

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own)
motion, of the implementation of 2000 PA 141.)
_____)

Case No. U-12464

INDIANA MICHIGAN POWER COMPANY,
D/B/A AMERICAN ELECTRIC POWER

RESTRUCTURING IMPLEMENTATION PLAN
FOR THE STATE OF MICHIGAN

October 2, 2000

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INDIANA MICHIGAN POWER COMPANY,
D/B/A AMERICAN ELECTRIC POWER (AEP),
RESTRUCTURING IMPLEMENTATION PLAN
FOR THE STATE OF MICHIGAN

A. Overview

Indiana Michigan Power Company (I&M), which is authorized to do business in Michigan as American Electric Power (AEP), hereby provides its Restructuring Implementation Plan (Plan) in compliance with the Michigan Public Service Commission's (MPSC or Commission) Opinion and Order (Order) dated June 19, 2000, in Case No. U-12464. AEP's Plan was submitted to the Commission through the MPSC's electronic filing system in accordance with the directive of the Commission's June 19, 2000, Order in this matter.

AEP is a wholly-owned subsidiary of American Electric Power Company, Inc. AEP is a corporation organized and existing under the laws of the state of Indiana with its principal executive offices located at One Summit Square in the city of Fort Wayne, Indiana. AEP has the corporate power and authority to engage in, among other things, generating, transmitting, distributing, and selling electric energy within the state of Michigan and within the state of Indiana.

AEP's electric system is a completely integrated and interconnected entity and is operated as a single utility. AEP's service area is located in southwestern Michigan and northern and eastern Indiana within which AEP provides electric service to approximately 121,000 retail electric customers in the state of Michigan. Pursuant to the Commission's Order in Case No. U-9912, AEP's service area in

Michigan consists of two rate areas, the St. Joseph Rate Area and the Three Rivers Rate Area.

On June 3, 2000, Governor Engler signed Enrolled Senate Bill No. 937. The bill was filed on June 5, 2000, and became 2000 PA 141.

Section 10a of 2000 PA 141 provides in part:

(1) No later than January 1, 2002, the commission shall 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. The orders shall provide for full recovery of a utility's net stranded costs and implementation costs as determined by the commission.

(5) The orders issued by the commission before the effective date of the amendatory act that added this section that allow customers of an electric utility to choose an alternative electric supplier, including orders that determine and authorize recovery of net stranded costs and implementation costs and that confirm any voluntary commitments of electric utilities, are in compliance with this act and enforceable by the commission. An electric utility that has not had voluntary commitments to provide customer choice previously approved by orders of the commission shall file a restructuring plan to allow customers to choose an alternative electric supplier no later than the date ordered by the commission. The plan shall propose a methodology to determine the electric utility's net stranded costs and implementation costs.

Section 10b(2) of 2000 PA 141 provides:

No later than 1 year from the effective date of the amendatory act that added this section, each electric utility shall file an application with the commission to unbundle its existing commercial and industrial rate schedules and separately identify and charge for their discrete services. No earlier than 1 year from the effective date of the amendatory act that added this section, the commission may order the electric utility to file an application to unbundle existing residential rate schedules. The commission may allow the unbundled rates to be expressed on residential billings in terms of percentages in order to simplify residential billing. The commission shall allow recovery by electric utilities of all just and reasonable costs incurred by electric utilities to implement and administer the provisions of this subsection.

On June 19, 2000, in Case No. U-12464, the Commission ordered each investor-owned electric utility, other than Consumers Energy Company and The Detroit Edison Company, to file a restructuring plan in compliance with 2000 PA 141 that permits all of its retail customers to choose an energy service provider (ESP) no later than January 1, 2002. AEP is an investor-owned electric utility subject to the filing requirements of the Commission's June 19, 2000, Order. While the Commission did not specify a particular form and content for the restructuring plans, AEP, participating in discussions coordinated by the Michigan Electric and Gas Association during August 2000, obtained important feedback from the Commission Staff regarding information to be included in the initial plan filing. Based on those discussions, all participants realized that there are significant regulatory issues to be addressed and, in some cases, coordinated before customer choice becomes effective in January 2002. The terms and conditions of the implementation program, including specific tariff language, will necessarily continue to be developed over time in this and other proceedings. This filing represents AEP's best efforts to specify the elements as known today to be included in its overall restructuring plan.

AEP's Plan, as detailed below, is in compliance with and satisfies the requirements of the Commission's June 19, 2000, Order in Case No. U-12464 and provides a meaningful initiation of the process of defining the terms and conditions, in accordance with 2000 PA 141 and the authority of the Commission, under which AEP's customers will have the opportunity to choose an ESP. The Plan proposes that all AEP customers will have the opportunity to receive energy from an ESP commencing on the first calendar day of 2002 and describes AEP's intentions and

preparations with respect to, among other things, supplier transactions, customer transactions, awareness and education programs, customer usage determination, rate unbundling, customer choice information systems, corporate separation, regional transmission organization participation, the joint available transmission capability expansion plan, and employee transition programs. The Plan proposes the methodology to be employed to determine AEP's stranded costs and implementation costs, describes the methodology for the calculation of a Transition Cost Adjustment Factor, defines the annual true-up procedure, reflects the continuation of AEP's non-bypassable nuclear decommissioning wires charge, and describes certain accounting authority for which AEP will request Commission approval. AEP necessarily reserves the right to propose reasonable amendments to the Plan prior to approval of the final tariffs.

As the 15 weeks from the issuance of the Commission's June 19, 2000, Order to the filing date of the Restructuring Implementation Plans did not allow sufficient time for AEP to prepare and file its unbundled existing rates, open access tariffs, and modified Terms and Conditions of Service, and because the AEP System expects to gain further knowledge and experience in customer choice in Virginia, Texas, and Ohio programs, the commencement of which are imminent, AEP proposes to file, for all customer classes, its unbundled existing rates, open access tariffs, modified Terms and Conditions of Service, and any additional support deemed necessary and appropriate for the various aspects of its Michigan Customer Choice Program on June 5, 2001. AEP believes that this proposed filing

date will provide ample procedural time for the Commission to process AEP's tariffs in order to comply with the requirements of 2000 PA 141.

AEP therefore respectfully requests that this Commission:

1. Accept AEP's Restructuring Implementation Plan for filing and approve AEP's Plan as in compliance with the Commission's June 19, 2000, Order in Case No. U-12464.
2. Promptly make such investigation and give such notice as it may deem necessary or advisable in the circumstances.
3. Promptly enter an Order in this proceeding approving AEP's Plan and establishing a filing date of June 5, 2001, for AEP's unbundled and open access tariffs and Terms and Conditions of Service for all customer classes. Further, AEP proposes that on that date of June 5, 2001, to the extent necessary or advisable, AEP would file an Application with the Commission requesting that the MPSC make and enter appropriate Orders:
 - (a) Approving for AEP new schedules of electric service rates, and related terms and conditions of service, consistent with the relief requested by AEP.
 - (b) Authorizing AEP to treat certain costs as retail jurisdictional regulatory assets for future recovery through regulated rates including certain restructuring implementation costs and customer education costs and return of and on capital expenditures in excess of depreciation levels and expenses

incurred as a result of changes in taxes, laws, or other state or federal governmental actions.

- (c) Approving such other relief as then requested by AEP and deemed reasonable and appropriate by the Commission.

B. Projects Supporting Supplier Transactions

1. Supplier Qualification

The overall concept supported by AEP is that the supplier is to be licensed by the state and registered with the utility in order to be certified to provide energy services to end-use customers in Michigan. It is important that the state verify through a licensing process the eligibility and capability of all ESPs to provide the services that they will be offering to the market participants. The licensing process would also place on record the agreement of the ESP to follow the business rules and standards of conduct that have been put in place in Michigan. The business rules and standards of conduct should describe the relationships between ESPs and utilities and between ESPs and retail customers. The primary objective of these rules and standards is to promote a workable, competitive marketplace in which consumers can make an informed choice of a supplier from numerous ESPs. In regard to state licensing procedures, AEP acknowledges the licensing program for ESPs approved in the Commission's June 19, 2000, Order in Case No. U-11915.

Additionally, it is important that an ESP be registered with each Local Distribution Company (LDC or utility) individually. Once the ESP has been licensed by the state as eligible and capable of performing their desired services, it would be necessary for the supplier and the utility to reach agreement on how they are going to conduct business together. Upon reaching agreement on how the parties are going to conduct business, the supplier would be identified as having been registered with the utility.

There are several factors that might prevent a state-licensed ESP from being registered with an individual utility. One factor could be a difference in the level of financial soundness that the utility is looking for. For example, the state might find acceptable a level of financial soundness that covers an ESP's tax liability, while the utility might seek a level of financial soundness that covers the potential liability of the cost of energy for a period of time in case the ESP fails to deliver. This potential liability will vary with the size of the ESP's customer base with each utility, so the registration needs to be utility-specific. Another factor could be the ESP's ability to meet each utility's electronic data transaction requirements.

a. Supplier Registration Process

AEP will require the completion of the following documents and agreements for an ESP. The instructions for completing and handling these forms and agreements are included with each document. ESPs may initiate this process by contacting AEP Provider Support or by downloading the forms and agreements from the AEP web site. AEP Provider Support (i.e., Supplier Support) is a group of employees dedicated to supporting the needs of service providers.

ESP registration requirements:

Forms

- (1) Supplier Registration Application
- (2) Trading Partner Set-up Form
- (3) Trading Partner Certification Checklist

Agreements

- (1) LDC/Competitive Supplier Agreement
- (2) EDI Trading Partner Agreement
- (3) Network Transmission Service Agreement (Open Access Transmission Tariff [OATT] Attachment F) or Point-to-Point Transmission Service Agreement (OATT Attachment A)

Upon receipt of an application from an ESP, AEP will determine if the application is complete. If incomplete, the applicant will be notified and missing information requested. Once the application is deemed complete, it is AEP's goal to make every effort to process the registration in a two week time period. The applicant will be notified of the result of their creditworthiness evaluation and advised if any financial instrument for security will be required. Once any necessary financial instrument is provided to AEP, the Electronic Data Interchange (EDI) certification is completed, a Michigan license is obtained, and all appropriate agreements are executed, the ESP will be registered to operate in AEP's Michigan service territory.

b. Financial Credit Requirements

AEP requires an appropriate level of financial security, which may be provided by one of the following:

- (1) Irrevocable Letter of Credit
- (2) Surety Bond
- (3) Corporate Guaranty Agreement
- (4) Cash Deposit

Cash deposits must be received and funds deposited in AEP's account before registration will be granted.

2. Transmission Service Agreements

Transmission service agreement administration will be provided by the RTO (when operational) in coordination with AEP's Transmission and Interconnection Services staff. The administration of these agreements will include the development and execution of all contracts between transmission customers eligible under FERC OATT and the transmission provider regarding:

- (a) Network and Point-to-Point Transmission Service
- (b) Ancillary Services
- (c) Energy Imbalance Service
- (d) Metering and Profiling for Loads
- (e) Delivery Points Covered by Enrollment Process/System
- (f) Creditworthiness—Initial and On-going Requirements
- (g) Billing and Settlements
- (h) Dispute Resolution

3. Transmission Reservation

The transmission reservation process will be administered by the transmission provider (RTO when operational). Eligible transmission customers will request transmission and ancillary services on the OASIS and execute service agreements for long-term transmission service, pursuant to FERC requirements. Transmission capacity reservation will be required for Network Resources and Point-to-Point transactions.

4. Energy Scheduling

The transmission provider and control area operator will provide and administer an electronic scheduling (e-Tag) system by which ESPs will arrange for delivery of the energy requirements of their customers.

5. Reconciliation and Ancillary Charges

Reconciliation is the process of determining the energy imbalance between the scheduled energy and the actual energy used by the customer. The resulting energy imbalance is either billed or credited to the ESP after accounting for transmission and distribution losses. Transmission and ancillary service charges will be determined and invoiced by the transmission provider in cooperation with the control area operator.

6. Supplier Billing and Collections

The supplier billing and collections function will accumulate ESP charges for transmission and related services and produce an invoice. The supplier billing and collections system will track the receipt of payment and credit the payment to the proper account and monitor outstanding invoiced charges. If payment is untimely or insufficient funds are received, the system will initiate additional collection procedures as appropriate to the circumstances.

a. Supplier Billing and Collections Functions and Additional Requirements

- (1) Verify that suppliers meet financial commitments.

- (2) Produce a monthly bill which will provide suppliers with accurate, timely information on the status of transactions for transmission and ancillary services furnished.
- (3) Bill for all transmission charges under the OATT schedules including ancillary service charges.

b. Information System Implications

- (1) Develop a load data management functionality to efficiently aggregate customer loads by supplier for billing reconciliation and energy imbalance purposes.
- (2) Develop the EDI functionality to support sending and receiving load and billing data between AEP and suppliers.
- (3) Modify the credit and cash management collection system as needed to support receivables and collection from suppliers.

7. Supplier Support

AEP will have in place a staff of employees dedicated to providing support for suppliers to facilitate their entry into the competitive marketplace. This staff will coordinate education, contract administration, customer enrollment, and other activities essential to the new business relationships that will be established between the ESP and AEP. This staff will also ensure that the latest information is made available to the ESP through such tools as the Internet and the Service Provider Handbook, which is more fully described in Section D.2, Supplier Education.

C. Projects Supporting Customer Transactions

1. Customer Enrollment/Switching

In the traditional electric utility environment, all account activities were simple transactions between the customer and the electric company. With Customer Choice and the introduction of numerous service providers, activities related to the processing of account transactions become more complex and critical. The expedient completion of enrollment and switching transactions and their related activities is essential to assure continuity of service.

a. Enrollment and Switching Process Definitions

The enrollment and switching processes record relationships between customers and service providers. The principal processes are:

- (1) Initially identifying and enrolling all existing customers for the appropriate Customer Choice implementation date.
- (2) Enrolling a customer who moves into the territory.
- (3) Switching a customer's service from one provider to another, either at the customer's initiation or because the provider has dropped the customer.
- (4) Recording the termination of a customer's relationship with AEP and the service provider(s) when the customer leaves the area.

Associated services—meter service (MSP), meter data management (MDMA), and billing (BA)—may be provided by the LDC

or they may be competitive services, depending upon jurisdictional rules.

b. AEP's Position on Enrollment and Switching

AEP is committed to the success of Customer Choice. Enrollment and switching processes must support customers' interests in facilitating and executing their choice of provider(s), protecting the customer against "slamming" and other undesirable practices, and arranging for default service when necessary.

Customer Choice infrastructure and supporting systems will strongly impact the facilitation of customers' choices and, consequently, could influence the overall success of Customer Choice. Such infrastructure and support systems must facilitate all participants' ability to access high quality data and information necessary to process the transactions required by Customer Choice. Infrastructure must be fast, flexible, comprehensive, reliable, and accurate. To meet those goals, AEP is developing its infrastructure through a relationship with the Market Data ClearingHouse (MDCH). AEP will utilize the MDCH for the storage, processing, tracking, and reporting of information required to support newly competitive functions. The MDCH facility, built and operated by Logica, Inc., provides the necessary additional IT functionality as will be required by the Michigan restructuring effort.

c. Process Initiation

Upon selection by a customer, the ESP is responsible for establishing a contractual agreement with the customer and then initiating the appropriate process to activate the enrollment or switch with the LDC. The ESP will become obligated to provide the services and, therefore, should be responsible for ensuring that the contract was appropriately obtained.

d. ESP/Customer Contractual Relationship

Processing customer activity or recording a relationship with an ESP should be predicated on a verifiable contract between the ESP and the customer.

(1) Timing

(a) Switch Effective Date – Switches will be effective on the first calendar day of each month. Using consistent dates rather than traditional next meter read dates will:

- (i) Be easier for customers to follow.
- (ii) Coincide with ESPs' scheduling and arranging for power supply on a calendar month basis.
- (iii) Not require special process triggers such as a missed read date due to unforeseen circumstances such as bad weather.
- (iv) Eliminate the need to track meter read cycle changes in a master customer list of ESP prospects.
- (v) Avoid the expense of special, off-cycle meter reads.

- (vi) Facilitate establishing future competitive MDMA services because MDMA's will be able to adjust meter cycles without being encumbered by ESPs' various switching dates.
 - (vii) Not create additional work to allocate a customer's energy consumption between original and new ESPs since an energy consumption estimate by customer is prepared for the settlement process whether or not a switch occurs.
- (b) Switching Window – Switching requests must be received by the LDC (MDCH) from the new ESP during a switching window which closes by the 15th calendar day of the month to be effective on the first day of the following month.
- (i) The time period between the switching window and the end of the month allows customers time to object to a switch and for ESPs to contest a switch.
 - (ii) To provide the consumer with the required contract rescission protection period, the ESP must hold the switch request and can initiate processing with the LDC only after the rescission period has expired.

e. MSP, MDMA, and BA Selection

The selection of additional providers may increase complexity to a level that could impede customers' decision-making processes. The ESP will arrange for competitive services (MSP, MDMA, and BA), if applicable, in addition to energy because:

- (1) The ESP is uniquely positioned to determine that the additional services obtained by the customer match the requirements of the energy service offering.
- (2) Centralized coordination will help control costs over the separate processing and tracking of enrollment and switching transactions for individual service providers.

2. Customer Billing and Collections

Unlike the pre-Choice era, wherein billing for electrical service was a straightforward transaction between AEP and the customer, billing in the Choice era involves at least two principal components (energy service & delivery) with, usually, two distinct business entities. Accordingly, the process of acquiring, developing, and presenting billing data is considerably more complex than in the pre-Choice era.

AEP encourages ESP Consolidated Billing and will also support Dual Billing. AEP believes that it would be inappropriate for the LDC to be required to perform billing services for the ESP and, therefore, would only plan to offer that option at a negotiated price.

The EDI 867 transaction is used to transmit usage information as captured from the meter, including interval data recorders (IDR), required for billing. The EDI 867 will be sent in all cases for billing and will contain bill data. (Note: In the event a customer has more than one ESP, the EDI 867 transaction will transmit total metered consumption and indicate the appropriate share.)

The EDI 810 transaction is used to transmit billing usage and billing components for generating a customer invoice under Consolidated Billing (it is not necessary for Dual Billing). It also transmits the amount billed on behalf of the ESP.

When a customer receives a final bill or a final meter reading, the EDI 810 and/or EDI 867 should indicate it as "final."

The principal billing elements are embodied in the following processes:

- a. Gathering or retrieval of meter usage data.
- b. Application of tariffs/rates against the data to calculate charges.
- c. Presentation of the charges to the customer.
- d. Forwarding of the LDC's charges that are to be presented to the customer by the ESP on the behalf of AEP.
- e. Receipt of the remittance notice from the ESP.

3. Customer Support

The Customer Support Plan provides for the identification, analysis, design, and implementation of a customer support network that will provide answers to customers' questions and inquiries about Customer Choice. The areas of primary focus include enrollment, billing, collection, outage and trouble calls, orders, and general inquiries.

The plan includes the review and modification of current practices, policies, and procedures, if required. It also encompasses the identification, development, and implementation of new processes, procedures, activities, staffing and training needs, and systems and infrastructure requirements that are necessary to support Customer Choice. The following summarizes the key tasks, activities, and deliverables for this project.

a. Customer Solutions Centers

- (1) Train Customer Solutions Center staff on the principles, concepts, processes, procedures, and practices relating to Customer Choice.

- (2) Develop Frequently Asked Questions (FAQ) and scripted answers to address common customer questions.
- (3) Prepare and provide a delivery mechanism for customer education collateral materials specific to Customer Choice.
- (4) Prepare and provide lists of Retailers to customers to aid in their selection of a new energy provider.
- (5) Establish metrics for service level and customer satisfaction.
- (6) Designate a special toll free number for Customer Choice questions.
- (7) Implement changes in IT systems and infrastructure to facilitate efficient, effective handling of Customer Choice customer inquiries.
- (8) Define resource needs to accommodate additional call volumes.
- (9) Design, produce, and distribute collateral materials to support job training to employees.
- (10) Monitor, collect, and review data as established in measurement metrics for service level and customer satisfaction.
- (11) Integrate Customer Choice requirements for outage notification into standard operations and systems design.

b. Customer Billing and Collections

- (1) Identify, design, and implement changes required in the Customer Information and Billing Systems to accommodate Customer Choice.
- (2) Modify current bill presentment formats to include new line items or breakdowns and new provider contact information as required.
- (3) Conduct gap analysis between billing functionality currently in use and that required for Customer Choice.
- (4) Determine new market billing arrangements and requirements to accommodate Customer Choice billing.
- (5) Design and prepare customer education materials to aid customers in understanding new bill formats or line items.

- (6) Identify, design, implement, and test billing systems to provide for responses to customer billing inquiries and account maintenance.
- (7) Train Customer Operation's staff on the principles, concepts, processes, procedures, and practices relating to Customer Choice.
- (8) Identify and implement modifications to customer accounting systems.
- (9) Define resource needs to accommodate new activities associated with provider billing.
- (10) Design, produce, and distribute collateral materials to support job training to employees.
- (11) Develop information exchange functionality to support the flow of billing information via Electronic Business Transactions between the utility and providers.

c. Enrollment

- (1) Identify new functionality required to accommodate customer's objection or rescission of an enrollment or switch.
- (2) Design and develop systems to identify the customer to provider relationship both currently in effect and pending to be able to advise customer of status and enrollment/switch or drop effective dates.
- (3) Design and prepare customer communications to advise customer of enrollments/switches and drops and inform them of their options.
- (4) Train Customer Solutions Center and Customer Operations staff on the principles, concepts, processes, procedures, and practices relating to Customer Choice enrollment/switches and drops.
- (5) Develop information exchange functionality to support the flow of enrollment/switch and drop information via Electronic Business Transactions between the utility and providers.

d. Orders

- (1) Identify order types that will be required in Customer Choice and modify systems to accommodate them.

- (2) Train Customer Solutions Center and Customer Operations staff on the principles, concepts, processes, procedures, and practices relating to Customer Choice order processing.
- (3) Determine what order types will require notification to the new provider.
- (4) Design communication method to communicate the order resolution to providers.
- (5) Design communication method to receive order requests from providers.
- (6) Identify and implement bill generation to providers for orders in which fees are collected.
- (7) Identify the accounting system modification required to bill and collect for orders in which fees are collected.

D. Projects Supporting Awareness and Education

1. Employee Education

The purpose of the employee education process is to ensure AEP employees are prepared to provide the necessary information and assist customers with participation in the Customer Choice program. The education process will raise awareness and educate AEP employees about the changing electric marketplace and provide AEP customer contact employees with information, education, and support to enable Customer Choice transactions. AEP will utilize an array of existing Company communication systems to support employee awareness and education including an employee-accessible AEP intranet web site. AEP will also conduct employee education classes and workshops for management and staff who have customer contact responsibility.

a. Features

- (1) Differentiate between employee awareness (the what) and education (the how).
- (2) Provide employees with accurate and timely Customer Choice information prior to release to participants and customers.
- (3) Leverage AEP intranet web site so employees have access to Customer Choice information.
- (4) Facilitate customer choice job or task specific training conducted by individual AEP organizational units.

b. Key Deliverables

- (1) Perform a requirements scope and comprehensive assessment of employee awareness and education requirements necessary to implement Customer Choice.
- (2) Design a comprehensive employee communications plan with key messages for each specific employee audience.
- (3) Identify and secure resource requirements to deploy the employee communications plan (e.g., conduct workshops and meetings, publish materials).
- (4) Construct the framework and deploy systems to implement the education plan.
- (5) Evaluate plan effectiveness and provide feedback.

c. Information Systems Implications

- (1) Develop employee awareness and education content for the AEP web site.
- (2) Provide specific Customer Choice information, including FAQs, from an employee perspective.
- (3) Link AEP intranet to the AEP web site.

2. Supplier Education

AEP is committed to provide the appropriate level of education for suppliers to facilitate their participation in the competitive marketplace in Michigan. This will largely be accomplished through workshops, the Service Provider Handbook, the AEP web site, and direct communication between the suppliers and the Company's Supplier Support staff.

The Provider Handbook will communicate critical information regarding participation in AEP's Customer Choice Program.

The Handbook will help suppliers to:

- a. Understand how to become licensed with the state and registered with AEP.
- b. Enroll customers who choose to receive their services.
- c. Schedule and deliver energy in AEP's service territory.
- d. Understand how disputes with AEP will be resolved.
- e. Interpret the procedures for Electronic Data Interchange (EDI).
- f. Clarify load profiling and the settlement process.

The Provider Handbook will be organized as follows:

Chapter 1	Introduction
Chapter 2	Overview
Chapter 3	Retail Competition Implementation Requirements
Chapter 4	Customer Enrollment
Chapter 5	Billing
Chapter 6	Metering
Chapter 7	Meter Data Management
Chapter 8	Transmission Load Estimation, Scheduling & Balancing
Chapter 9	Glossary of Terms

3. Customer Awareness and Education

The purpose of the Customer Awareness process is to inform and educate all customers about Customer Choice, communicating what is going to happen, why it will happen and the potential benefits of Choice. It is a precursor to Customer Education. The Customer Education process is intended to educate customers on how to participate in Customer Choice. Clear and accurate information should be made available to all customers to assist them in making effective decisions regarding Customer Choice. The

overall objective should generally be to implement a comprehensive customer awareness and education plan that:

- a. Eases the transition to a competitive marketplace.
- b. Prepares customers to participate in the new marketplace.
- c. Minimizes customer confusion.
- d. Raises customer awareness.
- e. Educates all customers, including the hard-to-reach.

In this regard, as a member of the Michigan CHOICE Council, AEP is participating with the Commission Staff and other interested parties in the development of a statewide customer awareness and education program proposal. AEP plans to abide by the Commission's final directives in Case No. U-12133 pertaining to that program.

In addition, AEP may take additional steps to communicate with its specific customers regarding the "hows" of Customer Choice such as:

- a. Performing an assessment of the customer awareness and education requirements needed for effective implementation of customer choice in AEP's service area.
- b. Designing a comprehensive customer choice communications plan supporting the planned Customer Choice schedule.
- c. Identifying and securing the resource requirements necessary to implement a customer communications plan.
- d. Developing the following:
 - (1) Direct mail materials for residential/small commercial customers.
 - (2) Print materials for customers.
 - (3) Call Center fulfillment information.
 - (4) News releases (as necessary).

- (5) Web site content including FAQ's, glossary of terms, customer education "how to" materials, and a link to the MPSC web site.
 - (6) Bill inserts.
 - (7) Information packets for Community Based Organizations.
 - (8) Appropriate media vehicle to support specific customer choice phases.
- e. Evaluating plan effectiveness through customer research and feedback.

4. Disclosure Standards

a. Marketing and Sales

2000 PA 141 states:

Sec. 10r. (1) The commission shall establish minimum standards for the form and content of all disclosures, explanations, or sales information disseminated by a person selling electric service to ensure that the person provides adequate, accurate, and understandable information about the service that enables a customer to make an informed decision relating to the source and type of electric service purchased. The standards shall be developed to do all of the following:

- (a) Not be unduly burdensome.
- (b) Not unnecessarily delay or inhibit the initiation and development of competition for electric generation service in any market.
- (c) Establish different requirements for disclosures, explanations, or sales information relating to different services or similar services to different classes of customers, whenever such different requirements are appropriate to carry out the purposes of this section.

AEP is participating in Case No. U-12487 initiated on the Commission's own motion on June 19, 2000, to implement the customer

information and environmental notice requirements of 2000 PA 141 and plans to abide by the Commission's final directives in that proceeding.

b. Fuel-Generation Sources and Environmental

2000 PA 141 states:

Sec. 10r. (3) The commission shall require that, starting January 1, 2002, all electric suppliers disclose in standardized, uniform format on the customer's bill with a bill insert, on customer contracts, or, for cooperatives, periodicals issued by an association of rural electric cooperatives, information about the environmental characteristics of electricity products purchased by the customer, including all of the following:

(a) The average fuel mix, including categories for oil, gas, coal, solar, hydroelectric, wind, biofuel, nuclear, solid waste incineration, biomass, and other fuel sources. If a source fits into the other category, the specific source must be disclosed. A regional average, determined by the commission, may be used only for that portion of the electricity purchased by the customer for which the fuel mix cannot be discerned. For the purposes of this subdivision, "biomass" means dedicated crops grown for energy production and organic waste.

(b) The average emissions, in pounds per megawatt hour, sulfur dioxide, carbon dioxide, and oxides of nitrogen. An emissions default, determined by the commission, may be used if the regional average fuel mix is being disclosed.

(c) The average of the high-level nuclear waste generated in pounds per megawatt hour.

(d) The regional average fuel mix and emissions profile as referenced in subsection (3)(a), (b), and (c).

(4) The information required by subsection (3) shall be provided no more than twice annually, and be based on a rolling annual average. Emissions factors will be based on annual publicly available data by generation source.

AEP is participating in Case No. U-12487 initiated on the Commission's own motion on June 19, 2000, to implement the customer information and environmental notice requirements of 2000 PA 141 and plans to abide by the Commission's final directives in that proceeding.

2000 PA 141 also states:

Sec. 10d. (9) The public service commission shall take the necessary steps to ensure that all electrical power generating facilities in this state comply with all rules, regulations, and standards of the federal environmental protection agency regarding mercury emissions.

AEP is participating in Case No. U-12486 initiated on the Commission's own motion on June 19, 2000, to enforce the provisions of 2000 PA 141 with respect to mercury emissions and plans to abide by the Commission's final directives in that proceeding.

E. Projects Supporting Customer Usage Determination

1. Metering

AEP recognizes that in order to reasonably and accurately represent ESPs' loads through the load estimation, reconciliation, and settlement processes, there is an increased need for interval metering for retail customers. However, AEP also recognizes that for smaller customers, the cost of such metering may represent a potential barrier to participation in the Customer Choice program while providing minimal benefit in calculating ESP load requirements. Upon careful consideration, AEP has chosen a threshold for requiring interval metering. Customers choosing to switch to an ESP and whose 12-month average maximum demand exceeds 200 kW will be required to have an interval meter installed. The cost of any interval metering facilities installed by AEP to comply with this requirement shall be paid by the customer. In addition, the customer will be billed a monthly net charge to cover the incremental cost of operation and maintenance and meter data management associated with such interval metering. The customer will be required to provide a telephone communication connection at the metering location for remote interrogation. The customer will also be responsible for all initial and ongoing costs associated with providing this telephone communication connection. Any customer below the 200 kW threshold may opt to have their load represented via an interval meter in lieu of load profiling by having an interval meter installed at the customer's cost as described above.

2. Load Profiling

AEP endorses a load profiling methodology that balances cost-effectiveness, ease of implementation, impact to the billing/reconciliation process, acceptability to ESPs, and comprehensibility by all parties. This methodology is intended to provide reasonable estimates of ESP load requirements and minimize gaming opportunities, while at the same time eliminating the interval metering costs for the majority of the customers.

For all customers who fall below the aforementioned threshold, as well as customers above the threshold without interval metering because they have not chosen an ESP, load profiles will be utilized in lieu of interval metering.

AEP currently has interval recorders installed on samples of customers in order to represent the major rate classes within its Michigan territory. The resulting class load profiles will represent the basis for estimating the hourly loads of such customers. The rate classes to be represented by sampled class load profiles are:

- a. Residential
- b. Small General Service
- c. Medium General Service
- d. Large General Service
- e. Large Power
- f. Quantity Power
- g. Electric Heat General
- h. Electric Heat Schools
- i. Municipal & School Service
- j. Water & Sewage Service

Via the use of the class profiles and the data from interval meters, ESP load requirements can be produced in order to represent a load forecast, a load

backcast (i.e., a load estimate following the end of a given day, but prior to all pertinent data being available), and to represent a final reconciled ESP load requirement.

For the purposes of a load forecast or a load backcast, a "proxy day" load profiling methodology will be utilized. This method finds a day in recent history with a comparable load shape to use as a proxy day. Class profiles and interval metered data from that proxy day are then used to estimate the ESP load requirements for the day in question.

For the purposes of a final reconciliation, AEP will use a load profiling method referred to as "lagged dynamic". With this method, load research data is collected from sample recorders and then processed to develop class load profiles for the days to be reconciled. This method utilizes actual same-day data to build up the ESP load requirements. The results are the same as would be obtained from using the "dynamic load profiling" methodology but are obtained significantly later - after the manual meter reading process has been completed.

For purposes of load profiling and reconciliation, AEP non-switched customer loads (i.e. those customers receiving bundled electric service from AEP) will be treated in a manner similar to ESP loads. This means that the AEP "bundled" portion of AEP's Michigan system load will be estimated and aggregated in the same bottom-up approach as ESP loads using class load profile information and interval metered data.

In both of these load profiling methodologies, appropriate distribution and transmission losses are added on a customer by customer basis prior to determining ESP loads. The loss-adjusted ESP loads, along with all the other load entities (e.g., AEP bundled customer loads, Muni and Co-op loads, etc.), are summed and compared to AEP's Michigan total system load. The difference between the bottom-up summation and the system load is what is referred to as Unaccounted For Energy (UFE). Once the UFE is identified, it is subsequently allocated to all load entities on a load proportional basis.

F. Customer Rate Unbundling

1. Methodology – Overview

AEP's overall approach to unbundling will be to utilize cost-of-service information as the basis for unbundling rates into the appropriate components of generation, transmission, and distribution. Additional tariff riders will be presented in order to recover stranded costs, regulatory assets, and implementation costs, as defined and presented in this plan.

Regarding its tariffs, AEP's goal is to present clear and understandable documents for use by both customers and other market participants by taking a two-tariff approach. The first tariff will apply to those customers who do not choose an ESP and continue to take energy-related services from AEP. This tariff will be referred to as the Standard Tariff. The second tariff will apply to those customers who choose an ESP and will be referred to as the Open Access Distribution Tariff.

AEP will first unbundle rates for the St. Joseph Rate Area. The rate unbundling methodology will generally be as follows:

First, customer-related costs will be recovered through a customer charge set equal to the existing tariff customer charge. Second, customers who currently receive service under demand metered schedules will be charged for distribution services based on a demand (per kW) charge under the Standard Tariff. Next, any residual demand and customer costs will be recovered through an energy charge. Customers without demand metering will be charged for distribution services through an energy charge (per kWh).

Unbundled rates for the Three Rivers Rate Area will be based on the unbundled rates for the St. Joseph Rate Area. In general, comparable rate schedules for the two rate areas will be based on the same distribution and transmission components. The distribution components of St. Joseph Rate Area rates will be applied to billing determinants for the Three Rivers Rate Area in order to determine distribution revenues. Three Rivers distribution rates will then be designed using current Three Rivers customer charges and the remainder of the distribution requirement recovered through demand and/or energy charges, depending upon the rate schedule. A similar approach will be used to determine the transmission component of Three Rivers Rate Area rates. The generation components will then be determined such that the sum of the generation, transmission and distribution components equals existing Three Rivers rates.

2. Cost-of-Service Studies

In order to unbundle rates for the St. Joseph Rate Area, AEP will utilize the class cost-of-service study as filed in Case No. U-9656, adjusted to reflect the settlement in that case.

The individual components of the cost-of-service study will be functionalized. The best available information from that case, and the allocation basis for each component, will be the basis for functionalizing each item in the cost-of-service study. Adjustments will then be made to reflect the results of the settlement in that case and to reflect any rate changes which have occurred since then.

Adjustments will be made to unbundled revenues in order to utilize the applicable OATT rates. Additional adjustments will be required to reassign ancillary service related revenues from generation to transmission. AEP intends to file a document that utilizes the unbundled cost-of-service results and details all adjustments to the functionalization of revenues by customer class.

3. Rate Adjustment Plans

Changes in AEP's basic rates and charges are limited by the terms of Settlement Agreements approved by the Commission in consolidated Case Nos. U-11181-R, U-11531-R, and U-11792, and Case No. U-12204. Ancillary services, which are generation-related, will be reassigned to be part of the final unbundled transmission component.

4. Tariffs

a. Distribution

The second tariff will apply only to those customers who choose an alternative supplier and will be referred to as the Open Access Distribution Tariff. While many of the provisions are the same as those contained in the Standard Tariff, some differentiation is necessary to distinguish the entity providing the customer with energy.

The Open Access Distribution Tariff will contain the Terms and Conditions of Open Access Distribution Service, Supplier Terms and Conditions of Service, open access distribution rate schedules and applicable riders. If a customer chooses an alternative supplier, then AEP

provides only distribution-related services to that customer and the open access distribution rate schedules provide for such service. It should be noted that all customers receive some type of distribution service. However, details will also be required which relate to the provision of competitive services. Such details will be set forth for customers in the Terms and Conditions of Open Access Distribution Service. The details for suppliers of competitive services will be set forth in the Supplier Terms and Conditions of Service.

The Terms and Conditions of Open Access Distribution Service will be generally comparable to the existing Terms and Conditions of Service and relate to regulated distribution service provided by AEP. However, provisions, fees and information for customers will be included which relate to initially choosing an alternative supplier, switching between alternative suppliers, transmission service, losses, and metering and load profiling. The Terms and Conditions of Open Access Distribution Service will also contain the specific conditions under which customers are permitted to return to the Standard Tariff should they no longer take service from an alternative supplier.

The Supplier Terms and Conditions of Service will contain provisions and fees that relate to the suppliers of competitive services. Requirements for alternative supplier registration with AEP will be included as well as details such as AEP's processes regarding choice of alternative supplier,

customer enrollment, obligations for obtaining transmission service, billing options for suppliers and other information required by AEP.

The open access distribution rate schedules will contain provisions for the recovery of distribution charges and the applicable riders. The distribution rates contained in open access distribution rate schedules will be the same as the distribution component of the rates set forth in the Standard Tariff. Provisions for minimum charge, delayed payment charge and due date, monthly billing demand, metered voltage adjustment and term of contract will also be included.

The Open Access Distribution Tariffs, applicable only to those customers choosing an alternative supplier, may also include provisions by which these customers may elect a competitive supplier of metering, meter data management or billing services.

b. Transmission (FERC OATT)

Transmission service will be provided under the provisions of the applicable FERC Open Access Transmission Tariff for customers served under the Open Access Distribution Tariff. For customers served under AEP's Standard Tariff, the transmission component of rates will be based on the applicable OATT and recovered through demand charges where possible. For customers without demand metering, these transmission costs will be recovered through an energy charge.

Ancillary services will be calculated for each class based on the FERC OATT and will be reassigned from the generation function to the transmission function.

c. Generation

(1) Customers Choosing Alternative Suppliers

Please refer to Sections F.1. and F.4.a. above. Customers who choose an alternative supplier will only be charged for generation-related regulatory assets, other stranded costs, implementation costs, and nuclear decommissioning charges, as approved by the Commission. These costs will be recovered through riders to the open access distribution rate schedules.

(2) Customers Remaining With Utility

Customers remaining with AEP for generation service will take service under the Standard Tariff as described in Section F.1. above. The Standard Tariff will consist of Terms and Conditions of Service, rate schedules, and riders that are generally comparable to those in effect today. The rate schedules will detail the generation, transmission and distribution components of existing rates and include riders for recovery of regulatory assets, other stranded costs, implementation costs, nuclear decommissioning charges, and power supply cost recovery charges. All components of the Standard Tariff (Terms and Conditions of Service, rate schedules including generation, transmission and distribution rate components, and the riders

mentioned above) will apply only to customers continuing to take generation service from AEP. The Terms and Conditions of Service will also reflect any necessary changes given that customers are free to choose an ESP. Generation costs included in the standard rate schedules will be recovered through a demand charge, energy charge, or both, depending upon the structure of the existing rate schedule.

d. Power Supply Cost Recovery (PSCR) – Act 304

Effective with the first billing cycle of January 2000, AEP's Power Supply Cost Recovery (PSCR) factors in its St. Joseph and Three Rivers Rate Areas were fixed and its PSCR clauses suspended through December 31, 2003, in accordance with the provisions of a Settlement Agreement approved by the Commission's Opinion and Order of December 16, 1999, in consolidated Case Nos. U-11181-R, U-11531-R, and U-11792. This Opinion and Order is presently the subject of an action taken in the Michigan Court of Appeals by an intervenor in the consolidated cases.

e. Miscellaneous

AEP intends to provide in its June 5, 2001, unbundling filing unmarked and scored copies of its Standard and Open Access Distribution Tariffs indicating the proposed modifications relative to current tariffs.

AEP also intends to file at that time a Statement E-6 Billing Analysis that will show the bundled rates and revenues for AEP's Three Rivers and St. Joseph Rate Areas resulting from Case Nos. U-9205 and U-9656,

respectively, as adjusted to reflect the rates currently in effect. The corresponding unbundled rates and calculated revenues that will be shown in the billing analysis will produce the same total revenue for each class, except for implementation cost recovery and regulatory asset charges.

G. Information Systems Summary

1. IT Solutions Overview

Building upon AEP's significant involvement with Customer Choice in its other states and through careful planning and anticipation of various jurisdictional and market needs, AEP has moved forward with building and implementing significant infrastructure to support Customer Choice. The approach that AEP has chosen is one that is felt to offer AEP greatest versatility, scalability and cost control.

The particular solution path that AEP has chosen has three significant and discrete components. First, AEP is leveraging its existing legacy systems by modifying and expanding these systems to the minimal extent required to meet limited additional requirements and to interface to new systems. Second, for the functional areas of Customer Choice that are new or expanded significantly from those offered by AEP's existing legacy systems, AEP has chosen the path of utilizing the MDCH for the storage, processing, tracking, and reporting of information required to support newly competitive functions. This MDCH facility, built and operated by Logica, Inc., provides the necessary additional IT functionality as will be required by the Michigan Restructuring effort. Third, in order to provide robust and flexible interconnections between various AEP legacy systems and between these legacy systems and the MDCH, AEP is building an Integrated Management Framework (IMF).

Significant modifications to AEP's legacy systems are currently being implemented to contain additional required data elements and to provide

external interfaces to new competitive market systems. Some of the most significant efforts involve the AEP CIS system. A variety of additional minor systems are undergoing enhancements as well to support Customer Choice. These system changes are well underway and should be largely in place in time to support the Michigan Restructuring effort.

The IMF facility will provide AEP the ability to interface all of the various related systems on a platform independent basis. By using state-of-the-art messaging and brokering middleware facilities and the building of appropriate legacy system interface adapters, the IMF will permit the implementation of changes to or replacement of legacy systems without necessitating significant reengineering of existing systems to facilitate interfacing to the replacement system.

As indicated above, the MDCH facility performs the vast majority of new functions as required by restructuring. The core functions of the MDCH are as follows:

- a. Service Provider Registration
- b. Customer Switching
- c. Billing Data Delivery
- d. Estimation and Reconciliation
- e. Market Settlement
- f. Measurement Services
- g. External Assets Tracking

The MDCH will act as the long-term repository and audit source of all key market enabling data, offering continuity over time as participants enter and leave the market. The benefits of the MDCH service to AEP include elimination of up-front IT capital investment and the opportunity to obtain synergies by the

utilization of a common clearinghouse facility being utilized by other market participants. The major functions performed by the MDCH are detailed below.

a. Service Provider Registration

The MDCH will maintain details of service providers certified to operate within AEP's Michigan service territory. The MDCH will maintain information about the various services offered by those providers, as well as contact information, registration data and electronic business transaction testing certification.

b. Customer Switching

The MDCH will serve as the central repository for the tracking of relationships (and their history) between customers, premises and service providers (ESP, MDMA, MSP, BA, etc.). The MDCH will manage and process the day to day movement of customers from one service provider to another, including the receipt of any objections to switches. The MDCH will receive and forward customer switching data to multiple market participants and customers as prescribed by the appropriate business rules.

c. Billing Data Delivery

The MDCH will route data between external service providers to facilitate billing processes relative to end use energy customers. The MDCH will manage the incoming billing related data, store it and forward it to AEP or to the service provider's core billing systems, as appropriate.

d. Estimation and Reconciliation

The MDCH will determine each ESP's load liability, utilizing current and/or historical cumulative meter readings, interval data recorder information and load profiles. The MDCH will estimate hourly usage for customers without interval metering, and for customers with interval meters but for whom no data has been received. Usage data will then be aggregated by the ESP and reconciled to AEP's Michigan system load.

e. Market Settlement

The MDCH Market Settlement will calculate the physical determinants used for market settlement as specified in the applicable OATT including energy imbalance. Subsequently, the MDCH will determine each ESP's financial liability, including determination of transmission and ancillary service charges.

f. Measurement Services

The MDCH will serve as a repository of usage information. The MDCH will receive and store appropriate usage information, both cumulative and interval meter data, and will make such data available for the load estimation, reconciliation and settlement processes.

g. External Assets Tracking

The MDCH will track information concerning measurement assets owned by external market participants. The MDCH will receive external asset data and premise data. The MDCH will serve as the system of record for asset relationship information.

2. Information Exchange

AEP strongly supports the utilization of industry standards for data exchange. AEP is an active participant in industry standards groups including the Utility Industry Group (UIG) and the EEI Uniform Business Practices group.

The vast majority of electronic exchange will occur through the MDCH. The MDCH will utilize electronic data interchange (EDI) to the extent possible through an assortment of vehicles including Secure Multipurpose Internet Mail Extensions (S/MIME), Virtual Private Network (VPN) and Value Added Network (VAN). AEP and the MDCH plan to support the current version of the ANSI X12 4010 UIG transaction sets, and future releases. AEP, in conjunction with the MDCH, plans to stay abreast of emerging electronic business transaction (EBT) facilities and standards and will be a proponent of facilities representing reduced transaction costs and increased reliability and stability.

H. Related Projects

1. T&D Service Quality/Reliability Standards

2000 PA 141 states:

Sec. 10p. (5) The commission shall adopt generally applicable service quality and reliability standards for the transmission and distribution systems of electric utilities and other entities subject to its jurisdiction, including, but not limited to, standards for service outages, distribution facility upgrades, repairs and maintenance, telephone service, billing service, operational reliability, and public and worker safety. In setting service quality and reliability standards, the commission shall consider safety, costs, local geography and weather, applicable codes, national electric industry practices, sound engineering judgment, and experience. The commission shall also include provisions to upgrade the service quality of distribution circuits that historically have experienced significantly below-average performance in relationship to similar distribution circuits.

In the Settlement Agreement approved by the Commission on December 16, 1999, in Case No. U-12204 regarding the merger of AEP Company, Inc. and Central and South West Corporation, AEP agreed to maintain or enhance the adequacy and reliability of retail electric service and to annually provide to the Commission information regarding the quality of its electric service in Michigan.

In addition AEP is participating in Case No. U-12270 initiated on the Commission's own motion on January 3, 2000, to investigate methods to improve the reliability of electric service in Michigan and plans to abide by the Commission's final directives in that proceeding.

2. Code of Conduct – Affiliate Transactions

2000 PA 141 states:

Sec. 10a. (4) Within 180 days after the effective date of the amendatory act that added this section, the commission shall establish a code of conduct that shall apply to all electric utilities. The code of conduct shall include, but is not limited to, measures to prevent cross-subsidization, information sharing, and preferential treatment, between a utility's regulated and unregulated services, whether those services are provided by the utility or the utility's affiliated entities. The code of conduct established under this subsection shall also be applicable to electric utilities and alternative electric suppliers consistent with section 10, this section, and sections 10b through 10bb.

A component of the Settlement Agreement approved by the Commission on December 16, 1999, in Case No. U-12204 regarding the merger of AEP Company, Inc. and Central and South West Corporation is Section 8 "Affiliate Standards". The Affiliate Standards section is an extensive listing of affiliate transaction requirements and code of conduct provisions applicable to AEP's operations in Michigan and is consistent with Affiliate Standards approved by the Indiana Utility Regulatory Commission for AEP's Indiana jurisdictional operations. On July 17, 2000, in order to effect the Affiliate Standards approved in Case No. U-12204, AEP filed in Case No. U-12529 a request for a waiver from the generic Affiliate Guidelines approved by the Commission on May 3, 2000, in Case No. U-11916.

In addition, AEP is participating in Case No. U-12134 initiated on September 14, 1999, to consider modifications to the provisional codes of conduct approved for Consumers Energy Company and The Detroit Edison Company. AEP would plan to abide by the Commission's final directives in that proceeding to the extent that any final directives of the Commission in that proceeding apply to AEP.

a. Corporate Separation

AEP has generally completed functional separation and is also in the process of planning for corporate separation. This planning process is not complete, therefore no specific proposal for corporate separation and associated costs have been included in this filing. AEP respectfully reserves the right to provide to the Commission the specific corporation separation details and related costs either in the June 5, 2001 filing or as soon thereafter as practical.

b. Corporate Separation - Financial Implications

As indicated in the prior section, AEP is in the process of corporate separation, and has generally completed functional separation.

Associated with these processes is the issue of asset transfers and associated financial refinancing (i.e., debt/equity retirement and reissuance). With any corporate separation the goal would be to accomplish this in an orderly and economically efficient manner, and to minimize additional transition costs that result from prematurely unwinding the existing financial arrangements. However, as previously discussed, the specific corporate separation plan is not in place and therefore the associated costs are not yet known or quantifiable.

3. Participation In An RTO

On June 3, 1999, AEP, along with FirstEnergy Corporation, Consumers Energy Company, The Detroit Edison Company, and Virginia Electric and Power Company, filed with the FERC under Section 203 of the Federal Power Act for transfer of control and/or ownership of jurisdictional transmission facilities to the Alliance RTO. A companion application under Section 205 of the FPA was filed for approval and contains the basic Alliance Agreement, Governance Structure, Protocols for Planning, Operation and Pricing, an Operation Agreement, an Agency Agreement and an Open Access Transmission Tariff (OATT).

Overall, the Alliance RTO will serve a combined area of approximately 124,000 square miles in nine states encompassing a population of 26 million people and representing load of about 67,000 MW. The Alliance RTO is larger than many of the RTOs approved thus far by the FERC including California, Pennsylvania-New Jersey-Maryland (PJM), the New York ISO and the New England ISO.

In the part of its System where the Alliance is expected to initially operate, AEP supplies electricity through seven operating companies to three million customers in the states of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. Its transmission system consists of approximately 22,000 miles of transmission lines. Consumers Energy supplies electricity to 1.6 million customers in Michigan through more than 5,300 miles of transmission lines. Detroit Edison's transmission system consists of

approximately 3,000 miles of lines and serves 2.1 million customers in Michigan. FirstEnergy's transmission system consists of approximately 7,000 miles of lines and serves 2.2 million customers in Ohio and Pennsylvania. Virginia Power serves more than two million customers in Virginia and North Carolina through more than 6,000 miles of transmission lines.

There is generating capacity of approximately 72,000 MW, or roughly ten percent of the electric supply in the United States, that is connected to the transmission facilities that the Alliance RTO will control. Such generating capacity includes approximately 24,000 MW connected to the AEP System, 8,000 MW connected to Consumers Energy's system, 10,000 MW connected to Detroit Edison's system, 12,000 MW connected to FirstEnergy's system.

The Alliance, as proposed to FERC, is expected to take the form of an independent transmission company (Transco). The Alliance Transco will be a limited liability company which, in turn, will be managed by an independent corporation.

Participating owners need not sell their transmission facilities to the RTO. They have the option of entering into an agreement with the RTO under which it would operate their facilities much as would an ISO. The Alliance RTO is expected to begin operations during the year 2001.

On December 20, 1999, the FERC issued an order conditionally approving the Alliance proposal. *Alliance Companies*, 89 FERC ¶ 61,298 (2000). The FERC indicated that it was "[E]ncouraged by the Applicants' substantial efforts to form a new entity to own or control their transmission

facilities”, and that the Alliance RTO, “if modified to address the concerns of this order, can provide significant benefits to the industry and consumers.” The modifications directed by the FERC were mainly in the areas of governance and pricing. In addition, the FERC provided guidance as to how the Alliance could comply with the requirements of its Order 2000, issued concurrently with the Alliance Order, which describes the minimum required characteristics and functions of a Regional Transmission Organization.

On January 19, 2000, the Alliance participants and certain intervenors filed requests for rehearing or clarification of certain aspects of the FERC’s December 20, 1999, Order. In addition, on February 17, 2000, the Alliance participants submitted a compliance filing containing certain modifications of the Alliance documents as directed by the December 20, 1999, Order. On May 18, 2000, the FERC issued an Order on Compliance Filing and Requests for Rehearing and Clarification, *Alliance Companies*, 91 FERC ¶ 61,152 (2000). In that Order, the FERC ruled on the various requests for rehearing, including the Alliance participants’ request for rehearing, clarified certain aspects of its December 20, 1999, Order, and provided additional guidance as to the modifications it expects to be made to the Alliance documents.

On September 15, 2000, the Alliance participants made a compliance filing which addresses the FERC’s directives and concerns outlined in its December 20, 1999, and May 18, 2000, Orders. The filing includes a new pricing proposal that complies with the pricing directives contained in the

FERC's orders, and includes changes to the corporate documents addressing the FERC's concerns with respect to governance.

4. Projects to Increase Transmission System Capability

Over the past year, AEP, Consumers Energy Company, The Detroit Edison Company, FirstEnergy Corporation, Northern Indiana Public Service Company, and Ontario Hydro Services Company (Hydro One) participated in a Michigan power import study to identify transmission system constraints and mitigation measures to increase the import capability into Michigan to 6,000 MW. These studies were monitored by the staffs of the MPSC, Indiana Utility Regulatory Commission, and Ohio Public Utility Commission. In March and July 2000, the study group issued two reports entitled "Michigan 6,000 MW Import Constraints Assessment" and "Michigan 6,000 MW Import Constraint Mitigation Assessment." These studies were based on projected summer 2003 conditions.

The reports concluded that the non-simultaneous total transfer capability into Michigan from the east, south, or west during the Summer 2003 peak load periods could range from 3,000 to 6,000 MW depending upon the prevailing transmission and generation conditions as well as the source of the imported energy. Based upon the conditions studied at that time, the study group concluded that a 6,000 MW Michigan import level from generation resources located either east, south, and/or west of Michigan is achievable for a total estimated cost of approximately \$32.6 Million.

System upgrades necessary to achieve a 6,000 MW Michigan import level would be required on the systems of several of the study participants. No system upgrades in addition to already approved transmission improvement projects were determined to be necessary on The Detroit Edison Company, Consumers Energy Company, and Hydro One transmission systems. However, system upgrades in the FirstEnergy, Northern Indiana Public Service Company, and AEP systems were identified. The upgrades identified for the AEP System were estimated to cost \$20.05 million in year 2000 dollars. The associated operations and maintenance costs are estimated to be \$50,000 per year.

The Constraint Mitigation Assessment issued in July 2000 was based on the electric transmission system as anticipated to exist in 2003 at the time the study was initiated. Some facilities (transmission and generation) not in service in July 2000 were assumed to either have been added as planned or returned to service by Summer 2003. Furthermore, the plans of IPP developers are continuing to evolve. As such, the actual system that emerges for 2003 and the way it performs may be different from the projected system studied earlier this year.

Such changes to the electric system between now and the 2003 timeframe may result in the need to reassess the transmission upgrade plan required to increase the Michigan import capability to the 6,000 MW level. For example, the installation of non-utility generation within Michigan, and especially IPPs located near the constrained transmission facilities, may impact the need and timing of transmission additions. The Constraint Mitigation

Assessment did not model any IPPs near the constrained facilities. However, since the time this study was initiated, interest has been expressed by several developers to install non-utility generators in southwestern Michigan. If these pending generation facilities are indeed built, these facilities and others could impact the transmission facility loadings in the area. Such impacts could mitigate existing and anticipated transmission constraints or could result in additional constraints. Therefore, a reassessment of potential transmission additions would then be required to take into account newly committed generation projects.

2000 PA 141, Sec. 10v., requires electric utilities serving more than 100,000 retail customers in Michigan to file by January 1, 2001, a joint plan with the Commission detailing measures to permanently expand, within two years of the effective date of 2000 PA 141, the available transmission capability by at least 2,000 megawatts over the available transmission capability in place as of January 1, 2000. The law also requires that the joint plan detail all actions including additional facilities required, the proposed schedule for accomplishing the actions, the cost of the actions, and the proposed ratemaking treatment for the costs.

At this time it is expected that the July 2000 Constraint Mitigation Assessment will serve as the basis for the joint plan required to be filed with the Commission by January 1, 2001. However, the potential changes to the southwestern Michigan electric system described above will need to be continually monitored and transmission needs reassessed.

5. Employee Transition

AEP has not at this time identified any employee positions affected by 2000 PA 141.

To the extent that employee positions are subsequently determined to be affected by 2000 PA 141, AEP's management would meet with the appropriate parties (union officials and employees) to inform them of the benefits provided under AEP's Employee Assistance Plan. AEP's programs to provide information and internal employment opportunities to all employees affected by restructuring are described as follows:

a. JOBS Program

All AEP employees are eligible to participate in the AEP's JOBS (Jobs Opportunities Bulletin Services) Program. Qualified job openings in AEP's eleven-state service territory are posted in three ways:

- i. JOBS Online – A Lotus Notes database employees can access from their computer.
- ii. JOBS On Board – Bulletin board notices that are posted throughout the AEP System.
- iii. JOBS Directory – A hard-copy book of job postings that employees can browse through in their local Human Resources office.

Through the JOBS Program, AEP employees are the first to know about openings within the AEP System and have a process by which they can make application.

b. Relocation Assistance

AEP also offers a special relocation assistance program designed to enable and encourage employees to continue their careers with the Company. The program is specifically designed to help the employee make decisions that will be good for the employee and the employee's family. Affected employees have a full range of financial and advisory services available to them. All employees who are selected for a position requiring relocation will receive assistance with:

- i. Disposing of an owned residence (includes marketing assistance, cost basis protection, lease termination for renters, company buyout).
- ii. Choosing a community.
- iii. Duplicate residence expenses.
- iv. Buying/building a residence (includes assistance with mortgage, closing costs, bridge loan, mortgage point reimbursement).
- v. Movement of household goods.
- vi. Miscellaneous expense allowance.
- vii. Spouse employment assistance.
- viii. Gross-up for taxable expenses.

c. Outplacement

AEP will provide an outplacement program for employees affected by restructuring as follows:

An outplacement services firm will provide outplacement services and a re-employment workshop that will assist the affected employee to:

- i. Recognize and manage the emotions of a job loss and job search.
- ii. Develop a plan for action.
- iii. Prepare an effective resume.
- iv. Use letters and the telephone effectively.
- v. Project the right image.
- vi. Develop contacts.
- vii. Answer newspaper ads correctly.
- viii. Deal with employment agencies and recruiters (includes enrollment in "Resume Link," a nationwide database of resumes).
- ix. Zero-in on the opportunity (Includes access to "Job Bank", a nationwide database of job openings).
- x. Come across well in interviews.
- xi. Negotiate pay and benefits.

d. Employee Counseling Service

Employees and covered family members will be eligible to continue participation in the Employee Counseling Service Program for 18 months following the date of termination, or until the individual gains other employment, whichever occurs first.

AEP's Employee Counseling Service provides counseling concerning the following issues:

- i. Anxiety/depression
- ii. Alcohol/drug use
- iii. Eating disorders
- iv. Parenting
- v. Family relationships
- vi. Job stress
- vii. Career and vocational issues
- viii. Job performance
- ix. Peer and work relationships
- x. Marital or other relationship difficulties
- xi. Health-related issues
- xii. Legal issues
- xiii. Financial concerns

e. Educational Assistance Program

Employees who have received educational assistance within one year of termination will not be required to repay their tuition assistance.

Employees who have completed a bachelor or advanced degree and would have been eligible for an additional 25% reimbursement after continuing employment with AEP for three years, will receive a prorated reimbursement based upon the number of full months worked since receiving the degree.

f. Early Retirement Programs

The normal retirement date under the Retirement Plan is the first day of the month closest to a person's 65th birthday, with five years of vested service with AEP. However, a person at least age 55, with five years of vested service is retirement eligible, with a reduction of pension benefits of 3% per year for commencement of such benefits prior to age 62.

Special provisions apply to a retirement plan member under age 55 whose employment is terminated as a direct result of a restructuring, consolidation or downsizing program. The plan participant may elect to commence monthly benefits as early as the first day of the month following the date of termination, or postpone pension commencement to a later date, provided one of the following is met at the time of termination:

- i. The member has earned 25 or more years of benefit service.
- ii. The member has attained age 50 and has earned 10 or more years of benefit service.

A member defined above will be entitled to a subsidized early retirement benefit.

g. Severance Plan

For employees, if any, affected by restructuring in Michigan, AEP will pay the employee an amount equal to one-half month's base pay for each year of service (or portion thereof), with a minimum of 1½ months and a maximum of 12 months base pay, with deductions to be made as required by law.

AEP will also offer the employee (or surviving covered dependent) the opportunity to continue group personal and family medical and/or dental coverage at the applicable active employee/dependent contribution rate for up to 12 months after the employee's termination of employment and for an additional six months by paying 100% of the cost of the coverage continued. Thereafter, the employee (or surviving covered dependents)

may extend only the medical coverage by continuing to pay 100% of the cost of the coverage until the employee (or surviving covered dependents) is eligible for medical coverage through Medicare or other public program, or through subsequent employment, whichever occurs first.

AEP will offer the employee the option to continue basic and supplemental life insurance, in an amount not exceeding that carried as an employee, at a monthly cost of 100% of the appropriate contribution rate per \$1,000 of coverage applicable to retirees until the employee becomes eligible for life insurance coverage through subsequent employment, or until age 65, whichever comes first; or per the employee election, if the Survivor Benefit Plan is applicable.

Note: Employees who are at least age 55, with the requisite years of service at termination of employment, are eligible to continue group personal and family retiree medical coverage and basic and supplemental life insurance under the terms described in those plans.

Note: The Severance Plan will be extended to any employees affected by restructuring. As an alternative, union represented employees are eligible, per the working agreements, for a Layoff Allowance Plan which, if selected, provides up to six months' base pay less any benefits provided under any federal, state, county, or local law by reason of being unemployed, and by any income earned in the course of other employment, including self-employment.

Note: All benefits provided to employees are subject to periodic review, revision, or discontinuance on a prospective basis.

I. Proposed Schedule

1. Milestones

Typical milestone events anticipated for implementation in Michigan include:

June 5, 2001

Filing with MPSC

Summer 2001

Initiate detailed employee training
Initiate customer education program
Provide Customer Choice information on web site
Conduct service provider Workshop

Fall 2001

Accept service provider registration applications
Conduct EDI testing with service providers
Accept customer enrollments

January 1, 2002

Competitive power flows to AEP-Michigan customers

Attached as Exhibit I.1. to this Plan is a draft chart of milestone events prepared by AEP for the implementation of Customer Choice in the Ohio jurisdiction. This chart is provided for illustrative purposes and continues to evolve as restructuring progresses in Ohio toward a January 1, 2001, customer choice date. AEP plans to prepare a comparable document to chart the milestones of Michigan electric restructuring implementation. The Michigan chart will be provided to the Commission with AEP's proposed June 5, 2001,

filing to document AEP milestone events in preparation for the January 1, 2002, customer choice date.

2. Dates

The AEP System expects to gain further knowledge and experience in customer choice in Virginia, Texas, and Ohio programs, the commencement of which are imminent. This further knowledge and experience will be beneficial to AEP in the development and implementation of its Michigan Customer Choice initiative, the culmination of which is scheduled to occur on January 1, 2002. AEP proposes to file, for all customer classes, its unbundled rates, open access tariffs, modified Terms and Conditions of Service, and any additional support deemed necessary and appropriate for the various aspects of its Michigan Customer Choice Program, on June 5, 2001. AEP believes that this proposed filing date will provide ample procedural time for the Commission to process AEP's tariffs in order to comply with the requirements of 2000 PA 141. As described in Section I. 1. of this Plan, AEP plans to prepare a document to chart the milestones of Michigan electric restructuring implementation and provide this chart to the Commission with AEP's proposed June 5, 2001, filing. Beyond the dates of the proposed June 5, 2001, filing with the Commission and the January 1, 2002, date of customer choice, significant dates to be identified in the preparation of this chart would include the dates of key communications with customers, providers, and employees.

J. Projected Costs

AEP's projected costs relative to the industry restructuring defined by 2000 PA 141 represent initial estimates based upon the best information available to AEP at the time of the compilation and filing of this Plan. AEP would expect that further refinement of these projected costs and the identification of additional costs would be possible prior to the proposed June 5, 2001, filing.

1. Implementation Costs

a. Restructuring Plan Filing Expenses

AEP expects that certain out-of-pocket costs will be incurred in the filing and processing of the Michigan Restructuring Implementation Plan. AEP initially estimates that its out-of-pocket costs for the filing and processing of the Plan will total \$200,000 comprised of the following components:

Publication of Notices	\$ 5,000
Hearing Transcripts	15,000
Consultant's Fees	50,000
Outside Legal Expense	100,000
Other Costs: Travel, Office Supplies, etc.	<u>30,000</u>
Total Filing Expenses	<u>\$200,000</u>

b. Operational Implementation Costs

Customer Choice brings with it a large number of new processes that must be performed by the Company in order to facilitate competition. The implementation costs represent incremental costs the Company will incur to implement Customer Choice in the marketplace. Some of these costs will

be incurred as one-time development costs to create IT systems and processes and some of these costs will be incurred on a daily basis to process transactions between the various market participants and end-use customers. Based on current legislation, within the AEP System, Customer Choice will be implemented in Ohio, Virginia, West Virginia, Texas, and Arkansas, as well as Michigan. Thus, the costs to implement Choice are shared among the AEP operating companies in these various jurisdictions. As a part of the AEP System, each individual operating company avoids the full cost of the one-time development expenses while also realizing the benefits of scale in operational efficiency.

The annual costs include such activities as: customer support, service provider support, MSP, MDMA certification, load profiling processing, settlement processing, EDI transactions, employee education, and ongoing IT O&M expenses. The IT infrastructure costs include costs to develop new systems along with modification of existing systems and the integration of all those systems. The cost estimate does not include expenditures for any unregulated businesses in which the Company may participate. The cost estimate also does not include currently unknown expenditures that might be necessary in the future due to any new requirements that are likely to be identified as business rules are established.

Total operational implementation costs through 2007 for AEP's Michigan jurisdiction are estimated to be \$6.4 million, as illustrated below.

MICHIGAN OPERATIONAL IMPLEMENTATION COSTS	
	Total
Annual Ongoing Operations Costs (Includes Customer Support, Service Provider Support, Load Profiling Processing, Settlement Processing, MSP/MDMA Certification, and Employee Education)	\$ 250,000
Total for 6 years inflated at a rate of 2.5% per year (2002-2007)	1,597,000
System Costs:	
Program Management	231,000
IT Infrastructure Costs	318,000
IT Integration, Maintenance and Processing Costs	4,262,000
Total	\$6,408,000

c. Transmission System Capacity Expansion Plan Costs

As described in Section H. 4. of this Plan, AEP has been a participant in a Michigan power import study to identify transmission system constraints and mitigation measures to increase the import capability into Michigan. At this time it is tentatively planned that the July 2000 Constraint Mitigation Assessment issued by the study group will serve as the basis for the joint plan required by 2000 PA 141 to be filed with the Commission by January 1, 2001. The upgrades identified for the AEP System were estimated to potentially be \$20.05 million in year 2000 dollars and the associated operation and maintenance costs were estimated to be \$50,000 per year.

d. Code of Conduct Costs

AEP expects to incur costs to implement a code of conduct and affiliate standards in the Michigan jurisdiction. At this time AEP has not made an estimate regarding the magnitude of those implementation costs but reserves for purposes of this Plan filing the right to make an estimate and to seek recovery of such costs in its proposed June 5, 2001, filing.

e. Corporate Separation Plan Costs

At this time AEP has not made an estimate regarding the magnitude of corporate separation plan costs but respectfully reserves the right to provide to the Commission the costs either in the June 5, 2001, filing or as soon thereafter as practical and to seek recovery of those costs.

f. Employee Transition Costs

As indicated in Section H. 5. of this Plan, AEP has not at this time identified any employee positions affected by 2000 PA 141. For purposes of this Plan filing, AEP reserves the right to make an estimate and to seek recovery of employee transition costs in its proposed June 5, 2001, filing.

g. Alliance RTO Costs

Given the 2000 PA 141 mandate for FERC approved multistate regional transmission system organization membership, and given AEP's involvement described in this Plan in the development of the Alliance RTO, AEP would reasonably expect to incur costs related to membership,

development, implementation, or operation of the Alliance RTO. AEP has not estimated at this time the extent to which such costs would not be recovered through FERC transmission rates but reserves the right to make an estimate and to seek recovery of such costs in its proposed June 5, 2001, filing.

2. Customer Choice Education Costs

As a member of the Michigan CHOICE Council, AEP is participating with the Commission Staff and other interested parties in the development of a statewide customer awareness and education program proposal for electric restructuring. AEP plans to abide by the Commission's final directives in Case No. U-12133 pertaining to that program. Based in part upon information compiled by Staff during the program development process, AEP estimates its share of Customer CHOICE Education Costs to be \$750,000.

As more fully described in Section D. 3. Customer Awareness and Education, AEP may take additional steps to communicate with its specific customers regarding the "hows" of Customer Choice. While a number of alternatives in this regard were described in Section D. 3., the precise mix of options has not at this time been determined by AEP and, therefore, an estimate of out-of-pocket costs for any such additional customer awareness and education measures has not yet been developed.

3. Nuclear Decommissioning

AEP was first authorized to recover its Michigan jurisdictional costs of decommissioning the Donald C. Cook Nuclear Plant in the MPSC's Order of August 26, 1986, in Case No. U-6150 (Reopened) as implemented by the Order dated December 17, 1986, in Case No. U-8559. The initial annual provision for the recovery of nuclear decommissioning costs resulted from a generic settlement involving all utilities in the state with nuclear facilities. AEP's annual provision was subsequently reviewed in 1990, 1993, 1994, and 1997, and is scheduled to again be reviewed with a planned November 1, 2000, filing in Case No. U-6150 (Reopened). AEP's Michigan jurisdictional nuclear decommissioning annual provision is reviewed at least every three years in accordance with the Commission's Order in Case No. U-6150 (Reopened).

The Commission's Order of November 26, 1996, in Case No. U-11237 approved AEP's requested Flexible Funding Plan (Plan) providing AEP the ability to deposit pre-April 7, 1983 spent nuclear fuel (SNF) disposal cost collections, from time to time depending upon the actual funded status of the pre-April 7, 1983 SNF trust, into the non-qualified nuclear decommissioning trust fund or to transfer amounts to the decommissioning trust from the SNF trust in accordance with specific procedures set forth in the Plan. AEP reports the results of the Plan in its periodic reviews of the Michigan jurisdictional nuclear decommissioning annual provision filed at least every three years in accordance with the Commission's Order in Case No. U-6150 (Reopened).

4. Stranded Costs

Under the terms of a Settlement Agreement approved by the Commission on December 16, 1999, in consolidated Case Nos. U-11181-R, U-11531-R, and U-11792, AEP is precluded in any event, including the enactment of legislation providing for stranded cost recovery, from seeking or accepting the recovery of certain costs related to AEP's Donald C. Cook Nuclear Plant. With regard to this provision of the Commission-approved Settlement Agreement and in the interest of simplifying and expediting the processing of AEP's Restructuring Implementation Plan to provide supplier choice to AEP's Michigan jurisdictional customers on January 1, 2002, AEP does not plan at this time through its proposed June 5, 2001, filing in this proceeding to seek recovery of any stranded Michigan jurisdictional generation costs other than regulatory assets.

5. Regulatory Assets

a. SFAS No. 109 Net Regulatory Assets

Regulatory assets exist as a result of past regulatory practices and would not exist in the absence of regulation and their probable recovery through rates in the future.

SFAS 109 Regulatory Assets are regulatory assets related to deferred income taxes that were not recorded in the past due to regulatory practices in which the current tax benefits of temporary book/tax differences were passed-through to rate payers immediately. This type of "flow-

through” accounting was permitted under Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71). SFAS 71 did not require the recordation of deferred income tax liabilities, unless required under the Internal Revenue Code, as long as recovery of these flowed-through current income tax benefits was probable through the ratemaking process in a future period when the temporary differences reverse causing an increase in the then current tax expense.

SFAS 109 required, starting in 1993, that “an enterprise shall recognize a deferred tax liability or asset for all temporary differences” and that “regulated enterprises that meet the criteria for application of FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation, are not exempt from the requirements of this statement. Specifically, this statement . . . requires recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate. . .” and “If, as a result of an action by a regulator, it is probable that the future increase or decrease in taxes payable for ‘Deferred Tax Liabilities’ will be recovered from or returned to customers through future rates, an asset or liability is recognized for that probable future revenue or reduction in future revenue pursuant to paragraphs 9-11 of Statement 71. That asset or liability is a temporary difference for which a deferred tax liability or asset shall be recognized.”

In this instance, the ratepayer's obligation to repay the utility (and thus the regulatory asset) existed prior to the issuance of SFAS 109, but SFAS 71 effectively allowed it to be netted against the deferred income tax liability. The issuance of SFAS 109 had no impact on the ratepayers' obligation to pay utilities such amounts in the future, nor on the utilities' obligations to pay the deferred income tax liabilities to the government in the future. The issuance of SFAS 109 merely required that the existing regulatory asset that resulted from flow-through rate treatment and the existing deferred income tax liability be separately recognized in the financial statements.

Even before the issuance of SFAS 109, the MPSC allowed the reversal of previously flowed-through tax benefits to be reflected in utility revenue requirements in setting utility rates as the related tax benefit reversed and the deferred income tax liability was repaid to the IRS. This regulatory treatment has continued, and SFAS 109 has had no impact on the regulatory treatment of income taxes. Based on this rate treatment, which provides for recovery of flowed-through tax benefits when the temporary differences reverse, recovery of these amounts is probable and the amounts qualify for recordation as regulatory assets.

Determination of SFAS 109 Jurisdictional Generation-Related Regulatory Assets as of December 31, 1999

The individual SFAS 109 Regulatory Assets for AEP are maintained in a detailed tax accounting system, developed as a result of the implementation of SFAS 109. At the inception of SFAS 109, a regulatory

asset was established on the balance sheet for all book/tax temporary differences that existed but for which no deferred income taxes were recorded on the books as a result of past Commission orders and accounting practices. These balances have been updated monthly since that initial date based on Schedule M and rate-based deferred tax activity. These balances are not maintained on a functional and a jurisdictional basis in the tax accounting system.

For purpose of AEP's Michigan Restructuring Plan, an estimate of the Michigan Jurisdictional Generation-Related SFAS No. 109 regulatory assets as of December 31, 2001, was prepared using the following methodology. The Michigan retail generation portion of the non-property related regulatory assets was determined by multiplying the total Company regulatory asset item, from the tax accounting system as of December 31, 1999, by the appropriate generation and jurisdictional allocation factors. Due to the complexity of the property accounts and the various temporary differences and deferred taxes involved, the property related SFAS 109 Regulatory Asset for generation plant was allocated on a jurisdictional generation related basis on a more detailed level.

This property-related SFAS 109 Regulatory Asset computation was performed by utilizing the principles contained in SFAS 109, in which the net book basis of generation plant (obtained from the Company financial statements and FERC Form 1 Reports) is compared to the net tax basis of generation plant (obtained from the Company tax depreciation system).

The difference between the book and tax basis represents the taxable temporary difference, which will reverse in future years. This temporary difference was multiplied by the current income tax rates to determine the amount of deferred federal income taxes required under SFAS 109. The difference between the deferred income taxes required and the appropriate deferred income taxes recorded on the books for ratemaking purposes represents the amount of additional deferred income taxes that will be owed to the taxing authorities in the future and must be collected through rates. This amount was then grossed-up since any amounts collected in rates will result in a future taxable event. The grossed-up amount represents the SFAS 109 Regulatory Asset recorded on the books for generation plant.

The deferred federal income taxes for generation plant allocated to the Michigan retail jurisdiction were derived from the Company tax accounting systems. For items for which jurisdictional information exists, the historic per books Michigan deferred income tax amounts were used. For items for which full-deferred tax normalization exists in all jurisdictions, a jurisdictional allocation was made. For non-depreciation, plant book/tax basis differences, the deferred income taxes were then further allocated based on production plant ratios since these balances are not maintained on a functional plant basis.

The SFAS 109 Regulatory Asset related to state income taxes was calculated in essentially the same manner as explained above for federal income taxes. The total temporary book/tax difference was multiplied by

the effective state income tax rate for AEP as determined from the state income tax returns filed in Indiana, West Virginia, Kentucky, and Illinois, and an allocation was made to the Michigan retail jurisdiction.

As the result of this above-described calculation, the total SFAS 109 Regulatory Asset related to federal and state income taxes as of December 31, 1999, for Michigan Retail Generation is estimated to be \$39,938,000.

Determination of Projected SFAS 109 Jurisdictional Generation-Related Regulatory Assets as of December 31, 2001

The next step was to roll forward the SFAS 109 Regulatory Asset as of December 31, 1999, based on information available for actual account activity recorded through June 30, 2000, in the tax accounting system. This activity level was then extrapolated to estimate what the balances would be as of December 31, 2000, and December 31, 2001.

This methodology was utilized to forecast the regulatory asset balances, and it is expected that the trend of account activity recorded through June 30, 2000, should continue for the remainder of 2000 and into the year 2001. This methodology was not used for all SFAS 109 Regulatory Asset items. For items that are very difficult to forecast and for which trending information is not available, the SFAS 109 Regulatory Asset balances at June 30, 2000, were used as proxies for projected December 31, 2001, balances.

For the purposes of the Michigan Restructuring Implementation Plan, the total SFAS 109 Regulatory Asset related to federal and state income taxes as of December 31, 2001, for Michigan Retail Generation is estimated

to be \$27,748,000 and \$5,222,000, respectively, for a total of \$32,970,000. This balance is detailed on Exhibit J.5.a. consisting of two pages.

b. Other Regulatory Assets

A regulatory asset exists as a result of past regulatory practice and would not exist in the absence of regulation. If the actions of a regulator can provide reasonable assurance of the existence of an asset, the company will capitalize all or part of an incurred cost that would be otherwise charged to expense. AEP's presentation of its regulatory assets has been segregated to present its regulatory assets related to the Financial Accounting Standards Board Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes, apart from its presentation of all other regulatory assets. The Company projects that approximately \$8.2 million of deferred costs qualify for treatment as Michigan jurisdictional, generation-related other regulatory assets as of December 31, 2001. These assets include other regulatory assets recorded in Account 182.3 (Other Regulatory Assets), unamortized loss on reacquired debt recorded in Account 189 (Unamortized Loss on Reacquired Debt), and deferred preferred stock acquisition costs recorded in Account 210 (Gain (Loss) on Resale or Cancellation of Reacquired Capital Stock). Please refer to Exhibit J.5.b. to this Plan for a detailed listing of AEP's Other Regulatory Assets and Projected December 31, 2001, Balances.

6. Excess Capital Expenditures

Section 10d. (3) of 2000 PA 141 states:

Beginning January 1, 2004, annual return of and on capital expenditures in excess of depreciation levels incurred during and before the time period described in subsection (2), and expenses incurred as a result of changes in taxes, laws, or other state or federal governmental actions incurred by electric utilities during the period described in subsection (2), shall be accrued and deferred for recovery. After notice and hearing, the commission shall determine the amount of reasonable and prudent costs, if any, to be recovered and the recovery period, which shall not exceed 5 years, and shall not commence until after the expiration of the period described in subsection (2).

AEP acknowledges that as a utility serving less than 1,000,000 customers in Michigan as of May 1, 2000, and a utility not electing to issue Michigan securitization financing under Section 10i., Section 10d. (3) by the terms of 2000 PA 141 is not explicitly applicable to AEP. However, AEP reserves the right in a subsequent filing in this proceeding to provide estimates of any expected capital expenditures in excess of depreciation levels and to seek the appropriate accounting authority from the Commission in order to effect procedures consistent with those described in Section 10d. (3) of 2000 PA 141. AEP, by the terms of the Commission's Orders in consolidated Case Nos. U-11181-R, U-11531-R, and U-11792, and Case No. U-12204, is subject to a cap on its Michigan retail basic rates and charges until January 1, 2005, and in addition has a long history of low retail electric rates in Michigan and infrequent base rate proceedings. AEP should not be comparatively disadvantaged by an inability to avail itself of favorable ratemaking and/or accounting treatment afforded other Michigan investor-owned electric utilities.

AEP believes that the accounting treatment described in Section 10d. (3) of 2000 PA 141, if subsequently requested by AEP and if approved by the Commission, would be beneficial to AEP and its customers in providing AEP an opportunity to continue its past practice of extending to the extent possible the time elapsing between base rate proceedings.

K. Cost Recovery/Required Accounting Authority

1. Cost Recovery

a. Nuclear Decommissioning

Since January 1, 1987, in its St. Joseph Rate Area and November 1, 1993, in its Three Rivers Rate Area, pursuant to Commission Orders in Case Nos. U-8559 and U-10347, respectively, AEP has recovered the costs of decommissioning the Donald C. Cook Nuclear Plant through a separate Nuclear Decommissioning Surcharge on customers' bills. Prior to November 1, 1993, nuclear decommissioning costs were recovered through basic rates and charges in the Three Rivers Rate Area.

Seemingly since the time of early discussions regarding Michigan electric industry restructuring, interested parties have supported the continuation of the recovery of nuclear decommissioning costs through a separate non-bypassable charge. The December 19, 1996, [MPSC] Staff Report on Electric Industry Restructuring stated "As part of current rates, utilities with nuclear plants collect NRC mandated costs to ensure nuclear site security and safety throughout the life of the plant as well as total costs of decommissioning after the plants are shut-down. The Staff recommends that these obligations be funded through a non-bypassable charge. This charge should continue until adequate funding exists for those activities or until the obligations to perform them are fulfilled." Reasons for the support of the continuation of non-bypassable nuclear decommissioning surcharges

would include those related to environmental benefit, public health and safety, and aesthetics.

AEP proposes in this Michigan Restructuring Implementation Plan the continuation of its approved nuclear decommissioning surcharges at their existing levels until adequate funding exists for those activities or until the obligations to perform them are fulfilled subject to the review procedure ordered by the Commission in Case No. U-6150 (Reopened) as described in Section J. 3. of this Plan. The surcharge factors will be applied to the bills of all AEP Michigan jurisdictional service customers.

b. Transition Charges

As described in Section J. of this Plan, AEP has preliminarily identified costs it has incurred that would not be recovered from customers choosing an alternative supplier and costs it expects to incur as the result of the implementation of the 2000 PA 141 restructuring of the Michigan electric industry. Another category of potential AEP costs are the transmission-related costs mandated by 2000 PA 141.

2000 PA 141 Sec. 10a. (1) states:

“No later than January 1, 2002, the commission shall 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. The orders shall provide for full recovery of a utility’s net stranded costs and implementation costs as determined by the commission.”

Sec. 10a. (5) states:

The orders issued by the commission before the effective date of the amendatory act that added this section that allow

customers of an electric utility to choose an alternative electric supplier, including orders that determine and authorize recovery of net stranded costs and implementation costs and that confirm any voluntary commitments of electric utilities, are in compliance with this act and enforceable by the commission. An electric utility that has not had voluntary commitments to provide customer choice previously approved by orders of the commission shall file a restructuring plan to allow customers to choose an alternative electric supplier no later than the date ordered by the commission. The plan shall propose a methodology to determine the electric utility's net stranded costs and implementation costs.

Sec. 10a. (9) indicates that:

The commission shall, after a contested case proceeding, issue annually an order approving for each electric utility a true-up adjustment to reconcile any overcollections or undercollections of the preceding 12 months to ensure the recovery of all amounts of net stranded costs. The rates for customers remaining with an incumbent electric utility will not be affected by the true-up process under this subsection. The commission shall review the electric utility's stranded cost recovery charges and securitization charges implemented for the preceding 12 months, and adjust the stranded cost recovery charge, by way of supplemental surcharges or credits, to allow the netting of stranded costs.

Sec. 10b. (2) states:

No later than 1 year from the effective date of the amendatory act that added this section, each electric utility shall file an application with the commission to unbundle its existing commercial and industrial rate schedules and separately identify and charge for their discrete services. No earlier than 1 year from the effective date of the amendatory act that added this section, the commission may order the electric utility to file an application to unbundle existing residential rate schedules. The commission may allow the unbundled rates to be expressed on residential billings in terms of percentages in order to simplify residential billing. The commission shall allow recovery by electric utilities of all just and reasonable costs incurred by electric utilities to implement and administer the provisions of this subsection.

Net Stranded Cost Recovery

For the reasons indicated in Section J. 4. of this Plan, AEP does not expect at this time through its proposed June 5, 2001, filing in this proceeding to seek recovery of any stranded Michigan jurisdictional generation costs, except for regulatory assets described below.

Regulatory Asset Recovery

Generation-related regulatory assets consist of costs that AEP has incurred in the past that would appropriately be recovered from those customers choosing to continue to receive generation-related services from AEP and those customers choosing a supplier other than AEP and who would, absent a separate surcharge, no longer be paying for generation-related regulatory assets as generation would be purchased through ESPs. AEP proposes to identify generation-related regulatory assets and recover the costs through separate riders applicable to all customers regardless of their choice of energy supplier.

AEP's recoveries under the riders would be monitored and reported to the Commission annually under the true-up procedure defined in 2000 PA 141 Sec. 10a. (9). Annual true-ups would be proposed by AEP for changes in generation-related regulatory asset balances and load. Recoveries under these proposed riders would continue until the earlier of December 31, 2007, or the full recovery

of generation-related regulatory assets. As indicated in Section J of this Plan, AEP's initial estimates, subject to further refinement in the proposed June 5, 2001 filing, of its Michigan jurisdictional generation-related regulatory assets at December 31, 2001, are:

SFAS 109 Regulatory Assets	\$32,970,000
Other Regulatory Assets	8,200,000

Implementation Cost Recovery

Certain other costs described in Section J. of this Plan, specifically those costs related to the filing of the Plan and tariffs, operational systems implementation, code of conduct implementation, corporate separation, employee transition programs, and the Customer Choice awareness and education program, are now being incurred or will in the future be incurred by AEP, are not being recovered through current rates and would appropriately be recovered through the surcharging of the bills of all AEP Michigan jurisdictional customers. All AEP Michigan customers would have the opportunity to benefit from customer awareness and education programs and to choose an ESP using the systems and procedures made possible by AEP's implementation of various restructuring information systems, code of conduct protections, and the corporate separation plan.

AEP proposes the establishment of a surcharge rider, effective on the date of customer choice, applicable to all AEP Michigan jurisdictional customers. The initial rider would be

calculated based upon costs projected in AEP's proposed June 5, 2001, filing and the load of AEP's Michigan jurisdictional customers. AEP proposes to monitor and report to the Commission annually AEP's recoveries under this rider and to propose any appropriate adjustment to or cessation of the surcharge rider. As indicated in Section J. of this Plan, AEP's initial estimates, subject to further refinement in the proposed June 5, 2001 filing, of its Michigan jurisdictional implementation costs at December 31, 2001, are:

Restructuring Plan Filing Expenses	\$ 200,000
Operational Implementation Costs	6,400,000
Code of Conduct Implementation Costs	Not estimated at this time
Corporate Separation Plan Costs	Not estimated at this time
Employee Transition Costs	Not estimated at this time
Customer CHOICE Education Costs	\$ 750,000

Transmission-Related Cost Recovery

(a) Transmission System Capacity Expansion Plan

2000 PA 141, in Section 10v., states:

(1) Electric utilities serving more than 100,000 retail customers in this state shall file, by January 1, 2001, a joint plan with the commission detailing measures to permanently expand, within 2 years of the effective date of this section, the available transmission capability by at least 2,000 megawatts over the available transmission capability in place as of January 1, 2000.

(2) The joint plan shall detail all actions including additional facilities required, the proposed schedule for accomplishing the actions, the cost of the actions, and the proposed ratemaking treatment for the costs. The joint plan shall also identify all actions and facilities that are required of other transmission owners, including out-of-state entities, to accommodate the actions described in the joint plan.

(3) The commission may order modifications to the joint plan to make it consistent with this act. If the electric utilities are unable to agree upon a joint plan to meet the

requirements of this act, the commission shall conduct a hearing to establish a joint plan. The commission shall authorize recovery from benefiting customers of all reasonable and prudent costs incurred by transmission owners for authorized actions taken and facilities installed to meet the requirements of this section that are not recovered through FERC transmission rates.

(4) If an electric utility or an affiliate that is the owner of the transmission assets is denied cost recovery of the reasonable and prudent costs expended to implement the joint plan, then the electric utility or affiliate shall have no further obligation to implement the joint plan. If an electric utility or its affiliate is subsequently granted cost recovery, then the obligation to implement the original joint plan is required. If cost recovery of the reasonable and prudent costs of implementing the joint plan is denied, an electric utility or its affiliate shall develop a new joint plan as provided under this section.

As described in Section H. 4. of this Plan, AEP has been a participant in a Michigan power import study to identify transmission system constraints and mitigation measures to increase the import capability into Michigan. At this time it is tentatively planned that the July 2000 Constraint Mitigation Assessment issued by the study group will serve as the basis for the joint plan required by 2000 PA 141 to be filed with the Commission by January 1, 2001. As identified in Section J. 1. c. of this Plan, the upgrades identified for the AEP System were estimated to potentially be \$20.05 million in year 2000 dollars and the associated operation and maintenance costs were estimated to be \$50,000 per year. It is anticipated that, in compliance with 2000 PA141, Sec. 10v. (2), the January 1, 2001, filing will propose a ratemaking treatment for the expected costs and will seek the Commission's authority to recover from benefiting customers all reasonable and prudent costs incurred by the transmission owners for authorized

actions taken and facilities installed to meet the requirements of Section 10v. not expected to be recovered through FERC transmission rates.

(b) Participation In An RTO

2000 PA 141, Sec. 10w., states:

(1) Each investor-owned electric utility in this state shall, at the utility's option, either join a FERC approved multistate regional transmission system organization or other FERC approved multistate independent transmission organization or divest its interest in its transmission facilities to an independent transmission owner.

(2) An investor-owned electric utility that is party to a legitimate filing that was pending before the FERC on December 31, 2001 which is seeking FERC approval of a proposed multistate regional transmission system organization shall be considered to be in compliance with this section. Subsection (3) shall apply if FERC rejects a pending filing or if the electric utility withdraws from the filing or from a regional transmission system organization. This section does not provide guidance to FERC with respect to any pending filing.

(3) If an electric utility has not complied with this section by December 31, 2001, the commission shall direct the electric utility to join a FERC approved multistate regional transmission system organization selected by the commission."

As described in Section H. 3. of this Plan, on June 3, 1999, AEP, along with FirstEnergy Corporation, Consumers Energy Company, The Detroit Edison Company and Virginia Electric and Power Company filed with the FERC under Section 203 of the Federal Power Act for transfer of control and/or ownership of jurisdictional transmission facilities to the Alliance RTO. On September 15, 2000, the Alliance participants made a compliance filing that addressed the FERC's directives and concerns outlined in its December 20, 1999, and May 18, 2000, orders. Given the

2000 PA 141 mandate for FERC approved multistate regional transmission system organization membership, AEP reserves the right for purposes of this Plan filing to seek approval from the Commission at a later date to recover from the appropriate Michigan benefiting customers of any RTO membership, development, implementation, or operation costs not expected to be recovered through FERC transmission rates.

2. Requested Accounting Authority

With its proposed June 5, 2001, filing of unbundled and open access tariffs and modified Terms and Conditions of Service, or in a separate limited purpose filing, AEP plans to file an Application with the Commission requesting that the MPSC make and enter appropriate Orders authorizing AEP to treat certain costs as retail jurisdictional regulatory assets for future recovery through regulated rates. The costs incurred or expected to be incurred by AEP for which accounting authority may be requested could include, among other things, the costs described in Section J. 1. of this Plan related to AEP's restructuring plan filing, restructuring systems implementation, the transmission system capacity expansion plan, Alliance RTO costs, code of conduct implementation, corporate separation implementation, and employee transition program; Section J. 2., related to the customer awareness and education program; Section J.5, regarding generation-related regulatory assets; and Section J. 6., pertaining to return of and on capital expenditures in excess of depreciation levels and expenses incurred as a result of changes in taxes, laws, or other state or federal governmental actions. Without such authority AEP

would be required, under financial accounting rules promulgated by the Financial Accounting Standards Board, to write off those costs as expense, thereby reducing net income and retained earnings. Thus, AEP would plan to request specific authority by a Commission Order to record certain costs as retail jurisdictional regulatory assets and to recover those regulatory assets through rates over a time period proposed by AEP and deemed reasonable and appropriate by the Commission.

L. Conclusion

In conclusion, AEP therefore respectfully requests that this Commission:

1. Accept AEP's Restructuring Implementation Plan for filing and approve AEP's Plan as in compliance with the Commission's June 19, 2000, Order in Case No. U-12464.
2. Promptly make such investigation and give such notice as it may deem necessary or advisable in the circumstances.
3. Promptly enter an Order in this proceeding approving AEP's Plan and establishing a filing date of June 5, 2001, for AEP's unbundled and open access tariffs and Terms and Conditions of Service for all customer classes. Further, AEP proposes that on that date of June 5, 2001, to the extent necessary or advisable, AEP would file an Application with the Commission requesting that the MPSC make and enter appropriate Orders:

- (a) Approving for AEP new schedules of electric service rates, and related terms and conditions of service, consistent with the relief requested by AEP.
- (b) Authorizing AEP to treat certain costs as retail jurisdictional regulatory assets for future recovery through regulated rates including certain restructuring implementation costs and customer education costs and return of and on capital expenditures in excess of depreciation levels and expenses incurred as a result of changes in taxes, laws, or other state or federal governmental actions.
- (c) Approving such other relief as then requested by AEP and deemed reasonable and appropriate by the Commission.

Categ	AEP (EDU)	MDCH	CRES
CUST	Bill insert 1 - "Opt Out"		
CUST	Bill insert 2 - "How to Enroll"		
PS	Practice Provider Workshop		
PS CRES	Provider Workshop		Provider Workshop
PS	Choice website (provider portion) fully operational		
PS CRES MDCH	Prepared to receive provider registration forms from CRES, process & send to MDCH	Receive & Process Provider Registration forms	Provider registration begins
REG	Commission order expected		
PS	Final review of draft provider handbook		
PS CRES MACS MDCH	Provide pre-enrollment list to CRES via MDCH	Receive from MACSS/submit to CRES pre-enrollment customer list	Receive pre-enrollment list
CRES			Begin marketing
MACS MDCH CRES	Accept EDI enrollment	Process EDI enrollment	Submit EDI enrollment
CUST	Choice website (customer portion) fully operational		
PS CRES	Complete Provider Handbook - Send to Providers		Receive Provider Handbook
REG	Compliance tariffs available to intervenors		
EDI MDCH CRES		Complete Level 1 EDI certification	Complete Level 1 EDI certification
REG	Last day for comments from intervenors		
REG	Final day for filing rehearing request		
REG	File final compliance tariffs		
DM	Complete Data Migration Testing		
TRAIN	Overview training (CSC/B&C)		
TRAIN	Enrollment training (CSC)		
DM MDCH	Data Migration: send forms & MACSS (AMP, CUM) files to MDCH (test files)	Initialize Data Base: MORSE & LERS (test)	
REG	Final day for PUCO ruling on rehearing request		
EDI MDCH CRES		Complete Level 2 Certification for CRES	Complete Level 2 EDI certification
PS MACS	Able to generate switch report		
DM	Full Production Data Migration		
PS	Able to accept requests for usage history from CRES		
CRES			Customer Enrollment Begins
MDCH CRES		Ready to receive EDI formats (814 E, DR, D, etc)	Send EDI Enrollment (814) formats to MDCH
MACS MDCH	Begin sending messages to update MDCH 1.)MACSS cum usg-I210, 2.)MV90 int usg-I200 (Daily)	Begin receiving MACSS messages (I200, I210) daily	

Categ	AEP (EDU)	MDCH	CRES
MACS MDCH CRES	Send usage data to CRES via MDCH	Send 12 mo'yly usage to CRES	Receive usage history
MACS MDCH	Receive daily CDT updates from MDCH	Daily CDT updates sent to AEP	
PS MACS MDCH	Generate Switch Report	Generate Customer Switch Notification	
TRAIN	Billing training (B&C)		
MDCH		LERS testing completed	
PS	Agreements (AEP/CRES, Transmission, E-Commerce) to be used rev'wd & approved by Legal		
PS	Agreements available for use by Provider Support, others as appropriate		
PS			Last day to apply for state license to achieve xx/xx/xx flow
MDCH		New settlement testing completed	
MDCH		Message interface testing completed	
MDCH		Legacy systems modifications test completed	
MDCH	E2E Testing Complete (MDCH & NTS)	MDCH E2E Testing Complete (DM, MORSE & LERS)	Last day to register with AEP to achieve xx/xx/xx flow
CRES			
REG	Environmental Disclosure Method to PUCO		
PS	Finalize all agreements for 1/02/01 flow		Finalize all agreements for xx/xx/xx flow
MDCH		Final configuration, systems migration to production state	
PS	Produce first forecast of CRES Loads (daily)		Receive forecast; submit schedules
	Electrons Flow		
PS	Provide first backcast (for January 1st)		
REG	Appeal period ends (assume PUCO ruling on 11/27)		
BILL	All approved billing options supported	All approved billing options supported	
BILL MACSM DCH CRES	First choice bills created	Retail settlement data available	Customer billing begins
MDCH		First invoice determinants sent to AEP	
INV	First Initial invoice (for first month)		Receive first initial invoice (for first month)
MDCH		First adjusted CRES loads provided (first month)	
INV	First Adjustment Invoice (for first month)		Receive first adjustment invoice (for first month)
MDCH		First final CRES loads provided (first month)	
INV	First Final Settlement (for first month)		Receive first final settlement invoice (for first month)

INDIANA MICHIGAN POWER CO.
REGULATORY ASSET ANALYSIS

Exhibit J.5.a.

Page 1 of 2

Projected as of December 31, 2001		Projected Total Company	Projected Generation Total Company	Projected Generation Michigan
Regulatory Asset <Liability> - FASB 109 - Federal				
Acct 182.3 -- Regulatory Assets:				
Property Related	4	212,870,000	137,801,000	27,192,000
Amort Step-Up ITC to T.I. - Rkpt U2	4	12,826,000	12,826,000	1,870,000
FERC - MPCO Defd FIT @ Merger	4	(2,279,000)	(1,121,000)	(1,121,000)
Various Nuclear Fuel Adjustments	4	246,000	246,000	38,000
Clearing Accounts	0	(124,000)	(61,000)	(61,000)
Defd Tax Gain - Rockport Land	4	696,000	696,000	696,000
Provision - Self Insurance	0	(196,000)	(96,000)	(96,000)
LTD Term Electric Plant	4	68,000	33,000	5,000
State Tax Expensed	4	(31,000)	(15,000)	(2,000)
All Other	0	10,000	5,000	1,000
Acct 182.3 -- Total Regulatory Assets - Gross		A 224,086,000	150,314,000	28,522,000
Acct 254.4 -- Regulatory Liabilities (Excess DFIT):				
Protected Property Related Excess DFIT	4	(16,313,000)	(9,620,000)	(1,481,000)
Non-Protected Property Related	4	(7,357,000)	0	0
Nuc Decommissioning - L/T Excess DFIT Reserve	4	(2,310,000)	(2,310,000)	(30,000)
Spent Nuclear Fuel - L/T Excess DFIT Reserve	4	(3,642,000)	(3,642,000)	(557,000)
CIAC - Book Receipts	4	(14,000)	0	0
Defd Bk Gain - Rkpt 2 Sale / Leaseback	4	(1,194,000)	(1,194,000)	(174,000)
Accrued Book Pension Expense	4	(46,000)	(23,000)	(4,000)
Defd Pre 4-7-83 Nuclear Fuel Disposal Costs	4	(294,000)	(294,000)	(30,000)
Amort - Int Pre 4-7-83 Nuclear Fuel Disposal Costs	4	89,000	89,000	8,000
Bk Exp - Nuc Decontam Fund	4	13,000	13,000	2,000
Accrued NQ Nuc Decom Exp	4	(273,000)	(273,000)	(4,000)
Loss on Reacquired Debt	4	64,000	32,000	5,000
Post Employment Benefits Payment	4	4,000	2,000	0
Reg Asset - Reaq Debt - Rkpt U2	4	67,000	67,000	10,000
All Other	4	1,000	0	0
Acct 254.4 -- Total Regulatory Liabilities (Excess DFIT) - Gross		B (31,205,000)	(17,153,000)	(2,255,000)
Net Regulatory Asset <Liability> (Acct 182.3 Less Acct 254.4)		A + B 192,881,000	133,161,000	26,267,000
Net Regulatory Asset <Liability> (Excluding Protected Excess DFIT)		209,194,000	142,781,000	27,748,000

Regulatory Asset <Liability> - FASB 109 - State				
Acct 182.3 -- Regulatory Asset	4	61,204,000	33,926,000	5,222,000

INDIANA MICHIGAN POWER CO.
SFAS 109 REGULATORY ASSETS

Exhibit J.5.a.
Page 2 of 2

Per Books as of December 31, 1999	Total Company	Estimated Generation Total Company	Estimated Generation Michigan
SFAS 109 Deferred Federal Income Taxes:			
Acct 182.3 -- Total Regulatory Assets - Gross	279,519,560	186,601,776	35,502,570
Acct 254.4 -- Total Regulatory Liabilities (Excess DFIT) - Gross	(41,224,388)	(20,911,172)	(2,726,316)
Net Regulatory Asset <Liability> (Acct 182.3 Less Acct 254.4)	238,295,172	165,690,604	32,776,254
Net Regulatory Asset <Liability> (Excluding Protected Excess DFIT)	259,661,370	178,291,226	34,715,656
SFAS 109 Deferred State Income Taxes:			
Net Regulatory Asset <Liability>	61,204,000	33,926,000	5,222,000
Projected as of December 31, 2000	Projected Total Company	Projected Generation Total Company	Projected Generation Michigan
SFAS 109 Deferred Federal Income Taxes:			
Acct 182.3 -- Total Regulatory Assets - Gross	251,707,000	168,411,000	31,965,000
Acct 254.4 -- Total Regulatory Liabilities (Excess DFIT) - Gross	(36,216,000)	(19,033,000)	(2,490,000)
Net Regulatory Asset <Liability> (Acct 182.3 Less Acct 254.4)	215,491,000	149,378,000	29,475,000
Net Regulatory Asset <Liability> (Excluding Protected Excess DFIT)	234,331,000	160,489,000	31,185,000
SFAS 109 Deferred State Income Taxes:			
Net Regulatory Asset <Liability>	61,204,000	33,926,000	5,222,000
Projected as of December 31, 2001	Projected Total Company	Projected Generation Total Company	Projected Generation Michigan
SFAS 109 Deferred Federal Income Taxes:			
Acct 182.3 -- Total Regulatory Assets - Gross	224,086,000	150,314,000	28,522,000
Acct 254.4 -- Total Regulatory Liabilities (Excess DFIT) - Gross	(31,205,000)	(17,153,000)	(2,255,000)
Net Regulatory Asset <Liability> (Acct 182.3 Less Acct 254.4)	192,881,000	133,161,000	26,267,000
Net Regulatory Asset <Liability> (Excluding Protected Excess DFIT)	209,194,000	142,781,000	27,748,000
SFAS 109 Deferred State Income Taxes:			
Net Regulatory Asset <Liability>	61,204,000	33,926,000	5,222,000

INDIANA MICHIGAN POWER COMPANY
OTHER REGULATORY ASSETS - EXCLUDING SFAS 109 DEFERRED TAX ASSETS
MICHIGAN JURISDICTIONAL
ACTUAL 6/30/2000 and PROJECTED 12/31/2001

9/29/2000

ITEMS	Remaining Amortization Period	Per Books June 30, 2000	Michigan Jurisdictional Allocation Factor	Allocation Factor Type	Michigan Jurisdictional Amount	Projected Deferral (Amort) 7/2000-12/2001	Projected Jurisdictional Balance December 31, 2001	Functional Allocation Factor	Allocation Factor Type	Projected Functional Balance December 31, 2001
VEBA Trust Contributions	N/A	\$1,545,605	Specific	Historical	\$354,500.00	0	\$354,500	66.51579%	Labor	\$235,798
Unrecovered Fuel Costs	3.5 Years	131,253,921	Specific	Historical	28,944,076	(12,404,592)	16,539,484	0.00000%	PSCR Settlement	0
SFAS 112 Postemployment Benefits	N/A	4,798,204	14.50314%	Demand	695,890	0	695,890	66.51579%	Labor	462,877
Cook Refueling Outage Levelization	Various	5,428,263	14.50314%	Demand	787,269	937,036	1,724,305	100.00000%	All Generation	1,724,305
Loss on Recquired Debt-Rockport Sale/Leaseback	22.5 Years	4,653,750	14.50314%	Demand	674,940	(46,675)	628,265	100.00000%	All Generation	628,265
Unrealized Loss on Forward Commitments	N/A	7,741,388	14.50314%	Demand	1,122,742	0	1,122,742	N/A	N/A	0
Deferred 1999 Cook Nuclear O&M Restart Expense	3.5 Years	140,000,000	Specific	Historical	35,000,000	(15,000,000)	20,000,000	0.00000%	PSCR Settlement	0
Loss on Recquired Debt - First Mortgage Bonds	Various	7,587,754	14.50314%	Demand	1,100,463	(283,754)	816,709	61.70225%	Gross Plant	503,928
Loss on Recquired Debt - Installment Purchase Contracts	Various	5,848,869	14.50314%	Demand	848,270	(69,822)	778,448	61.70225%	Gross Plant	480,320
Loss on Recquired Debt - Debentures	Various	548,425	14.50314%	Demand	79,539	(4,331)	75,208	61.70225%	Gross Plant	46,405
Deferred Preferred Stock Reacquisition Costs	Various	1,350,487	14.50314%	Demand	195,863	(30,218)	165,645	61.70225%	Gross Plant	102,206
Total		\$310,756,647			\$69,803,550	(\$26,902,355)	\$42,901,195			\$4,184,104
PSCR RELATED ITEMS										
Uranium Decommissioning and Decontamination Allowances	7.25 Years	32,967,460	15.11490%	Energy	4,982,999	(1,021,642)	3,961,357	100.00000%	All Generation	3,961,357
	N/A	647,318	15.11490%	Energy	97,841	0	97,841	100.00000%	All Generation	97,841
Total		\$33,614,778			\$5,080,840	(\$1,021,642)	\$4,059,198			\$4,059,198

**I&M Michigan Restructuring Implementation Plan
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MPSC Case No. U-12652**

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**I&M Michigan Restructuring Implementation Plan
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