135,339,750** | 13.7% |
| $/MWh | $ 0.101 | $ 0.102 | $ 0.121 | $ 0.113 | $ 0.132 | $ 0.114 | |
| **Maintenance Supervision & Engineering** | $ 14,697,116 | $ 11,486,295 | $ 12,724,772 | $ 15,413,879 | $ 17,093,724 | **$ 71,415,786** | 7.3% |
| $/MWh | $ 0.063 | $ 0.048 | $ 0.054 | $ 0.063 | $ 0.072 | $ 0.060 | |
| **Maintenance of General Plant** | $ 9,752,068 | $ 10,333,528 | $ 9,187,218 | $ 11,434,134 | $ 11,336,218 | **$ 52,043,166** | 5.3% |
| $/MWh | $ 0.042 | $ 0.043 | $ 0.039 | $ 0.047 | $ 0.048 | $ 0.044 | |
| **Salaries and Wages[1]** | $ 31,387,894 | $ 35,260,814 | $ 36,782,908 | $ 39,182,222 | $ 42,436,596 | **$ 185,050,434** | 18.8% |
| $/MWh | $ 0.134 | $ 0.148 | $ 0.156 | $ 0.160 | $ 0.179 | $ 0.156 | |
| **Administrative** | | | | | | | |
| **Total Administrative Costs** | $ 170,245,671 | $ 162,843,105 | $ 150,458,886 | $ 107,426,538 | $ 107,892,132 | **$ 698,866,332** | 71.0% |
| $/MWh | $ 0.729 | $ 0.685 | $ 0.639 | $ 0.439 | $ 0.455 | $ 0.588 | |
| **Salaries and Wages[1]** | $ 30,175,943 | $ 35,388,118 | $ 35,192,252 | $ 38,059,753 | $ 34,613,017 | **$ 173,429,083** | 17.6% |
| $/MWh | $ 0.129 | $ 0.149 | $ 0.149 | $ 0.155 | $ 0.146 | $ 0.146 | |
| **Customer Assistance Expense** | $ 2,548,127 | $ 2,360,238 | $ 2,153,607 | $ 2,367,700 | $ 2,540,551 | **$ 11,970,223** | 1.2% |
| $/MWh | $ 0.011 | $ 0.010 | $ 0.009 | $ 0.010 | $ 0.011 | $ 0.010 | |
| **Customer Records and Collection Exp.** | $ 4,535,598 | $ 4,656,850 | $ 4,874,010 | $ 4,955,716 | $ 3,987,605 | **$ 23,009,779** | 2.3% |
| $/MWh | $ 0.019 | $ 0.020 | $ 0.021 | $ 0.020 | $ 0.017 | $ 0.019 | |
| **Office Supplies and Expense** | $ 5,772,481 | $ 5,200,857 | $ 5,366,858 | $ 5,365,186 | $ 4,813,495 | **$ 26,518,877** | 2.7% |
| $/MWh | $ 0.025 | $ 0.022 | $ 0.023 | $ 0.022 | $ 0.020 | $ 0.022 | |
| **Rents** | $ 42,745,929 | $ 44,411,089 | $ 45,032,111 | $ 19,655,260 | $ 18,964,539 | **$ 170,808,928** | 17.3% |
| $/MWh | $ 0.183 | $ 0.187 | $ 0.191 | $ 0.080 | $ 0.080 | $ 0.144 | |
| **Regulatory Costs** | $ 6,759,610 | $ 2,548,195 | $ 1,573,346 | $ 964,215 | $ 3,233,775 | **$ 15,079,141** | 1.5% |
| $/MWh | $ 0.029 | $ 0.011 | $ 0.007 | $ 0.004 | $ 0.014 | $ 0.013 | |
| **Consulting Fees/Outside Services** | $ 15,143,481 | $ 13,002,642 | $ 15,376,455 | $ 19,101,709 | $ 16,507,165 | **$ 79,131,452** | 8.0% |
| $/MWh | $ 0.065 | $ 0.055 | $ 0.065 | $ 0.078 | $ 0.070 | $ 0.067 | |
| **Depreciation Expense** | $ 48,574,402 | $ 45,681,679 | $ 23,276,006 | $ 15,729,517 | $ 17,965,299 | **$ 151,226,903** | 15.4% |
| $/MWh | $ 0.208 | $ 0.192 | $ 0.099 | $ 0.064 | $ 0.076 | $ 0.127 | |
| **Interest Expense** | $ 17,732,964 | $ 16,667,116 | $ 6,880,584 | $ 6,922,721 | $ 9,494,750 | **$ 57,698,135** | 5.9% |
| $/MWh | $ 0.076 | $ 0.070 | $ 0.029 | $ 0.028 | $ 0.040 | $ 0.049 | |

Note 1: Part of this category is included in other cost catgories.

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **California ISO** | | | | | | | | | |
| **Overview** | | | | | | | | | |
| | | | | | | | | | |
| **Cost Category** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| | | | | | | | | | |
| **Operating Revenue** | **400** | **457.1** | **$ 263,568,893** | **$ 196,476,458** | **$ 254,052,435** | **$ 225,326,585** | **$ 214,471,771** | | **p. 114** |
| **Total Operational Costs** | | | **$ 54,605,595** | **$ 52,007,237** | **$ 55,884,977** | **$ 59,887,060** | **$ 63,719,381** | | |
| **Total Administrative Costs** | | | **$ 170,245,671** | **$ 162,843,105** | **$ 150,458,886** | **$ 107,426,538** | **$ 107,892,132** | | |
| **Net Other Income and Deductions** | | | **$ 4,055,832** | **$ 2,781,383** | **$ 2,076,122** | **$ 2,412,382** | **$ 9,037,896** | | **p. 117** |
| | | | | | | | | | |
| **NET INCOME** | | | **$ 42,773,459** | **$ (15,592,501)** | **$ 49,784,694** | **$ 60,425,369** | **$ 51,898,154** | | **p. 117** |

| Detailed Data Table of RTO Operational and Administrative Costs (From FERC Form 1 Data) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **California ISO** | | | | | | | | | | |
| **Operational Costs** | | | | | | | | | | |
| | | | | | | | | | | |
| **Cost Category** | **Common or RTO Specific** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| | | | | | | | | | | |
| **Operation Supervision and Engineering** | **Common** | **560** | | **$ 4,696,131** | **$ 3,490,109** | **$ 3,278,539** | **$ 3,114,082** | **$ 2,719,699** | | **pp. 320-323** |
| **Load Dispatching** | | **561** | | **$ 23,553,659** | **$ 24,334,773** | **$ 28,510,876** | **$ 27,783,431** | **$ 31,157,011** | | **pp. 320-323** |
| OATT Administration | **Common** | | 575.3 | | | | | | Included in Load Disptaching | |
| OASIS Administration | **Common** | | 575.3 | | | | | | Included in Load Disptaching | |
| Balancing Authority Administration | **Common** | | 561.2 | | | | | | Included in Load Disptaching | |
| Regional Planning | **Common** | | 561.5 | | | | | | Included in Load Disptaching | |
| **Maintenance Supervision and Engineering** | **Common** | **568** | | **$ 14,697,116** | **$ 11,486,295** | **$ 12,724,772** | **$ 15,413,879** | **$ 17,093,724** | | **pp. 320-323** |
| **Maintenance of General Plant** | **Common** | **935** | **569.4** | **$ 9,752,068** | **$ 10,333,528** | **$ 9,187,218** | **$ 11,434,134** | **$ 11,336,218** | | **pp. 320-323** |
| **Meter Reading Expenses** | **Common** | **902** | | **$ 1,906,621** | **$ 2,362,532** | **$ 2,183,572** | **$ 2,141,534** | **$ 1,412,729** | | **pp. 320-323** |
| | | | | | | | | | | |
| **Total Operational Costs** | | | | **$ 54,605,595** | **$ 52,007,237** | **$ 55,884,977** | **$ 59,887,060** | **$ 63,719,381** | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Total Operational Salaries and Wages** | **Common** | | | **$ 31,387,894** | **$ 35,260,814** | **$ 36,782,908** | **$ 39,182,222** | **$ 42,436,596** | Included above | **p. 354** |

## Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)

### California ISO

### Administrative Costs

| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Supervision** | **Common** | **901** | | **$ 357,698** | **$ 341,938** | **$ 488,289** | **$ 466,900** | **$ 653,750** | | **pp. 320-323** |
| **Customer Records and Collection Expense** | **Common** | **903** | | **$ 4,535,598** | **$ 4,656,850** | **$ 4,874,010** | **$ 4,955,716** | **$ 3,987,605** | | **pp. 320-323** |
| **Miscellaneous Customer Accounts Expense** | **Common** | **905** | | **$ 330,154** | **$ 81,281** | **$ 599,390** | **$ 453,907** | **$ 199,607** | | **pp. 320-323** |
| **Customer Assistance Expense** | **Common** | **908** | | **$ 2,548,127** | **$ 2,360,238** | **$ 2,153,607** | **$ 2,367,700** | **$ 2,540,551** | | **pp. 320-323** |
| **Administrative and General Salaries** | **Common** | **920** | | **$ 22,246,289** | **$ 25,618,785** | **$ 26,361,936** | **$ 28,977,853** | **$ 27,143,161** | | **pp. 320-323** |
| **Office Supplies and Expense** | **Common** | **921** | **567.1** | **$ 5,772,481** | **$ 5,200,857** | **$ 5,366,858** | **$ 5,365,186** | **$ 4,813,495** | | **pp. 320-323** |
| **(Less) Administrative Expense Transferred** | **Common** | **922** | | **$ 15** | | | | | | **pp. 320-323** |
| **Outside Services Employed** | **Common** | **923** | | **$ 15,143,481** | **$ 13,002,642** | **$ 15,376,455** | **$ 19,101,709** | **$ 16,507,165** | | **pp. 320-323** |
| **Property Insurance** | **Common** | **924** | | **$ 599,563** | **$ 1,326,996** | **$ 1,960,214** | **$ 1,844,300** | **$ 1,906,288** | | **pp. 320-323** |
| **Injuries and Damages** | **Common** | **925** | | **$ 375,951** | | **$ 15,772,505** | **$ 91,337** | **$ 16,018** | | **pp. 320-323** |
| **General Advertising Expense** | **Common** | **930.1** | | **$ 34,276** | **$ 25,890** | **$ 5,507** | **$ 5,315** | **$ 30,205** | | **pp. 320-323** |
| **Rents** | **Common** | **931** | **567** | **$ 42,745,929** | **$ 44,411,089** | **$ 45,032,111** | **$ 19,655,260** | **$ 18,964,539** | | **pp. 320-323** |
| | | | | | | | | | | |
| **Regulatory Costs** | | | | | | | | | | |
| FERC Hearings | RTO | | | $ 6,759,610 | $ 2,548,195 | $ 1,573,346 | $ 964,215 | $ 3,233,775 | | **p. 350** |
| **Total Regulatory Costs** | **Common** | **928** | | **$ 6,759,610** | **$ 2,548,195** | **$ 1,573,346** | **$ 964,215** | **$ 3,233,775** | | **pp. 320-323 and 350** |
| *Note: All RTOs will have Regulatory Cost on the Form 1 but the specific items are RTO Specific.* | | | | | | | | | | |
| | | | | | | | | | | |
| **Miscellaneous General Expense** | | | | | | | | | | |
| Bank Fees | | | | $ 16,853 | $ 103,039 | $ 140,662 | $ 179,347 | $ 117,956 | | **p. 335** |
| Board Member Expense | | | | $ 50,867 | $ 28,466 | $ 21,340 | $ 18,730 | $ 52,974 | | **p. 335** |
| Board Member Compensation | | | | $ 102,150 | $ 63,126 | $ 50,208 | $ 65,035 | $ 151,798 | | **p. 335** |
| FERC Fees | | | | $ 39,358 | | | | | | **p. 335** |
| **Total Miscellaneous General Expense** | **RTO** | **930.2** | | **$ 209,228** | **$ 194,631** | **$ 212,210** | **$ 263,112** | **$ 322,728** | | **pp. 320-323 and 335** |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Depreciation Expense** | **Common** | **403** | | **$ 48,574,402** | **$ 45,681,679** | **$ 23,276,006** | **$ 15,729,517** | **$ 17,965,299** | | **p. 114** |
| **Taxes Other Than Income Taxes** | **Common** | **408.1** | | **$ 481,445** | **$ 551,651** | **$ 402,624** | **$ 76,372** | **$ 370,984** | | **p. 114** |
| **Interest on Long-Term Debt** | **Common** | **427** | | **$ 17,732,964** | **$ 14,253,125** | **$ 4,811,381** | **$ 3,813,657** | **$ 5,609,937** | | **p. 117** |
| **Amort. Of Debt Disc. And Expense** | **Common** | **428** | | **$ 196,894** | **$ 173,267** | **$ 123,234** | **$ 185,418** | **$ 521,561** | | **p. 117** |
| **Other Interest Expense** | **Common** | **431** | | | **$ 2,413,991** | **$ 2,069,203** | **$ 3,109,064** | **$ 3,884,813** | | **p. 117** |
| **(Less) AFUDC** | **RTO** | **432** | | | | | | **$ (779,349)** | | **p. 117** |
| **(Less) Extraordinary Deductions** | **RTO** | **435** | | **$ 1,601,566** | | | | | | **p. 117** |
| | | | | | | | | | | |
| **Total Administrative Costs** | | | | **$ 170,245,671** | **$ 162,843,105** | **$ 150,458,886** | **$ 107,426,538** | **$ 107,892,132** | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Salaries and Wages** | | | | | | | | | | |
| Customer Accounts | | | | $ 5,836,725 | $ 6,905,685 | $ 6,893,415 | $ 6,630,430 | $ 5,209,411 | Included above | **p. 354** |
| Customer Service and Informational | | | | $ 2,093,918 | $ 2,073,497 | $ 1,938,169 | $ 2,088,851 | $ 2,285,909 | Included above | **p. 354** |
| Administrative and General | | | | $ 22,245,300 | $ 26,408,936 | $ 26,360,668 | $ 29,340,472 | $ 27,117,697 | Included above | **p. 354** |

| **Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **California ISO** | | | | | | | | | | |
| **Administrative Costs** | | | | | | | | | | |
| | | | | | | | | | | |
| **Cost Category** | **Common or RTO Specific** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| **Total Administrative Salaries and Wages** | **Common** | | | **$ 30,175,943** | **$ 35,388,118** | **$ 35,192,252** | **$ 38,059,753** | **$ 34,613,017** | Included above | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| Total Operational and Administrative Salaries Check | | | | $ 61,563,837 | $ 70,648,932 | $ 71,975,160 | $ 77,241,975 | $ 77,049,613 | | p. 354 |

# C2 - ISO New England

**Summary Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**ISO New England**

**Major Cost Breakdown**

**Note: RTO Major Costs are those that are typically over 2% of the Total Cost for a year.**

| | 2001 | 2002 | 2003 | 2004 | 2005 | Survey Period Total | % of Total Cost |
|---|---|---|---|---|---|---|---|
| **ISO-NE Annual Load (MWh)** | 125,976,457 | 127,455,232 | 130,777,995 | 132,518,126 | 136,355,309 | 653,083,119 | N/A |
| **Total Costs** | $ 62,631,558 | $ 63,869,435 | $ 102,924,027 | $ 116,842,065 | $ 124,421,028 | **$ 470,688,113** | 100.0% |
| $/MWh | $ 0.497 | $ 0.501 | $ 0.787 | $ 0.882 | $ 0.912 | $ 0.721 | |
| **Operational** | | | | | | | |
| **Total Operational Costs** | $ 16,764,265 | $ 19,028,071 | $ 21,762,406 | $ 24,838,507 | $ 25,379,347 | **$ 107,772,596** | 22.9% |
| $/MWh | $ 0.133 | $ 0.149 | $ 0.166 | $ 0.187 | $ 0.186 | $ 0.165 | |
| **Load Dispatching** | $ 2,200,648 | $ 2,458,669 | $ 2,862,469 | $ 3,334,577 | $ 3,613,262 | **$ 14,469,625** | 3.1% |
| $/MWh | $ 0.017 | $ 0.019 | $ 0.022 | $ 0.025 | $ 0.026 | $ 0.022 | |
| **Misc. Transmission Expense** | $ 5,396,570 | $ 6,029,305 | $ 7,019,529 | $ 8,177,263 | $ 8,860,672 | **$ 35,483,339** | 7.5% |
| $/MWh | $ 0.043 | $ 0.047 | $ 0.054 | $ 0.062 | $ 0.065 | $ 0.054 | |
| **Salaries and Wages**[1] | $ 5,724,507 | $ 6,172,014 | $ 5,407,751 | $ 7,398,006 | $ 7,797,502 | **$ 32,499,780** | 6.9% |
| $/MWh | $ 0.045 | $ 0.048 | $ 0.041 | $ 0.056 | $ 0.057 | $ 0.050 | |
| **Operation Supervision and Engineering** | $ 6,601,945 | $ 7,376,006 | $ 8,587,406 | $ 10,003,731 | $ 10,839,785 | **$ 43,408,873** | 9.2% |
| $/MWh | $ 0.052 | $ 0.058 | $ 0.066 | $ 0.075 | $ 0.079 | $ 0.066 | |
| **Administrative** | | | | | | | |
| **Total Administrative Costs** | $ 45,867,293 | $ 44,841,364 | $ 81,161,621 | $ 92,003,558 | $ 99,041,681 | **$ 362,915,517** | 77.1% |
| $/MWh | $ 0.364 | $ 0.352 | $ 0.621 | $ 0.694 | $ 0.726 | $ 0.556 | |
| **Salaries and Wages**[1] | $ 16,321,253 | $ 17,736,114 | $ 22,549,749 | $ 28,339,821 | $ 31,605,348 | **$ 116,552,285** | 24.8% |
| $/MWh | $ 0.130 | $ 0.139 | $ 0.172 | $ 0.214 | $ 0.232 | $ 0.178 | |
| **Consulting Fees/Outside Services** | $ 9,055,602 | $ 10,117,349 | $ 11,778,973 | $ 13,721,685 | $ 14,868,464 | **$ 59,542,073** | 12.7% |
| $/MWh | $ 0.072 | $ 0.079 | $ 0.090 | $ 0.104 | $ 0.109 | $ 0.091 | |
| **Employee Pensions and Benefits** | $ 4,569,636 | $ 5,105,414 | $ 5,943,903 | $ 6,924,233 | $ 7,502,921 | **$ 30,046,107** | 6.4% |
| $/MWh | $ 0.036 | $ 0.040 | $ 0.045 | $ 0.052 | $ 0.055 | $ 0.046 | |
| **Misc. Customer Accounts Expense** | $ 2,603,785 | $ 2,909,072 | $ 3,386,844 | $ 3,945,438 | $ 4,275,175 | **$ 17,120,314** | 3.6% |
| $/MWh | $ 0.021 | $ 0.023 | $ 0.026 | $ 0.030 | $ 0.031 | $ 0.026 | |
| **Misc. Customer Service and Info. Exp.** | $ 1,657,928 | $ 1,852,316 | $ 2,156,532 | $ 2,512,209 | $ 2,722,166 | **$ 10,901,151** | 2.3% |
| $/MWh | $ 0.013 | $ 0.015 | $ 0.016 | $ 0.019 | $ 0.020 | $ 0.017 | |
| **Miscellaneous General Expense** | $ 7,716,513 | $ 2,429,836 | $ 2,547,861 | $ 2,639,587 | $ 2,661,893 | **$ 17,995,690** | 3.8% |
| $/MWh | $ 0.061 | $ 0.019 | $ 0.019 | $ 0.020 | $ 0.020 | $ 0.028 | |
| **Depreciation Expense** | $ 3,561,031 | $ 4,279,392 | $ 28,800,263 | $ 34,582,778 | $ 38,850,138 | **$ 110,073,602** | 23.4% |
| $/MWh | $ 0.028 | $ 0.034 | $ 0.220 | $ 0.261 | $ 0.285 | $ 0.169 | |
| **Interest Expense** | $ 1,036,848 | $ 793,059 | $ 3,066,034 | $ 2,666,378 | $ 2,681,326 | **$ 10,243,645** | 2.2% |
| $/MWh | $ 0.008 | $ 0.006 | $ 0.023 | $ 0.020 | $ 0.020 | $ 0.016 | |

Note 1: Part of this category is included in other cost categories.

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **ISO New England** | | | | | | | | | |
| **Overview** | | | | | | | | | |
| | | | | | | | | | |
| **Cost Category** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| | | | | | | | | | |
| **Operating Revenue** | **400** | **457.1** | **$ 62,631,558** | **$ 63,869,435** | **$ 102,924,027** | **$ 116,842,065** | **$ 124,421,028** | | **p. 114** |
| **Total Operational Costs** | | | **$ 16,764,265** | **$ 19,028,071** | **$ 21,762,406** | **$ 24,838,507** | **$ 25,379,347** | | |
| **Total Administrative Costs** | | | **$ 45,867,293** | **$ 44,841,364** | **$ 81,161,621** | **$ 92,003,558** | **$ 99,041,681** | | |
| **Net Other Income and Deductions** | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **p. 117** |
| | | | | | | | | | |
| **NET INCOME** | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **p. 117** |

**Detailed Data Table of RTO Operational and Administrative Costs (From FERC Form 1 Data)**

**ISO New England**

**Operational Costs**

| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Operation Supervision and Engineering** | **Common** | **560** | | **$ 6,601,945** | **$ 7,376,006** | **$ 8,587,406** | **$ 10,003,731** | **$ 10,839,785** | | **pp. 320-323** |
| **Load Dispatching** | | **561** | | **$ 2,200,648** | **$ 2,458,669** | **$ 2,862,469** | **$ 3,334,577** | **$ 3,613,262** | | **pp. 320-323** |
| OATT Administration | **Common** | | 575.3 | | | | | | Included in Load Disptaching | |
| OASIS Administration | **Common** | | 575.3 | | | | | | Included in Load Disptaching | |
| Balancing Authority Administration | **Common** | | 561.2 | | | | | | Included in Load Disptaching | |
| Regional Planning | **Common** | | 561.5 | | | | | | Included in Load Disptaching | |
| **Miscellaneous Transmission Expense** | **Common** | **566** | | **$ 5,396,570** | **$ 6,029,305** | **$ 7,019,529** | **$ 8,177,263** | **$ 8,860,672** | | **pp. 320-323** |
| **Rents** | **Common** | **567** | | **$ 1,753,157** | **$ 2,401,117** | **$ 2,265,284** | **$ 2,277,044** | **$ 956,082** | | **pp. 320-323** |
| **Maintenance of General Plant** | **Common** | **935** | **569.4** | **$ 811,945** | **$ 762,974** | **$ 1,027,718** | **$ 1,045,892** | **$ 1,109,546** | | **pp. 320-323** |
| | | | | | | | | | | |
| **Total Operational Costs** | | | | **$ 16,764,265** | **$ 19,028,071** | **$ 21,762,406** | **$ 24,838,507** | **$ 25,379,347** | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Total Operational Salaries and Wages** | **Common** | | | **$ 5,724,507** | **$ 6,172,014** | **$ 5,407,751** | **$ 7,398,006** | **$ 7,797,502** | Included above | **p. 354** |

**Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**ISO New England**

**Administrative Costs**

| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Supervision - Customer Accounts** | Common | 901 | | $ 499,487 | $ 558,051 | $ 649,703 | $ 756,858 | $ 820,112 | | pp. 320-323 |
| **Miscellaneous Customer Accounts Expense** | Common | 905 | | $ 2,603,785 | $ 2,909,072 | $ 3,386,844 | $ 3,945,438 | $ 4,275,175 | | pp. 320-323 |
| **Supervision - Customer Service and Info.** | Common | 907 | | $ 117,877 | $ 131,698 | $ 153,327 | $ 178,616 | $ 193,544 | | |
| **Misc. Customer Service and Info. Expense** | Common | 910 | | $ 1,657,928 | $ 1,852,316 | $ 2,156,532 | $ 2,512,209 | $ 2,722,166 | | |
| **Administrative and General Salaries** | Common | 920 | | $ 13,386,820 | $ 14,956,392 | $ 17,412,755 | $ 20,284,651 | $ 21,979,926 | | pp. 320-323 |
| **Office Supplies and Expense** | Common | 921 | 567.1 | $ 440,482 | $ 411,757 | $ 496,202 | $ 568,957 | $ 683,369 | | pp. 320-323 |
| **Outside Services Employed** | Common | 923 | | $ 9,055,602 | $ 10,117,349 | $ 11,778,973 | $ 13,721,685 | $ 14,868,464 | | pp. 320-323 |
| **Property Insurance** | Common | 924 | | $ 709,270 | $ 811,663 | $ 1,024,659 | $ 1,411,906 | $ 1,482,884 | | pp. 320-323 |
| **Employee Pensions and Benefits** | Common | 926 | | $ 4,569,636 | $ 5,105,414 | $ 5,943,903 | $ 6,924,233 | $ 7,502,921 | | pp. 320-323 |
| **Rents** | Common | 931 | 567 | $ 1,240,524 | $ 1,191,976 | $ 584,925 | $ 232,334 | $ 120,487 | | pp. 320-323 |
| | | | | | | | | | | |
| **Miscellaneous General Expense** | | | | | | | | | | |
| Board of Directors Expense | | | | $ 855,160 | $ 855,160 | $ 930,680 | $ 851,405 | $ 723,868 | | p. 335 |
| Meetings, Travel, and Seminars | | | | $ 1,455,579 | $ 1,455,579 | $ 1,492,029 | $ 1,655,626 | $ 1,785,336 | | p. 335 |
| Taxes | | | | $ 121,451 | $ 119,097 | $ 125,152 | $ 132,556 | $ 152,689 | | p. 335 |
| Communications Expenses | | | | $ 1,395,219 | | | | | | p. 335 |
| Computer Services | | | | $ 3,360,700 | | | | | | p. 335 |
| Charitable Contributions | | | | $ 5,490 | | | | | | p. 335 |
| Other Income and Expense | | | | $ 496,640 | | | | | | p. 335 |
| Auto Expense | | | | $ 26,274 | | | | | | p. 335 |
| **Total Miscellaneous General Expense** | RTO | 930.2 | | $ 7,716,513 | $ 2,429,836 | $ 2,547,861 | $ 2,639,587 | $ 2,661,893 | | pp. 320-323 and 335 |
| | | | | | | | | | | |
| **Depreciation Expense** | Common | 403 | | $ 3,561,031 | $ 4,279,392 | $ 28,800,263 | $ 34,582,778 | $ 38,850,138 | | p. 114 |
| **Amortization & Depl. Of Utility Plant** | Common | 404-405 | | $ (728,510) | $ (706,611) | $ 3,108,126 | $ 644,711 | $ 70,991 | | p. 114 |
| **Losses from Disp. Of Utility Plant** | Common | 411.7 | | | | $ 51,514 | $ 933,217 | | | p. 114 |
| **Interest on Long-Term Debt** | Common | 427 | | $ 1,036,848 | $ 622,212 | $ 3,066,034 | $ 2,666,378 | $ 2,615,660 | | p. 117 |
| **Amort. Of Debt Disc. And Expense** | Common | 428 | | | | | | $ 128,285 | | p. 117 |
| **Other Interest Expense** | Common | 431 | | | $ 170,847 | | | $ 65,666 | | p. 117 |
| | | | | | | | | | | |
| **Total Administrative Costs** | | | | $ 45,867,293 | $ 44,841,364 | $ 81,161,621 | $ 92,003,558 | $ 99,041,681 | | |

| **Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **ISO New England** | | | | | | | | | | |
| **Administrative Costs** | | | | | | | | | | |
| | | | | | | | | | | |
| **Cost Category** | **Common or RTO Specific** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| **Salaries and Wages** | | | | | | | | | | |
| Customer Accounts | | | | $ 1,401,463 | $ 1,317,411 | $ 1,154,895 | $ 1,546,841 | $ 1,685,406 | Included above | **p. 354** |
| Customer Service and Informational | | | | $ 710,485 | $ 838,643 | $ 508,555 | $ 1,283,109 | $ 1,466,100 | Included above | **p. 354** |
| Administrative and General | | | | $ 14,209,305 | $ 15,580,060 | $ 20,886,299 | $ 25,509,871 | $ 28,453,842 | Included above | **p. 354** |
| **Total Administrative Salaries and Wages** | **Common** | | | **$ 16,321,253** | **$ 17,736,114** | **$ 22,549,749** | **$ 28,339,821** | **$ 31,605,348** | Included above | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| Total Operational and Administrative Salaries Check | | | | $ 22,045,760 | $ 23,908,128 | $ 27,957,500 | $ 35,737,827 | $ 39,402,850 | | p. 354 |

# C3 - Midwest ISO

| Summary Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Midwest ISO** | | | | | | | |
| **Major Cost Breakdown** | | | | | | | |
| **Note: RTO Major Costs are those that are typically over 2% of the Total Cost for a year.** | | | | | | | |
| | | | | | | | |
| | **2001** | **2002** | **2003** | **2004** | **2005** | **Survey Period Total** | **% of Total Cost** |
| **MISO Annual Load (MWh)** | | 343,816,582 | 427,998,509 | 592,780,417 | 652,763,614 | **2,017,359,122** | N/A |
| | | | | | | | |
| **Total Costs** | $ - | $ 83,240,390 | $ 84,050,582 | $ 155,669,224 | $ 273,421,246 | **$ 596,381,442** | 100.0% |
| $/MWh | | $ 0.242 | $ 0.196 | $ 0.263 | $ 0.419 | $ 0.296 | |
| | | | | | | | |
| **Operational** | | | | | | | |
| **Total Operational Costs** | $ - | $ 1,164,637 | $ 1,569,242 | $ 2,026,034 | $ 2,544,847 | **$ 7,304,760** | 1.2% |
| $/MWh | $ - | $ 0.003 | $ 0.004 | $ 0.003 | $ 0.004 | $ 0.021 | |
| | | | | | | | |
| | | | | | | | |
| **Administrative** | | | | | | | |
| **Total Administrative Costs** | $ - | $ 82,075,753 | $ 82,481,340 | $ 153,643,190 | $ 270,876,399 | **$ 589,076,682** | 98.8% |
| $/MWh | | $ 0.239 | $ 0.193 | $ 0.259 | $ 0.415 | $ 0.292 | |
| | | | | | | | |
| **Salaries and Wages** | $ - | $ 21,110,044 | $ 28,751,903 | $ 43,414,243 | $ 57,232,164 | **$ 150,508,354** | 25.2% |
| $/MWh | | $ 0.061 | $ 0.067 | $ 0.073 | $ 0.088 | $ 0.075 | |
| | | | | | | | |
| **Office Supplies and Expense** | $ - | $ 8,673,157 | $ 14,424,930 | $ 21,550,827 | $ 23,824,919 | **$ 68,473,833** | 11.5% |
| $/MWh | | $ 0.025 | $ 0.034 | $ 0.036 | $ 0.036 | $ 0.034 | |
| | | | | | | | |
| **Rents** | $ - | $ 2,049,709 | $ 2,416,952 | $ 3,083,768 | $ 5,189,434 | **$ 12,739,863** | 2.1% |
| $/MWh | | $ 0.006 | $ 0.006 | $ 0.005 | $ 0.008 | $ 0.006 | |
| | | | | | | | |
| **Regulatory Costs** | $ - | $ - | $ 18,087,987 | $ 19,797,671 | $ 32,830,138 | **$ 70,715,796** | 11.9% |
| $/MWh | | $ - | $ 0.042 | $ 0.033 | $ 0.050 | $ 0.035 | |
| | | | | | | | |
| **Regulatory Debits** | $ - | $ 9,819,026 | $ 13,384,575 | $ 38,986,382 | $ 54,228,017 | **$ 116,418,000** | 19.5% |
| $/MWh | | $ 0.029 | $ 0.031 | $ 0.066 | $ 0.083 | $ 0.058 | |
| | | | | | | | |
| **Employee Pension and Benefits** | $ - | $ 3,420,794 | $ 5,212,733 | $ 8,064,556 | $ 10,526,726 | **$ 27,224,809** | 4.6% |
| $/MWh | | $ 0.010 | $ 0.012 | $ 0.014 | $ 0.016 | $ 0.013 | |
| | | | | | | | |
| **Consulting Fees/Outside Services** | $ - | $ 8,910,654 | $ 23,450,919 | $ 45,949,236 | $ 50,326,037 | **$ 128,636,846** | 21.6% |
| $/MWh | | $ 0.026 | $ 0.055 | $ 0.078 | $ 0.077 | $ 0.064 | |
| | | | | | | | |
| **Depreciation Expense** | $ - | $ 14,300,334 | $ 19,827,081 | $ 23,795,263 | $ 44,075,342 | **$ 101,998,020** | 17.1% |
| $/MWh | | $ 0.042 | $ 0.046 | $ 0.040 | $ 0.068 | $ 0.051 | |
| | | | | | | | |
| **Interest Expense** | $ - | $ 9,985,867 | $ 12,168,838 | $ 17,694,106 | $ 24,766,972 | **$ 64,615,783** | 10.8% |
| $/MWh | | $ 0.029 | $ 0.028 | $ 0.030 | $ 0.038 | $ 0.032 | |

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Midwest ISO | | | | | | | | |
| Overview | | | | | | | | |
| | | | | | | | | |
| Cost Category | Current FERC Account Number | Future FERC Account Number | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
| | | | | | | | | |
| Operating Revenue | 400 | 457.1 | $ 82,558,024 | $ 83,125,485 | $ 153,299,738 | $ 267,258,103 | | p. 114 |
| Total Operational Costs | | | $ 1,164,637 | $ 1,569,242 | $ 2,026,034 | $ 2,544,847 | | |
| Total Administrative Costs | | | $ 82,075,753 | $ 82,481,340 | $ 153,643,190 | $ 270,876,399 | | |
| Net Other Income and Deductions | | | $ 682,366 | $ 925,097 | $ 2,369,486 | $ 6,163,143 | | p. 117 |
| | | | | | | | | |
| NET INCOME | | | $ - | $ - | $ - | $ - | | p. 117 |

| Detailed Data Table of RTO Operational and Administrative Costs (From FERC Form 1 Data) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Midwest ISO** | | | | | | | | | |
| **Operational Costs** | | | | | | | | | |
| | | | | | | | | | |
| **Cost Category** | **Common or RTO Specific** | **Current FERC Account Number** | **Future FERC Account Number** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| | | | | | | | | | |
| **Maintenance of General Plant** | **Common** | **935** | **569.4** | **$ 1,164,637** | **$ 1,569,242** | **$ 2,026,034** | **$ 2,544,847** | | **pp. 320-323** |
| | | | | | | | | | |
| **Total Operational Costs** | | | | **$ 1,164,637** | **$ 1,569,242** | **$ 2,026,034** | **$ 2,544,847** | | |

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Midwest ISO** | | | | | | | | | |
| **Administrative Costs** | | | | | | | | | |
| **Cost Category** | **Common or RTO Specific** | **Current FERC Account Number** | **Future FERC Account Number** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| **Customer Assistance Expense** | Common | 908 | | $ 155,686 | $ 468,508 | $ 290,709 | $ 283,451 | | pp. 320-323 |
| **Misc. Customer Service and Informational Exp.** | Common | 910 | | $ 5,109 | $ 18,685 | $ 20,676 | $ 29,906 | | pp. 320-323 |
| **Administrative and General Salaries** | Common | 920 | | $ 21,110,044 | $ 28,751,903 | $ 43,414,243 | $ 57,232,164 | | pp. 320-323 |
| **Office Supplies and Expense** | Common | 921 | 567.1 | $ 8,673,157 | $ 14,424,930 | $ 21,550,827 | $ 23,824,919 | | pp. 320-323 |
| **(Less) Administrative Expense Transferred** | Common | 922 | | | | | | | pp. 320-323 |
| **Outside Services Employed** | Common | 923 | | $ 8,910,654 | $ 23,450,919 | $ 45,949,236 | $ 50,326,037 | | pp. 320-323 |
| **Property Insurance** | Common | 924 | | $ 2,981,771 | $ 1,957,037 | $ 3,206,716 | $ 2,549,665 | | pp. 320-323 |
| **Injuries and Damages** | Common | 925 | | $ 483 | $ 9,406 | | | | pp. 320-323 |
| **Employee Pensions and Benefits** | Common | 926 | | $ 3,420,794 | $ 5,212,733 | $ 8,064,556 | $ 10,526,726 | | pp. 320-323 |
| **General Advertising Expense** | Common | 930.1 | | $ 84,722 | $ 76,887 | $ 66,470 | $ 140,667 | | pp. 320-323 |
| **Rents** | Common | 931 | 567 | $ 2,049,709 | $ 2,416,952 | $ 3,083,768 | $ 5,189,434 | | pp. 320-323 |
| | | | | | | | | | |
| **Regulatory Commission Expense** | Common | 928 | | $ - | $ 18,087,987 | $ 19,797,671 | $ 32,830,138 | | pp. 320-323 |
| | | | | | | | | | |
| **Miscellaneous General Expense** | | | | | | | | | |
| Industry Association Dues | | | | $ 16,712 | $ 5,300 | Data N/A | $ 65,620 | | p. 335 |
| Annual Report Expense | | | | $ 15,359 | $ 12,742 | | $ 18,258 | | p. 335 |
| Board of Director Fees and Expenses | | | | $ 533,546 | $ 515,526 | | $ 663,887 | | p. 335 |
| Other Miscellaneous | | | | $ 3,420 | $ 994 | | $ 67,286 | | p. 335 |
| **Total Miscellaneous General Expense** | RTO | 930.2 | | $ 569,037 | $ 534,562 | $ 657,661 | $ 815,051 | | pp. 320-323 and 335 |
| | | | | | | | | | |
| **Depreciation Expense** | Common | 403 | | $ 14,300,334 | $ 19,827,081 | $ 23,795,263 | $ 44,075,342 | | p. 114 |
| **Regulatory Debits** | Common | 407.3 | | $ 9,819,026 | $ 13,384,575 | $ 38,986,382 | $ 54,228,017 | | p. 114 |
| **(Less) Regulatory Credits** | Common | 407.4 | | $ (1,334,897) | $ (60,979,033) | $ (77,319,199) | $ (41,161,929) | | p. 114 |
| **Taxes Other Than Income Taxes** | Common | 408.1 | | $ 1,248,418 | $ 2,512,153 | $ 3,965,379 | $ 4,724,321 | | p. 114 |
| **Interest on Long-Term Debt** | Common | 427 | | $ 8,150,190 | $ 10,221,136 | $ 14,115,833 | $ 19,506,189 | | p. 117 |
| **Amort. Of Debt Disc. And Expense** | Common | 428 | | $ 95,839 | $ 157,217 | $ 418,726 | $ 495,518 | | p. 117 |
| **Other Interest Expense** | Common | 431 | | $ 1,835,677 | $ 1,947,702 | $ 3,578,273 | $ 5,260,783 | | p. 117 |
| | | | | | | | | | |
| **Total Administrative Costs** | | | | $ 82,075,753 | $ 82,481,340 | $ 153,643,190 | $ 270,876,399 | | |

# C4 - New York ISO

**Summary Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**New York ISO**

**Major Cost Breakdown**

**Note: RTO Major Costs are those that are typically over 2% of the Total Cost for a year.**

| | 2001 | 2002 | 2003 | 2004 | 2005 | Survey Period Total | % of Total Cost |
|---|---|---|---|---|---|---|---|
| **NYISO Annual Load (MWh)** | 156,787,408 | 158,744,782 | 158,013,534 | 160,209,093 | 167,204,055 | 800,958,872 | N/A |
| **Total Costs** | $ 90,043,956 | $ 99,410,931 | $ 117,819,269 | $ 136,661,595 | $ 149,170,862 | **$ 593,106,613** | 100.0% |
| $/MWh | $ 0.574 | $ 0.626 | $ 0.746 | $ 0.853 | $ 0.892 | $ 0.740 | |
| **Operational** | | | | | | | |
| **Total Operational Costs** | $ 8,479,312 | $ 10,143,333 | $ 10,454,079 | $ 11,399,077 | $ 12,246,311 | **$ 52,722,112** | 8.9% |
| $/MWh | $ 0.054 | $ 0.064 | $ 0.066 | $ 0.071 | $ 0.073 | $ 0.066 | |
| **Operation Supervision & Engineering** | $ 6,955,044 | $ 7,757,605 | $ 8,146,003 | $ 8,632,633 | $ 8,752,454 | **$ 40,243,739** | 6.8% |
| $/MWh | $ 0.044 | $ 0.049 | $ 0.052 | $ 0.054 | $ 0.052 | $ 0.050 | |
| **Salaries and Wages**[1] | $ 8,202,359 | $ 9,789,243 | $ 10,102,019 | $ 10,891,459 | $ 11,403,661 | **$ 50,388,741** | 8.5% |
| $/MWh | $ 0.052 | $ 0.062 | $ 0.064 | $ 0.068 | $ 0.068 | $ 0.063 | |
| **Administrative** | | | | | | | |
| **Total Administrative Costs** | $ 81,564,644 | $ 89,267,598 | $ 107,365,190 | $ 125,262,518 | $ 136,924,551 | **$ 540,384,501** | 91.1% |
| $/MWh | $ 0.520 | $ 0.562 | $ 0.679 | $ 0.782 | $ 0.819 | $ 0.675 | |
| **Salaries and Wages**[1] | $ 12,135,805 | $ 13,383,975 | $ 15,551,731 | $ 17,585,504 | $ 24,195,818 | **$ 82,852,833** | 14.0% |
| $/MWh | $ 0.077 | $ 0.084 | $ 0.098 | $ 0.110 | $ 0.145 | $ 0.103 | |
| **Office Supplies and Expense** | $ 6,559,983 | $ 9,621,562 | $ 8,953,495 | $ 13,537,959 | $ 14,793,299 | **$ 53,466,298** | 9.0% |
| $/MWh | $ 0.042 | $ 0.061 | $ 0.057 | $ 0.085 | $ 0.088 | $ 0.067 | |
| **Regulatory Costs** | $ 5,644,495 | $ 12,078,258 | $ 14,030,534 | $ 10,231,947 | $ 14,411,734 | **$ 56,396,968** | 9.5% |
| $/MWh | $ 0.036 | $ 0.076 | $ 0.089 | $ 0.064 | $ 0.086 | $ 0.070 | |
| **Consulting Fees/Outside Services** | $ 24,295,228 | $ 17,351,446 | $ 20,118,785 | $ 23,547,390 | $ 22,240,283 | **$ 107,553,132** | 18.1% |
| $/MWh | $ 0.155 | $ 0.109 | $ 0.127 | $ 0.147 | $ 0.133 | $ 0.134 | |
| **Property Insurance** | $ 1,232,783 | $ 2,030,079 | $ 3,429,429 | $ 3,297,068 | $ 3,317,969 | **$ 13,307,328** | 2.2% |
| $/MWh | $ 0.008 | $ 0.013 | $ 0.022 | $ 0.021 | $ 0.020 | $ 0.017 | |
| **Employee Pension and Benefits** | $ 4,538,331 | $ 4,948,183 | $ 5,108,581 | $ 6,773,499 | $ 8,066,276 | **$ 29,434,870** | 5.0% |
| $/MWh | $ 0.029 | $ 0.031 | $ 0.032 | $ 0.042 | $ 0.048 | $ 0.037 | |
| **Miscellaneous General Expense** | $ 2,775,337 | $ 3,161,767 | $ 4,000,927 | $ 5,381,710 | $ 5,737,315 | **$ 21,057,056** | 3.6% |
| $/MWh | $ 0.018 | $ 0.020 | $ 0.025 | $ 0.034 | $ 0.034 | $ 0.026 | |
| **Regulatory Debits** | $ 11,918,649 | $ 12,092,095 | $ 10,988,489 | $ 10,988,489 | $ - | **$ 45,987,722** | 7.8% |
| $/MWh | $ 0.076 | $ 0.076 | $ 0.070 | $ 0.069 | $ - | $ 0.057 | |
| **Depreciation Expense** | $ 4,781,676 | $ 8,420,385 | $ 17,570,115 | $ 24,375,869 | $ 35,856,529 | **$ 91,004,574** | 15.3% |
| $/MWh | $ 0.030 | $ 0.053 | $ 0.111 | $ 0.152 | $ 0.214 | $ 0.114 | |
| **Interest Expense** | $ 4,339,032 | $ 1,977,272 | $ 1,324,241 | $ 2,425,503 | $ 3,150,742 | **$ 13,216,790** | 2.2% |
| $/MWh | $ 0.028 | $ 0.012 | $ 0.008 | $ 0.015 | $ 0.019 | $ 0.017 | |

Note 1: Part of this category is included in other cost categories.

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| New York ISO | | | | | | | | | |
| Overview | | | | | | | | | |
| | | | | | | | | | |
| Cost Category | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
| | | | | | | | | | |
| Operating Revenue | 400 | 457.1 | $ 88,891,449 | $ 99,218,202 | $ 117,578,794 | $ 136,407,122 | $ 145,833,589 | | p. 114 |
| Total Operational Costs | | | $ 8,479,312 | $ 10,143,333 | $ 10,454,079 | $ 11,399,077 | $ 12,246,311 | | |
| Total Administrative Costs | | | $ 81,564,644 | $ 89,267,598 | $ 107,365,190 | $ 125,262,518 | $ 136,924,551 | | |
| Net Other Income and Deductions | | | $ 1,152,507 | $ 192,729 | $ 240,475 | $ 254,473 | $ 3,337,272 | | p. 117 |
| | | | | | | | | | |
| NET INCOME | | | $ - | $ - | $ - | $ - | $ (1) | | p. 117 |

| Detailed Data Table of RTO Operational and Administrative Costs (From FERC Form 1 Data) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| New York ISO | | | | | | | | | | |
| Operational Costs | | | | | | | | | | |
| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
| **Other Power Supply Expenses** | **Common** | **557** | | **$ 1,247,315** | **$ 2,031,638** | **$ 1,956,016** | **$ 2,258,826** | **$ 2,651,207** | | **pp. 320-323** |
| **Operation Supervision and Engineering** | **Common** | **560** | | **$ 6,955,044** | **$ 7,757,605** | **$ 8,146,003** | **$ 8,632,633** | **$ 8,752,454** | | **pp. 320-323** |
| **Maintenance of General Plant** | **Common** | **935** | **569.4** | **$ 276,953** | **$ 354,090** | **$ 352,060** | **$ 507,618** | **$ 842,650** | | **pp. 320-323** |
| **Total Operational Costs** | | | | **$ 8,479,312** | **$ 10,143,333** | **$ 10,454,079** | **$ 11,399,077** | **$ 12,246,311** | | |
| **Salaries and Wages** | | | | | | | | | | |
| Production | | | | $ 1,247,315 | $ 2,031,638 | $ 1,956,016 | $ 2,258,826 | $ 2,651,207 | Included above | **p. 354** |
| Transmission | | | | $ 6,955,044 | $ 7,757,605 | $ 8,146,003 | $ 8,632,633 | $ 8,752,454 | Included above | **p. 354** |
| **Total Administrative Salaries and Wages** | **Common** | | | **$ 8,202,359** | **$ 9,789,243** | **$ 10,102,019** | **$ 10,891,459** | **$ 11,403,661** | Included above | |

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| New York ISO | | | | | | | | | | |
| Administrative Costs | | | | | | | | | | |
| | | | | | | | | | | |
| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
| | | | | | | | | | | |
| **Miscellaneous Customer Accounts Expense** | **Common** | **905** | | **$ 903,129** | **$ 1,170,682** | **$ 1,203,028** | **$ 1,320,064** | **$ 1,295,174** | | **pp. 320-323** |
| **Informational and Instructional Expense** | **Common** | **909** | | **$ 308,891** | **$ 445,201** | **$ 446,701** | **$ 510,863** | **$ 520,009** | | **pp. 320-323** |
| **Misc. Customer Service and Info. Expense** | **Common** | **910** | | **$ 1,519,944** | **$ 1,870,764** | **$ 2,140,079** | **$ 2,152,271** | **$ 2,114,271** | | **pp. 320-323** |
| **Administrative and General Salaries** | **Common** | **920** | | **$ 9,403,841** | **$ 9,897,327** | **$ 11,761,923** | **$ 13,602,306** | **$ 20,266,364** | | **pp. 320-323** |
| **Office Supplies and Expense** | **Common** | **921** | **567.1** | **$ 6,559,983** | **$ 9,621,562** | **$ 8,953,495** | **$ 13,537,959** | **$ 14,793,299** | | **pp. 320-323** |
| **Outside Services Employed** | **Common** | **923** | | **$ 24,295,228** | **$ 17,351,446** | **$ 20,118,785** | **$ 23,547,390** | **$ 22,240,283** | | **pp. 320-323** |
| **Property Insurance** | **Common** | **924** | | **$ 1,232,783** | **$ 2,030,079** | **$ 3,429,429** | **$ 3,297,068** | **$ 3,317,969** | | **pp. 320-323** |
| **Injuries and Damages** | **Common** | **925** | | **$ 535,448** | **$ 945,496** | **$ 2,341,702** | **$ 2,525,849** | **$ 827,983** | | **pp. 320-323** |
| **Employee Pensions and Benefits** | **Common** | **926** | | **$ 4,538,331** | **$ 4,948,183** | **$ 5,108,581** | **$ 6,773,499** | **$ 8,066,276** | | **pp. 320-323** |
| **Rents** | **Common** | **931** | **567** | **$ 1,340,619** | **$ 1,425,846** | **$ 1,709,630** | **$ 1,952,052** | **$ 1,463,765** | | **pp. 320-323** |
| | | | | | | | | | | |
| **Regulatory Costs** | | | | | | | | | | |
| Northeast Power Coordinating Council Fees | | | | $ 1,503,343 | | $ 1,496,308 | $ 1,506,734 | $ 1,689,802 | | **p. 350** |
| FERC Proceedings | | | | $ 4,141,152 | | $ 4,671,296 | $ 3,413,539 | $ 3,828,250 | | **p. 350** |
| FERC Fees | | | | | | $ 7,862,930 | $ 5,311,674 | $ 8,893,682 | | **p. 350** |
| **Total Regulatory Costs** | **Common** | **928** | | **$ 5,644,495** | **$ 12,078,258** | **$ 14,030,534** | **$ 10,231,947** | **$ 14,411,734** | | **pp. 320-323 and 350** |
| *Note: All RTOs will have Regulatory Cost on the Form 1 but the specific items are RTO Specific.* | | | | | | | | | | |
| | | | | | | | | | | |
| **Miscellaneous General Expense** | | | | | | | | | | |
| Telecommunication Charges | | | | $ 2,009,198 | $ 2,236,582 | $ 3,110,895 | $ 4,525,625 | $ 4,642,279 | | **p. 335** |
| Board of Director Fees and Expenses | | | | $ 766,139 | $ 925,185 | $ 890,032 | $ 856,085 | $ 1,095,036 | | **p. 335** |
| **Total Miscellaneous General Expense** | **RTO** | **930.2** | | **$ 2,775,337** | **$ 3,161,767** | **$ 4,000,927** | **$ 5,381,710** | **$ 5,737,315** | | **pp. 320-323 and 335** |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Depreciation Expense** | **Common** | **403** | | **$ 4,781,676** | **$ 8,420,385** | **$ 17,570,115** | **$ 24,375,869** | **$ 35,856,529** | | **p. 114** |
| **Regulatory Debits** | **Common** | **407.3** | | **$ 11,918,649** | **$ 12,092,095** | **$ 10,988,489** | **$ 10,988,489** | | | **p. 114** |
| **Taxes Other Than Income Taxes** | **Common** | **408.1** | | **$ 1,461,363** | **$ 1,812,811** | **$ 2,235,787** | **$ 2,591,805** | **$ 2,816,921** | | **p. 114** |
| **Losses from Disp. Of Utility Plant** | **Common** | **411.7** | | **$ 5,895** | **$ 18,424** | **$ 1,744** | **$ 47,874** | **$ 45,917** | | **p. 114** |
| **Interest on Long-Term Debt** | **Common** | **427** | | **$ 4,227,992** | **$ 1,958,119** | **$ 782,367** | **$ 2,322,006** | **$ 3,077,969** | | **p. 117** |
| **Other Interest Expense** | **Common** | **431** | | **$ 111,040** | **$ 19,153** | **$ 541,874** | **$ 103,497** | **$ 72,773** | | **p. 117** |
| | | | | | | | | | | |
| **Total Administrative Costs** | | | | **$ 81,564,644** | **$ 89,267,598** | **$ 107,365,190** | **$ 125,262,518** | **$ 136,924,551** | | |

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| New York ISO | | | | | | | | | | |
| Administrative Costs | | | | | | | | | | |
| | | | | | | | | | | |
| **Cost Category** | **Common or RTO Specific** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| **Salaries and Wages** | | | | | | | | | | |
| Customer Accounts | | | | $ 903,129 | $ 1,170,682 | $ 1,203,028 | $ 1,320,064 | $ 1,295,174 | Included above | **p. 354** |
| Customer Service and Informational | | | | $ 1,828,835 | $ 2,315,966 | $ 2,586,780 | $ 2,663,134 | $ 2,634,280 | Included above | **p. 354** |
| Administrative and General | | | | $ 9,403,841 | $ 9,897,327 | $ 11,761,923 | $ 13,602,306 | $ 20,266,364 | Included above | **p. 354** |
| **Total Administrative Salaries and Wages** | **Common** | | | **$ 12,135,805** | **$ 13,383,975** | **$ 15,551,731** | **$ 17,585,504** | **$ 24,195,818** | Included above | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| Total Operational and Administrative Salaries Check | | | | $ 20,338,164 | $ 23,173,218 | $ 25,653,750 | $ 28,476,963 | $ 35,599,479 | | p. 354 |

# C5 – PJM

**Summary Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**PJM Interconnection**

**Major Cost Breakdown**

**Note: RTO Major Costs are those that are typically over 2% of the Total Cost for a year.**

| | 2001 | 2002 | 2003 | 2004 | 2005 | Survey Period Total | % of Total Cost |
|---|---|---|---|---|---|---|---|
| **PJM Annual Load (MWh)** | 263,811,916 | 310,721,075 | 326,401,266 | 437,342,067 | 682,317,607 | 2,020,593,932 | N/A |
| **Total Costs** | $ 137,859,535 | $ 271,411,002 | $ 259,103,173 | $ 241,129,511 | $ 267,859,394 | **$ 1,177,362,615** | 100.0% |
| $/MWh | $ 0.523 | $ 0.873 | $ 0.794 | $ 0.551 | $ 0.393 | $ 0.583 | |
| **Operational** | | | | | | | |
| **Total Operational Costs** | $ 79,662,974 | $ 175,407,304 | $ 136,630,639 | $ 91,977,747 | $ 79,932,444 | **$ 563,611,108** | 47.9% |
| $/MWh | $ 0.302 | $ 0.565 | $ 0.419 | $ 0.210 | $ 0.117 | $ 0.279 | |
| **Load Dispatching** | $ 35,452,793 | $ 45,784,005 | $ 51,036,905 | $ 58,951,113 | $ 68,946,588 | **$ 260,171,404** | 22.1% |
| $/MWh | $ 0.134 | $ 0.147 | $ 0.156 | $ 0.135 | $ 0.101 | $ 0.129 | |
| **Maintenance of General Plant** | $ 4,322,086 | $ 5,595,057 | $ 5,973,680 | $ 6,154,076 | $ 7,066,532 | **$ 29,111,431** | 2.5% |
| $/MWh | $ 0.016 | $ 0.018 | $ 0.018 | $ 0.014 | $ 0.010 | $ 0.014 | |
| **Salaries and Wages**[1] | $ 19,507,614 | $ 19,985,330 | $ 19,524,537 | $ 23,425,264 | $ 29,632,333 | **$ 112,075,078** | 9.5% |
| $/MWh | $ 0.074 | $ 0.064 | $ 0.060 | $ 0.054 | $ 0.043 | $ 0.055 | |
| **Interconnection Services Consulting** | $ 39,059,251 | $ 123,671,711 | $ 79,408,909 | $ 26,652,698 | $ 3,699,464 | **$ 272,492,033** | 23.1% |
| $/MWh | $ 0.148 | $ 0.398 | $ 0.243 | $ 0.061 | $ 0.005 | $ 0.135 | |
| **Administrative** | | | | | | | |
| **Total Administrative Costs** | $ 58,196,561 | $ 96,003,698 | $ 122,472,534 | $ 149,151,764 | $ 187,926,950 | **$ 613,751,507** | 52.1% |
| $/MWh | $ 0.221 | $ 0.309 | $ 0.375 | $ 0.341 | $ 0.275 | $ 0.304 | |
| **Salaries and Wages**[1] | $ 28,035,165 | $ 32,687,005 | $ 24,961,708 | $ 25,279,745 | $ 31,191,658 | **$ 142,155,281** | 12.1% |
| $/MWh | $ 0.106 | $ 0.105 | $ 0.076 | $ 0.058 | $ 0.046 | $ 0.070 | |
| **Customer Assistance Expense** | $ 5,998,235 | $ 7,013,877 | $ 10,178,389 | $ 13,009,219 | $ 14,238,087 | **$ 50,437,807** | 4.3% |
| $/MWh | $ 0.023 | $ 0.023 | $ 0.031 | $ 0.030 | $ 0.021 | $ 0.025 | |
| **Office Supplies and Expense** | $ 1,436,198 | $ 3,396,523 | $ 3,811,797 | $ 6,802,372 | $ 7,664,136 | **$ 23,111,026** | 2.0% |
| $/MWh | $ 0.005 | $ 0.011 | $ 0.012 | $ 0.016 | $ 0.011 | $ 0.011 | |
| **Regulatory Costs** | $ 5,613,881 | $ 12,872,930 | $ 14,550,642 | $ 27,404,756 | $ 33,553,333 | **$ 93,995,542** | 8.0% |
| $/MWh | $ 0.021 | $ 0.041 | $ 0.045 | $ 0.063 | $ 0.049 | $ 0.047 | |
| **Consulting Fees/Outside Services** | $ 3,140,680 | $ 7,116,665 | $ 5,888,529 | $ 10,306,657 | $ 5,485,286 | **$ 31,937,817** | 2.7% |
| $/MWh | $ 0.012 | $ 0.023 | $ 0.018 | $ 0.024 | $ 0.008 | $ 0.016 | |
| **Employee Pensions and Benefits** | $ 10,630,896 | $ 13,763,047 | $ 12,546,402 | $ 11,302,993 | $ 13,217,734 | **$ 61,461,072** | 5.2% |
| $/MWh | $ 0.040 | $ 0.044 | $ 0.038 | $ 0.026 | $ 0.019 | $ 0.030 | |
| **Depreciation Expense** | $ 30,610,497 | $ 38,655,028 | $ 45,895,874 | $ 30,502,666 | $ 47,466,372 | **$ 193,130,437** | 16.4% |
| $/MWh | $ 0.116 | $ 0.124 | $ 0.141 | $ 0.070 | $ 0.070 | $ 0.096 | |
| **Interest Expense** | $ 9,018,654 | $ 9,078,348 | $ 6,938,367 | $ 7,113,159 | $ 9,213,823 | **$ 41,362,351** | 3.5% |
| $/MWh | $ 0.034 | $ 0.029 | $ 0.021 | $ 0.016 | $ 0.014 | $ 0.020 | |

Note 1: Part of this category is included in other cost categories.

**Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**PJM Interconnection**

**Overview**

| Cost Category | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|
| Operating Revenue | 400 | 457.1 | $ 95,400,000 | $ 143,798,000 | $ 176,404,242 | $ 211,844,875 | $ 260,041,283 | | p. 114 |
| Total Operational Costs | | | $ 79,662,974 | $ 175,407,304 | $ 136,630,639 | $ 91,977,747 | $ 79,932,444 | | |
| Total Administrative Costs | | | $ 58,196,561 | $ 96,003,698 | $ 122,472,534 | $ 149,151,764 | $ 187,926,950 | | |
| Net Other Income and Deductions | | | $ 42,507,535 | $ 127,661,002 | $ 82,649,931 | $ 29,308,369 | $ 7,253,289 | | p. 117 |
| | | | | | | | | | |
| NET INCOME | | | $ 48,000 | $ 48,000 | $ (49,000) | $ 23,733 | $ (564,822) | | p. 117 |

**Detailed Data Table of RTO Operational and Administrative Costs (From FERC Form 1 Data)**

**PJM Interconnection**

**Operational Costs**

| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Load Dispatching** | | **561** | | **$ 35,452,793** | **$ 45,784,005** | **$ 51,036,905** | **$ 58,951,113** | **$ 68,946,588** | | **pp. 320-323** |
| OATT Administration | **Common** | | 575.3 | | | | | | Included in Load Disptaching | |
| OASIS Administration | **Common** | | 575.3 | | | | | | Included in Load Disptaching | |
| Balancing Authority Administration | **Common** | | 561.2 | | | | | | Included in Load Disptaching | |
| Regional Planning | **Common** | | 561.5 | | | | | | Included in Load Disptaching | |
| **Interconnection Services Consulting** | **RTO** | | **561.7** | **$ 39,059,251** | **$ 123,671,711** | **$ 79,408,909** | **$ 26,652,698** | **$ 3,699,464** | | **p. 335** |
| **Project Expense** | **RTO** | | | **$ 609,152** | **$ 136,671** | **$ (8,715)** | | | | **p. 335** |
| **Maintenance of General Plant** | **Common** | **935** | **569.4** | **$ 4,322,086** | **$ 5,595,057** | **$ 5,973,680** | **$ 6,154,076** | **$ 7,066,532** | | **pp. 320-323** |
| **Amort. Property Losses, Unrecov Plant and Regulatory Study Costs** | **Common** | **407** | | **$ 219,692** | **$ 219,860** | **$ 219,860** | **$ 219,860** | **$ 219,860** | | **p. 114** |
| **Total Operational Costs** | | | | **$ 79,662,974** | **$ 175,407,304** | **$ 136,630,639** | **$ 91,977,747** | **$ 79,932,444** | | |
| **Total Operational Salaries and Wages** | **Common** | | | **$ 19,507,614** | **$ 19,985,330** | **$ 19,524,537** | **$ 23,425,264** | **$ 29,632,333** | Included above | **p. 354** |

## Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)

### PJM Interconnection

### Administrative Costs

| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Customer Records and Collection Expense** | **Common** | **903** | | **$ 2,386,117** | **$ 1,026,993** | **$ 1,294,642** | **$ 1,532,896** | **$ 2,206,055** | | **pp. 320-323** |
| **Customer Assistance Expense** | **Common** | **908** | | **$ 5,998,235** | **$ 7,013,877** | **$ 10,178,389** | **$ 13,009,219** | **$ 14,238,087** | | **pp. 320-323** |
| **Administrative and General Salaries** | **Common** | **920** | | **$ 8,419,872** | **$ 10,647,906** | **$ 13,955,966** | **$ 15,895,883** | **$ 19,983,088** | | **pp. 320-323** |
| **Office Supplies and Expense** | **Common** | **921** | **567.1** | **$ 1,436,198** | **$ 3,396,523** | **$ 3,811,797** | **$ 6,802,372** | **$ 7,664,136** | | **pp. 320-323** |
| **Outside Services Employed** | **Common** | **923** | | **$ 3,140,680** | **$ 7,116,665** | **$ 5,888,529** | **$ 10,306,657** | **$ 5,485,286** | | **pp. 320-323** |
| **Property Insurance** | **Common** | **924** | | **$ 412,479** | **$ 634,645** | **$ 193,450** | **$ 160,802** | **$ 195,386** | | **pp. 320-323** |
| **Injuries and Damages** | **Common** | **925** | | **$ 1,173,978** | **$ 1,808,431** | **$ 2,968,171** | **$ 3,288,269** | **$ 3,163,360** | | **pp. 320-323** |
| **Employee Pensions and Benefits** | **Common** | **926** | | **$ 10,630,896** | **$ 13,763,047** | **$ 12,546,402** | **$ 11,302,993** | **$ 13,217,734** | | **pp. 320-323** |
| **Rents** | **Common** | **931** | **567** | **$ 401,630** | **$ (261,235)** | **$ 62,321** | | | | **pp. 320-323** |
| | | | | | | | | | | |
| **Regulatory Costs** | | | | | | | | | | |
| Legal and Consulting Fees | RTO | | | | | | $ 2,047,664 | $ 3,449,666 | | **p. 350** |
| Salaries, benefits and expenses | RTO | | | | | | $ 1,738,399 | $ 1,638,029 | | **p. 350** |
| Other | RTO | | | | | | $ 100,550 | $ 216,200 | | **p. 350** |
| FERC Fees | RTO | | | $ 2,500,000 | $ 9,800,000 | $ 11,033,080 | $ 23,518,143 | $ 28,249,438 | | **p. 350** |
| lobbying costs | RTO | | | | $ 246,059 | $ 2,104,125 | | | | **p. 350** |
| Various FERC filings | RTO | | | $ 3,113,881 | $ 2,826,871 | $ 1,413,437 | | | | **p. 350** |
| **Total Regulatory Costs** | **Common** | **928** | | **$ 5,613,881** | **$ 12,872,930** | **$ 14,550,642** | **$ 27,404,756** | **$ 33,553,333** | | **pp. 320-323 and 350** |
| *Note: All RTOs will have Regulatory Cost on the Form 1 but the specific items are RTO Specific.* | | | | | | | | | | |
| | | | | | | | | | | |
| **Miscellaneous General Expense** | | | | | | | | | | |
| Telecom/Telephone Expense | Common | | 384/567.4 | $ 157,280 | $ 592,094 | $ 429,051 | $ 161,412 | $ 238,724 | | **p. 335** |
| Employee Travel | RTO | | | | | | | $ 763,241 | | **p. 335** |
| Relocation Expense | RTO | | | | | | | $ 549,871 | | **p. 335** |
| Training | RTO | | | | | | | $ 545,778 | | **p. 335** |
| Computer Licenses, Fees, Maintenance & Supplies | Common | | 576.2/576.3 | | | | | $ 1,877,940 | | **p. 335** |
| Accounting and Auditing Fees | Common | | | | | | | $ 1,179,623 | | **p. 335** |
| Legal Fees | Common | | | | | | | $ 1,281,248 | | **p. 335** |
| Overhead application | RTO | | | | | | $ (1,910,649) | | | **p. 335** |
| Board Activities and Administration | Common | | | $ 1,006,578 | $ 997,425 | $ 1,266,333 | | | | **p. 335** |
| Water & Sewer Expense | RTO | | | | | | | | | **p. 335** |
| Utilities Expense | RTO | | | | | | | | | **p. 335** |
| Miscellaneous Expense | RTO | | | $ 755,209 | $ 1,044,605 | $ 82,965 | $ 58,770 | $ 129,705 | | **p. 335** |
| **Total Miscellaneous General Expenses** | **RTO** | **930.2** | | **$ 1,919,067** | **$ 2,634,124** | **$ 1,778,349** | **$ (1,690,467)** | **$ 6,566,130** | | **pp. 320-323 and 335** |

**Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data)**

**PJM Interconnection**

**Administrative Costs**

| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| **Depreciation Expense** | **Common** | **403** | | **$ 30,610,497** | **$ 38,655,028** | **$ 45,895,874** | **$ 30,502,666** | **$ 47,466,372** | | **p. 114** |
| **Amort. Of Conversion Expenses** | **Common** | **407** | | **$ (23,485,553)** | **$ (12,117,216)** | | | | | **p. 114** |
| **Regulatory Debits** | **Common** | **407.3** | | | | **$ 2,353,670** | **$ 21,003,911** | **$ 16,366,160** | | **p. 114** |
| **Taxes Other Than Income Taxes** | **Common** | **408.1** | | **$ 223,523** | **$ 70,870** | **$ 60,000** | **$ (110,000)** | **$ 5,000** | | **p. 114** |
| **Income Tax Expenses - Federal** | **Common** | **409.1** | | **$ 296,407** | **$ (337,238)** | **$ (4,035)** | **$ 40,197** | **$ 3,749,000** | | **p. 114** |
| **Income Tax Expenses - Other** | **Common** | **409.1** | | | | | **$ 2,588,451** | **$ 4,854,000** | | **p. 114** |
| **Interest on Long-Term Debt** | **Common** | **427** | | | | | **$ 6,927,319** | **$ 5,362,789** | | **p. 117** |
| **Other Interest Expense** | **Common** | **431** | | **$ 9,018,654** | **$ 9,078,348** | **$ 6,938,367** | **$ 185,840** | **$ 3,851,034** | | **p. 117** |
| **Total Administrative Costs** | | | | **$ 58,196,561** | **$ 96,003,698** | **$ 122,472,534** | **$ 149,151,764** | **$ 187,926,950** | | |
| **Salaries and Wages** | | | | | | | | | | |
| Customer Accounts | | | | $ 1,141,161 | $ 1,011,997 | $ 989,600 | $ 938,604 | $ 1,285,845 | Included above | **p. 354** |
| Customer Service and Informational | | | | $ 4,880,041 | $ 5,082,241 | $ 6,561,569 | $ 7,190,610 | $ 8,738,671 | Included above | **p. 354** |
| Administrative and General | | | | $ 22,013,963 | $ 26,592,767 | $ 17,410,539 | $ 17,150,531 | $ 21,167,142 | Included above | **p. 354** |
| **Total Administrative Salaries and Wages** | **Common** | | | **$ 28,035,165** | **$ 32,687,005** | **$ 24,961,708** | **$ 25,279,745** | **$ 31,191,658** | Included above | |
| Total Operational and Administrative Salaries Check | | | | $ 47,542,779 | $ 52,672,335 | $ 44,486,245 | $ 48,705,009 | $ 60,823,991 | | p. 354 |

# C6 - Southwest Power Pool

| Summary Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Southwest Power Pool** | | | | | | | |
| **Major Cost Breakdown** | | | | | | | |
| **Note: RTO Major Costs are those that are typically over 2% of the Total Cost for a year.** | | | | | | | |
| | | | | | | | |
| | **2001** | **2002** | **2003** | **2004** | **2005** | **Survey Period Total** | **% of Total Cost** |
| **SPP Annual Load (MWh)** | | | | | 201,511,494 | 201,511,494.290 | N/A |
| | | | | | | | |
| **Total Costs** | $ - | $ - | $ - | $ - | $ 48,392,404 | **$ 48,392,404** | 100.0% |
| $/MWh | | | | | $ 0.240 | $ 0.240 | |
| | | | | | | | |
| **Operational** | | | | | | | |
| **Total Operational Costs** | $ - | $ - | $ - | $ - | $ 1,942,496 | **$ 1,942,496** | 4.0% |
| $/MWh | | | | | $ 0.010 | $ 0.010 | |
| | | | | | | | |
| **Maintenance of General Plant** | $ - | $ - | $ - | $ - | $ 1,942,496 | **$ 1,942,496** | 4.0% |
| $/MWh | | | | | $ 0.010 | $ 0.010 | |
| | | | | | | | |
| | | | | | | | |
| **Administrative** | | | | | | | |
| **Total Administrative Costs** | $ - | $ - | $ - | $ - | $ 46,449,908 | **$ 46,449,908** | 96.0% |
| $/MWh | | | | | $ 0.231 | $ 0.231 | |
| | | | | | | | |
| **Salaries and Wages**[1] | $ - | $ - | $ - | $ - | $ 12,704,051 | **$ 12,704,051** | 26.3% |
| $/MWh | | | | | $ 0.063 | $ 0.063 | |
| | | | | | | | |
| **Employee Pensions and Benefits** | $ - | $ - | $ - | $ - | $ 4,512,354 | **$ 4,512,354** | 9.3% |
| $/MWh | | | | | $ 0.022 | $ 0.022 | |
| | | | | | | | |
| **Office Supplies and Expense** | $ - | $ - | $ - | $ - | $ 3,943,730 | **$ 3,943,730** | 8.1% |
| $/MWh | | | | | $ 0.020 | $ 0.020 | |
| | | | | | | | |
| **Regulatory Costs** | $ - | $ - | $ - | $ - | $ 9,196,078 | **$ 9,196,078** | 19.0% |
| $/MWh | | | | | $ 0.046 | $ 0.046 | |
| | | | | | | | |
| **Consulting Fees/Outside Services** | $ - | $ - | $ - | $ - | $ 10,412,326 | **$ 10,412,326** | 21.5% |
| $/MWh | | | | | $ 0.052 | $ 0.052 | |
| | | | | | | | |
| **Depreciation Expense** | $ - | $ - | $ - | $ - | $ 2,805,300 | **$ 2,805,300** | 5.8% |
| $/MWh | | | | | $ 0.014 | $ 0.014 | |
| | | | | | | | |
| **Interest Expense** | $ - | $ - | $ - | $ - | $ 1,374,356 | **$ 1,374,356** | 2.8% |
| $/MWh | | | | | $ 0.007 | $ 0.007 | |
| | | | | | | | |
| | | | | | | | |
| Note 1: Part of this category is included in other cost categories. | | | | | | | |

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Southwest Power Pool** | | | | | | | | | |
| **Overview** | | | | | | | | | |
| | | | | | | | | | |
| **Cost Category** | **Current FERC Account Number** | **Future FERC Account Number** | **2001** | **2002** | **2003** | **2004** | **2005** | **Notes** | **Form 1 Ref.** |
| | | | | | | | | | |
| **Operating Revenue** | **400** | **457.1** | | | | | **$ 54,945,828** | | **p. 114** |
| **Total Operational Costs** | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ 1,942,496** | | |
| **Total Administrative Costs** | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ 46,449,908** | | |
| **Net Other Income and Deductions** | | | | | | | **$ (80,925)** | | **p. 117** |
| | | | | | | | | | |
| **NET INCOME** | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ 6,472,499** | | **p. 117** |

| Detailed Data Table of RTO Operational and Administrative Costs (From FERC Form 1 Data) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Southwest Power Pool | | | | | | | | | | |
| Operational Costs | | | | | | | | | | |
| | | | | | | | | | | |
| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
| | | | | | | | | | | |
| Maintenance of General Plant | Common | 935 | 569.4 | | | | | $ 1,942,496 | | pp. 320-323 |
| | | | | | | | | | | |
| Total Operational Costs | | | | $ - | $ - | $ - | $ - | $ 1,942,496 | | |

| Detailed Data Table of RTO Operational and Administrative Costs (from FERC Form 1 Data) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Southwest Power Pool | | | | | | | | | | |
| Administrative Costs | | | | | | | | | | |
| Cost Category | Common or RTO Specific | Current FERC Account Number | Future FERC Account Number | 2001 | 2002 | 2003 | 2004 | 2005 | Notes | Form 1 Ref. |
| **Administrative and General Salaries** | **Common** | **920** | | | | | | **$ 12,704,051** | | **pp. 320-323** |
| **Office Supplies and Expense** | **Common** | **921** | **567.1** | | | | | **$ 3,943,730** | | **pp. 320-323** |
| **Outside Services Employed** | **Common** | **923** | | | | | | **$ 10,412,326** | | **pp. 320-323** |
| **Employee Pensions and Benefits** | **Common** | **926** | | | | | | **$ 4,512,354** | | **pp. 320-323** |
| | | | | | | | | | | |
| **Regulatory Costs** | | | | | | | | | | |
| Federal Energy Regulatory Commission | | | | | | | | $ 7,517,645 | | **p. 350** |
| North American Electric Reliability Council | | | | | | | | $ 708,464 | | **p. 350** |
| Regional State Committee | RTO | | | | | | | $ 969,969 | | **p. 350** |
| **Total Regulatory Costs** | **Common** | **928** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ 9,196,078** | | **pp. 320-323 and 350** |
| *Note: All RTOs will have Regulatory Cost on the Form 1 but the specific items are RTO Specific.* | | | | | | | | | | |
| | | | | | | | | | | |
| **Miscellaneous General Expense** | **RTO** | **930.2** | | | | | | **$ 427,403** | | **pp. 320-323 and 335** |
| | | | | | | | | | | |
| **Depreciation Expense** | **Common** | **403** | | | | | | **$ 2,805,300** | | **p. 114** |
| **Taxes Other Than Income Taxes** | **Common** | **408.1** | | | | | | **$ 993,358** | | **p. 114** |
| **Interest on Long-Term Debt** | **Common** | **427** | | | | | | **$ 1,374,356** | | **p. 117** |
| **Amort. Of Debt Disc. And Expense** | **Common** | **428** | | | | | | **$ 80,952** | | **p. 117** |
| | | | | | | | | | | |
| **Total Administrative Costs** | | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ 46,449,908** | | |

# Appendix D – Cost Recovery Detail

# D1 - California ISO

The California ISO recovers its administrative and operational costs using Schedule 1, Grid Management Charge ("GMC"), of its Transmission Tariff. The GMC is used to recover the following costs:

- Operating costs
- Financing costs, including Start-Up and Development costs
- Operating and Capital Reserve Costs.

The GMC is divided into the following eight components:

1. Core Reliability Services – Demand Charge:
   This service is charged on a $/MWh rate by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year, excluding Demand associated with Energy Exports.

2. Core Reliability Services – Energy Exports Charge:
   This service is charged based on the total of the forecasted Scheduling Coordinator' metered volume of Energy Exports as a $/MWh charge.

3. Energy Transmission Services Net Energy Charge:
   The $/MWh rate for this service is charged based on the total annual forecasted Metered Control Area Load.

4. Energy Transmission Services Uninstructed Deviations[1] Charge:
   This service is charged based on the absolute value of the total annual forecasted net uninstructed deviations netted with the Settlement Interval summed over the calendar month. The rate for this charge is $/MWh.

5. Forward Scheduling Charge:
   The Forward Scheduling Charge is charged based on the annual forecasted number of non-zero MW Final Hour-Ahead Schedules. This charge is recovered on a per schedule basis, therefore the rate is expressed as $ per Schedule.

6. Congestion Management Charge:
   The Congestion Management Charge is charged based on the total annual forecasted Scheduling Coordinators' inter-zonal scheduled flow per path in MWh. This charge is recovered using a $/MWh rate.

[1] Uninstructed Deviation: A deviation from the resources' Dispatch Operating Point. (CAISO, FERC Electric Tariff, Appendix A, Sheet 535).

7. Market Usage Charge:
   The Market Usage Charge is based on dividing the GMC costs allocated to this service category by the annual forecasted total purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy. This charge is expressed as a rate in $/MWh.

8. Settlements, Metering, and Client Relations Charge:
   This charge is a fixed rate of $500.00 per month.

CASIO Tariff Appendix F, Schedule 1 provides the details of how each type of operational and administrative charge experienced by the ISO is split into the eight (8) components above.

# D2 - ISO New England

ISO-NE recovers its operational and administrative costs through Section IV.A of its FERC filed tariff, which includes the following schedules:

- Section IV.A, Schedule 1 – Scheduling, System Control and Dispatch Service
- Section IV.A, Schedule 2 – Energy Administration Service
- Section IV.A, Schedule 3 – Reliability Administration Service
- Section IV.A, Schedule 4 – Collection of FERC Annual Charges

Schedule 1 covers the ISOs operational expenses for the processing and implementation of transmission service requests and coordination of transmission service operations. The costs associated with Schedule 1 are recovered from the ISO Customers that take Regional Network Service based on its Monthly Network Load at a charge of $0.07986 per kilowatt times its Monthly Network Load for that month.

Schedule 2 is charged based on both operational and administrative functions of the ISO related to the Energy Market, such as core operation of the Energy Market, generation dispatch, energy accounting, loss determination, billing preparation, market power monitoring and mitigation, sanctions activities, and market assessment and reports. Schedule 2 is assessed to Market Participants that have an account for Energy settled by the ISO under rates that vary based on the Market Participants' usage.

Schedule 3 recovers the operational and administrative costs associated with the ISOs facilitation of reliability-associated transactions and arrangements. Each ISO customer is charged for this service based on their use of the transmission system. RAS Customers pay a charge of $0.09255 per kilowatt times the Market Participants Non-Coincident Peak Load Obligation.

Schedule 4 is charged to each jurisdictional Transmission Owner in the ISO based on the Transmission Owner's total reported MWh of transmission of electric energy. This schedule is used to recover the FERC assessment of annual charges for the New England Control Area.

# D3 - Midwest ISO

The Midwest ISO recovers its operational and administrative costs through the following Electric Tariff Schedules:

- Schedule 1 – Scheduling, System Control and Dispatch Service
- Schedule 10 – ISO Cost Recovery Adder
- Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder
- Schedule 17 – Energy Market Support Administrative Service Cost Recovery Adder

Schedule 1 recovers all costs associated with control area operations and allocates them to Network customers by multiplying the Monthly Rate by each MW of Network Load. This schedule is also recovered from Point-to-Point customers by MWs of reserved transmission for both Firm and Non-Firm Point-to-Point Transmission Service.

Schedule 10 recovers all pre-operating costs, the building and operating of the Security Center, and costs related to administering the Tariff. This Schedule is charged to Transmission Customer and Transmission Owners based on the budgeted costs and estimated MWhs of Transmission Service per month. The Schedule 10 charges are trued-up the following month to reflect actual costs and MWhs of service. Additionally, Schedule 10-FERC is assessed to Transmission Providers on an annual basis to cover the FERC assessments charged to the ISO.

Schedule 16 provides for the recovery of all costs incurred by the Transmission Provider for providing services associated with the administration of FTRs. This Schedule is charged based on the total amount of FTR volume for all FTR holders.

Schedule 17 allows the Transmission Provider to recover any costs associated with the development and support of the Energy Market. This schedule is assessed to Market Participants based on all MWh injected into the Transmission System, all MWh extracted from the Transmission System, and all Bids or Offers that settle in the Day-Ahead Energy Markets, but do not actually inject or extract MWh from the Transmission System in the Real-Time Energy Market.

# D4 - New York ISO

The New York ISO recovers its operational and administrative costs through Schedule 1, Scheduling, System Control and Dispatch Service of its Transmission Tariff. The NYISO Schedule 1 provides for the recovery of the following cost components on a monthly basis:

1. ISO Annual Budget and FERC Regulatory Fees
   Annual budget and regulatory fees are allocated 20% to injections and 80% to withdrawals to/from the system.

2. ISO Unbudgeted Costs
   Unbudgeted costs are allocated 100% to withdrawals from the system.

3. ISO Start-Up and Formation Costs
   These costs are recovered from withdrawals from the system using a monthly rate schedule which is updated and posted prior to the start of each month.

4. Residual Adjustment and Bid Protection Guarantees
   This charge is used as a True-Up for prior billing months.

# D5 – PJM

PJM recovers its operations and administrative costs through the following schedules in its Transmission Tariff:

- Schedule 1 – Scheduling, System Control and Dispatch Service
- Schedule 1A – Transmission Owner Scheduling, System Control and Dispatch Service
- Schedule 9 - PJM Interconnection, L.L.C. Administrative Services
    - 9-1 - Control Area Administrative Service
    - 9-2 - Financial Transmission Rights Administrative Servic
    - 9-3 - Market Support Service
    - 9-4 - Regulation and Frequency Response Administrative Servic
    - 9-5 - Capacity Resource and Obligation Management Service
    - 9-6 - Management Service Cost
    - 9-FERC - FERC Annual Charge Recovery
    - 9-OPSI - OPSI Funding
- Schedule 13 - Expansion Cost Recovery
- Attachment H-13 - RTO Start-up Cost Recovery
- Attachment H-14 - RTO Start-up Cost Recovery

Schedule 1 – Scheduling, System Control and Dispatch Service:

PJM does not invoice a Schedule 1 but instead divides the costs into the eight sub-schedules that are included below as Schedule 9.

Schedule 1A – Transmission Owner Scheduling, System Control and Dispatch Service:

This schedule recovers the cost for the operation of the control centers of the various Transmission Owners in PJM. Each Zone in PJM has a different Schedule 1A rate. These rates range from $0.0186 per MWh for the Potomac Electric Power Company Zone to $0.2475 per MWh for the Rockland Electric Company Zone.

Schedule 9 – PJM Interconnection, L.L.C. Administrative Services:

PJM's Schedule 9 is divided into eight sub-schedules. The costs associated with these sub-schedules are charged based on a fixed rate that is updated annually.

Schedule 9-1 – Control Area Administrative Service:

The Control Area Administrative Service schedule is used to recover the costs for activities by PJM associated with preserving the reliability of the region and administering Network and Point-to-Point Transmission Service. In 2006, Schedule 9-1 is charged to transmission customers based on their monthly transmission use at a rate of $0.1903 per MWh for 2006.

Schedule 9-2 – Financial Transmission Rights Administrative Service:
This schedule is used to recover the cost of administering the Financial Transmission Rights ("FTR") market. In 2006, it is charged to FTR holders at a rate of $0.0029/FTR MWh for 2006.

Schedule 9-3 – Market Support Service:
The Market Support Service schedule recovers the costs associated with supporting the PJM Interchange Energy market and related functions. For 2006, the rate is $0.0432/MWh for transmission customers based on their network load[2] and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, demand bids, and up-to congestion bids. A rate of $0.0593/MWh is charged for energy bids and offers submitted in the PJM eMKT system.

Schedule 9-4 – Regulation and Frequency Response Administrative Service:
This schedule is used to recover the costs incurred by PJM for the support of the regulation and frequency response market. For 2006, this cost was recovered from load serving entities based on their regulation obligation and to regulation providers based on their scheduled regulation at a rate of $0.2599/Regulation MWh.

Schedule 9-5 – Capacity Resource and Obligation Management Service:
This schedule recovers the costs associated with assuring that PJM customer have arranged for sufficient generation capacity to meet their obligations under the PJM Reliability Assurance Agreements, processing Network Integration Transmission Service, administering the capacity credit market, and providing technical support for the PJM Region. For 2006 a rate of $0.0992/MW-day is charged to load serving entities based on their daily capacity obligations and to capacity resource owners based on their daily capacity.

Schedule 9-6 – Management Service Cost:
The Management Service Cost schedule provides for the recovery of overhead and administrative costs incurred by PJM. It is not recovered as a separate charge on the PJM Invoices but rather it is recovered through Schedule 9-1 through 9-5.

Schedule 9-FERC – FERC Annual Charge Recovery:
The FERC Annual Charge Recovery schedule recovers the annual charges assessed to PJM by FERC. These charges are recovered from transmission customers based on their monthly usage of the PJM transmission system at a rate of $0.0512/MWh.

[2] In PJM Network, load is the customer's non-coincidental peak with the Zone expressed in MWhs.

Schedule 9-OPSI – OPSI Funding:

The OPSI Funding schedule is used to fund the Organization of PJM States, Inc. ("OPSI") and is recovered from transmission customers based on their usage of the PJM transmission system at a rate of $0.00057/MWh.

Schedule 13 – Expansion Cost Recovery:

Schedule 13 recovers the expenses incurred by transmission owners for integration into PJM. This cost is recovered from all network customers at a rate of $5.20/MW-month for the AEP, Dayton, and ComEd zones and $2.50/MW-month for all other zones, except Dominion. This charge is expected to be discontinued in April 2015.

Attachments H-13 and H-14 – RTO Start-up Cost Recovery:

An RTO Start-up Cost Recovery charge is assessed to all network and point-to-point customers in the AEP and ComEd Zone. In 2006, ComEd customers pay a rate of $57.67/MW-year and AEP customers pay a rate of $103.20/MW-year.

# D6 - Southwest Power Pool

SPP recovers its operational and administrative costs from its customers through application of Schedule 1 and Schedule 1-A of its Tariff.

Schedule 1, Scheduling, System Control and Dispatch Service is charged to Firm and Non-Firm Point-to-Point Transmission customers based on a filed rate of $0.1711 per MWh multiplied by the capacity reserved. For Network Integration Transmission customers the Schedule 1 charge is based on the approved Schedule 1 in the Zone where the load is located.

Schedule 1-A, Tariff Administrative Service is charged to Network Integration Transmission customers at a rate of up to $0.20 per MWh for the 12 month average of the Transmission Customer's coincident Zonal Demand multiplied by the number of all hours of the applicable month.

# Appendix E – Data Sources and References

- FERC Form Nos. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental were used for the following ISO/RTOs:

| **ISO/RTO** | **Year(s)** |
|---|---|
| California ISO | 2001-2005 |
| ISO New England | 2001-2005 |
| Midwest ISO | 2002-2005 |
| New York ISO | 2001-2005 |
| PJM Interconnection | 2001-2005 |
| Southwest Power Pool | 2005 |

- Tariffs
  - California ISO FERC Electric Tariff, Third Replacement Volume No. II
  - ISO New England FERC Electric Tariff No. 3
  - Midwest ISO FERC Electric Tariff, Third Revised Volume No. 1
  - New York ISO FERC Electric Tariff, Original Volume No. 1
  - PJM Interconnection FERC Electric Tariff, Sixth Revised Volume No. 1
  - Southwest Power Pool FERC Electric Tariff, Fourth Revised Volume No. 1
- Customer Guide to PJM Billing
- Accounting and Financial Reporting for Public Utilities Including RTOs (FERC 18 CFR Part 101, Docket No. RM04-12-000; Order No. 668)
- Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization (FERC Docket No. PL04-16-000)
- Electric Industry Landmark FERC Orders
  - http://ferc.gov/legal/maj-ord-reg/land-ord.asp
- FERC Orders and Rulings
  - http://ferc.gov/industries/electric.asp
- PJM Overview and History
  - http://www.pjm.com/
    - http://www.pjm.com/about/overview.html
- NYISO Overview and History
  - http://www.nyiso.com/
    - http://www.nyiso.com/public/company/about_us/index.jsp
- ISO-NE Overview and History
  - http://www.iso-ne.com
    - http://www.iso-ne.com/aboutiso/co_profile/history/index.html
- SPP Overview and History
  - http://www.spp.org/
    - http://www.spp.org/About_PressReleases.asp
- MISO Overview and History
  - http://www.midwestiso.org/home

        - http://www.midwestmarket.org/publish/Document/3e2d0_106c609 36d4_-7ba50a48324a/FactSheet_0510f%20(2).pdf
- CAISO Overview and History
    - http://caiso.com/
        - http://caiso.com/docs/2002/05/20/2002052011004217950.pdf
- Load Data

| **ISO/RTO** | **Source** | **Year(s)** |
|---|---|---|
| California ISO | FERC Form 714 | 2001-2005 |
| ISO New England | FERC Form 714 | 2001-2005 |
| Midwest ISO | FERC Form 582 | 2002-2005 |
| New York ISO | FERC Form 714 | 2001-2005 |
| PJM Interconnection | PJM Web Site | 2001-2005 |
| Southwest Power Pool | FERC Form 714 | 2002-2005 |

# ENERGY PROBE INTERROGATORY 10

2.0 Usage Fee

## INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Page 5 and Exhibit B, Tab 1, Schedule 2, Page 3

Preamble: To parse the work of the IESO or to attempt to separate the costs or benefits of the IESO's operations is difficult now and will be increasingly difficult and decreasingly practical in the future.

a) What in IESO's view is the purpose of a Cost Allocation Study, such as the Elenchus Report? Please provide in detail the objectives and comment on each of these.

b) Did Elenchus perform Time Studies to allocate specific costs to Domestic and Export Functions? If not, why not?

c) Is IESO rejecting the Elenchus Cost allocation study? If so, please expand on why/how the principle functions performed by the IESO are independent of IESO's Capital and Operating costs and accordingly, why "One Size Fits All".

d) Specifically indicate why the Regional and Grid Planning Functions benefit both domestic and Export customers.

e) Please explain in detail why embedded generation creates costs for IESO at a different level than managing Bulk Generation and Exports.

f) Has IESO done a Jurisdictional Review of other System Operators in support of its position regarding Cost Allocation and a single fee? If so, please provide a copy of this.

g) In any event, based on IESOs knowledge of other ISOs, please provide its best information on the allocation of costs and fee structures by these entities.

## RESPONSE

a) Cost allocation studies typically examine the drivers for organizational costs by customer class, and then allocate costs based on these causal relationships. The resulting cost allocation information can then be used in combination with established revenue to cost ratio ranges to inform rate design. As described in Exhibit B-1-1, the IESO's decision to hire Elenchus was to specifically address the Board's concern in the OPA's 2011 Revenue Requirement Submission to the Board (EB-2010-0279), when it requested to expand the base of customers it recovered its usage fee from to include export customers, that the OPA's proposal was not supported by empirical evidence.

Despite the fact that the IESO believes that the proposal to move to one fee for the organization, recovered from both domestic and export volumes on a gross load basis, should be accepted on its own merits, the IESO hired Elenchus "to develop a cost allocation model that would allocate the IESO's costs in a manner consistent with standard regulatory cost allocation principles and practices, in particular the principle of cost causality."(Section 2.4 of Elenchus' report at Exhibit B-1-1, Attachment 3). Sensitivity to year-over-year changes in forecast energy volumes in Elenchus' model, as described at Exhibit B-1-2, illustrated that Elenchus' cost allocation model does not produce robust results for the IESO. Therefore, the value of a traditional cost allocation model in setting the IESO fee is called into question. As stated on page 3 of Exhibit B-1-2, "The IESO does not believe a traditional cost allocation model is the appropriate tool to examine or support how the IESO fee is set as it is not representative of cost causality within the IESO."

b) Time studies were not used as the work of the IESO is not divided or segregated between domestic and export functions, hence, work effort (time) cannot be tracked on that basis. Please also see the response to HQEM-APPRO Interrogatory 24, at Exhibit I, Tab 6.2, Schedule 2.24.

c) The IESO does not believe that a traditional cost allocation study is appropriate for the IESO for the reasons described in Exhibit B-1-2. Specifically, sensitivity to year-over-year changes in the cost allocation model, which results in significant changes to the resulting revenue to cost ratios but do not reflect actual fluctuations in IESO's work, is indicative, in the IESO's view, that a traditional cost allocation study is not robust or appropriate for the IESO. The majority of the IESO's costs are akin to operational overhead or administrative and general costs of other regulated electric utilities, which are difficult to directly attribute to specific customers.

As described in Exhibit B-1-1, the IESO believes that as both domestic and export classes of customers benefit from the work that the IESO carries out, it is appropriate and fair that both should pay the same fee for the work performed by the IESO. The IESO believes that it is incorrect to assume the work of the IESO is performed primarily for one group and then to attempt to parse out only the 'incremental' costs associated with a second group. The work of the IESO is generally influenced and performed equally for the benefit of both domestic and export customers. It would be false, for example, to assume that because the IESO is required to size system facilities and assets based on 'worst case scenarios' as defined by NERC, NPCC and IESO standards, which thereby creates spare transmission and generation capacity very often available for use by exporters, that only incremental costs associated with allowing exporters to use this capacity should be attributed to exporters. If the approach for setting industry standards changed and spare capacity was no longer available, significantly more dedicated facilities would be required by exporters to participate in the IESO market. If transmission facilities were not planned and built to meet peak demand requirements and transmit electricity for domestic use, there would be no network available for getting electrons to the border for export. Likewise, if generation facilities were not planned and built to meet peak demand requirements in Ontario, there would be few megawatts available for export to other jurisdictions. The interconnected nature of Ontario's electricity system is an essential element of the system that is reflected in the way it is operated and planned. All stakeholders benefit from a properly functioning electricity system, which is the responsibility of the IESO. The work carried out by virtually all areas of the IESO creates an interdependent relationship between domestic customers and exporters, and to imply otherwise, by presuming that an incremental approach is appropriate for allocating costs, is false. Also, as Elenchus noted in the response to HQEM-APPRO Interrogatory 25, Exhibit I, Tab 2.1, Schedule 6.25, having developed what it considers to be the most appropriate cost allocation model for allocating costs to the domestic and export class, the observed instability raises questions about the approach to rate design that is appropriate.

d) Please see response to part c) above.

e) Embedded generation requires management by the IESO in the same manner as the rest of the system, including bulk generation and exports, which is why the IESO has applied to charge one fee for all groups. The IESO does not believe that it is appropriate for customers of LDCs with embedded generation to receive a discount in the amount of usage fee that they pay, given that this discount does not reflect any cost reductions to the IESO for these customers. Please also see the response to BOMA Interrogatory 28, at Exhibit I, Tab 2.0, Schedule 3.28.

f) No, the IESO has not done a formal jurisdictional review, however Elenchus provided to the IESO a cost review performed by the American Public Power Association Electric Market Reform Initiative (EMRI) Task 2 Analysis of Operational and Administrative Cost of RTOs provided as Attachment 1 to this exhibit. In its summary, the report is described as "as an examination of the costs incurred by the nation's Regional Transmission Organizations".

g) The IESO does not have specific information on the allocation of costs by other ISOs or their fee structures as the IESO has not itself performed a jurisdictional review of other ISOs, as described above in part f). While the IESO does not have specific information on the fee structures of other ISOs, the report referenced in f) above provides information on other jurisdictions and it is generally understood that a number of ISOs recover their costs through transmission rates and charges.

# SEC INTERROGATORY 9

2.0 Usage Fee

2-SEC-9

## INTERROGATORY

[B-1-1, Attach 3] In the 2011 OPA Fees application proceeding (EB-2010-0270), Elenchus Inc. filed an expert report on behalf of HQ Energy Marketing Inc. regarding the proposal for an OPA export usage fee. Please explain how the recommendations in that report are consistent with its evidence in this proceeding. If some aspects are not consistent, please provide an explanation.

## RESPONSE

Elenchus has interpreted this question to refer to the evidence prepared by Elenchus and filed by HQEM in proceeding EB-2010-0279, Ontario Power Authority 2011 Revenue Requirement. Seven recommendations appear in section 5 of that evidence. Each recommendation is repeated below followed by the relevant commentary, recognizing that the OPA has now been merged with the IESO. As a result of the merger, the functionalization envisioned in 2010 (i.e., reference to the strategic objectives) and the available accounting information, the comments below necessarily address the 2010 recommendations at a conceptual level.

> ***#1: The principle of cost causality should be applied to the OPA in determining the extent to which different types of customers should be responsible for the recovery of OPA's revenue requirement.***

The principle of cost causality was the primary consideration in developing the IESO's cost allocation model for the current proceeding.

> ***#2: All of OPA's costs, direct costs and indirect generation procurement and conservation costs should be allocated using a consistent approach based on cost causality principles.***

This approach to allocating all costs that are recoverable in the IESO's fee was taken by Elenchus in developing the IESO's cost allocation model.

> ***#3: The OPA's conservation activities are not caused by exporters; hence, these costs should not be recovered from exporters.***

The relevant identifiable costs were allocated to the domestic class.

> ***#4: The OPA's generation procurement activities are not being imposed by exporters; hence, these costs should not be recovered from exporters.***

The relevant identifiable costs were allocated to the domestic class.

> ***#5: Based on cost causality principles, the OPA's objective #1 which is related to transmission planning could be recovered from domestic and export consumers.***

The relevant identifiable costs were allocated to the domestic and export classes using the TWh allocator.

> ***#6: Strategic Objective #4 includes overhead costs that support all other strategic objectives. Some allocation of these costs to the other four strategic objectives would be appropriate and should be based on the share of costs for each of the other four strategic objectives.***

The relevant identifiable costs were allocated to the domestic and export classes using the Other O&M allocator.

> ***#7: No new usage fee on exporters should be levied by the OPA until such cost allocation study has been prepared by the OPA and evidence reviewed by the Board at the OPA's next fees case.***

The IESO retained Elenchus to prepare the cost allocation model that is the subject of the Elenchus evidence in the current IESO fees case.

# VECC INTERROGATORY 7

2.0 Usage Fee

2.0-VECC-7

## INTERROGATORY

Reference: B/T1/S1/pg.2

a) Please provide the derivation for the 2016 forecast of $1million for FIT and Large Renewable Procurement service revenues.

b) Please provide the actual amounts collected for these services in each of 2013 through 2015.

## RESPONSE

a) Please see the response to BOMA Interrogatory 27, at Exhibit I, Tab 1.5, Schedule 3.27.

b) The total registration fees collected in 2013, 2014 and 2015, were $1.7 million, $2.7 million and $2.2 million respectively.

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# VECC INTERROGATORY 8

2.0 Usage Fee

2.2 Is the methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2.0-VECC-8

## INTERROGATORY

Reference: B/T1/S1/Table 3/pg.6

a) Why is an 18th month demand forecast used rather than a 12 month forecast?

b) Please provide the derivation (source) for each of the components for the Charge Determinants shown in Table 2.

## RESPONSE

a) Please see response to OEB Staff Interrogatory 2, at Exhibit I, Tab 2.2, Schedule 1.02.

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# VECC INTERROGATORY 9

2.0 Usage Fee

2.2 Is the methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2.0-VECC-9

## INTERROGATORY

Reference: EB/T1/S1/pg.7

a) Other than the fact that the $10 million operating reserve is the sum of the prior agencies reserves what rationale has IESO provided for the continuance of a reserve?

b) Why would it not be more appropriate to establish a reserve based on a proportion of forecast revenues rather than what appears to be an arbitrary lump sum amount?

c) What lines of credit or other banking facilities are utilized by the IESO?

## RESPONSE

a) and (b)
Please see the response to CME Interrogatory 2 at Exhibit I, Tab 4.4, Schedule 4.02 for information relating to the IESO's operating reserve.

b) Please see the IESO's 2015 Annual Report – pages 44 and 50– at Exhibit A-3-4.

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# VECC INTERROGATORY 10

2.0 Usage Fee

2.2 Is the methodology used to derive the proposed IESO Usage Fee of 1.13/MWh appropriate?

2.0-VECC-10

## INTERROGATORY

Reference: EB/T1/S1/pg.9

a) Please provide the prior year IESO and OPA forecast of the annual Ontario electricity demand forecast and the actuals for each year 2010 through 2015.

## RESPONSE

a) Please see the response to Energy Probe Interrogatory 8, at Exhibit I, Tab 2, Schedule 5.08.

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# VECC INTERROGATORY 11

2.0 Usage Fee

2.3 Is the proposed cost allocation study in support of the proposed IESO Usage Fee appropriate?

2.0-VECC-11

## INTERROGATORY

Reference: B1/Attachment 3/pg. 6, 17-

a) Are distribution utilities, directly connected and export customers the entire group of parties who receive services from the IESO?

b) Do Distribution utilities, directly connected market participants and export customers all receive the same services? If not please provide a listing of the differences.

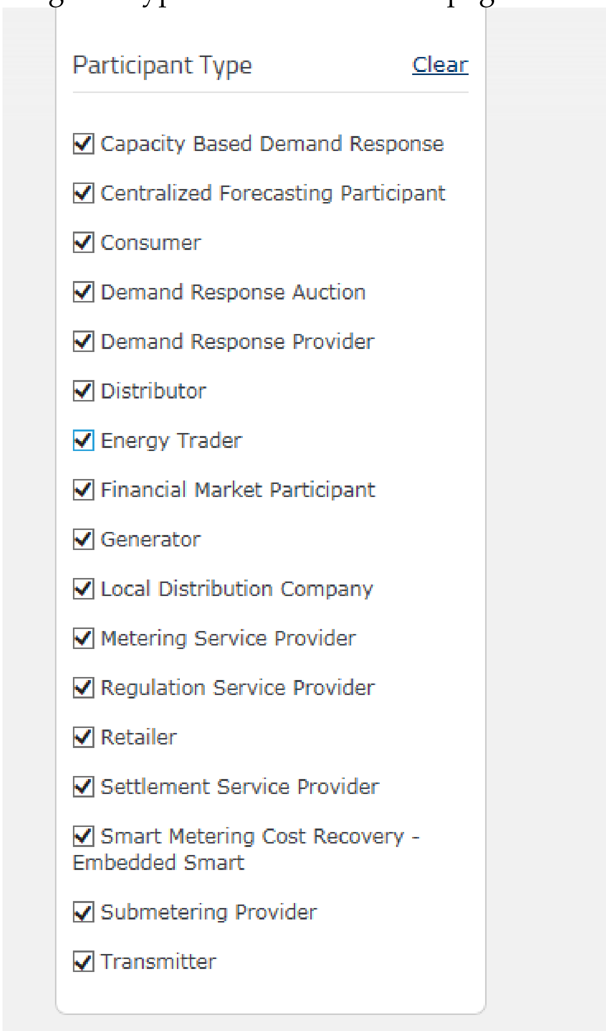
c) Was any study or review undertaken of customer classification as part of the Elenchus study?

## RESPONSE

a) The scope of the IESO's activities extend across the electricity sector - from planning new infrastructure, to funding development of energy projects by indigenous communities and municipalities, to dispatching generation. Anyone that uses, purchases or sells electricity in Ontario either directly or indirectly benefits from the services of the IESO.

   This not only includes LDCs, directly connected customers, and exporters, but also transmitters, aggregators, generators, and other sector participants. A full listing of all market participants is available on the IESO's website at http://www.ieso.ca/Pages/Participate/Participants.aspx and the Participant/Service

Program Types shown on the webpage are also pasted below:




b) Each electricity sector participant interacts with the IESO in a different way. For example, LDCs' predominant point of contact may be with the IESO's Planning and Conservation groups, whereas an exporter's primary point of contact may be the IESO's Control Room. In fact, however, each of these participants benefits from a broader cross section of the IESO's organization. As described in Exhibit B-1-1, the IESO does not operate to serve single customers: the IESO operates to benefit all sector participants without discretion. As such, it is extremely difficult to parse out the work of the IESO and attempt to separate the costs or benefits of particular area of the IESO's operations for certain types of customers.

c) No study or review of customer classification was undertaken as part of the Elenchus cost allocation study.

# VECC INTERROGATORY 12

2.0 Usage Fee

2.3 Is the proposed cost allocation study in support of the proposed IESO Usage Fee appropriate?

2.0-VECC-12

## INTERROGATORY

Reference: B1/Attachment 3/pg.

a) In 2015 what was the total revenue collected from market participants who were not a regulated distribution utility?

## RESPONSE

a) The total 2015 revenue collected from non-LDC market participants (which includes directly connected, generators, and exporters) was $41,520,918.61.

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# VECC INTERROGATORY 13

2.0 Usage Fee

2.3 Is the proposed cost allocation study in support of the proposed IESO Usage Fee appropriate?

2.0-VECC-13

## INTERROGATORY

Reference: B1/Attachment 3/pg. 12

a) Please provide the analysis showing which market participants will see a net increase in fees under the proposed change to gross billing.

b) How many customers contributed to this revenue in 2015?

## RESPONSE

a) Sixty two market participants, which are LDCs with embedded generation, will see a net increase in their fees under the IESO's proposal to recover the new IESO charge on a gross load basis (i.e. including embedded generation in the charge determinant). This is a result of the inconsistency between the basis on which distributors collect the usage fees from customers (gross load) and the payment to the IESO on a net load basis

b) The IESO does not have access to information on the number of customers LDCs serve. The number of market participants will not change with the IESO's proposed move to charging the former OPA's charge on a gross load basis.

# VECC INTERROGATORY 14

## 2.0 Usage Fee

2.3 Is the proposed cost allocation study in support of the proposed IESO Usage Fee appropriate?

2.0-VECC-14

## INTERROGATORY

Reference: B1/Attachment 3/pg. 19

a) What is the basis for splitting NERC costs 50% to domestic and export customers?

## RESPONSE

a) The split of NERC costs on the basis of 50% to domestic and 50% to export was based on judgment. The primary consideration was that NERC membership is required both to facilitate power exports to the United States and to maintain reliability standards for the integrated cross-border power grid. Elenchus was not able to identify a basis for the allocation to the two classes that appeared to be more reflective of cost causality.

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