STATE OF MICHIGAN
DEPARTMENT OF ENERGY, LABOR & ECONOMIC GROWTH
PUBLIC SERVICE COMMISSION

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October 6, 2010

Honorable Jennifer Granholm
Governor of Michigan

Honorable Members of the Senate Energy Policy
and Public Utilities Committee

Honorable Members of the House of Representatives
Energy and Technology Committee

The enclosed report, Advisability of Separating Generation and Distribution within Electric Utilities in Michigan, is submitted on behalf of the Michigan Public Service Commission (Commission) in accordance with Section 10r(6) of 2008 PA 286, MCL 460.10r(6), and represents the results of the research conducted by the Commission and its Staff. The report is available on the Commission's website under reports and also in Case No. U-16196. The report provides the Commission's findings regarding the advisability of separating generation and distribution within electric utilities in Michigan and the consequent impact on end-use customers.

The Commission reviewed the existing level of organization structural separation between generation and distribution assets that exists within electric utilities in Michigan and the additional separation requirements for compliance with the North American Electric Reliability Corporation (NERC) standards. In addition, the Commission investigated the rate changes in 13 states that have separated generation and distribution as part of a previous electric restructuring process. The study indicated the following: 1) those states that restructured generation and distribution experienced electric retail prices that increased at a higher rate than the U.S. average during the study period, and 2) those states that did not divest generation and distribution experienced electric retail prices that increased at a rate at or below the U.S. average. The Commission acknowledges that many factors affect electric retail prices such as fuel costs, fuel supply shifts, and the current economic recession, which has decreased load and fuel prices across the United States.

The Commission opened Case No. U-16196 to receive comments from interested parties regarding Section 10r(6) and to initiate formal investigations into current policies and practices used by Michigan electric utilities. The following interested parties submitted comments: The Detroit Edison Company (Detroit Edison), The Michigan Industrial Ratepayers (Industrial Ratepayers), Association of Businesses Advocating Tariff Equity (ABATE), Michigan Electric and Gas Association (MEGA), Energy Michigan, Inc., Michigan Electric Cooperative Association (MECA) and Consumers Energy Company (Consumers Energy). Detroit Edison, Consumers Energy, Industrial Ratepayers, ABATE, MEGA and MECA oppose separation of distribution from generation within electric utilities. Of the commentors, only Energy Michigan supports separation. In addition, a workgroup was formed for all interested stakeholders to participate and meetings were held on March 14, 2010 and April 14, 2010. Representatives from Detroit Edison, Consumers Energy, MECA, MEGA, ITC Transmission, Constellation Energy, Integrys Energy Group, Michigan South Central Power Agency (MSCPA), and Commission Staff attended the meetings to discuss the goals of section 10r(6) and the collect data from the utility companies for the analysis required for this report.

The Commission's investigation indicates that the utilities would be forced to make substantial expenditures associated with capital and operations and maintenance to comply with such a separation. Any benefits that may be experienced by separating generation would be outweighed by the cost and would not result in a net economic benefit. The implementation of structural separation of generation and distribution would lead to higher customer costs as a result of the additional resource requirements, required capital and operations and maintenance investments, and the subsequent recognition of the Midwest ISO locational marginal price in electricity procurement. The Commission recommends that the electric utilities continue to maintain their current levels of separation with each business unit operating in an efficient, productive, and reliable manner.

The Commission did not receive any evidence that further separation of generation and distribution is necessary or desirable. The current system provides adequate integration to address issues related to cost, efficiency of operations, electric system power quality, and electric reliability. The likely costs associated with a structural separation of generation and distribution should be avoided. For reasons discussed in this report, with emphasis on likely costs to electric customers, the Commission does not recommend new laws to require further separation of electric distribution and generation.

Very truly yours,

Orjiakor N. Isiogu, Chairman

Monica Martinez, Commissioner

Greg R. White, Commissioner

# REPORT ON THE ADVISABILITY OF SEPARATING GENERATION AND DISTRIBUTION WITHIN ELECTRIC UTILITIES IN MICHIGAN

**Orjiakor N. Isiogu, Chairman**
**Monica Martinez, Commissioner**
**Greg White, Commissioner**

**MICHIGAN PUBLIC SERVICE COMMISSION**
Department of Energy, Labor & Economic Growth

October 6, 2010

MICHIGAN PUBLIC SERVICE COMMISSION

**TABLE OF CONTENTS**

## Executive Summary

The restructuring of electric generation and distribution assets has been widely discussed by state regulators since the mid 1990's. Many states ordered or encouraged the divestiture of generating assets by electric utilities as part of the restructuring policy initiatives to facilitate retail customer choice. In June 2000, the Michigan Legislature passed Michigan's Customer Choice and Electric Reliability Act, 2000 PA 141 (Act 141) that established a framework to allow retail customers to choose an alternative electric supplier (AES) to provide their electric generation service in the state.

The Michigan Public Service Commission (MPSC or Commission) opened MPSC Case No. U-16196 to receive comments from interested parties regarding MCL 460.10r(6), which requires the Commission to investigate the advisability of separation of generation and distribution within electric utilities in Michigan. The docket initiated formal investigations into current policies and practices used by Michigan electric utilities. The following interested parties submitted comments: The Detroit Edison Company (Detroit Edison), Michigan Industrial Ratepayers (Industrial Ratepayers), Association of Businesses Advocating Tariff Equity (ABATE), Michigan Electric and Gas Association (MEGA), Energy Michigan, Inc., Michigan Electric Cooperative Association (MECA) and Consumers Energy Company (Consumers Energy). Detroit Edison, Consumers Energy, Industrial Ratepayers, ABATE, MEGA & MECA oppose separation of distribution from generation within electric utilities. Of the commentors, only Energy Michigan supports separation.

In addition, an Advisability of Separating Generation and Distribution within Electric Utilities in Michigan Workgroup was formed for all interested stakeholders to participate and meetings were held on March 14, 2010 and April 14, 2010. Representatives from Detroit Edison, Consumers Energy, MECA, MEGA, ITC, Constellation Energy, Integrys Energy Group, Michigan South Central Power Association (MSCPA), and Commission Staff (Staff) attended the meetings to discuss the goals of Section 10r(6) and collect data from the utility companies for analysis required for the report. Of those stakeholders that filed comments, ABATE, Industrial Ratepayers, and Energy Michigan did not participate in the workgroup meetings or provide information electronically.

The comments provided by stakeholders in Case No. U-16196 show that investor-owned utilities, cooperatives, and customer representatives oppose any further separation of generation and distribution within electric utilities out of concern that separation would lead to the need to hire additional personnel and incur unnecessary costs associated with creating two entities, and further inefficiencies resulting from additional contact points in problem resolution processes. These interested parties suggest that there are no discernable benefits to offset those inefficiencies. Energy Michigan, the only stakeholder that supported separation of distribution and generation within electric utilities in Michigan, believes that such separation fosters competition for generation supply without any negative effects on costs or reliability. Energy Michigan stressed that the 10 percent cap on customer participation in competitive markets will prevent full realization of the competitive effects of separation. Staff found the reports from the other parties contradicted those statements, and also found contradictory evidence through the investigations given in this report.

The Commission did not receive any evidence that further separation of generation and distribution is necessary or desirable. The current system provides adequate integration to address issues related to cost, efficiency of operations, electric system power quality, and electric reliability. The likely substantial costs associated with a structural separation of generation and distribution would outweigh the benefits of increased generator operating efficiencies. The implied benefits of separation experienced in other States during the restructuring process have been put in place in Michigan through Act 141.

The Commission Staff (Staff) also investigated 13 states that have separated generation and distribution as part of an electric restructuring process. Staff's review of the data showed that in the 13 states where electric restructuring was implemented, the electric retail rates in all customer classes were higher than the U.S. average before the restructuring and during the study period the costs continued to rise at a higher rate than the U.S. average. In the same time period, many of the states that did not restructure to the same extent had rates in all customer classes that were lower than the U.S. average before the study period and increased at or below the U.S average during the study period. This 13 state review suggests that if further separation of Michigan's utilities generation and distribution assets is pursued, it could correlate to an increase in electricity retail rates at a higher rate than the U.S. average such as experienced in the 13 states reviewed.

The Commission's investigation indicates that the utilities would be forced to make substantial expenditures associated with capital and operations and maintenance to comply with such a separation. Consumers Energy estimated that $30 million in capital investment would be required to maintain separate books and records. Detroit Edison estimated that $20 million in capital investments would be required to separate personnel to separate departments. The Commission recommends that the electric utilities continue to maintain their current levels of separation with each business unit operating in an efficient, productive, and reliable manner.

For reasons discussed in this report, with emphasis on likely costs to electric customers, the Commission does not recommend new laws to require further separation of electric distribution and generation.

## Introduction

In October 2008, Governor Jennifer M. Granholm signed into law 2008 PA 286 (Act 286), amending a previous energy law, 2000 PA 141, Section 10r(6) of Act 286, MCL 460.10r(6) which provides:

> Within 2 years of the effective date of the amendatory act that added this subsection, the commission shall conduct a study and report to the governor and the house and senate standing committees with oversight of public utilities issues on the advisability of separating electric distribution and generation within electric utilities, taking into account the costs, benefits, efficiencies to be gained or lost, effects on customers, effects on reliability or quality of service, and other factors which the commission determines are appropriate. The report shall include, but is not limited to, the advisability of locating within separate departments of the utility the personnel responsible for the day-to-day management of electric distribution and generation and maintaining separate books and records for electric distribution and generation.

The Michigan Public Service Commission (Commission or MPSC) has conducted its study and submits this report in accordance with the statutory directives. The Commission Staff (Staff) reviewed the advisability of a structural separation that would require that new separate subsidiaries be created within an electric utility. The new subsidiary would have a separate legal identity from its controlling corporate parent or other affiliated company and no longer exist entirely within a company.

For reasons discussed in this report, with emphasis on likely costs to electric customers, the Commission does not recommend new laws to require further separation of electric distribution and generation.

## Electric Utility Restructuring and Separations Study Background

The restructuring of generation and distribution assets within electric utilities has been widely discussed by state regulators since the mid 1990's. Many states in the Eastern Interconnect ordered or encouraged the divestiture of generating assets by electric utilities as part of the restructuring policy initiatives to facilitate retail customer choice among generating suppliers of electricity in an effort to promote competition within the electric industry and drive down high customer retail rates. In June 2000, the Michigan Legislature passed Michigan's Customer Choice and Electric Reliability Act, 2000 PA 141 (Act 141) that established a framework to allow retail customers to choose an alternative electric supplier (AES) to provide their electric generation service in the state.

Act 141 provided "that all retail customers in this state of electric power have a choice of electric suppliers" and directed the MPSC to "issue orders establishing the rates, terms, and conditions of service that allow all retail customers of an electric utility or provider to choose an alternative electric supplier."

Under Michigan's electric customer choice, the generation and supply of power has opened to competitive suppliers. However, the electric generation and distribution businesses of the bundled utilities remained under a regulated monopoly utility structure. Since the law took effect in June 2000, the MPSC issued many orders to implement its various provisions. Open access, or "Choice," became available to all customers of Michigan investor-owned utilities, beginning January 1, 2002. Customers of Michigan's member-owned cooperative electric distribution companies that have a maximum demand of 200 kilowatts or more also became eligible to participate. Other co-op customers became eligible after January 1, 2006.

Act 286 also provided that the Commission shall issue orders establishing that "no more than 10% of an electric utility's average weather adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time." On September 29, 2009, in Case No. U-15801, the MPSC approved procedures dealing with the administration and allocation of electric load allowed to be served by AESs, under Public Act 286 of 2008.

Act 141, in section 10d(2), also provides that: "In no event shall residential rates be increased before January 1, 2006 above the rates established under subsection (1)." Electric retail rates in Michigan were frozen for a period of at least three years and capped for a period thereafter.

The Federal Energy Regulatory Commission (FERC), which regulates interstate transmission and wholesale power transactions, issued its Order Number 888 (Order 888) in April, 1996. Order 888 fundamentally changed the generation, transmission and distribution of energy throughout the United States. Before Order 888, single entities controlled and owned all generation, transmission, and distribution assets in their service territory, typically a vertically integrated utility. Because these companies controlled the retail delivery of the energy from generation through their own power lines, consumers had little decision on which company's electricity they were buying. In economic terms, the existing structure constituted an impediment for new providers who might want to generate power, move energy or provide retail electricity to individual consumers.

Order 888 provided detailed definitions to help delineate the classification of electric lines and equipment as either the transmission or distribution facilities of electric utilities. It stated that FERC would "provide deference to state commission recommendations regarding certain transmission and local distribution matters that arise when retail wheeling occurs" and "will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the Commission's technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule." The order also provided seven factors which describe distribution facilities for particular classification within the States. This classification is significant because the FERC regulates transmission rates and service while distribution service remains a subject of state and regulatory oversight.

The Commission conducted hearings in Case Nos. U-11337 and U-11283 that resulted in the jurisdictional classification of Consumers Energy and Detroit Edison's transmission and distribution assets respectively. Per the seven-factor technical test outlined by FERC in Order 888, the Commission classified transmission and distribution power delivery facilities for the majority of utilities in the State. The following list is a summary of Michigan utilities and associated MPSC dockets ordering the approval of the classifications.

| Utility Company | Case No. | Date |
|---|---|---|
| Alpena Power Company | U-11856 | 3/8/1999 |
| Cloverland Electric Cooperative | U-12896 | 5/15/2001 |
| Detroit Edison Company | U-11337 | 1/14/1998 |
| Consumers Energy Company | U-11283 | 1/14/1998 |
| Edison Sault Electric Company | U-12690 | 12/20/2000 |
| Norther States Power Company | U-12744 | 10/29/2001 |
| Upper Peninsula Power Company | U-12706 | 12/20/2000 |
| Wisconsin Electric Power Company | U-12691 | 12/20/2000 |
| Wolverine Power Cooperative | U-13862 | 8/26/2003 |

In 1999, the FERC issued Order No. 2000 (Order 2000) which strongly encouraged electric utilities to transfer operating control of their electric transmission system to a regional transmission organization (RTO), or sell the facilities to an independent company. In addition, in June 2000, the Michigan legislature passed Act 141, which required investor-owned utilities to divest their transmission assets or join a regional transmission organization. Following these actions, the transmission assets of Michigan electric utilities were either divested to separate companies or placed under control of an RTO.

The Midwest Independent Transmission System Operator (Midwest ISO) is a FERC-regulated control area operator of the transmission grid within its footprint, also known as an RTO. Its responsibilities include providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. Currently, the Midwest ISO has over 300 members stretching across 13 states and Manitoba with a footprint of almost 1,000,000 square miles. As the official balancing authority of electric utilities in this region, the Midwest ISO has the authority to order utilities who have voluntarily relinquished control of their transmission facilities to immediately comply with any requests or mandates deemed necessary to maintain high reliability. Additionally, the Midwest ISO operates a wholesale market that operates on both a day-ahead and real time basis. One Michigan electric utility, Indiana Michigan Power Company (I&M), is a member of PJM. The Midwest ISO and PJM are two of the seven national RTO's and they both control the bulk flow of power across Michigan.

Since April 2005, when the Midwest ISO energy market began, Michigan utilities have offered their available generation to the wholesale markets. Michigan's electric utilities then bid in their electric load requirement into the Midwest ISO's energy markets. On a day-ahead basis, Midwest ISO performs both an economic and reliability dispatch assessment and selects which units will generate electricity the next day to serve the load requirements and the day-ahead locational marginal price (LMP) is determined for each hour. On a real time basis, the Midwest ISO sends dispatch signals to generation owners every five minutes of each hour informing them of current and target generation requirements. The generators are paid the LMP by the Midwest ISO for their generation and the electric utility purchases its energy requirement from the Midwest ISO at the LMP. The Midwest ISO dispatching enables the economic loading of the generation, reduced reserve requirement, and an increase in reliability.

International Transmission Company (ITC) was originally formed in 2001 as a subsidiary of Detroit Edison, an electric utility subsidiary of DTE Energy, and was acquired in 2003 by ITC Holdings. ITC owns the former assets of Detroit Edison's transmission system, including approximately 2,500 circuit miles of overhead and underground transmission lines rated at voltages of 120 kV to 345 kV with associated cables, towers and poles as well as approximately 169 substations. In May 2002, Consumers Energy sold its electric transmission system to Trans-Elect. Trans-Elect, through the limited liability company Michigan Electric Transmission Co. (METC), assumed operation of approximately 5400 miles of 345- and 138-kV transmission lines serving Consumers Energy's entire electric service territory in the lower peninsula of Michigan. The purchase also included approximately 80 substations. In October 2006, ITC Holdings acquired METC.

American Transmission Company (ATC) began operations on January 1, 2001, as the first multi-state electric transmission-only utility and started acquiring transmission facilities in Michigan's Upper Peninsula. Companies that transferred transmission assets or cash to ATC now are equity owners in the company.

Wolverine is a cooperative generation and transmission company that is owned by and supplies wholesale power to six electric cooperative utilities in Michigan. Wolverine has nearly 1,200 miles of 69 kV and 138 kV looped transmission lines and beginning January 1, 2006, Wolverine transferred operational control of its transmission facilities to the Midwest ISO.

The Commission opened Case No. U-16196 to receive comments from interested parties regarding Section 10r(6), which requires the Commission to investigate the advisability of separation of generation and distribution within electric utilities in Michigan. The docket initiated formal investigations into current policies and practices used by Michigan electric utilities. The following interested parties submitted comments: The Detroit Edison Company (Detroit Edison), Michigan Industrial Ratepayers (Industrial Ratepayers), Association of Businesses Advocating Tariff Equity (ABATE), Michigan Electric and Gas Association (MEGA), Energy Michigan, Inc., Michigan Electric Cooperative Association (MECA) and Consumers Energy Company. Detroit Edison, Consumers Energy, Industrial Ratepayers, ABATE, MEGA and MECA oppose separation of distribution from generation within electric utilities. Of the commentors, only Energy Michigan supports separation.

Although filed separately, Detroit Edison and Consumers Energy (Utilities) comments are very similar. The Utilities believe that mandated separation of distribution from generation within the electric utilities is unnecessary because such bifurcation serves no financial reason, no operational reason, and is not consistent with operation trends in electrical supply. The Utilities both maintain that distribution and generation are two distinct and separate organizations within each company and in order to continually improve upon efficiencies, customer service, and reliability while still being able to share and exchange personnel and other resources will allow each company to adapt to changing environments.

The comments from ABATE, Industrial Ratepayers, MEGA, and MECA also disfavor mandated separation of distribution from generation within electric utilities. First, ABATE's comments mirror some of the concerns expressed by the Utilities. Primarily, ABATE is concerned that separation would lead to the need to hire additional personnel and incur unnecessary costs associated with creating two entities. ABATE suggests that even further inefficiencies result from additional contact points in problem resolution process and that there are no discernable benefits to offset those inefficiencies.

The Industrial Ratepayers also oppose separation from distribution and point to California's experience as an example of electric restructuring failing to benefit customers. According to the Industrial Ratepayers, electric restructuring caused enormous electricity price spikes, supply interruptions and a wave of utility bankruptcies at a considerable expense to customers. They suggest expanding customer choice and tightening regulation over unreasonable or imprudently incurred power supply costs as an alternative means to benefit customers.

MEGA suggests through its comments that the prevention of potential market abuse and self dealing by utilities in control of all vertical functions has been accomplished through having transmission under separate ownership and operational control of the grid in the hands of regional transmission organizations. MECA concurs with the comments of MEGA and is also concerned about burdensome costs that separation of distribution from generation within electric utilities would have on its members and associated customers.

Energy Michigan was the only party to support full separation of distribution from generation. It believes that such separation fosters further competition for generation supply without any negative effects on costs or reliability. Energy Michigan believes that with the current 10 percent cap on customer participation in competitive markets, that the full realization of the competitive effects of separation will not be experienced. Energy Michigan argues that removal of the cap, combined with separation of distribution from generation within electric utilities, will have a tremendous benefit to customers so long as strong rules and regulations are put in place to prevent undue discrimination.

To facilitate the stated goals of Act 286, Staff determined that a workgroup comprised of electric utilities operating in Michigan, customer groups, and other relevant stakeholders would be the best venue for gathering information. The Advisability of Separating Generation and Distribution within Electric Utilities Workgroup was formed, which conducted meetings on March 14, 2010 and April 14, 2010. Representatives from Detroit Edison, Consumers Energy, MECA, MEGA, ITC, Constellation Energy, Integrys Energy Group, Michigan South Central Power Association (MSCPA), and Commission Staff attended both meetings to discuss the goals of section 10r(6) and the collect data from the utility companies for analysis required for the report. Of those stakeholders that filed comments, ABATE, Industrial Ratepayers, and Energy Michigan did not participate in the workgroup meetings or provide information electronically. The information that was gathered through the workgroup in support of the Act 286 requirements is detailed throughout the report.

**Part 1 - Report Requirements**

MCL 460.10r(6) requires that the Commission investigate the, "advisability of separating electric distribution and generation within electric utilities" while considering "the costs, benefits, efficiencies to be gained or lost, effects on customers, effects on reliability or quality of service, and other factors which the commission determines are appropriate."

In order to effectively investigate the advisability of separating generation and distribution within electric utilities in Michigan, it is necessary to have a clear understanding of the jurisdictional separation of generation and distribution for the utilities in Michigan. A typical electricity grid is made up of three separate parts: generation, transmission, and distribution. Generation is the act of producing electricity and most generally takes place at large power plants by converting an energy source to electricity. The transmission function involves the large-scale movement of electricity from generating plants to the distribution networks, which is the portion of the system that delivers the electricity to the customer. Transmission is distinguished from distribution by power line size and the voltages carried on those lines, which are generally much higher voltages. Transmission is described as the bulk transport of electricity primarily at wholesale, while distribution is the delivery to the customer of smaller amounts of electricity for retail sale.

In FERC Order 888, a technical test with seven factors for determining how local distribution facilities are used on the electric system was defined as:

> (1) Local distribution facilities are normally in close proximity to retail customers. (2) Local distribution facilities are primarily radial in character. (3) Power flows into local distribution systems; it rarely, if ever, flows out. (4) When power enters a local distribution system, it [is] reconsigned or transported on to some other market. (5) Power entering a local distribution system is consumed in a comparatively restricted geographic area. (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. (7) Local distribution system will be a reduced voltage.

Each utility filed for jurisdictional classification of their power delivery facilities with the MPSC based on this FERC order. The subsequent MPSC orders set forth previously in the table above established those power delivery facility classifications for each utility within Michigan, defining assets as transmission and distribution, and indirectly, generation.

Act 141 establishes the regulatory framework for retail access, which would allow electric customers to choose an AES to provide their electric generation service in the State. It also required the divestiture of or transfer of control over the transmission assets of utilities in Michigan to ensure compliance with FERC Order Number 2000. By the end of 2002, the transmission assets of the largest two electric utilities in Michigan and most of the other investor-owned utilities were divested. Those events led to the predominant Michigan investor-owned electric utility structure with functionally separate business divisions or units within the utility generating electricity and distributing power to customers. The regulated utility is typically wholly owned by a parent company. Such is the case with Consumers Energy and Detroit Edison that provide the large majority of the electric distribution service in Michigan.

Regulated electric cooperative utilities in Michigan are, for the most part, distribution service providers and have corporate separation between distribution services and power generation/transmission assets because they do not own them. Other than Cloverland and Thumb Electric, which own small peaking plants only, the electric distribution cooperatives buy 100 percent of their power supply needs from other entities such as Wolverine.

The amount of generated electricity that Cloverland and Thumb Electric supplied with their own assets in 2009 amounted to less than a few percentage points. For Thumb Electric, it has been zero percent for the last several years. The purpose of the cooperative is to provide reliable electric service at the least practical cost without the potential conflict between serving customers while maximizing shareholder return, as there is with investor-owned utilities. The two cooperatives that own generation operate their systems to maximize the savings to their members. Requiring further structural separation of generation and distribution within such a cooperative would increase costs to its members by requiring an increase in staffing to accommodate the separation while leaving all other factors the same.

## **1.1 – Costs and Benefits**

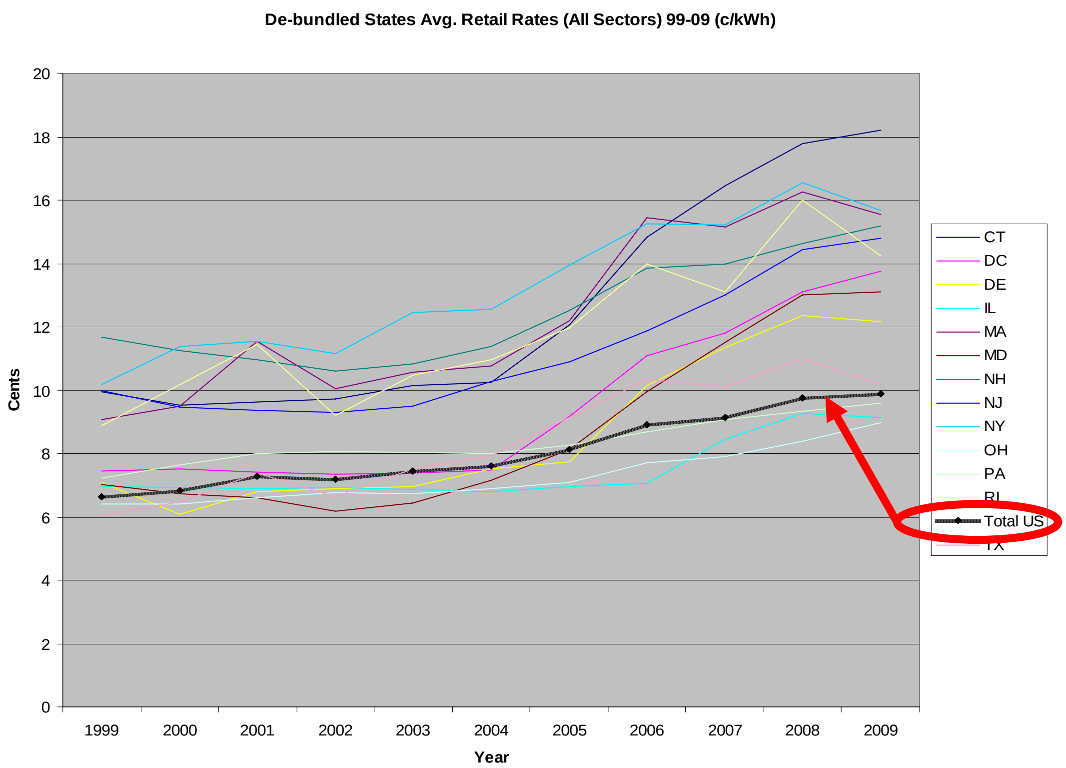
Commission Staff worked with the participants of the workgroup to investigate how separating generation and distribution would affect the customers in terms of cost impact and benefits that might be realized. They also reviewed retail electricity cost and other information from existing states that have restructured their electric industry to un-bundle generation and distribution to understand any correlating effects to retail electric costs that might be implied. The detailed summary of those effects are provided per the reporting requirements in the analysis below.

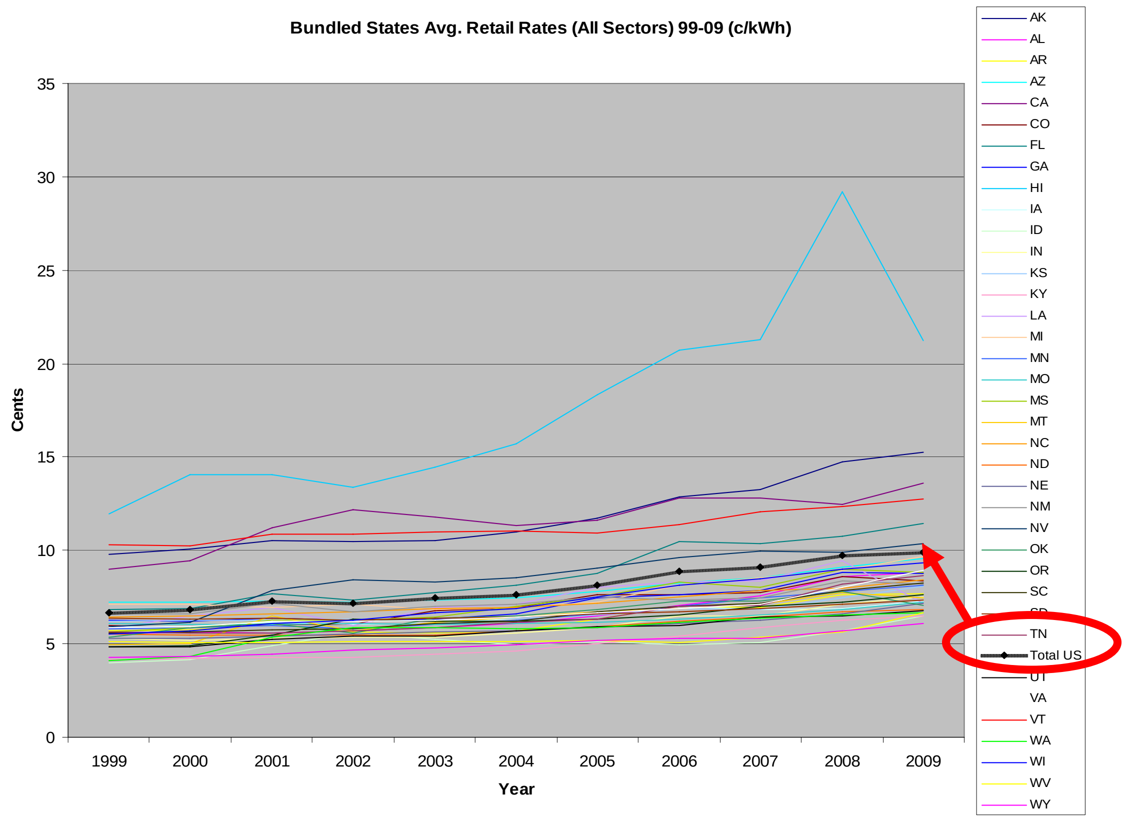
### ***13 State Review***

Commission Staff investigated the cost implications of 13 states that have separated generation and distribution as part of an electric utility restructuring process. The research sought to review the states that have gone through a restructuring process and review the relationship between un-bundling and the impact on costs to customers, if any. Staff initiated the review by referring to the United States Energy Information Administration (EIA) independent statistics and analysis review of the report "Status of Electricity Restructuring by State." The EIA data indicated 16 states as having active electricity restructuring, including Michigan for its transmission divestiture and customer choice program. Staff focused on studying 13 states consisting of Connecticut, Delaware, Illinois, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Washington D.C. with un-bundled generation and distribution facilities. *See*, Attachment A.

The investigation started by examining the relationship between each of the 13 states electricity restructuring and the changes in electricity retail rates over time. Staff utilized the EIA sales revenue data for the last 10 years (1999-2009) to review the changes in the average retail cost of electricity in cents/kilowatt hour for each rate class consisting of residential, commercial, industrial, and total average retail cost for all sectors. The data set started in 1999 because the majority of the states in the review had initial legislation in place at that time that required utilities to initiate un-bundling and incorporate retail choice programs in the near future. Staff acknowledges that retail choice, among other factors, also has an impact on the electric retail rates for customers. The data is used to study a correlation between electric restructuring and the changes to electric retail rates over an extended time period. Recent changes in fuel costs and a decrease in electricity demand during the current economic recession has impacted electric retail rates across the United States. Staff believes that the changes experienced since this study was completed are temporary and largely caused by the economic downturn and are not representative of a longer period still indicating that electric retail rates are higher over time.

The review of the data showed that in the 13 states where electric restructuring was implemented, the electric retail rates in all customer classes were higher than the U.S. average before the restructuring and during the study period the costs continued to rise at a higher rate than the U.S. average. In the same time period, many of the states that did not restructure to the same extent had rates in all customer classes that were lower than the U.S. average before the study period and increased at a rate at or below the U.S average during the study period. The following two graphics indicate the average electricity retail rates across all sectors (c/kWh) for bundled and un-bundled states in this review. *See*, Attachment B for data charts for residential, commercial, and industrial customer classes.






The Staff acknowledges that many factors affect electric retail costs such as fuel costs and fuel supply shifts. The base data shows an increase in electric retail costs that was higher than the U.S. average during the study period and subsequent un-bundling of generation and distribution. The study is not intended to be a complete economic analysis and only looks to indicate a general trend. Michigan has already initiated electric restructuring that introduced Customer Choice and led to the divesture of most transmission assets through PA 141, while still regulating utility distribution through cost-of-service tariffs. This 13 state review suggests that if further separation of Michigan's utilities generation and distribution assets is pursued, it could correlate to an increase in electricity retail rates at a higher rate than the U.S. average such as experienced in the 13 states reviewed to date.

### *Michigan Transmission Costs Review*

By the end of 2002, the transmission assets of the largest electric utilities in Michigan and most of the others were divested to independent transmission owners. Examining the possible relationship of transmission divestiture to total costs of electric service to the customer within the state could suggest the possible cost impact of future separation of generation and distribution assets. Staff led discussions and gathered data from the work group to understand the change in costs to Michigan electric customers that occurred after the divestiture of transmission assets from electric utilities in Michigan. The utilities provided a breakdown of the components that make up the most recent customer bill for each rate class in percentages of generation, transmission, and distribution. The existing transmission costs paid by electric utilities are regulated by FERC and processed through the ISO as electric transaction costs. Detroit Edison provided the following 2010 bill breakdown showing that, as an average across all customer classes, generation costs make up 58 percent of the bill, transmission costs make up 6 percent of the bill, and distribution makes up 36 percent of the bill:

**2010 DTE Bill Components by Major Rate Class**
(as a percent of revenue)

| | % Generation | % Transmission | % Distribution |
|---|---|---|---|
| Residential | 51.76% | 4.99% | 43.25% |
| C&I Secondary | 53.69% | 6.04% | 40.27% |
| C&I Primary | 69.88% | 7.93% | 22.19% |
| Total** | 58.20% | 6.21% | 35.59% |

** Does not include LCC, OPL, Street Lighting or Traffic Lights

Consumers Energy provided the following 2008 bill breakdown showing that, as an average across all customer classes, generation costs make up 41.28 percent of the bill, transmission costs make up 4.59 percent of the bill, and distribution makes up 51.10 percent of the bill:

**2008 Consumer's Bill Components by Major Rate Class**

| | % Generation | % Transmission | % Distribution |
|---|---|---|---|
| Residential | 39.01% | 4.28% | 56.71% |
| Secondary | 45.29% | 4.97% | 49.74% |
| Primary | 55.48% | 6.09% | 28.44% |
| Other | 27.48% | 3.01% | 69.51% |
| Total | 41.82% | 4.59% | 51.10% |

MECA provided a 2009 bill breakdown for each of the nine co-ops they represent as well as an averaged total for the collective group. Being that the co-ops purchase the large majority of their power as a package of generation and transmission, the cost is not broken up separately. The average across all customer classes showed that, generation and transmission costs make up 74 percent of the bill and distribution costs makes up 26 percent of the bill.

The participants also provided a detailed breakdown showing how the cost of transmission has changed since its divestiture and how that has resulted in a shift in the percentage of transmission costs in customer's bills. Detroit Edison provided the following data showing the trending change over time that they experienced on their system:

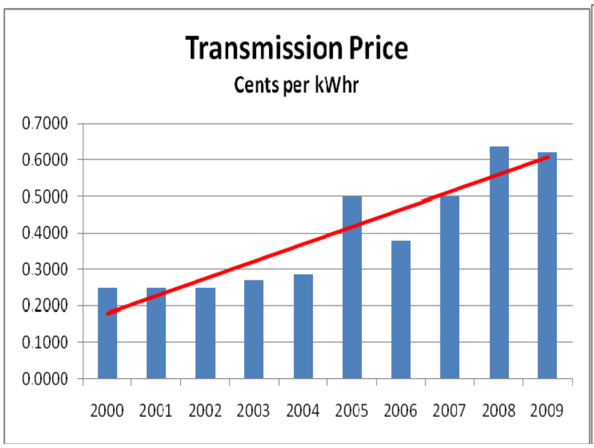
## The Detroit Edison Company
## Time Series Yearly Ave. Transmission Cost % by Major Rate Class*

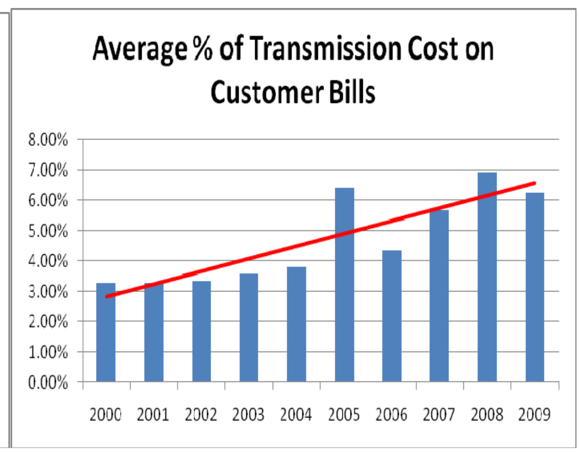
| | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Price | 0.6210 | 0.6365 | 0.4998 | 0.3785 | 0.4988 | 0.2867 | 0.2701 | 0.2485 | 0.2485 | 0.2485 |
| Residential | 4.99% | 5.71% | 4.64% | 3.57% | 5.53% | 3.22% | 3.01% | 2.77% | 2.78% | 2.73% |
| C&I Secondary | 6.04% | 6.22% | 5.15% | 3.78% | 5.49% | 3.01% | 2.94% | 2.96% | 2.66% | 2.51% |
| C&I Primary | 7.93% | 8.59% | 7.06% | 5.46% | 8.02% | 5.18% | 4.70% | 4.30% | 4.21% | 4.29% |
| Total | 6.24% | 6.91% | 5.65% | 4.33% | 6.42% | 3.79% | 3.55% | 3.35% | 3.29% | 3.27% |

February 2006 - Detroit Edison Unbundles Rates - Case U-14399

February 2003 - Detroit Edison sells ITC Transmission subsidiary

May 2000 - ITC Transmission becomes subsidiary of Detroit Edison




MEGA members I&M, part of the larger AEP interstate utility system, and Northern States Power (NSP) d/b/a Xcel Energy, also an interstate system, have not divested their transmission assets and continue to own their transmission networks subject to RTO operational control. MEGA member Alpena Power provides local distribution service and purchases its power supply from Consumers Energy. The cost impact of transmission divestiture for these companies is not being considered for this review.

Review of the data submitted to the workgroup showed that there is a possible correlation between (i) increases in both the costs of transmission and the percentage of transmission costs in customer bills, and (ii) the divestiture of transmission assets. Staff did not investigate the drivers of the increase in costs, such as the need for system improvements for increased reliability, and only reviewed the data for correlations to understand how those effects might translate to separation of distribution and generation.

The divestiture of transmission assets resulted in a fundamental change from being an upstream secondary focus for an integrated electric utility to being the primary focus for a transmission owner. The workgroup data showed that the percentage of customer bills related to transmission costs has nearly doubled since un-bundling. However, costs related to transmission are, on average, a small percentage of the customer's total bill and the overall impact to the customer is proportionally small. Generation costs are the largest portion of the customer's bill and Staff believes that a separation of generation assets that induces a correlating increase to generating costs, similar to that of transmission costs, would have a proportionally large impact to the customer's costs. The resulting change could substantially increase electric retail rates and negatively impact the customer. Given the current economic climate in the State of Michigan, the potential for the substantial increase in costs is not an acceptable risk the customers can afford to bear.

### *Midwest ISO Transfer Price*

Since April 2005, when the Midwest ISO energy market began, Michigan utilities have offered their available generation to the wholesale markets. Michigan's load serving entities (*i.e.*, utilities and alternative electric suppliers) then bid in their electric load requirement into the Midwest ISO's day ahead and real time energy markets. On a day-ahead basis, the Midwest ISO performs both an economic and reliability dispatch assessment and selects which units will generate electricity the next day to serve the load requirements and the day ahead locational marginal price (LMP) is determined for each hour. On a real time basis, the Midwest ISO sends dispatch signals to generation owners every five minutes of each hour informing them of current and target generation requirements. The generators are paid the LMP by the Midwest ISO for their generation and the load serving entity purchases its energy requirement from the Midwest ISO at the LMP. Because Consumers Energy and Detroit Edison both participate in the Midwest ISO and provide the majority of the electric distribution service in Michigan, Staff investigated the financial impact to customers of realizing the Midwest ISO LMP as the transfer price between the subsidiaries of generation and distribution within the investor-owned utilities (IOUs) involved in the workgroup.

Prior to the establishment of the Midwest ISO, a unit dispatch varied based on load conditions in Michigan, but in the current system, units are dispatch based on load conditions throughout the entire RTO footprint. In addition to calling upon a unit for economic reasons, generating units can also be called on for system reliability to ensure reserve margins are maintained. In these cases, because the unit is operating regardless of the LMP, the Midwest ISO pays the unit's cost of production. However, the Operations and Maintenance (O&M) costs incurred to operate the unit are covered under base rates.

One interpretation of structural separation is the formation of separate subsidiaries within the company. This means that a utility would recognize the Midwest ISO LMP as the transfer price between the two subsidiaries. Michigan IOU's participating in the Midwest ISO market creates negligible pricing impact on customers served from their native generation, since the related Midwest ISO sales and purchases are equally-priced, resulting in an "at cost" sale to themselves. The IOUs serve the majority of their load with their own resources thereby making simultaneous sales and purchases through the Midwest ISO at the hourly Midwest ISO price. Since the selling and purchase prices are identical, the transactions are "neutral" for the utilities, meaning that the Midwest ISO price does not impact the customer and the generation charges paid by customers are based on the utility's actual costs. Since the utility's actual costs will be different than the Midwest ISO price, reflecting a "transfer price" on separate books for distribution and generation is an extensive process. The accepted price in the Midwest ISO is its hourly price, but it is neither the revenue to the IOU's generation, nor the real cost to distribution. Detroit Edison supplied an example illustrating the substantial impact to its customers in an amount close to 1.2 billion dollars that recognizing the LMP as the transfer price would create, as shown in the example below:

| | | | |
|---|---|---|---|
| 2009 MISO Round The Clock DA LMP | $ 30.70 | | |
| | 2009 Actual | Generator Paid by MISO | Change |
| Generation & Fuel & Emissions | | | |
| - GWh | 48,535 | 48,535 | |
| - $1,000 | $ 866,247 | $ 1,490,023 | $ 623,776 |
| - $/MWh | $ 17.85 | $ 30.70 | |
| Ludington Losses | | | |
| - GWh | (534) | | |
| Net Purchased Power | | | |
| - GWh | 1,340 | | |
| - $1,000 | 81,869 | | |
| | | Load Pays to MISO | |
| Load Net System Output | | | |
| - GWh | 49,341 | 49,341 | |
| - $1,000 | $ 948,116 | $ 1,514,767 | $ 566,651 |
| - $/MWh | $ 19.22 | $ 30.70 | |

The new distribution subsidiary's focus would remain on serving the load reliably and would now include obtaining power at the lowest possible cost. The generation subsidiary's focus shifts towards maximizing the profit for its generators, much like their unregulated counterparts, since this subsidiary would be a separately identifiable profit center within the parent corporation.

The use of the Midwest ISO LMPs as a price for establishing the "transfer price" between the generating entities and the distribution entities would require additional system upgrades in metering, data collection, and analysis infrastructure, as well as additional staffing to perform the accounting and reporting of the profit or loss from the sale of the energy. Consumers Energy estimated that the additional metering, data collection and analysis infrastructure would cost approximately $1.5 million. Additionally, the staffing needed to perform the data analysis, accounting, and reporting would cost approximately $600,000 annually.

A similar effort would be required on the distribution portion of the system. The Midwest ISO calculates a LMP for the Consumers Energy load representing the average LMP at the approximately 300 connection points between the 138KV transmission system and the 46KVdistrbution system. Although these points are metered, the metering infrastructure is not of what they term as "billing" quality. Using the same estimate as above, Consumers Energy estimates that the replacement of this infrastructure with "billing" quality meters would cost approximately $30 million. The analytical, accounting, and reporting costs would be a similar degree of investment. Detroit Edison concurred with Consumers Energy's assumption that these additional costs would be necessary, but did not provide specific data related to their estimated capital required for these particular upgrades, although Staff assumes it would be a similar degree of investment.

MEGA member I&M, which is part of the AEP System and PJM Interconnection, participates in PJM's energy market, which is similar to that of the Midwest ISO. MEGA member Alpena Power does not operate generating units of its own and purchases nearly all of its electricity wholesale from Consumers Energy at FERC regulated rates. The MEGA electric utilities in the Upper Peninsula [NSP, Wisconsin Public Service Corporation (WPS), We Energies and Upper Peninsula Power Co (UPPCo)] participate in the Midwest ISO energy market with their generating units dispatched by the system operator as described above.

In summary, to establish a transfer price between the generation and distribution sides of the company would cost the Consumers Energy ratepayer the revenue requirement of an approximately $33 million capital investment, plus the additional operating expenses, for a much less substantial benefit. That amount does include the costs of the actual transaction price itself. The use of LMPs as a transfer price is not a true representation of the value of generation, or the cost of providing electricity for distribution in and of itself. If energy prices alone, which are fundamentally a "spot price" of energy, are used to determine profitability, the generation and distribution entities could be incentivized to make short-term decisions that are not in the long-term interest of the electric system.

### ***Additional Studies Reviewed***

Commission Staff also reviewed external studies submitted by participants of the workgroup for consideration in this report. In a study submitted by MEGA titled "Vertical Economies in Electric Power: Evidence on Integration and its Alternatives," by John E. Kwoka, the author points out that: "The efficiencies are greatest for utilities with generation nearly equal to their distribution requirements, that is, for nearly fully integrated systems." He goes on to mathematically show that economies of scale in vertical utilities allow for cost savings in the generation facilities. He concludes that:

> . . . integration arises as a direct result of important economies of coordination between generation with distribution. These cost savings are particularly large in the case of utilities with nearly equal generation and distribution, a fact that accounts for the predominance of such utility structures. By itself, therefore, disintegration raises the prospect of a loss of vertical economies. *(Id.)*

The two largest IOU's in Michigan, Consumers Energy and Detroit Edison fall within the utility structure that Kwoka mentions where generation and distribution are nearly equal. He elaborates on the cost savings to say that, "it would appear that vertical integration is indeed associated with cost savings, with much of the savings concentrated in the power supply function.... (and that) the largest cost savings from integration is the reduction in the O&M costs of power supply" (*Id.*)

In a secondary study provided by MEGA titled "The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Industry," by David L. Kaserman and John Mayo, the authors sought to analyze multiproduct cost economies at vertically related stages to conclude an explicit measure of the economies of vertical integration. The results concluded that,

> For a vertically integrated firm producing the sample mean generation and distribution levels, the estimations suggest that costs of vertically disintegrated production are 11.96 percent higher than for vertically integrated production . . . . (and that) the presence of vertical economies indicates that the cost of providing the total industry output vector would rise if the industry were vertically divested. (*Id.)*

They further state that "any post-divestiture cost savings due to reorganization and deregulation at the generation stage would be more than offset by the foregone vertical economies from divestiture." (*Id.*) The studies both support the existence of significant cost savings from a vertically integrated utility structure for generation and distribution. They illustrate that the cost benefits are yielded by vertical integration and generally supports continued recognition of utility discretion regarding the structure of the business and degree of separation.

ITC provided a report titled "Economic Regulation under Distributed Ownership: The Case of Electric Power Transmission," by Paul R. Kleindorfer, in which the author is a proponent for moving toward a transmission service model where it is viewed as a commercial activity. He states that, "the modified independent transmission entity and the fully divested transmission company have increased incentives to invest wisely. Their investment decisions directly affect their 'bottom line'." This review may suggest the drivers behind the increase in transmission costs that could potentially be replicated in a similar separation of generation assets, requiring investments to upgrade the inherited system and build new assets.

ITC also provided a report titled "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," by K. Fabrizio, N. Rose, and C. Wolfram, in which the authors test the suggestion that firms may not minimize costs in less-competitive or regulated environments using a detailed data analysis in which they conclude that:

> The results suggest restructuring may yield substantive medium-run efficiency gains. The estimates suggest that IOU plants in restructuring regimes reduced their labor and nonfuel operating expenses by three to five percent in anticipation of increased competition in electricity generation, relative to IOU plants in states that did not restructure their markets… There is little evidence of increases in fuel efficiency relative to plants in non-restructuring regimes.

The report goes on to say that: "Dynamic costs could be higher if restructuring reduces knowledge sharing that affects productivity growth over time." (*Id.*) The implied reduction in labor and nonfuel operating expenses in anticipation of increased competition is feasible and most likely already took place during Michigan's restructuring efforts with Customer Choice and RTO market participation requirements. The second part points out that while market competition can induce improved generator performance, separation of personnel results in a short term loss of productivity that was previously available.

Constellation Energy provided reports that address competitive wholesale procurement resulting from the functional separation of vertically integrated utilities. The first of which is "Competitive Electricity Markets: The Benefits for Customers and the Environment," by the National Economic Research Associates (NERA). The report concluded that:

> The implication that restructuring would always lead to lower prices was not accompanied by the obvious 'all else being equal' or 'over the long term' provisions. Abstracting from oil and gas prices, renewable mandates, equipment cost increases, and carbon reduction costs, it is likely that prices in restructured states would have declined as transition periods ended. But that did not happen, and industry structure cannot compensate for sharp increases in input prices.

The report outlines an explanation as to why restructured states experienced higher retail electricity costs as previously correlated in this report. The authors acknowledge that the industry is facing challenges as a result of this and proposes that the decline in costs will resume as the transition period to restructuring ends. While Michigan has restructured to some degree, the amount of Customer Choice access is capped and the cost-of-service utility regulation still exists for IOU's, which allows for a restructured model that also maintained retail rates that have been less than the U.S. average over the last 10 years.

## 1.2 Effects on Quality and Reliability

In December 2001, after Staff submitted their final report on the development of reliability measurements, the Commission issued an order in Case No. U-12270, which initiated rulemaking proceedings for service quality and reliability standards for electric distribution systems as required by Act 141. The order stated in part that "the public interest and the rulemaking process will be significantly furthered by the collection and submission of data." Effective January 1, 2002, all electric utility companies under the Commission's authority were directed to begin collecting service quality data for submission. The electric utilities were ordered to "measure, record, and report information necessary to demonstrate their performance in relation to the proposed performance standards." On January 29, 2004 the Commission issued its final order in Case No. U-12270, which formally adopted 10 new administrative rules on service quality, which can be found in Attachment A.

In 2009, Staff conducted an investigation into the quality and reliability of Michigan's electric service and submitted a Report on the Status of Power Quality on September 1, 2009 to the Michigan State Legislature per Act 286. In the report, the Commission found no indication through its investigation that there is currently a significant issue with power quality in Michigan. The report stated that:

> The number of informal complaints regarding power quality that Staff receives is minimal and they are dealt with on a case-by-case basis . . . Staff's investigation shows that the utilities respond to power quality issues as they arise. The circumstances of power quality disturbances lend themselves to variability . . . The Commission concludes as a result of Staff's investigation into power quality, reliability and power plant cost efficiency that no new or amended rules are needed at

this time regarding subsection (8) of Act 286. The electric utilities current method of addressing power quality complaints individually provides the most efficient means to solve the problem for the customer at the distribution level. However, as discussed above the Commission intends to adopt in subsequent orders Staff's recommendation that new additional reporting requirements be established for electric power quality, reliability and power plant generating cost efficiency for the purpose of continued monitoring of these issues.

The report indicated that the power quality issues experienced by Michigan customers are minimal and established a reporting method that will monitor any changes over the next three years. Given the current level of power quality and reliability in Michigan, the Commission believes that any further separation of generation and distribution that resulted in personnel changes would create a short term decrease in power quality and reliability as a result of experience and knowledge learning curves that each utility would face. The employee experience and knowledge related to electric distribution are closely related to reliability and could promote a negative impact to existing system stability.

### 1.3 Legal Considerations

If the Commission were to order separation of generation and distribution then jurisdictional issues differ as to whether functional separation or divestiture is required. Functional separation ordinarily requires separate accounting and employee organization for the separated activities, but allows ownership of both activities by the same owner. However, divestiture requires that ownership be separated completely. It is unlikely that functional separation would alter jurisdictional boundaries.

However, if a utility is required to divest generation facilities from distribution to form two distinct entities, then a question arises as to whether the FERC may assert jurisdiction. MEGA expressed concern in their filed comments that requiring separate generation facilities results in an additional step whereby electricity would be transferred from the generation subsidiary to the distribution subsidiary or parent company. MEGA is concerned that this transfer of electricity may result in the wholesale power transaction in interstate commerce and subsequently trigger FERC jurisdiction.

Pursuant to Section 201 of the Federal Power Act (FPA), 16 USC 824(b), FERC has jurisdiction over the transmission of electricity in interstate commerce and the sale of electricity at wholesale in interstate commerce. The FPA further grants FERC jurisdiction over all facilities for such transmission or sale. However, the FPA specifically allows States to retain jurisdiction over facilities used in local transmission or only for the transmission of electricity in intrastate commerce.

Based on the FPA, it appears that separation of generation would not result in FERC jurisdiction, but may result in the company becoming subject to market prices at wholesale with no direct control by the MPSC. For example, Connecticut's 1998 restructuring legislation resulted in separation of generation from distribution. The utilities sold off generation plants that became subject to competitive supply markets. Once divested, the Connecticut Commission did not have regulatory oversight and its involvement was limited to participation in the structure of the wholesale markets before the regional transmission operator. When a State no longer has the ability to regulate return on equity for an electric generator, the profits available to the company increased in some cases upwards of 20 percent on annual returns, all at the customer's expense. A recent statement by the American Public Power Association noted that:

> . . . the greatest profits continue to be earned by those companies that owned generation largely paid for by customers under cost-of-service regulation. In 2007 and 2008, the generating segments of Exelon, Public Service Enterprise Group and PPL Corp. realized annual returns on equity of 30 percent, three times the 10 percent returns for regulated companies."[1]

The current regulation of electric utilities in Michigan garners annual returns on equity of around 10 percent as mentioned in the data cited above. In the event that Michigan was to lose regulatory oversight of electric generating facilities, then the customers could potentially be subject to a 30 percent generator annual return on equity rather than the 10 percent return averaged for regulated companies in the study. Given the current economic climate in the state, the potential for this occurrence is not an acceptable outcome.

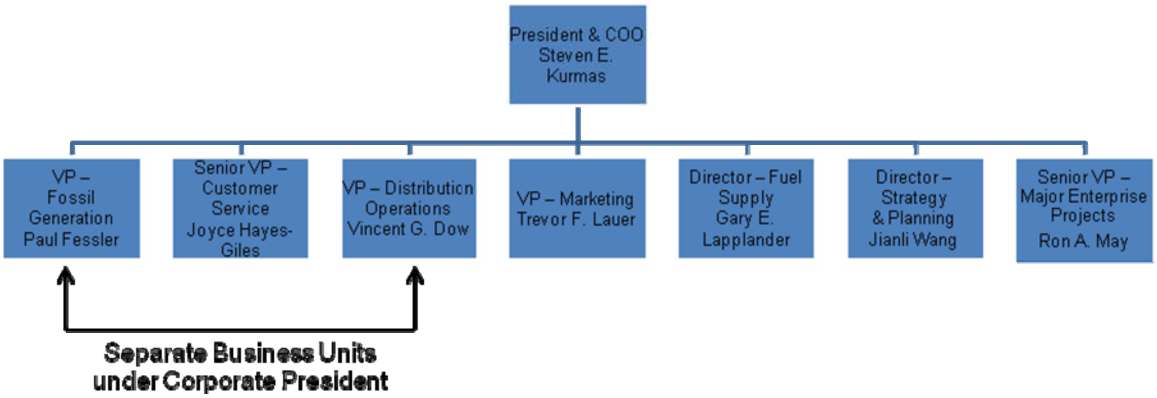
## 1.4 Advisability of Separating Personnel to Separate Departments

Staff reviewed information submitted to the workgroup to understand the advisability of separating personnel to separate departments. Consumers Energy reiterated that it has very few functions, other than corporate overhead functions, that are shared between the generation and distribution areas of the company. Both generation and distribution have separate budgets, cost structures, and management. The merchant functions of Consumers Energy required to maintain physical separation by FERC requirements are located in yet a third area of the company, also with its own structure and management. In some instances, the use of engineering, training, testing and environmental remediation management crosses the organizational boundaries between generation and distribution, but in those cases, the appropriate entity is billed for these services.

In the case of Detroit Edison, the company showed that nearly all operating aspects of distribution and generation are already separated into two distinct and autonomous organizations that only join at the Presidential level of Detroit Edison. Each distinct area is headed by different Vice-Presidents; each is charged with optimizing the performance of their area; and each measured by specific performance and cost targets. Thus, Detroit Edison is already striving toward achieving the positive impacts on efficiency, customer service, and reliability that might result from requiring such a separation. At the same time, each organization is free to share or exchange personnel and other resources as needed to adapt to changing circumstances as illustrated by the chart below:

[1] http://www.energycentral.com/functional/articles/energybizinsider/ebi_detail.cfm?id=895

## Detroit Edison Organization Chart




Detroit Edison also stated that the division of departments was driven more by their desire to improve each of the functions, performance, and efficiency by developing specialized operating and management expertise and keeping it focused on the one functional area. They maintain rigorous separation between distribution and any of Detroit Edison's "merchant" (meaning unregulated) generation or energy trading businesses in accordance with FERC directives.

Detroit Edison provided an estimate as to how they believed costs would increase if barriers existed between the electric distribution and generation within its Company. Detroit Edison examined a number of critical aspects of providing reliable and economical service to customers that are currently shared by Distribution and Generation and would result in additional costs if separated. First, Detroit Edison's System Operations Center (SOC) and Merchant Operations Center (MOC) use a single Emergency Management System (EMS) to monitor the performance of their entire system (loads and generation) in real time. Separating this shared resource into two independent functions, one serving Distribution and one serving Generation, requires duplication of the underlying EMS system. This would involve considerable capital investment and require up to 24 months to complete. The cost of separation is estimated at approximately $15,000,000 as shown by the following breakdown:

**High Level Cost Estimate to move Merchant Operations (MOC) to their own EMS environment**

| Environment | Description | Cost Estimate |
|---|---|---|
| Production - Detroit | On-Site Redundant EMS enviroment including all system hardware, software and licensing (Production System) | $4,000,000 |
| Production - ADC (Alternate Date Ctr ie Ann Arbor) | On-Site Redundant EMS enviroment including all system hardware, software and licensing (Production System) | $4,000,000 |
| Quality Assurance System - (QAS) | On-Site Redundant EMS environment (like to Production) used for system checking/pre-production testing | $4,000,000 |
| Project Development System - (PDS) | Subset EMS environment for system development/testing pre-QAS | $1,000,000 |
| Network and Infrastructure - Overall | Includes all network required hardware, software, electrical and cooling requirements | $2,000,000 |
| | **Total** | **$15,000,000** |

NERC & FERC Requirements

Detroit Edison continued to say that its Generation Optimization organization maintains the primary interface with the Midwest ISO not only for bidding in generation, but also for Detroit Edison as a LSE. Separating these functions would require Distribution, the LSE, to establish another interface to the Midwest ISO and create an additional settlements group. Distribution would then need to monitor and bid loads into the Midwest ISO on a round-the-clock basis (just as a similar group in Generation was doing the same for generation resources), distribution would also need to acquire the generation resources for meeting the planning and operating reserve requirements related to its loads, for performing the Midwest ISO settlements, and facilitation of active representation at the Midwest ISO. In addition, both the Systems Operation Center (SOC) and Merchant Operations Center (MOC) may require one additional person per shift to coordinate activities with the Midwest ISO and other entities as necessary. These changes are estimated to require approximately 15 additional Full-Time Equivalents (FTE), five each in SOC and MOC to add one person per shift, and five FTEs in Distribution to handle the Midwest ISO interface and settlements with an annual cost anticipated to be in excess of $2 million.

The third area of cost increase comes from the single engineering organization responsible for primary support of all electrical power equipment at Detroit Edison, the System Engineering and Equipment Engineering. This group presently has the engineering and technical professional employees that provide both subject matter expertise and on-site engineering and technical support for all electrical power equipment at the power plants through to the ITC transmission interconnection, from ITC through to the substations, from the substations through to the customer meter and at all peaking unit sites. The engineering group develops the specifications for the electrical power equipment and all associated protective relaying controls and the Supervisory Control and Data Acquisition (SCADA) monitoring systems in accordance with all applicable standards, reviews, and approves designs when required, supports and approves installation, provides guidance for operation, develops/directs maintenance activities, investigates/resolves equipment issues and failures, identifies emergency response plans for this equipment, provides round-the-clock support, develops equipment replacement strategies, monitors/tracks equipment performance, etc.

This shared resource is currently within the distribution function. Therefore, a separation of distribution and generation that prevents sharing these services means that generation would need to duplicate much of the expertise and resources to support the power plants to maintain efficient and reliable operation of the plants' electrical power equipment and to avoid extended outage times. A rough estimate of resources needed to support generation would be a minimum of 16 engineering staff and a minimum of 12 technical field personnel. In addition supporting technical labs, equipment, and tools would be needed. One-time start up costs to set up the infrastructure to support this function is estimated to be about $2.5 million. The majority of it would be for facilities such as office space, labs, test shops, test equipment, vehicles, etc. On-going costs; for personnel, office space, and operating and maintenance costs related to test facilities, equipment, and vehicles are estimated to be $4 million per year. In addition to these costs, there are likely to be significant costs resulting from the need to maintain a separate inventory of equipment, parts, etc. that they were unable to estimate at this time. Additionally, changes to SAP, Financial Reporting, and the Billing Systems would easily cost several million dollars and require up to three years to complete.

These rough estimates are substantial cost increases that would result in an explicit rise in retail electric costs to the ratepayer if separation of personnel to different departments was required. Not only would the costs be dramatically affected, the knowledge from personnel that are relocated to specific areas would cause a short term reduction in operational efficiencies while new personnel experience their own learning curve. Based on the investigation conducted by Staff into the advisability of separating personnel into different departments, the Commission finds the existing level of personnel separation within electric utilities to be satisfactory in operating efficiency, performance, reliability, and customer service. The benefits of separating personnel in this manner would not outweigh the immediate financial and reliability impact that customers would experience.

## 1.5 Advisability of Maintaining Separate Books and Records

Staff reviewed information submitted to the workgroup to understand the advisability of maintaining separate book and records. As mentioned in the above section on costs, a review of the separation of books and records that would require the recognition of the Midwest ISO's LMP price as the transfer price between generation and distribution entities. The IOU's in Michigan serve the majority of their load with their own resources whereby they essentially make simultaneous sales and purchases through the Midwest ISO at the hourly Midwest ISO price. Since the selling and purchase prices are identical, the transactions are "neutral" for the companies, meaning that the Midwest ISO price does not impact the customer and the generation charges paid by customers based on the Companies actual costs. Detroit Edison supplied an example showing the substantial impact to its customers in an amount close to $1.2 Billion dollars that would result from recognizing the LMP as the transfer price.

Consumers Energy estimated that the additional metering, data collection and analysis infrastructure would cost approximately $1.5 million. Additionally, the staffing needed to perform the data analysis, accounting, and reporting would cost approximately $600,000 annually. A similar effort would be required on the distribution portion of the system. Consumers Energy estimates that the replacement of this infrastructure with “billing” quality meters would cost approximately $30 million. Both utilities also point to the fact that the current rate setting process requires that distribution and generation costs be segregated and subjected to examination in a public proceeding before rates are established. Thus, in light of unbundling, mandating separate books and records for distribution and generation would be redundant.

In summary, to establish a transfer price between the generation and distribution sides of the company would cost the Consumers Energy ratepayer an estimated revenue requirement of an approximately $33 million capital investment, plus the additional operating expenses, for a much less substantial benefit. That amount does include the costs of the actual transaction price itself, which Detroit Edison demonstrated would be a large cost differential. Detroit Edison agreed that those estimates Consumer Energy provided would be necessary, but did not provide a similar estimation of the capital investment. These rough estimates are substantial cost increases that would result in an explicit rise in retail electric costs to the ratepayer if maintaining separate books and records was required beyond what is currently being done. Based on the investigation conducted by Staff into the advisability of maintaining separate books and records, the Commission finds that the existing level of maintaining separate books and records within electric utilities to be satisfactory in operating costs to benefit the customer. The benefits of maintaining separate books and records in this manner would not outweigh the financial impact that the customer would experience.

## 1.6 Conclusions and Recommendations

The Commission did not receive any evidence that further separation of generation and distribution is necessary or desirable. The current system provides adequate integration to address issues related to cost, efficiency of operations, electric system power quality, and electric reliability. The likely substantial costs associated with a structural separation of generation and distribution would outweigh the benefits of increased generator operating efficiencies. The implied benefits of separation experienced in other States during the restructuring process have been put in place in Michigan through Act 141.

Allowing each utility to maintain the current level of separation of generation and distribution provides an effective framework for the customers given the current economic conditions. Additionally, the comments provided by stakeholders in the Case No. U-16196 show that the investor-owned utilities, cooperatives, and customer representatives oppose any further separation of generation and distribution within electric utilities out of concern that separation would lead to the need to hire additional personnel and incur unnecessary costs associated with creating two entities, and further inefficiencies resulting from additional contact points in problem resolution processes. These interested parties suggest that there are no discernable benefits to offset those inefficiencies. Energy Michigan, the only stakeholder that supported separation of distribution and generation within electric utilities in Michigan, believes that such separation fosters competition for generation supply without any negative effects on costs or reliability. Energy Michigan stressed that the 10 percent cap on customer participation in competitive markets will prevent full realization of the competitive effects of separation. Staff found the reports from the other parties contradicted those statements, and also found contradictory evidence through the investigations given in this report.

The Commission's investigation indicates that the utilities would undergo substantial costs associated with capital and operations and maintenance expenditures to comply with such a separation. Any benefits that may be experienced by separating generation would be outweighed by these costs and would not result in a net economic benefit. The Commission recommends that the electric utilities continue to maintain their current levels of separation with each business unit operating in an efficient, productive, and reliable manner.

In addition, Staff investigation of 13 other states that have undergone un-bundling of generation and distribution assets and found that those states experienced electric retail rates that increased at a higher rate than the U.S. average during the study period. A secondary study of the divestiture of transmission assets in Michigan also showed a correlating increase in transmission costs in the transmission component of customer's bills. The likely costs associated with a structural separation of generation and distribution should be avoided. For reasons discussed in this report, with emphasis on likely costs to electric customers, the Commission does not recommend new laws to require further separation of electric distribution and generation.

**Explanation of Acronyms**

ABATE: Association of Businesses Advocating Tariff Equity
Act 141: Michigan's Customer Choice and Electric Reliability Act
Act 286: 2008 PA 286
AEP: American Electric Power
AES: Alternative Electric Supplier
ATC: American Transmission Company
Consumers Energy: The Consumers Energy Company
DA: Day Ahead
Detroit Edison: The Detroit Edison Company
EIA: Energy Information Administration
EMS: Emergency Management System
FERC: Federal Energy Regulatory Commission
FPA: Federal Powers Act
FTE: Full-Time Equivalents
IEEE: Institute of Electrical and Electronics Engineers
I&M: Indiana Michigan Power Co.
IOU: Investor-owned Utility
IRP: Integrated Resource Plan
ISO: Independent System Operator
ITC: International Transmission Company
LMP: Locational Marginal Price
LSE: Load Serving Entity
MECA: Michigan Electric Cooperative Association
MEGA: Michigan Electric and Gas Association
METC: Michigan Electric Transmission Company
Midwest ISO: Midwest Independent System Operator
MOC: Merchant Operations Center
MPSC: Michigan Public Service Commission
MSCPA: Michigan South Central Power Agency
NERA: National Economic Research Associates
NERC: North American Electric Reliability Council
NSP: Northern States Power
PJM: Pennsylvania, New Jersey, Maryland Interconnection LLC
PURPA: Public Utility Regulatory Policies Act
RT: Real Time
RTO: Regional Transmission Organization
SCADA: Supervisory control and data acquisition
SOC: System Operations Center
Staff: The Commission Staff
UPPCo: Upper Peninsula Power Company
Wolverine: Wolverine Power Cooperative
WPS: Wisconsin Public Service Corporation

# ATTACHMENT A:

# 13 STATE ELECTRICITY RESTRUCTURING TIMELINE

## Staff's State Review of Electric Restructuring[2]:

| | |
|---|---|
| **Connecticut:** | **04/98:** House Bill 5005, An Act Concerning Electric Restructuring, was signed into law on April 29, 1998. The bill would allow access to competitive suppliers for 35 percent of consumers by January 2000 and for all consumers by July 2000. Utilities would be required to sell non-nuclear generation assets by January 2000 and interests in nuclear generation by January 2004, making Connecticut the first State to require divestiture of nuclear assets. The bill also required participation in an ISO, public interest program funding, functional unbundling, renewable energy funding, a 5.5- percent renewable portfolio standard, environmental protections, and a 10-percent rate reduction beginning January 2000, and a rate cap at the December 31, 1996 level from July 1, 1998 until January 1, 2000.<br>**04/99:** The DPUC ordered generation charges to be shown as a separate charge beginning July 1999. Bills were scheduled to be completely unbundled by January 2000. Suppliers were scheduled to begin licensing as early as July and soliciting of customers would then begin. |
| **Delaware:** | **04/99**: Delaware passed the Electricity Restructuring Act of 1999, House Bill (HB 10). The act was intended to bring competition to Delaware's electricity generation. Rate caps were imposed for non-residential consumers of Conectiv from October 1999 through September 2002; caps for residences were imposed between October 1999 through September 2002. This involved a residential rate cut of 7.5 percent for Conectiv customers and a rate freeze for the coop customers; funding for public benefits programs; and for Conectiv, no provisions for stranded cost recovery (the cooperative had no public benefit funding and stranded cost recovery would have been determined by the PSC). These caps were eventually extended to May 2006.<br>Source: Delaware Energy Office.<br>http://www.delaware-energy.com/<br>http://www.legis.state.de.us/LIS/LIS140.NSF/vwLegislation/HB+10?Opendocument<br>**03/06**: The Electric Utilities Retail Customer Supply Act of 2006, House Bill 6 (HB 6) was introduced by the House. "The Act provides that all electric distribution companies subject to the jurisdiction of the Commission would be designated as the standard offer service supplier and returning customer service supplier in their respective territories. The Act provided further opportunity for distribution companies to enter into long and short-term supply contracts, own and operate generation facilities, build generation and transmission facilities, make investments in demand-side resources and take any other Commission approved action to diversify their retail load supply. Additionally, Delmarva Power is required to conduct Integrated Resource Planning for a forward-looking 10 year time frame and to file such plan with the Commission, the Controller General, the Director of the Office of Management and Budget and the Energy Office every two years starting with December 1, 2006. As part of the initial planning process, Delmarva Power is required to file a proposal to obtain long-term supply contracts. The proposal requires Delmarva Power to include a Request for Proposal (RFP) for the construction of new generation resources within Delaware." "With respect to rate increases for Standard Offer Service to be effective on May 1, 2006, residential and small commercial customers of DP&L, depending on rate classification, shall have the ability to opt out of the following rate deferral plan:<br>Date Rate % Increase<br>5/1/2006 15%<br>1/1/2007 25%<br>6/1/2007 19%<br>1/1/2008 True-up/Balance<br>a. A customer who did not opt out of the deferral plan would be placed on a non-by-passable tariff, under which the customer would be responsible for all of his/her incurred deferral amounts including carrying costs of the plan.<br>b. Customers will have from April 1, 2006 to April 28, 2006 to affirmatively opt out of this plan."<br>Source: State of Delaware<br>http://www.legis.state.de.us/LIS/lis143.nsf/vwLegislation/HB+6/$file/legis.html?open<br>**04/06:** A joint resolution was introduced in the Delaware House of Representatives (JR 23) which called for the Delaware Public Service Commission, in consultation with the Governor's Energy Advisory Council, to conduct a feasibility study in regards to re-regulating Delaware's electricity |

[2] http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

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| | industry.<br>Source: The State of Delaware<br>http://www.legis.state.de.us/LIS/LIS143.NSF/vwLegislation/HJR+23?Opendocument<br>**11/06:** The Delaware Public Service Commission entered Order No. 7078 which adopted the proposed "Rules for Certification and Regulation of Electric Suppliers" observed in the order. These rules were intended to be used for re-regulation of Delaware's electricity providers.<br>Source: Delaware Public Service Commission<br>http://depsc.delaware.gov/ |
| **Illinois:** | **07/99:** Senate Bill 24 was enacted to amend the restructuring law. The amendment moved up the transition to customer choice. The first third of commercial and industrial consumers would have retail access by October 1, 1999, the second third by June 1, 2000, and the final third by October 1, 2000. Residential customers would receive a 5 percent rate reduction by October 1, 2001, seven months earlier. The rate cap for utilities was increased by 2 percent, cogeneration was promoted, and ComEd was required to allocate $250 million to a special environmental initiatives and energy efficiency fund.<br>**02/06:** House Bill 5766 (HB 5766) was put forth to amend the Electric Service Customer Choice and Rate Relief Law of 1997 in the Public Utilities Act. This bill provided that the "mandatory transition period" extend through the date on which the Illinois Commerce Commission had approved declarations of competitive service for all classes of service offered in the service areas of all electric utilities that, on December 31, 2005, served at least 100,000 customers (now, the mandatory transition period extends through January 1, 2007). Furthermore, the bill prohibited the Commission from taking certain actions prior to 2010 with respect to (i) initiating, authorizing, or ordering any change by way of increase or (ii) in approving an application for a merger, imposing a condition requiring any filing for an increase, decrease, or change in or other review of an electric utility's rates or enforcing such a condition.<br>Source: Illinois General Assembly<br>http://www.ilga.gov/legislation/BillStatus.asp?DocNum=5766&GAID=8&DocTypeID=HB&LegId=25345&SessionID=50 |
| **Maryland:** | **04/99:** With House Bill 703 (HB 703) and Senate Bill (SB 300), "Maryland Customer Choice and Competition Act," restructuring legislation was enacted. The legislation included at least a 3 percent rate reduction for residential consumers, funding for low-income programs, stranded cost recovery to be determined by the Public Service Commission, disclosure of fuel sources by electric suppliers, recovery of stranded costs through a non bypassable wires charge, and a 3-year phase-in for competition beginning in July 2000 and becoming complete by July 2002. As of July 1, 2000, all customers of electric companies (had) the opportunity to choose electric suppliers. By default, however, a customer remains with the electricity supplied by the distributing electric company under Standard Offer Service. The PSC (had) extended the opportunity to provide SOS." "Part of this Act required that all customers receive a rate reduction, followed by a rate freeze. The rate reduction of 6.5 percent for BGE customers was based on the last BGE rate case which was in 1993. The Commission's Technical Staff estimated that in 2005 alone, this rate reduction saved customers $474 million or an average of $30 per month per customer."<br>Source: Maryland General Assembly<br>http://mlis.state.md.us/1999rs/billfile/HB0703.htm<br>http://mlis.state.md.us/1999rs/billfile/SB0300.htm<br>Source: State of Maryland Public Service Commission<br>http://www.psc.state.md.us/psc/<br>**04/02**: Senate Bill 285 (SB 285) required electric companies in Maryland to "conduct a study that tracks shifts in generation and emissions as a result of restructuring the electric industry." The electric companies must submit their studies twice to the PSC and the Department of the Environment on or before December 31, 2003 and on or before December 31, 2005. If it is determined that restructuring has a negative impact on Maryland's environment, then the PSC will consider "establishing an air quality surcharge or other mechanism."<br>Source: Maryland General Assembly<br>http://mlis.state.md.us/2002rs/billfile/SB0285.htm<br>**02/05:** House Bill 1525 (HB 1525) was introduced in the Maryland House of Delegates. During the winter of 2005, the market-based cost of electricity skyrocketed. In the wholesale electricity |

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| | auctions, the market-based cost of electricity for an average residential customer was due to increase 72 percent in July 2006 in the BG&E service territory. Increases of 35 percent and 39 percent were expected in services territories covered by Delmarva and PEPCO, respectively. In response to a pending 72 percent electricity price increase for residential customers of BG&E, HB 1525 required the Public Service Commission (PSC) to extend the obligation to provide standard offer service (SOS) to residential and small commercial electric customers unless the PSC makes specified findings; altering the required findings and terms for extending SOS; requiring investor-owned electric companies to obtain electricity supply for extended SOS to residential and small commercial customers in specified manners; authorizing the Commission to take specified actions; etc." HB 1525 failed in the Maryland Senate. SOS was automatically assigned to any customer who did not opt to select an electricity supplier.<br>Source: Maryland General Assembly<br>http://mlis.state.md.us/2006rs/billfile/HB1524.htm<br>**03/06:** Senate Bill 972 (SB 972) and House Bill 1736 (HB 1736) were intended to reregulate electricity companies. The synopsis of HB 1736 and SB 972 read: "Returning electric generation to the status of a utility service subject to regulation by the Public Service Commission; requiring a public service company to charge just and reasonable rates for its utility services; requiring a public service company to file a specified tariff schedule of specified rates and charges with the Commission; providing that a specified electric company or electricity supplier may apply to the Commission to adjust specified rates and charges; etc."<br>Source: Maryland General Assembly<br>http://mlis.state.md.us/2006rs/billfile/SB0972.htm<br>http://mlis.state.md.us/2006rs/billfile/HB1736.htm<br>**05/07:** Senate Bill 400 was passed by the Maryland General Assembly. The bill requested that the Public Service Commission "reevaluate the general regulatory structure, agreements, orders, and other prior actions of the Public Service Commission under the 1999 Maryland Customer Choice and Competition Act. The newly passed bill also requested the "determination of and allowances for stranded costs" and to "conduct hearings" as part of its evaluation of the 1999 Settlement.<br>Source: Maryland Public Service Commission<br>http://www.psc.state.md.us/<br>**01/10:** Governor Martin O'Malley of Maryland stated that he would not submit legislation to re-regulate energy markets in the upcoming legislative session. Governor O'Malley stated that he would instead rely on the Public Service Commission to use existing authority to build new power generation as needed.<br>Source: Office of Governor Martin O'Malley<br>http://www.governor.maryland.gov/ |
| **Massachusetts:** | **11/97:** House Bill 5117 was enacted to restructure the electric power industry. The law required retail access by March 1998, rate cuts of 10 percent by March 1998 and another 5 percent 18 months later, and encourages divestiture of generation assets. The legislation also allowed full recovery of stranded costs over a 10-year transition period; DTE approved 2 utilities' plans for stranded cost recovery. |
| **New Hampshire:** | **04/01:** House Bill 489 (HB 489) was enacted and extended the period of transition service which Public Service Company of New Hampshire (PSNH) was required to provide 24 months after the initial transition service end day for residential, street lighting, and general delivery service rate G customers. For all other customers, the transition service would be extended 12 months after the initial transition service end day. Also, the bill postponed the sale of certain PSNH fossil and hydro generation assets to February 2004.<br>Source: New Hampshire General Court<br>http://www.gencourt.state.nh.us/legislation/2001/HB0489.html<br>**04/03:** Senate Bill 170 (SB 170) was enacted and stated that the Public Service of New Hampshire (PSNH) could not sell certain fossil and hydro generation assets until April 2006.<br>Source: New Hampshire General Court<br>http://www.gencourt.state.nh.us/legislation/2003/sb0170.html |
| **New Jersey:** | **01/97:** The BPU issued an order releasing its Energy Master Plan for public comment. The proposal called for a phase-in of retail choice that would give all New Jersey residents and businesses the option of choosing their electricity supplier by April 2001. |

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| | **04/97:** The BPU issued an order adopting and releasing its final report for the Energy Master Plan. The revised plan accelerated the time line for retail competition to begin: phase-in should have begun with 10 percent by October 1998, 35 percent by April 1999, 50 percent by October 1999, 75 percent by April 2000, and all by July 2000. |
| **New York:** | **05/96:** The PSC issued its opinion and order regarding competitive opportunities for electric service that restructured New York's electric power industry. The Competitive Opportunities Case adopted the goal of having a competitive wholesale market by 1997, and a competitive retail market by early 1998. Electric utilities were required to submit restructuring plans by October 1996. It also stated that utilities should have a reasonable opportunity to recover stranded costs consistent with the goals of restructuring. |
| **Ohio:** | **07/99:** The restructuring legislation, Senate Bill 3, was signed into law by the governor on July 6, 1999. The legislation would allow retail customers to choose their energy suppliers beginning January 1, 2001. The new law required 5 percent residential rate reductions and a rate freeze for 5 years, contains consumer protections, environmental provisions, and labor protections, and empowers the PUCO to determine the amount and recovery period for stranded costs. Also, the property tax utilities paid in the past was replaced with an excise tax on consumer bills. Utilities were required to spend $30 million over the next six years on consumer education programs.<br>**10/99:** The PUCO issued an initial set of rules for transition to a competitive retail market. The draft rules included provisions for recovery of stranded costs, corporate unbundling, consumer education, and employee protections. |
| **Pennsylvania:** | **12/96:** House Bill 1509, the Electricity Generation Customer Choice and Competition Act, was enacted. The law proposed a schedule whereby consumers could begin choosing among competitive generation suppliers, beginning with one third of the State's consumers, by January 1999, two thirds by January 2000, and all consumers by January 2001. Utilities were required to submit restructuring plans by September 1997.<br>**12/97:** House Bill 1509 allowed stranded cost recovery through a competitive transition charge; however, the detailed decisions and amount of recoverable costs were left to the PUC. The legislation expected utilities to use reasonable mitigation measures, and securitization was allowed but not required. |
| **Rhode Island:** | **08/96:** The Rhode Island Utility Restructuring Act of 1996, House Bill 8124, allowed retail choice to be phased-in starting July 1997. In July 1997, Rhode Island became the first state to begin phase-in of statewide retail wheeling (for industrial customers). Residential consumers were scheduled to have retail access by July 1998. |
| **Texas:** | **1995:** Senate Bill 373 enacted to restructure the Texas' wholesale electric industry, consistent with FERC requirements. The law requires utilities to provide unbundled transmission service on a non-discriminatory basis and establish an ISO.<br>**06/99:** Restructuring legislation, Senate Bill 7, was enacted to restructure the Texas electric industry allowing retail competition. The bill requires retail competition to begin by January 2002. Rates will be frozen for 3 years, and then a 6 percent reduction will be required for residential and small commercial consumers. This will remain the "price to beat" for five years or until utilities lose 40 percent of their consumers to competition. The bill will also require a reduction of NOx and SO2 emissions from "grandfathered" power plants over a 2-year period. All net, verifiable, nonmitigated stranded costs may be recovered. Securitization will be allowed as a recovery mechanism. Utilities must unbundle into 3 separate categories, using separate companies or affiliate companies, the generation, the distribution and transmission, and the retail electric provider. Utilities will be limited to owning and controlling not more than 15 percent of installed generation capacity in their region (ERCOT). Municipals and cooperatives are not affected by the law, unless they choose (after January 2002) to open their territories to competition. The law also requires an increase in renewable generation and 50 percent of new capacity to be natural gas-fired.<br>**04/09:** Senate Bill 547 and House Bill 870 were introduced into the Texas Legislature to halt electricity deregulation in Southwestern Electric Power Company's service area in Eastern Texas in 2011. Under these two bills, a pilot program would first need to prove that electricity deregulation would lower rates before the entire service area could be deregulated.<br>Source: Texas Legislature Online<br>http://www.legis.state.tx.us/<br>**05/09:** The Texas House of Representatives unanimously approved Senate Bill 547 and House Bill |

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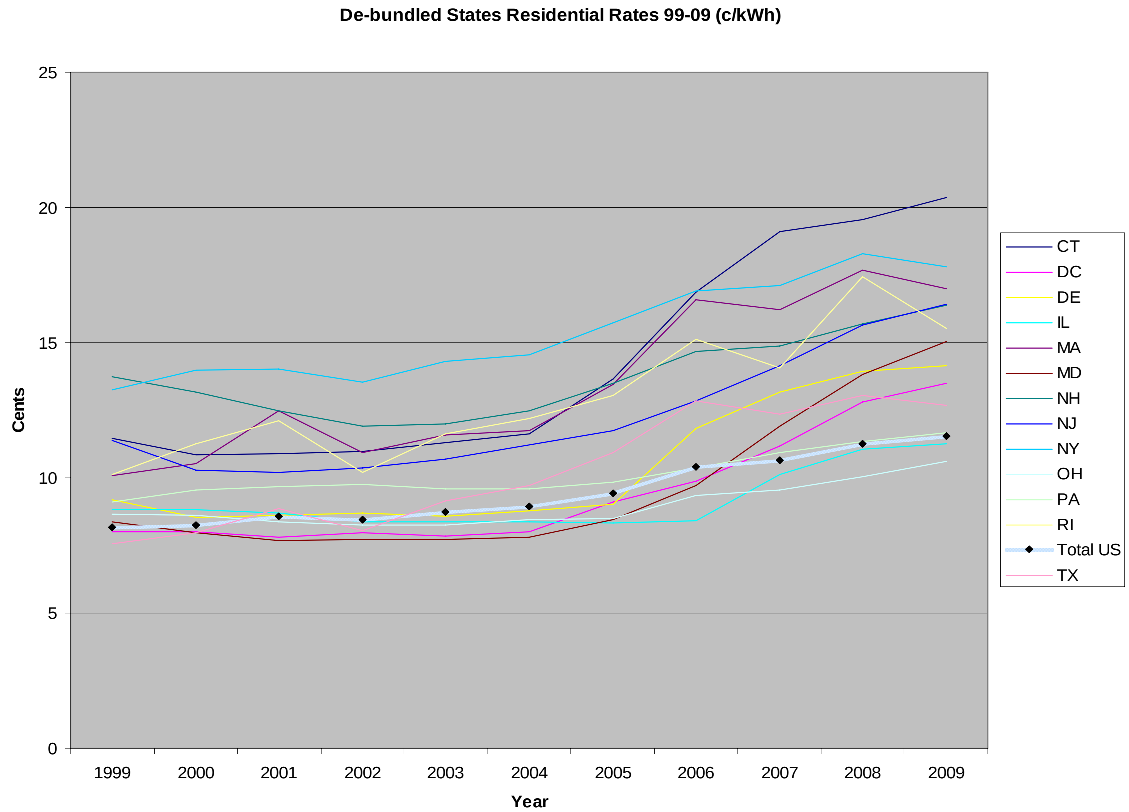
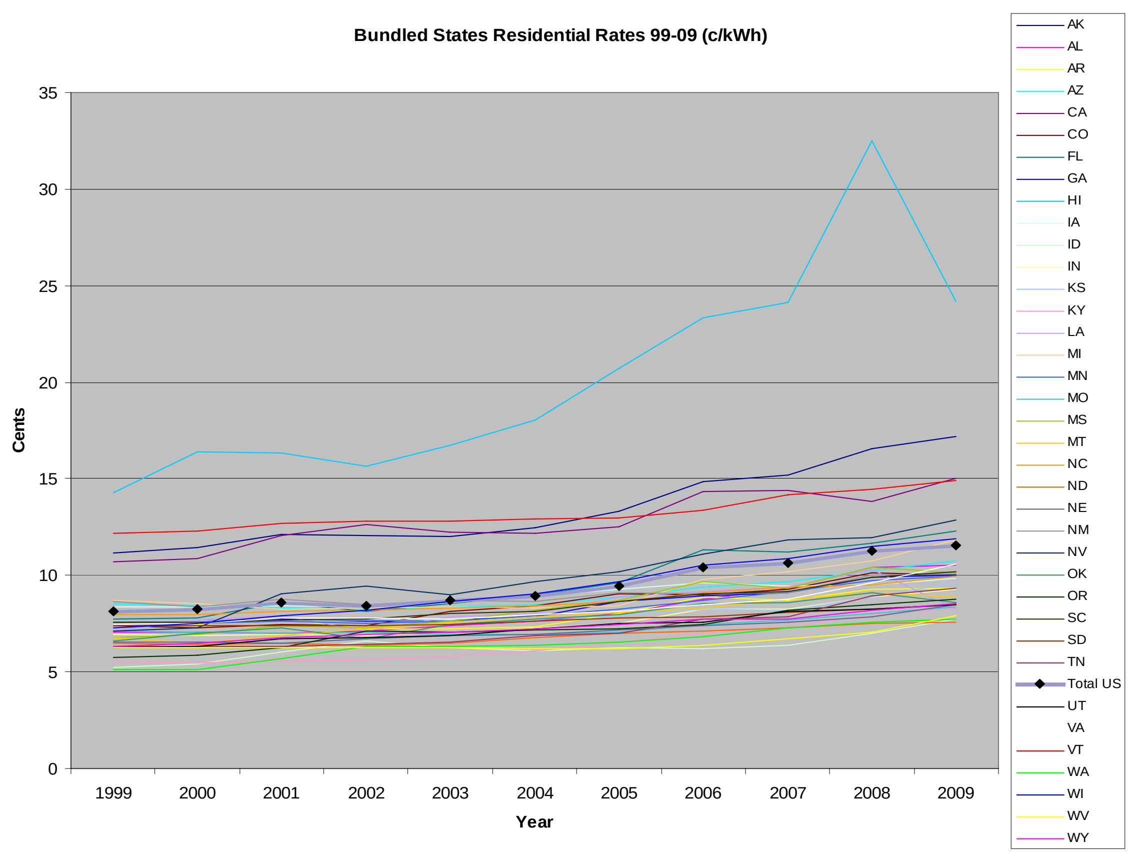
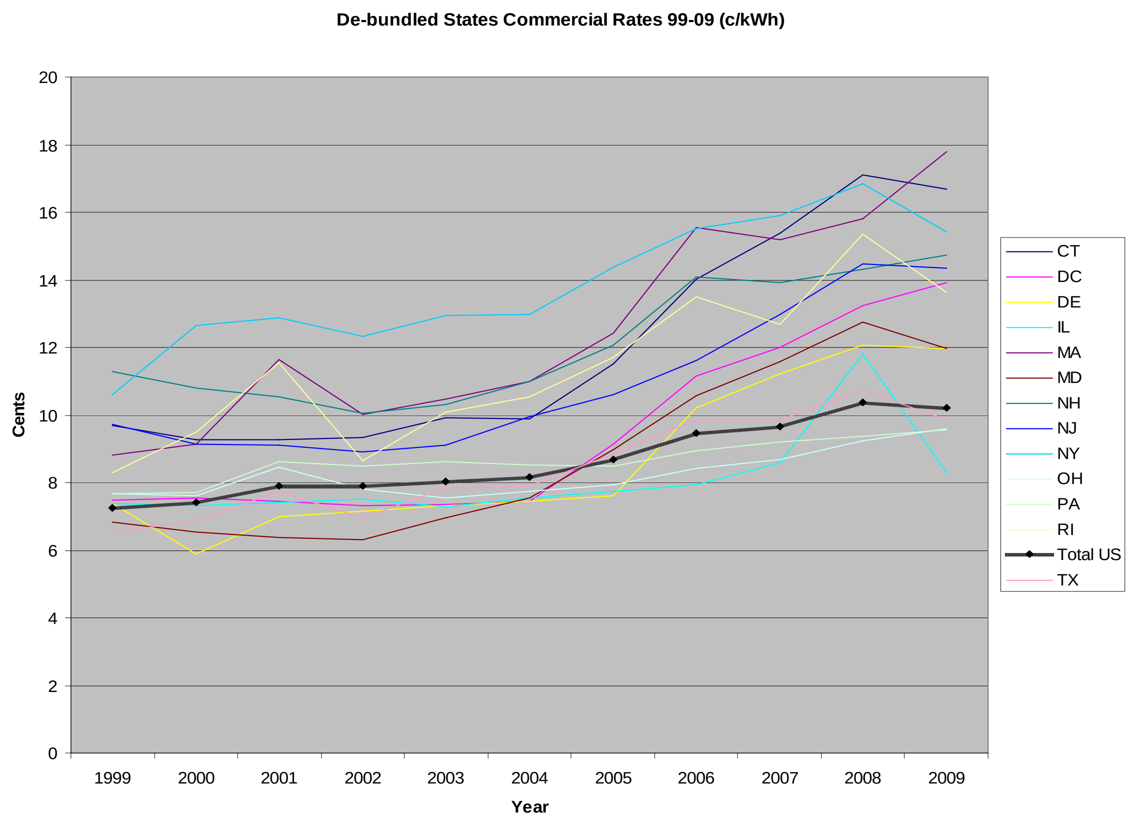
| | 870. The two bills delay deregulation of electric utilities in Northeast Texas indefinitely.<br>Source: Texas Legislature Online<br>http://www.legis.state.tx.us/ |
| **Washington D.C.:** | **08/98:** A report was issued by the PSC on electric restructuring issues. The report requested a restructuring plan from PEPCO and recommended retail access be phased-in over 3 years beginning January 2001.<br>**03/99:** Potomac Electric Power Co stated that it planned to sell its power plants and purchase power contracts. PEPCO intended to become a "wires" company, concentrating on power delivery, retailing power, cable TV, and Internet services.<br>**12/00:** Order 11845 unbundled retail rates into separate categories, generation, transmission, and distribution functions. Unbundling allowed customers to compare prices among electricity suppliers, and helped the Commission to determine "shopping credits" or "price to compare."<br>**06/08:** New Pepco electric generation rates became effective with bills issued on June 1, 2008 for Pepco's Standard Offer Service (SOS) customers in the District; that is, customers who have not chosen an alternative generation supplier. Since generation rates account for nearly 80 percent of residential customers' bills, Pepco anticipates that residential customers will see an average annual increase in bills of 15.5 percent or about $12.75 per month. Small commercial customers' annual bills will increase, on average, by approximately 11.9 percent (about $24.35 per month).<br>Source: District of Columbia Public Service Commission<br>http://www.dcpsc.org/ |

# Attachment B:

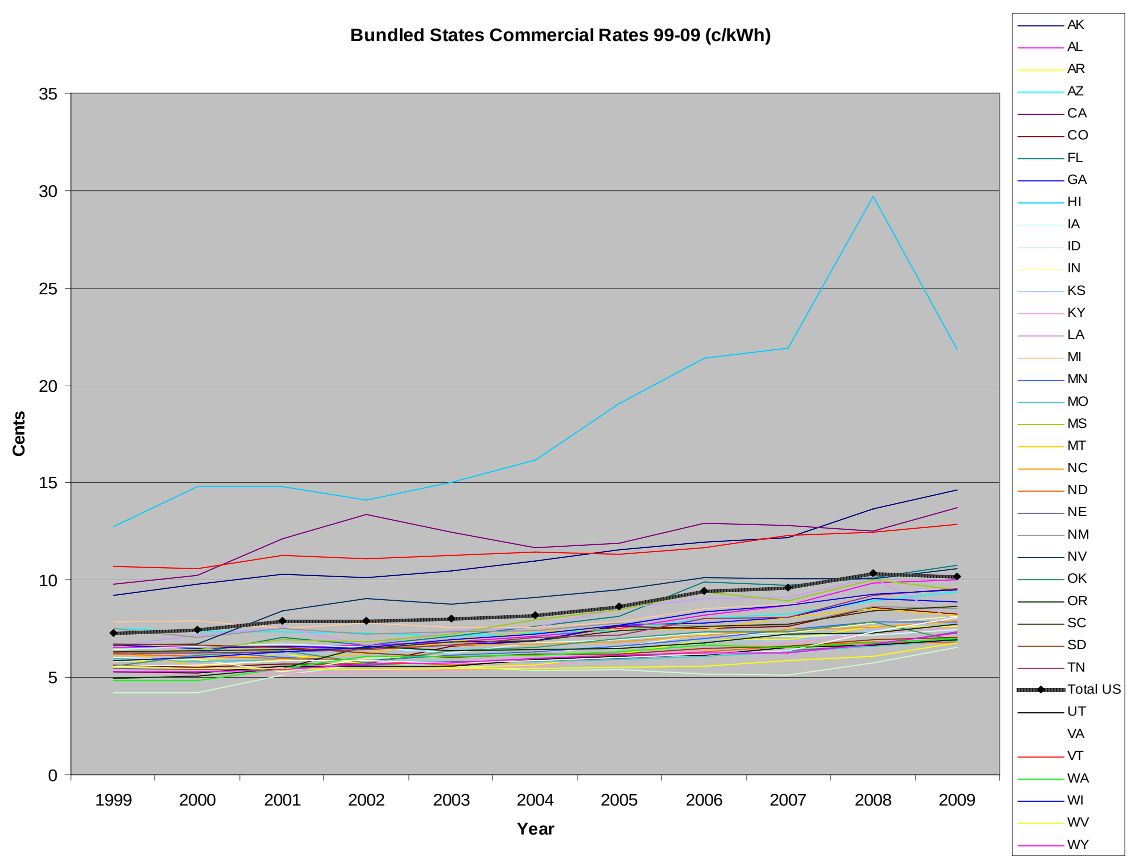
# 13 State Electricity Restructuring Electric Retail Price Data Graphs


De-bundled States Residential Rates 99-09 (c/kWh)
Cents
Year
0
5
10
15
20
25
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
CT
DC
DE
IL
MA
MD
NH
NJ
NY
OH
PA
RI
Total US
TX


Bundled States Residential Rates 99-09 (c/kWh)
Cents
Year
0
5
10
15
20
25
30
35
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
AK
AL
AR
AZ
CA
CO
FL
GA
HI
IA
ID
IN
KS
KY
LA
MI
MN
MO
MS
MT
NC
ND
NE
NM
NV
OK
OR
SC
SD
TN
Total US
UT
VA
VT
WA
WI
WV
WY

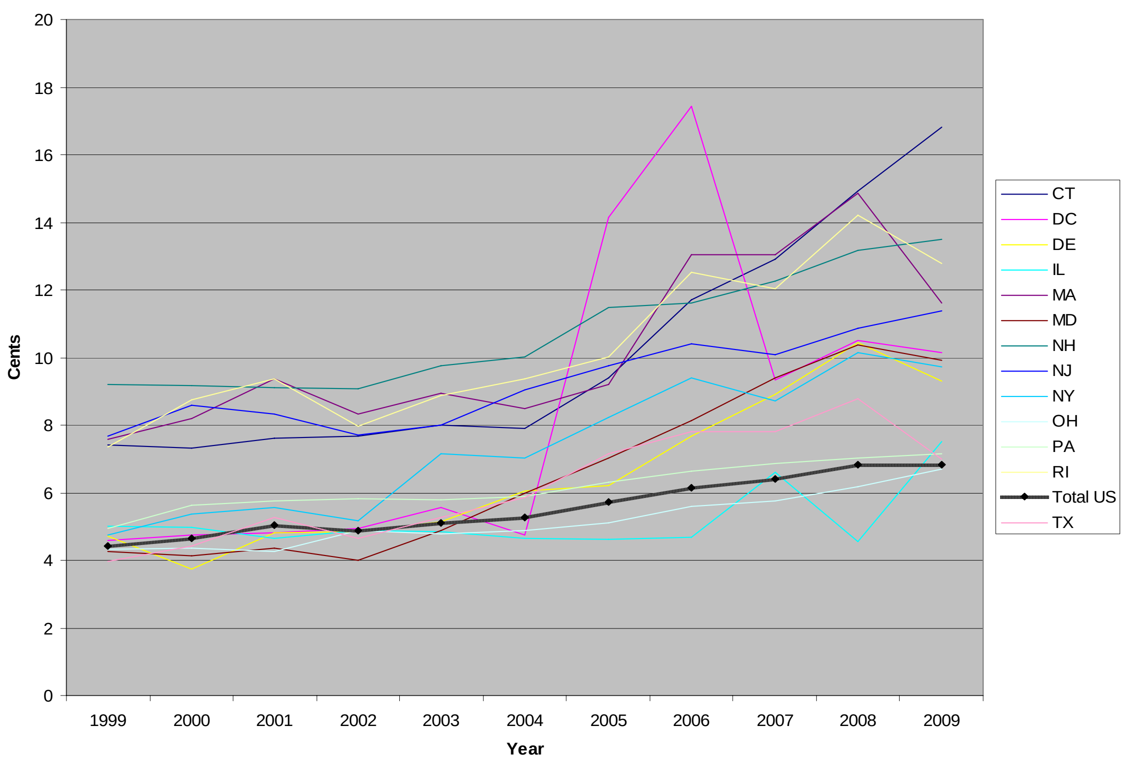


De-bundled States Commercial Rates 99-09 (c/kWh)
Cents
Year
20
18
16
14
12
10
8
6
4
2
0
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
CT
DC
DE
IL
MA
MD
NH
NJ
NY
OH
PA
RI
Total US
TX

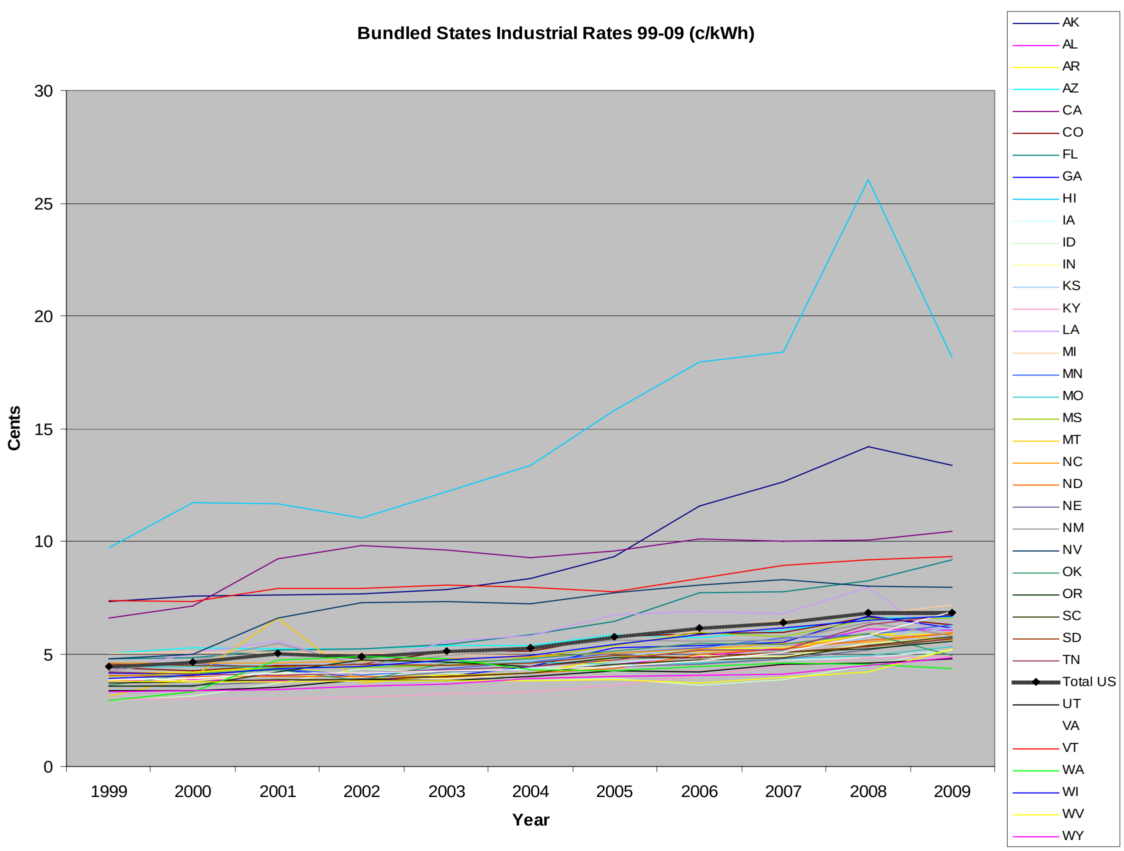



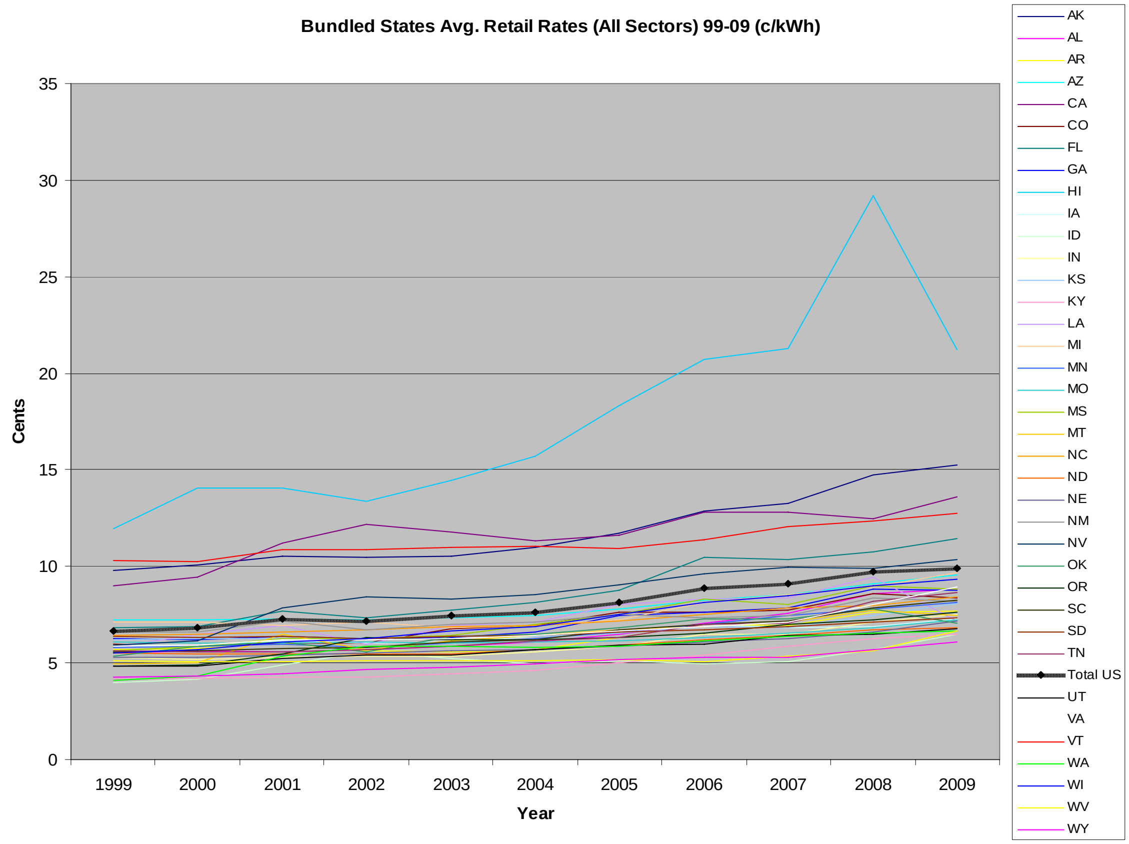
Bundled States Commercial Rates 99-09 (c/kWh)
Cents
Year
35
30
25
20
15
10
5
0
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
AK
AL
AR
AZ
CA
CO
FL
GA
HI
IA
ID
IN
KS
KY
LA
MI
MN
MO
MS
MT
NC
ND
NE
NM
NV
OK
OR
SC
SD
TN
Total US
UT
VA
VT
WA
WI
WV
WY

**De-bundled States Industrial Rates 99-09 (c/kWh)**

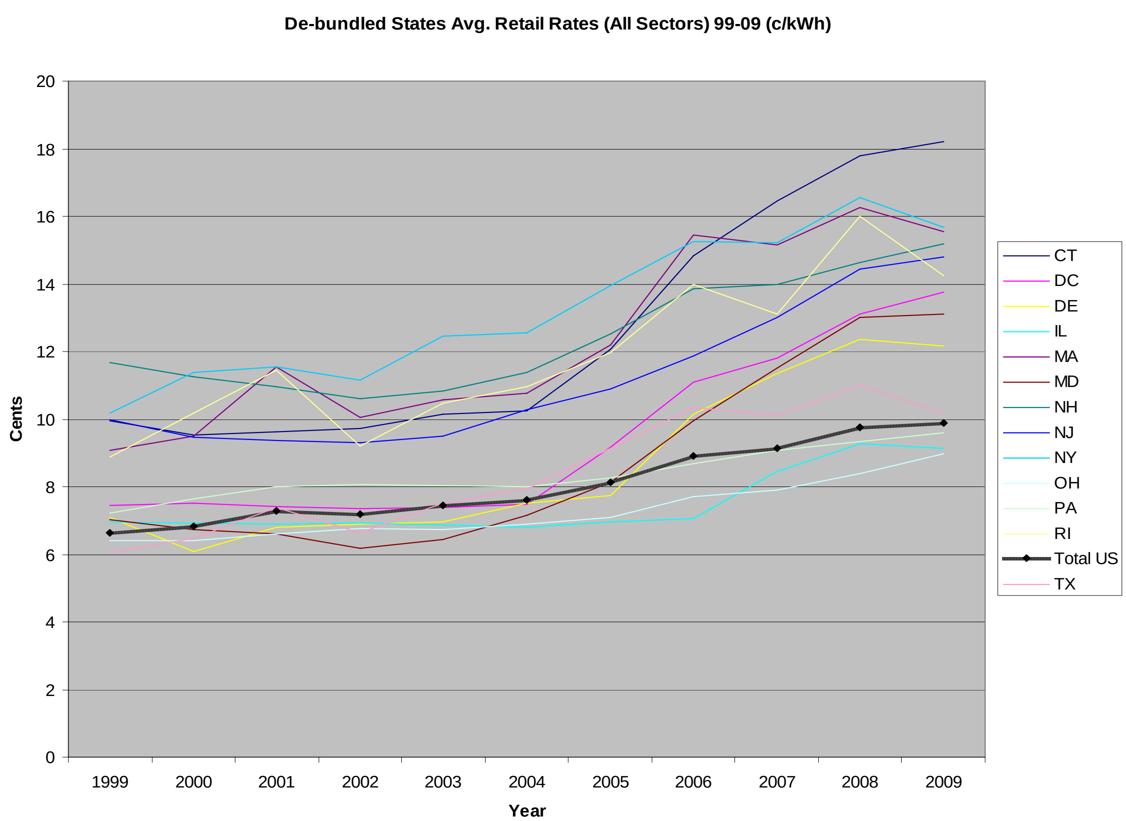



**Bundled States Industrial Rates 99-09 (c/kWh)**





Bundled States Avg. Retail Rates (All Sectors) 99-09 (c/kWh)
Cents
Year
0
5
10
15
20
25
30
35
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
AK
AL
AR
AZ
CA
CO
FL
GA
HI
IA
ID
IN
KS
KY
LA
MI
MN
MO
MS
MT
NC
ND
NE
NM
NV
OK
OR
SC
SD
TN
Total US
UT
VA
VT
WA
WI
WV
WY

De-bundled States Avg. Retail Rates (All Sectors) 99-09 (c/kWh)
Cents
Year
0
2
4
6
8
10
12
14
16
18
20
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
CT
DC
DE
IL
MA
MD
NH
NJ
NY
OH
PA
RI
Total US
TX