STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

TESTIMONY

OF

INDIANA MICHIGAN POWER COMPANY

VOLUME I

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PRE-FILED DIRECT TESTIMONY

OF

HELEN J. MURRAY

PRE-FILED DIRECT TESTIMONY OF HELEN J. MURRAY
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q Please state your name, position and business address.

A. My name is Helen J. Murray. I am President and Chief Operating Officer of Indiana Michigan Power Company (I&M or Company), One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801.

Q. Please summarize your educational background and business experience.

A. I hold a bachelor degree in computer technology from Purdue University and a master's of business administration degree from the University of Notre Dame. I have completed American Electric Power's (AEP) Executive Management Development Program at The Ohio State University and the Economic Development Training program at Ball State University. I joined I&M in 1977 as a programmer. After progressing to positions of increased responsibility in programming, I was promoted to Administrative Assistant to the South Bend, Indiana Division Manager in 1992. I was named St. Joseph/Benton Harbor, Michigan, District Manager in 1994 with responsibility for distribution, customer services, and community affairs.

I transferred to the AEP Service Corporation (AEPSC), a corporate support service subsidiary of AEP Company, Inc. (AEP), in 1996 to manage the implementation of a centralized customer information system. In 2000, I was named AEPSC Director-Business Systems and in January 2004 Director-Billing and Credit Operations. Subsequently, I was promoted to Vice

President of Customer Operations with responsibility for the AEP System Customer Solution (Call) Centers, billing, credit and collection, information technology, and customer services support. I became President and Chief Operating Officer of I&M on November 1, 2006.

Q. What are your duties as President and Chief Operating Officer?

A. I am responsible for the safe, reliable, and efficient day-to-day operation of I&M. I am accountable and responsible for I&M's financial performance, and the quality of the services we provide to our customers, including distribution service, customer services, community affairs, and economic development activities. In addition, I represent I&M as it interacts with other units of the AEP System.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to generally describe the relationship between AEP and I&M and the responsibilities faced by I&M as a member of the AEP system, including participation in the AEP System Pool. I will describe the benefits to customers derived from our membership in the AEP system as well as the general structure of I&M and its service territory. I will also discuss the long term strategy of the Company and the specific challenges it faces, such as providing the reliability our customers expect, complying with existing and anticipated environmental regulations, and encouraging and educating I&M's customers about the benefits of using our service more efficiently. In addition, my testimony provides a general overview of I&M's rate history and our current request for a rate increase. I will describe the reasons for the requested rate relief and the major elements of the filing, including merging of the two existing rate areas and the proposed rate adjustment mechanisms designed to track costs and align our rates. I introduce I&M's proposal for a Michigan Major Storm Damage Restoration Reserve. Last, I will identify the witnesses who will describe I&M's costs, revenues and operations in detail.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit I&M-1 (HJM-1)- Index of Witnesses and Subject Matters

Exhibit I&M-2 (HJM-2) – Comparison of Average Residential Rates Based on 1,000 kWh as of December 2009 Versus I&M Proposed

Q. Please outline the major elements and summarize the Company's testimony in this filing.

A. This is I&M's first base rate case before the Commission in nearly twenty years and I&M's first Michigan base rate case of the 21st Century. Significant changes, both internal and external to I&M, have occurred. I&M's testimony will detail the resources needed to provide customers with the service they will value going forward.

We welcome the opportunity to present comprehensive and detailed descriptions of who we are, what we do, and how we plan to continue to provide low cost, reliable electric service to our customers. To that end, we will be presenting 16 witnesses who are responsible for supporting the various aspects of our business and this filing. Exhibit I&M-1 (HJM-1) identifies the Company's witnesses and the subject areas of their testimonies.

I&M is presenting testimony and evidence from numerous subject matter experts responsible for providing generation, transmission, and distribution services. We will also present financial experts to discuss the financial condition and needs of the Company and technical witnesses to describe the level of costs and revenues going forward. We will also offer witnesses to support our proposed cost allocations and rate design.

Our testimony is intended to present a complete picture of our business, including our membership in the AEP System. It is our intent to provide the Commission with the information necessary to justify the reasonableness of the Company's requested rates and rate design.

I&M and the AEP System

Q. Please describe the relationship between AEP and I&M.

A. AEP is a holding company that owns eleven different operating companies, one of which is I&M. In key respects, the operating units function as an integrated utility system that provides electric service to 5.2 million customers located in eleven states. AEP provides corporate support services to the operating companies through AEPSC to effectively manage the costs of joint activities such as human resources, accounting, finance and legal.

I&M is located in the AEP System-East Zone[1], which is an integrated generation and transmission network that includes over 28,580 megawatts (MWs) of generating capacity and approximately 22,600 miles of transmission lines located in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. AEP's operating units, including I&M, are responsible for day-to-day operations and management of local business affairs.

Q. Please explain the AEP System Interconnection (Pool) Agreement.

A. AEP coordinates the provision of generating services through AEPSC under the AEP Pool Agreement that allocates the cost and responsibility among the pool members. I&M, Appalachian Power Company (APCo), Columbus Southern Power Company (CSP), Kentucky Power Company (KPCo) and Ohio Power Company (OPCo) are the five AEP System operating companies (hereafter AEP System–East Zone) which are members of the AEP Power Pool established pursuant to the FERC-approved AEP Pool Agreement. Although each operating company owns specific generating facilities, the AEP System is designed, built and operated on an integrated system basis. The AEP Pool Agreement defines the rights and obligations of the five operating companies (each called a member) and sets out the methodology for allocating the responsibilities among the members.

[1] The AEP System-East Zone consists of the following operating companies with generation capabilities - Indiana Michigan Power Company, Columbus Southern Power Company, Appalachian Power Company, Kentucky Power Company, and Ohio Power Company. In addition, there are two operating companies located within the AEP System-East Zone, Kingsport Power Company and Wheeling Power Company, that do not have generation capabilities.

The ability of I&M to rely on the AEP Pool Agreement has benefited I&M's customers. First, it allowed I&M to build large, coal and nuclear base-load units that produce low cost power. I&M can rely on the AEP Pool Agreement to meet its needs at peak, rather than building its own peaking generation.

Second, it has allowed I&M to weather prolonged outages of its own generating units through low cost purchases from the AEP Pool Agreement rather than having to obtain higher cost power from the market.

Third, it has allowed AEP to market its surplus capacity and energy to the market through an asset optimization organization created within AEPSC known as AEP Commercial Operations, the net benefit of which is shared by the AEP East pool members. AEP took the risk of crafting the talent and the resources needed to go beyond ordinary utility off-system sales efforts so that the generating assets of I&M and the other AEP Pool Agreement members could be optimized through the skill and experience of a world class organization.

Last, I&M's share of current capacity settlement credits, resulting from I&M's surplus capacity position relative to the AEP Pool Agreement, partially offsets I&M's cost increases. Company witness Allen discuses the AEP Pool Agreement in additional detail.

Q Please discuss the FERC-approved AEP Transmission Agreement.

A. Under the Transmission Agreement[2], I&M and the other AEP East Operating members share the cost of the AEP transmission system. Because I&M has relatively more transmission investment than other AEP companies in the transmission pool, it receives payments from those companies. Company witness Bethel discusses the Transmission Agreement in additional detail.

Q. Do I&M's customers receive additional benefits from I&M's membership in the AEP System?

A. Yes. I&M's membership allows it access to the corporate support services offered by AEPSC. These services are provided at cost and reflect economies and efficiencies that would not otherwise be available to secure these services on a stand alone basis.

Customers have benefited from I&M's share of AEPSC's success in the off-system sales (OSS) market. I&M's share of OSS is a result of the skill and experience employed at AEPSC, which goes beyond that of a more traditional utility. Going forward, AEP and I&M are proposing a more equitable sharing of the benefits to reflect the fact that it was AEP's shareholders who sponsored this innovative approach to enhanced sales and bore the risk of its success. Company witness Busby addresses the sharing proposal of OSS margins in greater detail.

Q. Please describe I&M and its organizational structure.

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[2] On May 5, 2009, AEP provided formal notification to the AEP East state commissions regarding the planned FERC filing to modify the Transmission Agreement between the AEP East companies. On June 5, 2009, AEP initiated Docket No. ER09-1279-000 for this purpose and that case presently remains pending before the FERC. The modified proposal is not reflected in this filing.

A. I&M supplies electric service to approximately 583,000 retail customers in southwestern Michigan and northern and east-central Indiana. I&M operates, plant and equipment in Michigan and Indiana that are in service and used and useful in the generation, transmission and distribution of electric service to the public. The Company was organized under the laws of the State of Indiana and received a certificate of authority to transact business in the State of Michigan on March 9, 1925.

I&M's four distribution and customer service districts (Benton Harbor, Fort Wayne, South Bend/Elkhart, and Muncie/Marion) are each responsible for a specific geographic portion of I&M's service territory. The Company owns and operates three major generating plants, specifically, the Donald C. Cook Nuclear Plant (Cook Plant) in Bridgman, Michigan, the Rockport Plant (co-owned by AEP Generating Company) in Spencer County, Indiana; and the Tanners Creek Plant in Dearborn County, Indiana. I&M also owns and operates six small hydroelectric plants on the St. Joseph River in southwestern Michigan and northern Indiana. As of December 1, 2009, I&M had approximately 2,700 employees of which approximately 1,500 are located in Michigan. I&M uses approximately 130 contract workers for distribution services related to tree trimming and network distribution. In addition, I&M requires the services of approximately 600-1000 temporary contract workers for planned and unplanned outages at the Cook plant.

I&M is subject to the regulatory authority of the Michigan Public Service Commission (MPSC or Commission), the Indiana Utility Regulatory Commission, and the Federal Energy Regulatory Commission.

Q. Please describe I&M's service territory.

A. As of December 1, 2009, I&M supplied retail electric service to approximately 128,000 customers in southwestern Michigan and 455,000 customers in northern and east-central Indiana. I&M's Michigan service territory is located in southwest Michigan and is rural in nature serving communities located in the counties of Berrien, Cass, St. Joseph, Van Buren, Kalamzoo, and Allegan. In addition, I&M's Michigan service territory consists of approximately 16 miles of 765 kilovolt (kV), 230 miles of 345 kV, 240 miles of 138 kV, and 450 miles of less than 138 kV transmission facilities. This is in addition to more than 5,300 miles of distribution lines and general plant facilities.

I&M also provides wholesale electric service in the states of Michigan and Indiana. In Michigan, I&M sells firm wholesale power to Wabash Valley Power Authority (which includes a sale to Midwest Energy Cooperative) and the individual municipalities of Niles, South Haven, Sturgis, Dowagiac, and Paw Paw.

I&M is a member of PJM Interconnection, LLC (PJM), which is a regional transmission organization (RTO) serving the eastern portion of the country.

Q. Do AEP and I&M have a long term strategy for meeting customer needs?

A. Yes. AEP is pursuing a portfolio of options to address sustainability, including clean coal technologies, carbon capture and storage, nuclear power, renewable energy, and energy efficiency. AEP's long-term strategy is to meet our customers' future needs for electricity through innovation, investment, and efficiency, both as we produce and deliver our service and as our customers consume it. We must help customers understand the value of our product. We also must allow our customers an opportunity to appreciate the value of electricity so they can become decision-makers regarding how much power they want to consume and when they want to consume it.

AEP has adopted a strategy to achieve 1,000 MW of demand reduction throughout our states by 2012. To that end, we are working with a third party administrator to introduce energy optimization programs in Michigan. AEP has also adopted a strategy calling for the addition of 2,000 MW of renewable energy to our generation portfolio by 2011. This is part of AEP's comprehensive climate change strategy. But to achieve these goals and plans it is important that I&M receive the rate recovery sought in this filing. Currently our rates do not reflect the true cost of providing power and send inappropriately low price signals to our customers. Without the requested adjustment in rates our customers will consume more power than they otherwise would, resulting in our needing to invest more in our system and less successful outcomes in the sustainability programs I have described above.

Q. What are the challenges facing AEP and I&M?

A. AEP and I&M recognize that, as one of the largest electric utility systems in the country, we have substantial impacts on the economy, the environment and the communities we serve. If we are to be successful going forward, we must work with our stakeholders, including our customers and regulators, to build a brighter future together.

Essentially, the major challenge facing I&M and AEP is how to continue to provide affordable and reliable electric service when costs are rising and customer needs are changing. The needs of our customers have significantly changed since we were last before this Commission seeking rate relief. The average retail customer is consuming more electricity than ever due to today’s digital age and the use of more new electronic devices and appliances. Industrial customers are demanding better reliability and relying more on electronic controls and computers to manage their production facilities and processes. The demand for a constant stream of electricity means our customers are less tolerant of even minor interruptions. While we have invested in maintaining and improving our facilities to ensure reliable service and high quality power, more can be done to better serve our customers’ changing needs.

We are proud of our heritage as a low-cost provider and appreciate the challenge of maintaining that position in the face of rising costs. Today’s reality, however, is that costs to supply reliable, affordable service are going up across the board. Certain aspects of our business face higher costs for labor, fuel, environmental compliance, and energy delivery. We also face new and growing challenges such as security for our generation and transmission facilities that were not present when we were last before the Commission. We are confident that I&M's rates, which have been the lowest among Michigan investor-owned companies, will continue to remain a good value after new rates are established in this case.

We know our customers want affordable service and our communities look to us to offer low rates to attract and retain businesses. We are committed to effectively managing our business so that we can meet these challenges, but we will need our customers and regulators to help us continue to be a low-cost, high quality provider of electric service.

We are also faced with the uncertainty of how climate change will be resolved and the impact it will have on our customers and the communities we serve. AEP is at the forefront of our industry, leading forward with investments in new technologies and a portfolio of voluntary actions to reduce, avoid or offset greenhouse gases (GHGs). Our Cook Plant, which supplies 2100 MWs of electricity to I&M's customers, is an important part of our energy portfolio and will help us to meet the climate change challenge in Michigan.

I&M Rate History

Q. When was I&M last before the Commission requesting a change in its basic rates and charges?

A. As a result of the merger of I&M and Michigan Power, I&M's service area in Michigan consists of two rate areas, the St. Joseph Rate Area and the Three Rivers Rate Area. I&M’s existing retail electric rates in the St. Joseph Rate Area were established pursuant to the Commission’s Order Approving Settlement Agreement dated February 12, 1991, in Case No. U-9656. Retail electric rates were established for the Three Rivers Rate Area (then Michigan Power Company) pursuant to the Commission’s Order Approving Settlement Agreement dated March 9, 1989, in Case No. U-9205. Three Rivers Rate Area retail electric rates were subsequently reduced by the Commission’s Opinion and Order dated December 16, 1999, approving a settlement agreement in Case Nos. U-11181-R, U-11531-R, and U-11792. (Cook settlement case)

In addition, I&M’s rates include an Energy Optimization Surcharge, in accordance with the Commission’s Order Approving Settlement Agreement dated May 12, 2009, in Case No U-15808 and a Nuclear Decommissioning Surcharge first established in accordance with the Commission’s Opinion and Order in Case No. U-8559 and most recently modified by a reduction authorized through the Commission Order Approving Settlement Agreement dated September 25, 2007, in Case Nos. U-15162 (Decommissioning Investigation) and U-15276 (Depreciation Request). Also, pursuant to

Commission Order Approving Settlement Agreement dated December 16, 1999, in Case No. U-12204, I&M's rates include an AEP/CSW (Central and Southwest Corporation) Merger Savings Reduction Rider credit, which will terminate effective with the implementation of new rates for electric service resulting from the instant proceeding as explained by Company witness Krawec.

While we know that rate increases are not popular with our customers in these economic times, we welcome the opportunity to open our electric utility operations for review and explain the reasons we now need an increase in our basic rates and charges.

Q. How has the average total bill for a residential customer changed during these past 18-20 years?

A. In March 1989, the average total bill for a resident in the Three Rivers Rate Area of I&M using 1,000 kw would have been $70.47. Twenty years later, as of December 2009, the average total bill for the same customer under existing rates would have increased to only $72.41. Rates have increased by only 2.75% in the last 20 years.

In February 1991, the average total bill for a resident in the St. Joseph Rate Area of I&M using 1,000 kw would have been $55.39. Eighteen years later, as of December 2009, the average total bill for the same customer under existing rates would have increased to only $63.31. Rates have increased by only 14.30% in the last 18 years.

I&M's history of low rates is a remarkable accomplishment and is a compliment to the efforts of our employees working productively and efficiently to meet the needs of our customers. As discussed by Company witness Ehler, recent customer satisfaction surveys indicate our customers generally believe we are doing a good job meeting their needs. Obviously, low rates favorably contribute to that satisfaction and I am proud that I&M has the lowest rates among investor-owned electric companies in Michigan. In addition, taking into consideration I&M's request in this case, I&M will continue to have among the lowest rates among investor owned electric companies in Michigan as shown on Exhibit I&M-2 (HJM-2).

I&M Revenue Request

Q. What is the rate relief being sought by I&M in this proceeding?

A. I&M is requesting that the Commission approve an annual increase (including the requested trackers) in revenues of approximately $62.5 million, or 29.8%, to be made effective as soon as reasonably possible. The amount is based on a projected calendar test year ended December 31, 2010. Included in this request is the recovery of existing and proposed regulatory assets. Company witnesses Hayes, Hruby, and Krawec will discuss the details of these existing and proposed regulatory assets. I&M is also seeking Commission approval of a unified and expanded PSCR as described by Company witnesses Krawec and Allen and supported by additional witnesses. In addition, I&M is seeking four new trackers.

Q. Generally, why is the requested rate relief necessary?

A. I&M's current rates no longer allow I&M an opportunity to recover its cost of providing service or provide I&M a reasonable opportunity to earn a fair return on invested capital. The rate relief will provide resources to enable I&M to continue to meet the needs of our customers on a going forward basis. While we are working hard to control our operating expenses, we are faced with known increases in costs in nearly every aspect of our business that must be recognized in rates. We are also faced with increased expectations of our customers and known challenges in our ability to continue to use existing equipment and facilities to meet those needs. We are proposing a plan to enhance the reliability of our distribution system, but implementation of this program depends on revenues from this case. We also have plans in place to implement energy efficiency programs for our customers that depend on recovery of net lost revenues in order to hold the company revenue neutral. A third plan that we have is to improve the way we manage our distribution grid, which will help us to reduce outages, improve power quality and reliability, and provide customers with more information and greater control of their usage. Last, I&M seeks to make generation investments with Commission approval. The potential future generation investments will be major in scope and involve projects constructed over a significant period of time.

Q. Can you generally describe the cost increases I&M has experienced since the last general rate proceeding?

A. Yes. Although I&M's customers are paying about the same for electricity today as they were in the late 1980's and early 1990's, I&M's operations have experienced cost escalations reflecting inflation and other cost changes over which I&M has limited control. As discussed by Company witness Ehler, the costs of materials and supplies have increased. In addition, the costs of operating our generating plants in a safe and environmentally responsible manner is increasing as discussed by Company witnesses Hruby and Peifer. Further, the costs of reasonably compensating our employees and providing them with work related benefits have also increased. Pension and Other Post Employment Benefit (OPEB) expenses have increased significantly as noted by Company witness Allen.

As measured by the Producer Price Index (PPI), excluding food and energy, overall prices have climbed from an index of 124.5 in January 1990 to an index of 172.4 in August 2009, or an increase of 38%. This illustrates that the cost of goods and services in general have increased. I&M has not been immune to these increases. During the same time period, January 1990 through August 2009, the Consumer Price Index (CPI) has increased from 127.4 to 215.8 or an increase of 69%. While the PPI and CPI do not directly correspond with the changes in utility costs, the difference between the PPI and CPI illustrates the fact that our customers have received an excellent value from our service. However, despite I&M's successful efforts to contain costs and improve productivity, our ability to meet the needs of our customers and maintain our financial condition will suffer if adequate rate relief is not granted.

Q. Has I&M been diligent in controlling its costs?

A. Yes, it has. I&M and its employees are dedicated to providing quality service at an affordable price. We want our customers to appreciate the value our service brings to their lives and, to do so, we have to be efficient and productive in our operations. Our managers are constantly looking for more effective processes and ways to reduce costs. Cost control, process improvement, and technological innovation have contributed to I&M's ability to avoid seeking rate relief over the years. Of course, we balance cost control with the obligation to provide safe and reliable service to customers, as well as our obligation to meet regulatory and legal requirements.

Q. Does I&M have a budgeting process to assist in cost control?

A. Yes, it does. I&M's major functional expenses are closely monitored through the use of annual budgets. The manager in charge of each department, operating district or power plant is primarily responsible for the preparation and submission of its proposed operating budget. Once approved by I&M and AEPSC management, individual managers are responsible and accountable for operating their department within the approved limit. Monthly managerial reports compare actual expenditures to budgeted amounts and are used as an aid in controlling costs. Cost control is a routine part of each manager's job assignment and is a metric for evaluating job performance.

Q. Has I&M taken specific actions to mitigate the need for rate relief?

A. Yes. In the face of rising costs, I&M constantly reviews its operations and implements cost-saving measures when possible. Staffing requirements are routinely evaluated to encourage a more efficient and responsive organization. Programs are implemented to improve productivity, such as the use of helicopters for maintenance on high voltage transmission lines and the development of a computer-based mapping system for distribution circuits. In addition, I&M has skillfully managed its distribution system during summer peak loading by analyzing engineering data and shifting loads to circuits with more available distribution capacity.

Q. What additional issues is I&M facing at this time?

A. When I returned to I&M in 2006 as President, one of my top priorities was to assess the condition of our system and its ability to meet the needs of our customers. I believe that I&M has operated in an efficient and effective manner since its current rates were approved by the Commission in 1989 (Three Rivers Rate Area) and 1991 (St. Joseph Rate Area). I&M's employees are committed to providing reliable service and our performance is good. Customers are indicating to us that they are generally satisfied with our service and our customer complaints are relatively low. As I mentioned previously, I&M has worked diligently to avoid the need for increasing rates by identifying and implementing more efficient work practices and by taking advantage of economies of scale.

However, we are being challenged by increased demands and aging equipment and have reached a point where additional investments, above normal maintenance and replacement, are appropriately under consideration for all phases of our operations. Specifically, we are evaluating a distribution reliability enhancement program that would enable us to better serve our customers. However, our current rates simply do not provide the necessary resources to allow I&M to meet the technological sophistication and power quality expectations of customers.

I&M recognizes the need to provide equipment, technologies, and a work force ready to meet current and future customer expectations, and the need for additional resources to do so. Continual reliance on aging equipment will require an exceptional effort and inevitably increase the operation and maintenance costs of delivering service. However, even with exceptional effort, we may not produce results that achieve the customer expectations in today's technological world without a specific funding mechanism.

Since I&M's last rate case, customers have increased their reliance on electronic and digital technologies through more computers, appliances, high definition televisions, and high-tech industrial equipment. Customers are demanding a higher level of power quality from I&M because their sophisticated digital equipment is less tolerant of power quality fluctuations. Given I&M's cost controls and diligence to efficient operation, we have maintained affordable and reliable service, but our customers also continue to develop increasingly greater expectations regarding power quality and reliability. In many instances, I&M's 1950s-vintage equipment is used to serve today's electrical and electronic technologies of customers. New environmental requirements also demand more sophisticated technologies for our generating facilities.

I&M is currently engaged in several new technologies in Michigan, including the purchase of wind generation and plug in hybrid cars. I&M seeks the support of the Commission as well as its customers for these efforts and acknowledgement that we are taking the appropriate path to meet the growing technological needs. As discussed further below, the challenges are addressed in part, through I&M's proposed trackers.

Rate Area Consolidation

Q. Is I&M requesting Commission approval to merge the St. Joseph and Three Rivers rate areas?

A. Yes, as discussed earlier, I&M's service territory in Michigan is comprised of two separate rate areas, the St. Joseph rate area and the Three Rivers rate area. The Three Rivers rate area is the former Michigan Power Company territory. I&M seeks to merge the two separate rate areas into one area. I&M's request is supported by Company witnesses Krawec, Hix, and Roush.

Trackers

Q. Please explain the trackers I&M is requesting.

A. Historically, I&M has not relied significantly on trackers as a means of adjusting its rates. In this filing the Company is proposing to unify I&M's service territory in Michigan into one rate area and to apply a uniform PSCR clause for both rate areas, as discussed by Company witness Krawec and supported by other witnesses.

In addition to the expanded and uniform PSCR clause, I&M's Application also requests new trackers, specifically, the Generation Investment Tracker, the gridSMART^{SM} tracker, the Net Lost Revenue Recovery Tracker and the Enhanced Distribution Reliability Tracker. Establishing this kind of regulatory treatment in a general rate case in conjunction with an overall review of I&M's other costs and revenues is proper as these are clearly costs that are appropriate to be recognized in rates. I will explain the trackers in further detail below.

Q. Please explain I&M's proposal to unify the PSCR clause.

A. As discussed above, I&M seeks approval to combine the two rate areas into one and unify the two PSCR clauses. Currently, the PSCR clauses in St. Joseph and Three Rivers, as established in separate cases, track different expenses. I&M's proposal will align the Three Rivers PSCR clause with the St. Joseph PSCR clause and be similar in nature to other Michigan utilities PSCR clauses. Company witnesses Krawec, Allen, and Bethel describe I&M's proposal and explain the expanded unified PSCR clause in additional detail.

Q. Please describe I&M's Off-System Sales proposal to be included in the unified PSCR clause.

A. I&M, as a member of the AEP System, receives a proportionate share of the OSS margins created by AEPSC as it operates in the wholesale market.

AEPSC has significantly invested in the technologies, skills, and expertise to succeed in the wholesale market, but the results are variable in nature and market conditions are beyond the control of AEPSC and I&M.

I&M proposes that I&M's margins from OSS be shared between I&M and its customers through the PSCR. I&M proposes to share OSS margins 50/50 with customers. Company witness Busby will further explain I&M's proposal.

Q. Please explain why these proposed trackers are reasonable and appropriate.

A. The proposed trackers are reasonable and appropriate because the expenses to be tracked are volatile, significant and, in some cases, beyond the control of I&M or mandated. Another benefit of rate adjustment mechanisms is to lower the overall cost to customers by spreading project costs over time and reassuring investors of the chance of recovery. In order to meet the challenges facing I&M, I&M needs to make substantial investments in its facilities. I&M plans to invest in various projects and assets to optimize their performance. The capital investments needed to prepare I&M to meet the needs of its customers going forward necessarily come from cash from operations and debt issuances. Investors and market analysts look at the ratemaking treatment afforded a company's investments by regulatory commissions when making investment and ratings decisions. If they are confident that a company will be allowed timely recovery of its investments, they will be more inclined to invest in that company or rate it more favorably, which is critical to being able to maintain the credit quality and lower the cost of capital required to be able to fund the initial projects I&M is proposing.

Q. Please describe the gridSMART^{SM} Tracker.

A. Our distribution network satisfied yesterday's customers, but is not expected to meet the needs of tomorrow. Modernization of our distribution infrastructure will change how our customers use energy as we communicate more directly about services and prices. In addition, a smarter grid will improve the way we manage demand to economically meet future electric energy needs. It is our challenge to provide for an orderly, cost effective plan that allows us to better manage our system, reduce outages, and improve power quality and reliability. Our plan, if supported by our regulators, also would put greater control of usage in our customers' hands.

I&M has dedicated substantial resources to developing a vision of enhancing the distribution and customer service business of the future under an initiative called gridSMART$^{SM.}$ GridSMART^{SM} is an initiative which includes a plan to deploy advanced technologies such as advanced metering that will modernize I&M's energy delivery system. The gridSMART^{SM} tracker will allow I&M to move forward on this initiative.

As explained in more detail by Company witness Walter, the gridSMART^{SM} tracker will recover the costs associated with the four year phase in of customer oriented technologies and programs. In addition, new grid management technologies are designed to improve reliability, achieve energy efficiency, help achieve demand reduction, and position the distribution grid to accommodate and optimize new energy sources and storage options.

Because of the planned four year roll out of gridSMART^{SM}, I&M proposes that the capital and Operation and Maintenance (O&M) costs of the gridSMART^{SM} program be reviewed and recognized in rates in a timely manner through the gridSMART^{SM} Tracker.

Q. Please briefly describe the Enhanced Distribution Reliability Tracker (EDRT).

A. As explained in more detail by Company witness Ehler, the EDRT will recover the capital and O&M costs associated with the distribution reliability improvement work, specifically, incremental vegetation management. Our customers expect affordable rates and reliable service. I have already described our efforts to operate efficiently so as to keep rates low. The EDRT is a key component for us to be able to satisfy our customer's growing expectations for reliable service. The incremental vegetation management program will prepare the distribution system to better meet the expectations of our customers.

Because of the nature of the EDRT plan, I&M proposes that the capital and O&M costs of the distribution reliability enhancement program be reviewed and recognized in rates in a timely manner through the EDRT.

Q. Please describe the Generation Investment Tracker (GIT).

A. AEP and, to a lesser extent, I&M are predominantly coal-based generators of electricity. In addition to existing environmental laws and regulations, climate legislation in the United States is likely to be enacted within the next few years with direct impacts on all fossil fuel use, but especially on coal, which fuels 67% of our generating fleet and half the nation's electricity. This has served I&M and our customers well, as it has allowed us to generate some of the lowest cost power in the country.

However, increasing environmental regulations will require additional emission and waste controls to be installed, which will increase the cost of coal-fired generation. In addition, I&M's depreciation rates and depreciation expense are now based on asset service lives that are longer than previously thought possible. It is our challenge to carry out the proper maintenance programs that will allow these lives to be achieved and to do so we need more timely recovery of those costs. As a result, the Company requests a GIT to provide recovery of costs related to significant commission approved generation investment projects as discussed by Company witness Krawec.

The GIT will allow I&M to more efficiently reflect in rates the cost for major large generation and environmental projects. I&M is proposing improvements to the Cook nuclear plant and also plans to make required environmental retrofits at the Rockport Plant. Company witness Peifer will discuss the planned retrofit of the environmental controls at the Rockport Plant and Company witness Hruby will describe the potential Cook Improvement Project, both of which are projects that I&M is proposing to include in future GIT filings.

Q. Please describe the Demand-Side Management / Energy Efficiency (DSM/EE) Net Lost Revenue proposal.

A. The Company believes it is appropriate to recover net lost revenues in order to make the Company whole for the throughput impacts of mandated energy efficiency programs. Company witness Roush supports the inclusion of net lost revenues in the proposed DSM Net Lost Revenue Tracker.

Q. Please describe I&M's request for an Economic Development Rider (EDR).

A. I&M is requesting an EDR to benefit Michigan economic development. The EDR provides limited demand charge reductions under certain criteria to promote economic development. Company witness Hix explains and supports I&M's EDR.

Q. Please describe I&M's proposal regarding a Michigan Major Storm Damage Restoration Reserve.

A. As explained by Company witness Krawec, and supported by Company witnesses Ehler, Hayes, and Allen, I&M is proposing a Michigan Major Storm Damage Restoration Reserve. I&M's O&M costs associated with repairs as a result of major storm damage are volatile in nature and this mechanism will address the volatile nature of these costs.

Q. Based on your experience and in your position, do you have an opinion on the reasonableness of expenses reflected in I&M's filing and the proposed rates?

A. Yes, the projected 2010 expenses are reasonable and necessary to provide safe, adequate and reliable service in the test year. The proposed rates will afford I&M an opportunity to earn a reasonable return on and return of its investments.

Q. Please summarize your testimony in this proceeding.

A. My testimony generally describes the relationship between AEP and I&M, the challenges facing AEP and I&M and our long term strategy. Further, I explain I&M's organization and service territory and review I&M's rate history. I identify the rate relief we are requesting, generally describe the reasons why our current rates are no longer adequate, and discuss I&M's efforts to control the costs we incur to provide service to our customers. I also discuss the reasons for seeking approval of the consolidation and expansion of the PSCR and four new rate adjustment mechanisms that would allow us to track certain costs so that they can be reviewed and recognized in rates in an efficient manner. Further, I discuss the need for I&M to establish a Michigan Major Storm Damage Restoration Reserve. Last, I identify the witnesses who are supporting I&M's request for rate relief in this case.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PREFILED DIRECT TESTIMONY

OF

WILLIAM E. AVERA

PREFILED DIRECT TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. Please describe your qualifications and experience.

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission ("FERC"), as well as the Federal Communications Commission, the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 42 states, including the Michigan Public Service Commission ("MPSC" or the "Commission").[1]

In 1995, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. In addition, I served as an outside director of Georgia System Operations Corporation, the system operator for electric cooperatives in Georgia.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA®)

[1] I previously testified before the MPSC in Case No. U-13531, on behalf of Michigan Bell Telephone Company d/b/a SBC Michigan.

designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners ("NARUC") Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit I&M-3 (WEA-1).

B. Overview

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the MPSC my independent assessment of the fair rate of return on equity ("ROE") that Indiana Michigan Power Company (I&M or the Company) should be authorized to earn on its investment in providing electric utility service. In addition, I also examined the reasonableness of I&M's capital structure, considering both the specific risks faced by I&M, as well as other industry guidelines.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this case.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to I&M and its parent company, American Electric Power Company, Inc. ("AEP"). I also reviewed information relating generally to capital market conditions and specifically to investor perceptions, requirements, and expectations for electric utilities. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for I&M, and they form the basis of my analyses and conclusions.

Q. What is the practical test of the reasonableness of the ROE used in setting a utility's rates?

A. The ROE compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[2] and *Hope*[3] cases, a utility's allowed ROE should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. How is your testimony organized?

A. I first reviewed the operations and finances of I&M and the general conditions in the electric utility industry and the capital markets. With this as a background, I conducted various well-accepted quantitative analyses to estimate the current cost of equity, including alternative applications of the discounted cash flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as reference to expected earned rates of return for

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[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

utilities. Based on the cost of equity estimates indicated by my analyses, I&M's ROE was evaluated taking into account the specific risks and potential challenges for its jurisdictional electric utility operations in Michigan, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity.

C. Summary of Conclusions

Q. What are your findings regarding the fair rate of return on equity for I&M?

A. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital, I recommend an ROE for I&M from the middle of my 10.95 percent to 12.55 percent reasonable range, or 11.75 percent. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with I&M's jurisdictional utility operations, my analyses focused on a proxy group of twenty other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sector of the economy;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied both the DCF and CAPM methods, as well as the expected earnings approach, to estimate a fair ROE for I&M;
- Based on my evaluation of the strength of the various methods, I concluded that the cost of equity for the proxy groups of utilities and non-utility companies is in the 10.8 percent to 12.4 percent range, or 10.95 percent to 12.55 percent after incorporating a minimum adjustment to account for the impact of common equity flotation costs;
- Investors view existing cost recovery mechanisms as supportive of I&M's financial integrity, but there is no evidence that these provisions

will result in a measurable change in the Company's investment risk or ROE relative to the proxy companies;

- The reasonableness of an 11.75 percent ROE for I&M is also supported by the exposures associated with the Company's nuclear generation, environmental mandates, and the need to support access to capital.

Q. What other evidence did you consider in evaluating your ROE recommendation in this case?

A. My recommendation was reinforced by the following findings:

- Sensitivity to financial market and regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in supporting utility credit standing and financial integrity; and,
- Providing I&M with the opportunity to earn a return that reflects these realities is an essential ingredient to support the Company's financial position, which ultimately benefits customers by ensuring reliable service at lower long-run costs.

Q. What is your conclusion as to the reasonableness of I&M's capital structure?

A. Based on my evaluation, I concluded that a common equity ratio of 49.52 percent represents a reasonable capitalization for I&M. This conclusion was based on the following findings:

- The common equity ratio implied by I&M's capital structure is consistent with the capitalizations maintained by the proxy group of electric utilities based on data at year-end 2008 and near-term expectations;
- The additional leverage implied by I&M's obligations under operating leases warrant a more conservative financial posture; and,
- The requested capitalization reflects the need to support the credit standing and financial flexibility of I&M as the Company seeks to fund system investments and meet the requirements of customers.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of I&M. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Indiana Michigan Power Company

Q. Briefly describe I&M.

Q. Headquartered in Fort Wayne, Indiana, I&M is principally engaged in the generation, transmission, and distribution of electric power. The Company provides electric service to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, with Michigan accounting for approximately 128,000 of this total. In addition to providing retail electric utility service, the Company also sells electric power at wholesale to municipalities and other utilities. Sales to residential customers comprised 38 percent of retail revenues, with 30 percent to commercial, and 32 percent to industrial and other end-users. At year-end 2008, I&M's total assets amounted to $6.2 billion, with total revenues amounting to approximately $2.2 billion.

I&M, along with other operating subsidiaries of AEP, is party to an interconnection agreement that defines how they share the costs and benefits associated with their respective generating plants. I&M operates approximately 4,511 megawatts (MW) of generating capacity including the portion of Rockport Plant owned by AEP Generating Company. The two units of the Donald C. Cook Nuclear Plant (Cook Plant) account for 2,191 MW of this total. While nuclear generation normally accounts for approximately 50 percent of energy produced by I&M, the Company was forced to shut down Unit 1 in September 2008 due to severe vibrations caused by turbine blade failure. While I&M expects to resume low-power operation of Unit 1 of the Cook Plant before year-end 2009, it does not expect a return to full power until 2011.

I&M's transmission and distribution facilities consist of over 23,000 miles of transmission and distribution lines. I&M is a member of the PJM Interconnection, LLC (PJM), a FERC-approved RTO, and provides transmission service pursuant to the PJM Open Access Transmission Tariff (OATT). The Company's retail utility operations are subject to the jurisdiction of the MPSC and the Indiana Utility Regulatory Commission, with wholesale transmission operations being regulated by the FERC. Additionally, I&M's Cook Plant is subject to licensing and oversight by the Nuclear Regulatory Commission ("NRC").

Q. Please describe the AEP System.

A. AEP delivers electricity to more than 5 million customers across 11 states, including Ohio, Indiana, West Virginia, Virginia, Kentucky, Michigan, Tennessee, Oklahoma, Texas, Louisiana, and Arkansas. AEP is one of the largest electric utilities in the U.S., with its combined utility system including nearly 38,000 MW of generating capacity and over 251,000 miles of transmission and distribution lines. AEP's electric utility subsidiaries rely primarily on coal-fired generation, which makes up approximately 65 percent of total system capacity. During 2008, AEP's revenues totaled approximately $14.4 billion, with total assets at year-end of $45.2 billion.

Q. Where does I&M obtain the capital used to finance its investment in electric utility plant?

A. As a wholly-owned subsidiary of AEP, I&M obtains common equity capital solely from its parent, whose common stock is publicly traded on the New York Stock Exchange. In addition to capital supplied by AEP, I&M also issues debt securities directly under its own name.

Q. What credit ratings have been assigned to I&M?

A. Currently, I&M is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation (S&P), with Moody's Investors Service (Moody's) assigning an issuer rating of "Baa2". These ratings are identical to those assigned to I&M's parent, AEP. Meanwhile, Fitch Ratings Ltd. (Fitch) has assigned a "BBB-" issuer default rating to I&M, while rating AEP one notch higher at "BBB".

B. Risks for I&M

Q. How have investors' risk perceptions for the utility industry evolved?

A. Implementation of structural change and related events caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the utility industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of the utilities themselves. As S&P recently concluded:

> Credit markets are tight. Liquidity is constrained. And construction, labor, and material costs are soaring. As if that weren't enough, the U.S. electric utility sector also faces aging

> infrastructure, declining capacity margins, and increasing environmental compliance requirements.[4]

Similarly, Fitch concluded that the short- and long-term outlook for investor-owned electric utilities is negative,[5] while Moody's observed, "Material negative bias appears to be developing over the intermediate and longer term due to rapidly rising business and operating risks."[6]

Q. Does I&M anticipate the need for additional capital going forward?

A. Yes. I&M will require capital investment to provide for necessary maintenance and replacements of its utility infrastructure, as well as to fund new investment in electric generation, transmission and distribution facilities. AEP noted in its most recent Form 10-K Report that it plans to invest an additional $2.6 billion in utility assets during 2009 alone,[7] while combined construction expenditures at I&M are anticipated to total approximately $360 million. Support for I&M's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

Q. Is the potential for energy market volatility an ongoing concern for investors?

A. Yes. In recent years utilities and their customers have had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets, and investors recognize the prospect of further turmoil in energy markets. Moody's has warned investors of ongoing exposure to

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[4] Standard & Poor's Corporation, "Recovery Mechanisms Help Smooth Electric Utility Cash Flow And Support Ratings," *RatingsDirect* (Mar. 9, 2009).
[5] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[6] Moody's Investors Service, "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[7] American Electric Power Company, Inc., *Form 10-K Report* (Dec. 31, 2008).

"extremely volatile" energy commodity costs, including purchased power prices, which are heavily influenced by fuel costs,[8] and Fitch noted that rapidly rising energy costs created vulnerability in the utility industry.[9]

For example, while coal has historically provided relative stability with respect to fuel costs, the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy (DOE), reported that prices for Central and Northern Appalachia coal spiked from approximately $45 per ton in June 2007 to over $140 per ton in September 2008, before falling back into the $40 to $50 range in September 2009.[10] Similarly, the EIA documented an increase of 40 percent in the weighted-average price paid for uranium oxide equivalent in 2008 compared to 2007 price levels, and coming on the heels of a 76 percent price increase during the previous year.[11] The power industry and its customers have also had to contend with dramatic fluctuations in gas costs due to ongoing price volatility in the spot markets. Moody's concluded that natural gas "remains highly volatile," and warned that such price fluctuations "could have a significant impact on a utility's liquidity profile."[12]

While expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the potential that such trends could quickly reverse. Indeed, Fitch highlighted

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[8] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* at 6 (Aug. 2007).
[9] Fitch Ratings Ltd., "Staying Afloat: Downstream Liquidity in the Energy and Power Sectors," *Oil & Gas / Global Power Special Report* (June 16, 2008).
[10] Energy Information Administration, *Coal News and Markets* (Jun. 20 & Sep. 26, 2008, Oct. 13, 2009).
[11] Energy Information Administration, *2008 Uranium Marketing Annual Report* (May 26, 2009).
[12] Moody's Investors Service, "Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector," *Special Comment* (March 2009).

the challenges that such dramatic fluctuations in commodity prices can have for utilities and their investors and recently noted that "uncertainty regarding fuel prices, in particular natural gas costs, has made planning for the future even more problematic."[13] The rapid rise in electricity costs that can result from higher wholesale energy prices has heightened investor concerns over the implications for regulatory uncertainty. S&P noted that, while timely cost recovery was paramount to maintaining credit quality in the electric power sector, an "environment of rising customer tariffs, coupled with a sluggish economy, portend a difficult regulatory environment in coming years."[14]

Q. What other financial pressures impact investors' risk assessment of I&M?

A. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments. As Moody's observed:

> [P]ressures are building. Utilities are facing rising operating costs and infrastructure investment needs that are prompting them to seek more-frequent requests for rate relief. Meanwhile, as energy (and other commodity) costs rise, so does the risk of a consumer backlash over electric rates that could prompt legislative intervention or a more contentious atmosphere between utilities and their regulators.[15]

Similarly, S&P noted that "heavy construction programs," along with rising operating and maintenance costs and volatile fuel costs, were a

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[13] Fitch Ratings, Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).
[14] Standard & Poor's Corporation, "Top 10 U.S. Electric Utility Credit Issues For 2008 And Beyond," *RatingsDirect* (Jan. 28, 2008).
[15] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

significant challenge to the utility industry.[16] Fitch echoed this assessment, concluding:

> Continued access to capital at reasonable rates in 2009 remains uncertain at a time when many utility holding groups have historically high capital investment programs and will require ongoing access to reasonably priced capital in order to fund new investment and refinance maturing debt.[17]

As noted earlier, investors anticipate that I&M will undertake significant electric utility capital expenditures. While providing the infrastructure necessary to meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on the Company.

Q. Are environmental considerations also affecting investors' evaluation of electric utilities, including I&M?

A. Yes. Utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. In early 2007 S&P cited environmental mandates, including emissions, conservation, and renewable resources, as one of the top ten credit issues facing U.S. utilities.[18] Similarly, Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities,"[19] while Fitch observed that "the structure, timing and implementation is still uncertain."[20]

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[16] Standard & Poor's Corporation, "Ratings Roundup: Utility Sector Experienced Equal Number Of Upgrades And Downgrades During Second Quarter Of 2008," *RatingsDirect* (Jul. 22, 2008).
[17] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).
[18] Standard & Poor's Corporation, "Top Ten Credit Issues Facing U.S. Utilities," *RatingsDirect* (Jan. 29, 2007).
[19] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).
[20] Fitch Ratings, Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

At the national level, the Obama administration has taken a far more active stance towards energy and environmental policy. It has endorsed the American Clean Energy and Security Act of 2009 ("ACES"), passed by the House of Representatives on June 26, 2009. In addition to creating a comprehensive, economy-wide cap-and-trade regulatory framework, ACES would reduce carbon emissions 17 percent by 2020 compared to 2005 levels and require electric utilities to meet 20 percent of their electricity needs from renewable sources by 2020.[21] Compliance with these evolving standards will undoubtedly require significant capital expenditures, especially for utilities like I&M that depend significantly on coal-fired generation. S&P concluded, "Although we expect the cap-and-trade program to be economywide and affect a variety of sectors, it will disproportionately affect the power sector."[22] S&P recently emphasized that because of uncertainty over the details and timing of future limits on CO_2 emissions, existing ratings do not fully reflect the impact of carbon risks.[23]

Q. What other exposures should be considered in evaluating I&M's financial requirements?

A. As noted earlier, the Cook Plant's two nuclear units account for approximately 50 percent of the generating capacity operated by I&M. While nuclear power confers advantages in terms of fuel cost savings and diversity, investors also associate nuclear facilities with risks that are not

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[21] Michigan has adopted a renewable portfolio standard that mandates utilities to obtain at least 10 percent of their retail electricity supply from renewable energy sources by 2015.
[22] Standard & Poor's Corporation, "The Potential Credit Impact Of Carbon Cap-And-Trade Legislation On U.S. Companies," *RatingsDirect* (Sep. 14, 2009).
[23] *Id.*

encountered with other sources of generation. S&P has long recognized the additional risks posed by nuclear facilities, as reflected in a 1994 article:

> Operating and maintaining [nuclear plants] is more complex compared with fossil plants because of safety considerations and the additional safety equipment and operational controls required.[24]

More recently, Moody's confirmed that "ownership of nuclear generating facilities brings a higher level of complexity associated with operating and maintaining the units."[25]

As Moody's noted, "[O]ne of the biggest risks associated with nuclear generation is an unanticipated extended outage," concluding that "an extended outage can significantly stress an owner's liquidity and over-all financial profile."[26] In addition, longer-term uncertainties regarding the disposal of spent fuel and the ultimate costs of decommissioning continue to accompany any investment in nuclear generating facilities. In order to mitigate against these potential exposures, Moody's cited the importance of a constructive regulatory relationship and "a need to establish financial policies over the near-term aimed at producing very strong financial credit ratios in order to maintain a given rating."[27]

[24] Standard & Poor's Corporation, "Measuring Nuclear Risk in a Competitive Environment," *CreditWeek* (Aug. 8, 1994).
[25] Moody's Investors Service, "New Nuclear Generation in the United States: Keeping Options Open vs. Addressing An Inevitable Necessity," *Special Comment* (Oct. 2007).
[26] *Id.*
[27] *Id.*

D. Impact of Capital Market Conditions

Q. What are the implications of recent capital market conditions?

A. The financial and real estate crisis that began during the third quarter of 2008 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase.

With respect to utilities specifically, as of September 30, 2009, the Dow Jones Utility Average stock index remained almost 30 percent below the level of June 30, 2008. This sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry was not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to Congressional representatives as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[28]

Similarly, an October 1, 2008, *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly

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[28] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).

alternatives to raise funds.[29] Meanwhile, a Managing Director with Fitch observed that "significantly higher regulated returns will be required to attract equity capital."[30] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions has increased the cost of capital for utilities:

> While credit is available to investment-grade issuers in the utilities, power and gas sectors, it is more expensive, particularly when viewed against the easy money environment which prevailed for most of this decade.[31]

Fitch recently concluded, "While utilities maintained relatively good market access during the credit crisis, the cost of capital is higher than prior to the credit crisis, and bank credit remains relatively tight."[32]

Q. Has the economy in I&M's service territory felt the impact of the global recession?

A. Yes. Investors recognize that electric utilities such as I&M are not immune to the declining sales and cash flow that accompanies an economic downturn. The economy in southwest Michigan has been hard-hit during the ongoing recession. For example, the unemployment rate in St. Joseph County reached 16.5 percent in June 2009, with the Board of Commissioners concluding that "the breadth of the distress … loss of jobs,

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[29] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).
[30] Fitch Ratings Ltd., "EEI 2008 Wrap-Up: Cost of Capital Rising," *Global Power North America Special Report* (Nov. 17, 2008).
[31] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).
[32] Fitch Ratings Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).

home foreclosures, and rapidly declining property values" warranted a formal designation of the area as a "Recovery Zone" under the terms of the American Recovery and Reinvestment Act of 2009.[33] Fitch noted that one of the primary rating concerns for I&M "primarily relate to I&M's exposure to industrial customers (33% of 2008 retail revenues) in local service territories with struggling economies."[34]

Q. What do these events imply with respect to the ROE for utilities such as I&M?

A. No one knows the future of our complex global economy. We know that the financial crisis that accelerated in 2008 had been building for a long time, but few predicted that the economy would fall as rapidly as it has, or that bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized, investors are apt to react swiftly and negatively to any future signs of trouble in the financial system or economy. Given the importance of reliable electric power for customers and the economy, it would be unwise to ignore investors' increased sensitivity to risk in evaluating the Company's ROE.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe DCF and

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[33] *Resolution Designating a "Recovery Zone" for Recovery Zone Facility Bonds and Recovery Zone Economic Development Bonds*, St. Joseph County Board of Commissioners (Oct. 6, 2009).
[34] Fitch Ratings Ltd., "Indiana Michigan Power Co.," *Global Power U.S. and Canada Credit Analysis* (Apr. 30, 2009).

CAPM analyses conducted to estimate the cost of common equity for benchmark groups of comparable risk firms and evaluate expected earned rates of return for utilities. Finally, I examine flotation costs, which are properly considered in evaluating a fair rate of return on equity.

A. Economic Standards

Q. What role does the rate of return on common equity play in a utility's rates?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Moreover, the return on common equity is integral in achieving the sound regulatory objectives of rates that are sufficient to: 1) fairly compensate capital investment in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q. What fundamental economic principle underlies the cost of equity concept?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (*k*) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders. They receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What does the above discussion imply with respect to estimating the cost of common equity for a utility?

A. Although the cost of common equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the cost of common equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. Did you rely on a single method to estimate the cost of common equity for I&M?

A. No. In my opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[35]

Therefore, I applied both the DCF and CAPM methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an earnings approach based on investors' current expectations in the capital

[35] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* at Part 2, p. 4 (1997).

markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

Q. Does the fact that there are different accepted methods to estimate the cost of common equity, each based on certain assumptions, imply that determining the ROE is subjective?

A. Absolutely not. The alternative approaches that I have applied to estimate the cost of common equity have considerable theoretical and practical support, and the body of knowledge on the topic of cost of capital attests to the significance of developing cost of capital estimates that work in the real world of financial markets. For example, the reality that investors require compensation for bearing the risk of putting their money in common stock is a fundamental tenet of the theory and practice of finance. While assumptions and judgment underlie these methods to estimate the cost of common equity, this does not imply that they are subjective or that the cost of common equity is unknowable.

Each method of estimating the cost of common equity is based on empirical evidence and accepted applications. While experts may disagree on particular nuances and details of their application, the reliability of these methods is confirmed by their use throughout the regulatory arena as well as in the worlds of investment management and corporate finance. The fact that alternative methods may give somewhat different results, or that different experts may come to different estimates using these methods, does not mean the methods are subjective or unreliable. It means simply that interpreting the results of these methods requires care and practical judgment.

B. Comparable Risk Proxy Groups

Q. How did you implement these quantitative methods to estimate the cost of common equity for I&M?

A. Application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

Q. What specific proxy group of utilities did you rely on for your analysis?

A. In order to reflect the risks and prospects associated with I&M's jurisdictional utility operations, my DCF analyses focused on a reference group of other utilities composed of those companies classified by The Value Line Investment Survey ("Value Line") as electric utilities with: (1) S&P corporate credit ratings of "BBB-" to "BBB+," (2) a Value Line Safety Rank of "2" or "3", and 3) a Value Line Financial Strength Rating of "B++" or higher. These criteria resulted in a proxy group composed of twenty companies, which I will refer to as the "Utility Proxy Group."

Q. What other proxy group did you consider in evaluating a fair ROE for I&M?

A. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful benchmark to evaluate a fair rate of return is relative risk, not the particular business activity or degree of regulation. As noted in *Regulatory Finance: Utilities' Cost of Capital,* "It should be emphasized that the definition of a comparable risk class of companies does not entail similarity of operation, product lines, or environmental conditions, but rather similarity of experienced business risk and financial risk."[36] Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Consistent with this accepted regulatory standard, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. What criteria did you apply to develop the Non-Utility Proxy Group?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have investment grade credit ratings from S&P, and 4) have an S&P Stock Quality Ranking of "B" or higher. In addition, I included only those firms with published earnings per share ("EPS") growth projections

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[36] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 58 (1994).

from at least two of the following sources: Value Line, Thomson Reuters ("IBES"),[37] First Call Corporation ("First Call"), and Zacks Investment Research ("Zacks").

Q. Do these criteria provide objective evidence to evaluate investors' risk perceptions?

A. Yes. Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "A+") are used to show relative standing within a category. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, other quality rankings published by investment advisory services also provide relative assessments of risks that are considered by investors in forming their expectations for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source

[37] Thomson Reuters separately compiles and publishes consensus securities analyst growth rates under the IBES (formerly Institutional Brokers Estimate System) and First Call brands.

of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Q. How do the overall risks of your proxy groups compare with I&M?

A. As shown below, Table WEA-1 compares the utility proxy group with the non-utility proxy group and I&M across four key indicators of investment risk. Because the Company has no publicly traded common stock, the Value Line risk measures shown reflect those published for its parent, AEP:

TABLE WEA-1
COMPARISON OF RISK INDICATORS

	S&P	Value Line		
	Credit Rating	Safety Rank	Financial Strength	Beta
Utility Group	BBB	2	B++	0.74
Non-Utility Proxy Group	A	1	A+	0.79
I&M	BBB	3	B++	0.70

Q. Does this comparison indicate that investors would view the firms in your proxy groups as risk-comparable to I&M?

A. Yes. As discussed earlier, I&M, like its parent, AEP, is rated "BBB" by S&P, which is identical to the average corporate credit rating for the utilities in the Utility Proxy Group. Similarly, the average Financial Strength Rating of

"B++" for the Utility Proxy group is the same as that assigned to AEP. And while AEP's Safety Rank of "3" indicates greater risk than for the proxy group of utilities, its lower beta value suggests somewhat less risk. Considered together, a comparison of these objective measures, which consider of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for I&M are comparable to those of the firms in the Utility Proxy Group.

With respect to the Non-Utility Proxy Group, its average credit ratings, Safety Rank, and Financial Strength Rating suggest less risk than for I&M, with its 0.79 average beta indicating greater risk. While any differences in investment risk attributable to regulation should already be reflected in these objective measures, my analyses nevertheless conservatively focus on a lower-risk group of non-utility firms.

C. Discounted Cash Flow Analyses

Q. How is the DCF model used to estimate the cost of common equity?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The general form of the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q. What form of the DCF model is customarily used to estimate the cost of common equity in rate cases?

A. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[38]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

[38] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (*g*). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. What form of the DCF model did you use?

A. I applied the constant growth DCF model to estimate the cost of common equity for I&M, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q. How is the constant growth form of the DCF model typically used to estimate the cost of common equity?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (*g*) for the firm. The final step is to sum the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. How was the dividend yield for the Utility Proxy Group determined?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by the corresponding stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the utility proxy group are presented on Exhibit I&M-4 (WEA-2). As shown there, dividend yields for the firms in the Utility Proxy Group ranged from 2.2 percent to 6.6 percent.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. Are historical growth rates likely to be representative of investors' expectations for utilities?

A. No. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. While the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratio for electric utilities falling from approximately 80 percent historically to on the order of 60 percent.[39] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community. As noted in *Finding Reality in Reported Earnings* published by the Association for Investment Management and Research:

> [E]arnings, presumably, are the basis for the investment benefits that we all seek. "Healthy earnings equal healthy investment benefits" seems a logical equation, but earnings are also a scorecard by which we compare companies, a filter through which we assess management, and a crystal ball in which we try to foretell future performance.[40]

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[39] The Value Line Investment Survey (Sep. 15, 1995 at 161, Dec. 26, 2008 at 687).

[40] Association for Investment Management and Research, "Finding Reality in Reported Earnings: An Overview" at 1 (Dec. 4, 1996).

Value Line's near-term projections and its Timeliness Rank, which is the principal investment rating assigned to each individual stock, are also based primarily on various quantitative analyses of earnings. As Value Line explained:

> The future earnings rank accounts for 65% in the determination of relative price change in the future; the other two variables (current earnings rank and current price rank) explain 35%.[41]

The fact that investment advisory services focus primarily on growth in earnings indicates that the investment community regards this as a superior indicator of future long-term growth. Indeed, "A Study of Financial Analysts: Practice and Theory," published in the *Financial Analysts Journal*, reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[42] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 3 ranked dividends first while 276 ranked it last. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[43]

More recently, the *Financial Analysts Journal* reported the results of a study of the relationship between valuations based on alternative multiples and actual market prices, which concluded, "In all cases studied, earnings dominated operating cash flows and dividends."[44]

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[41] The Value Line Investment Survey, *Subscriber's Guide* at 53.
[42] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[43] *Id.* at 88.
[44] Liu, Jing, Nissim, Doron, & Thomas, Jacob, "Is Cash Flow King in Valuations?," *Financial Analysts Journal*, Vol. 63, No. 2 at 56 (March/April 2007).

Q. Do the growth rate projections of security analysts consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. What are security analysts currently projecting in the way of growth for the firms in the Utility Proxy Group?

A. The earnings growth projections for each of the firms in the Utility Proxy Group reported by Value Line, IBES, First Call, and Zacks are displayed on Exhibit I&M-5 (WEA-3).

Q. Some argue that analysts' assessments of growth rates are biased. Do you believe these projections are inappropriate for estimating investors' required return using the DCF model?

A. No. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

The continued success of investment services such as Thompson Reuters and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *Regulatory Finance: Utilities' Cost of Capital*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[45]

[45] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 154 (1994).

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

Accordingly, while I believe that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, I have included the "sustainable growth" approach for completeness. The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

Q. What is the purpose of the "sv" term?

A. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. When a company's stock price is greater than its book value per share, the per-share contribution in excess of book value associated with new stock issues will accrue to the current shareholders. This increase to the book value of existing shareholders leads to higher expected earnings and dividends, with the “sv” factor incorporating this additional growth component.

Q. What growth rate does the earnings retention method suggest for the Utility Proxy Group?

A. The sustainable, “br+sv” growth rates for each firm in the Utility Proxy Group are summarized on Exhibit I&M-4 (WEA-2), with the underlying details being presented on Exhibit I&M-5 (WEA-3). For each firm, the expected retention ratio (b) was calculated based on Value Line’s projected dividends and earnings per share. Likewise, each firm’s expected earned rate of return (r) was computed by dividing projected earnings per share by projected net book value. Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, consistent with the theory underlying this approach to estimating investors’ growth expectations. Meanwhile, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio.

Q. What other growth rate did you consider?

A. As noted earlier, the DCF model assumes that investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation. Consistent with this paradigm, I also examined expected growth in each utility’s stock price based on Value Line’s 2011-2014 projections.

Q. What cost of common equity estimates were implied for the Utility Proxy Group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on Exhibit I&M-4 (WEA-2).

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate estimates that are extreme low or high outliers?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. How did you evaluate DCF estimates at the low end of the range?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for their risk bearing. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF results for the Utility Proxy Group must be adjusted to eliminate estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. In a 2002 opinion establishing its current precedent for determining ROEs for electric utilities, for example, FERC noted:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[46]

More recently, in its March 27, 2009 decision in *Pioneer*, FERC concluded that it would exclude low-end ROEs "within about 100 basis points above the cost of debt."[47]

Q. What does this test of logic imply with respect to the DCF results for the Utility Proxy Group?

A. The average corporate credit rating associated with the firms in the Utility Proxy Group is "BBB". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B bonds averaging approximately 6.14 percent in October 2009.[48] As highlighted on Exhibit I&M-4 (WEA-2), three of the individual equity estimates for the firms in the Utility Proxy Group exceeded this threshold by approximately 100 basis points, with another falling below the yield available on triple-B utility bonds.[49] In light of the risk-return tradeoff principle and the test applied in *Pioneer*, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the

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[46] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000) at p. 22.
[47] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 94 (2009) ("*Pioneer*").
[48] Moody's Investors Service, www.credittrends.com.
[49] As highlighted on Exhibit WEA-3, these DCF estimates ranged from 4.1 percent to 7.2 percent.

riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC, this value provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. Do you also recommend excluding estimates at the high end of the range of DCF results?

A. Yes. The upper end of the cost of common equity range produced by the DCF analysis presented in Exhibit I&M-4 (WEA-2) was set by a 25.1 percent cost of equity estimate for Allegheny Energy, Inc. In addition to this extreme outlier, I determined that, when compared with the balance of the remaining estimates, six other DCF estimates should also be excluded in evaluating the results of the DCF model for the Utility Proxy Group. This is also consistent with the precedent adopted by FERC, which has established that estimates found to be "extreme outliers" should be disregarded in interpreting the results of the DCF model.[50]

Q. What cost of common equity estimates are implied by your DCF results for the Utility Proxy Group?

A. As shown on Exhibit I&M-4 (WEA-2) and summarized in Table WEA-2, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates ranging from 10.1 percent to 12.4 percent, and generally trending toward 10.8 percent:

[50] See, *e.g.*, *ISO New England*, *Inc.*, 109 FERC ¶ 61,147 at P 205 (2004).

TABLE WEA-2
DCF RESULTS – UTILITY PROXY GROUP

Growth Rate	Average Cost of Equity
Value Line	10.1%
IBES	10.6%
First Call	10.4%
Zacks	11.1%
br+sv	10.8%
Stock Price	12.4%

Q. What were the results of your DCF analysis for the Non-Utility Proxy Group?

A. I applied the DCF model to the Non-Utility Proxy Group in exactly the same manner described earlier for the Utility Proxy Group. The results of my DCF analysis for the Non-Utility Proxy Group are presented in Exhibit I&M-6 (WEA-4), with the sustainable, "br+sv" growth rates being developed on Exhibit I&M-7 (WEA-5). As shown on Exhibit I&M-6 (WEA-4) and summarized in Table WEA-3, below, after eliminating illogical low- and high-end values, application of the constant growth DCF model resulted in cost of common equity estimates generally in the 12 percent to 13 percent range:

TABLE WEA-3
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average Cost of Equity
Value Line	11.4%
IBES	12.4%
First Call	12.8%
Zacks	13.0%
br+sv	12.3%
Stock Price	12.4%

As discussed earlier, reference to the Non-Utility Proxy Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

D. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. How did you apply the CAPM to estimate the cost of common equity?

A. Application of the CAPM to the Utility Proxy Group based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit I&M-8 (WEA-6). In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-half of the growth rate discussed subsequently (1 + *g*) to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 348 individual firms, current estimates imply an average growth rate over the next five years of 9.2 percent. Combining this average growth rate with an adjusted dividend yield of 2.7 percent results in a current cost of common equity estimate for the market as a whole of approximately 11.9 percent. Subtracting a 4.2 percent risk-free rate based on the average yield on 20-year Treasury bonds produced a market equity risk premium of 7.7 percent.

Q. What was the source of the beta values you used to apply the CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Value Line betas are computed on a theoretically sound basis using a broadly-based market index, and they are adjusted for the regression tendency of betas to converge to 1.00. . . . Value Line is the largest and most widely circulated independent investment advisory service, and exerts influence on a large number of institutional and individual investors and on the expectations of these investors.[51]

As shown on Exhibit I&M-8 (WEA-6), multiplying the 7.7 percent market risk premium by the respective Value Line betas for the firms in the Utility Proxy Group, and then adding the resulting risk premiums to the average long-

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[51] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* at 65 (1994).

term Treasury bond yield, results in an average indicated cost of common equity of 9.9 percent.

Q. What cost of common equity was indicated for the Non-Utility Proxy Group based on this forward-looking application of the CAPM?

A. As shown on Exhibit I&M-9 (WEA-7), applying the forward-looking CAPM approach to the firms in the Non-Utility Proxy Group results in an average implied cost of common equity of 10.3 percent.

Q. Do you have any observations regarding these CAPM results?

A. Yes. Applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. Thus, recent capital market conditions may cause CAPM cost of common equity estimates to understate investors' required returns for common stocks, particularly when historical data are used to calculate the market risk premium. While my application of the CAPM makes every effort to incorporate investors' forward-looking expectations, the full effect of the "flight to safety" may not be captured in my market risk premium estimate.

Second, the beta in CAPM theory is a measure of the investors' expected relationship of a firm's stock price to the market as a whole. Because investors' expected beta for a firm is not known, reported betas are estimated based on historical relationships. The precipitous drop and subsequent partial recovery in stock prices over the last year or so have caused many firms' historical betas to become unstable, so that reported betas may or may not reflect investors' expected beta. Because of this inherent mismatch between the historical circumstances underlying reported beta values and the current perceptions of investors, the CAPM may not accurately reflect investor's forward-looking rate of return requirements.

Meanwhile, forward-looking estimates of the market required rate of return may be distorted by the recent run-up in stock prices. It is not clear whether reported security analysts' dividend and growth projections have kept pace with the economic recovery expectations presumably pushing up stock prices; if not, there is a mismatch that under-estimates of the market required rate of return. This incongruity between current measures of the market risk premium and historical beta values is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. As a result, there is every indication that CAPM approaches fail to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

E. Expected Earnings Approach

Q. What other analyses did you conduct to estimate the cost of common equity?

A. As I noted earlier, I also evaluated the cost of common equity using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What rates of return on equity are indicated for utilities based on the expected earnings approach?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent in 2009, and 11.0 percent in 2010 and over its 2012-2014 forecast horizon.[52] Meanwhile, for the firms in the Utility Proxy Group specifically, the returns on common equity projected by Value Line over its three-to-five year forecast horizon are shown on Exhibit I&M-10 (WEA-8). Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit I&M-5 (WEA-3). As shown on Exhibit

[52] The Value Line Investment Survey at 2232 (Nov. 6, 2009).

I&M-10 (WEA-8), Value Line's projections for the utility proxy group suggested an average ROE of 11.3 percent.

F. Summary of Quantitative Results

Q. Please summarize the results of your quantitative analyses.

A. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-4, below:

A. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-4, below:

TABLE WEA-4
SUMMARY OF QUANTITATIVE RESULTS

DCF	Utility	Non-Utility
Value Line	10.1%	11.4%
IBES	10.6%	12.4%
First Call	10.4%	12.8%
Zacks	11.1%	13.0%
br+sv	10.8%	12.3%
Stock Price	12.4%	12.4%
CAPM	9.9%	10.3%
Expected Earnings		
Electric Utilities - 2009	10.5%	
Electric Utilities - 2010	11.0%	
Electric Utilities - 2012-14	11.0%	
Utility Proxy Group	11.3%	

As noted earlier, because the capital market crisis and ensuing recovery have created a number of problems in applying the CAPM, I largely disregarded the resulting cost of equity estimates. Based on my assessment of the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, I concluded that the cost of common equity indicated by my analyses is in the 10.8 percent to 12.4 percent range.

G. Flotation Costs

Q. What other considerations are relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. Has AEP recently issued additional common equity?

A. Yes. On April 7, 2009 AEP closed on the sale of 69 million shares of common stock. With the net proceeds raising approximately $1.64 billion of additional equity capital, AEP's stock sale constituted the largest in the utility industry since 1995.[53] Thus, in addition to flotation costs associated with past equity issues, AEP also incurred issuance costs associated with its recent sale of new common shares. Furthermore, in June 2009 I&M received $120 million in equity capital from AEP.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of

[53] Katz, David M. and Marie Leone, "How AEP Finance Chief Drove Jumbo Stock Offering," *CFO.com* (Apr. 8, 2009).

the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[54]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%,[55] with AEP incurring issuance costs equal to approximately 3.02 percent of the gross proceeds from its 2009 public offering.[56] Applying this 3.0 percent expense percentage for AEP to a representative dividend yield of 5.0 percent implies a minimum flotation cost adjustment on the order of 15 basis points.

Q. What then is your conclusion regarding a fair ROE based on your analyses for the companies in your proxy groups?

A. After incorporating a minimum adjustment for flotation costs of 15 basis points to my "bare bones" cost of equity range, I concluded that a fair ROE for the proxy group of electric utilities is currently in the 10.95 to 12.55 percent range.

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[54] Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 1994, at 166.

[55] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[56] American Electric Power Company, Inc., *Prospectus Supplement (To Prospectus dated December 22, 2008)* (Apr. 1, 2009).

IV. RETURN ON EQUITY FOR INDIANA MICHIGAN POWER CO.

Q. What is the purpose of this section?

A. In addition to presenting my conclusions regarding a fair ROE for I&M, this section also discusses the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital. In addition, I evaluate the reasonableness of I&M's requested capital structure and examine the implications of cost adjustment mechanisms for the Company's ROE.

A. Implications for Financial Integrity

Q. Why is it important to allow I&M an adequate ROE?

A. Given the importance of the utility industry to the economy and society, it is essential to maintain reliable and economical service to all consumers. While the Company remains committed to providing reliable electric service, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of the pressures associated with ongoing capital expenditure requirements, uncertain environmental compliance costs, and the potential for continued energy price volatility. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact.

While providing the infrastructure necessary to enhance the power system and meet the energy needs of customers is certainly desirable, it imposes additional financial responsibilities on I&M and its parent, AEP. Indeed, despite the dramatic and sustained fall in utility stock prices, AEP issued new common shares even at depressed prices in order to meet its capital needs and support financial strength. For a utility with an obligation to provide reliable service, investors' increased reticence to supply additional capital during times of crisis highlights the necessity of preserving the flexibility necessary to overcome periods of adverse capital market conditions. These considerations heighten the importance of allowing I&M an adequate ROE.

Q. What role does regulation play in ensuring that I&M has access to capital under reasonable terms and on a sustainable basis?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, the continuation of supportive regulation remains crucial to the Company's access to capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Fitch noted that:

> Regulatory risk remains a recurring theme for this year's outlook, as the pressure of a weak economic backdrop could result in political push-back to rate increase requests.[57]

[57] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22, 2008).

The report went on to conclude, "Fitch is concerned that the recent rapid escalation in the cost of capital will not be reflected on a timely basis in utility rates."[58] Moody's has also emphasized the need for regulatory support, concluding:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[59]

Similarly, S&P concluded, "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[60]

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. Providing a return on fair value that is both commensurate with those available from investments of corresponding risk and sufficient to maintain I&M's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the U.S. Supreme Court's *Bluefield* and *Hope* decisions; but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when the ability of the utility to attract capital is impaired and service quality is compromised.

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[58] *Id.*

[59] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).

[60] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

B. Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that will remain.

Q. What common equity ratio is implicit in I&M's requested capital structure?

A. The Company's capital structure is presented in the testimony of Renee V. Hawkins. As summarized on Exhibit I&M-12 (RVH-1), common equity as a percent of I&M's permanent capital projected at year-end 2010 was 49.52 percent.

Q. How can the Company's requested capital structures be evaluated?

A. It is generally accepted that the norms established by comparable firms provide one valid benchmark against which to evaluate the reasonableness of a utility's capital structure. The capital structure maintained by other electric utilities should reflect their collective efforts to finance themselves so as to minimize capital costs while preserving their financial integrity and ability to attract capital. Moreover, these industry capital structures should also incorporate the requirements of investors (both debt and equity), as well as the influence of regulators.

Q. What was the average capitalization maintained by the Utility Proxy Group?

A. As shown on Exhibit I&M-11 (WEA-9), for the firms in the Utility Proxy Group, common equity ratios at December 31, 2008 ranged between 39.4 percent and 65.4 percent and averaged 47.6 percent of long-term capital.

Q. What capitalization is representative for the Utility Proxy Group going forward?

A. As shown on Exhibit I&M-11 (WEA-9), Value Line expects an average common equity ratio for the Utility Proxy Group of 51.1 percent for its three-to-five year forecast horizon, with the individual common equity ratios ranging from 43.0 percent to 68.0 percent.

Q. What implication does the increasing risk of the utility industry have for the capital structure maintained by I&M?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the ongoing turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the opportunity to strengthen the balance sheet as a buffer against future uncertainties.[61] Moody's noted that, "maintaining unfettered access to capital markets will be crucial," and cited the importance of forestalling future downgrades by bolstering utility balance sheets.[62] As Moody's concluded:

> Our concerns are clearly growing, but we believe utilities have adequate time to adjust and revise their corporate finance polices and strengthen balance sheets, thereby improving their ability to manage volatility and address uncertainty.[63]

Similarly, in a review of the analytical methodology underlying its ratings assessment, S&P characterized a debt-to-total capital ratio in the range of 50 percent to 60 percent as "Aggressive",[64] and noted, "A total debt to capitalization level of 50% or greater is generally considered to be aggressive to highly leveraged for utilities."[65] Moody's affirmed that because of its significant investment plans, the utility industry "will need to attract a significant amount of new equity capital in order to maintain existing ratings."[66]

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[61] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).
[62] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).
[63] Id.
[64] Standard & Poor's Corporation, "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," *RatingsDirect* (May 27, 2009).
[65] Standard & Poor's Corporation, "Ratings Trend Turns Negative During First Quarter Of 2009 For U.S. Electric Utilities," *RatingsDirect* (Apr. 14, 2009).
[66] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities: Six-Month Industry Update," *Industry Outlook* (July 2008).

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Depending on their specific attributes, contractual agreements or other obligations that require the utility to make specified payments may be treated as debt in evaluating I&M's financial risk. Because investors consider the debt impact of such fixed obligations in assessing a utility's financial position, they imply greater risk and reduced financial flexibility. In order to offset the resulting debt equivalent, the utility must rebalance its capital structure by increasing its common equity in order to restore its effective capitalization ratios to previous levels.

These commitments have been repeatedly cited by major bond rating agencies in connection with assessments of utility financial risks,[67] with Fitch noting adjustments to I&M's credit ratios in order to take into account off-balance-sheet lease obligations related to the Rockport plant.[68] Similarly, S&P adjusts I&M's reported debt amounts upward to include approximately $902.5 million in debt equivalents associated with lease obligations.[69] Unless the Company takes action to offset this additional financial risk by maintaining a higher equity ratio, the resulting leverage will weaken I&M's creditworthiness and imply greater risk.

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[67] See, *e.g.*, Standard & Poor's Corporation, "Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements," *RatingsDirect* (May 7, 2007); Standard & Poor's Corporation, "Implications Of Operating Leases On Analysis Of U.S. Electric Utilities," *RatingsDirect* (Jan. 15, 2008)

[68] Fitch Ratings Ltd., "Indiana Michigan Power Co.," *Global Power U.S. and Canada Credit Analysis* (April 30, 2009).

[69] Standard & Poor's Corporation, "Indiana Michigan Power Co.," *RatingsDirect* (Dec. 19, 2008).

Q. What does this evidence suggest with respect to I&M's proposed capital structure?

A. Based on my evaluation, I concluded that I&M's requested capital structure represents a reasonable mix of capital sources from which to calculate the Company's overall rate of return. While industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. A public utility with an obligation to serve must maintain ready access to capital so that it can meet the service requirements of its customers. The need for access becomes even more important when the company has large capital requirements over a period of years, and financing must be continuously available, even during unfavorable capital market conditions.

I&M's proposed capital structure is entirely consistent with the capitalizations maintained by the utilities in the proxy group and reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of I&M's requested capital structure is reinforced by the ongoing uncertainties associated with the electric power industry and the importance of supporting continued investment in system improvements, even during times of adverse industry or market conditions.

C. Impact of Trackers

Q. How are fluctuations in energy costs for I&M accommodated in rates?

A. The Company's retail electric rates in Michigan contain a Power Supply Cost Recovery clause ("PSCR"), whereby increases and decreases in the cost of generating fuel and purchased power costs are reflected in the rates charged to retail electric customers. The MPSC requires annual filings and hearings to establish the amount of price adjustments under the PSCR and also provides for deferral and subsequent recovery or refund of variances between the estimated cost of fuel and purchased power and the actual costs incurred. To implement the clause, I&M is required to file a PSCR plan, as well as a five-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs.

While the PSCR is supportive of the Company's financial integrity, even for utilities with energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is fully recovered from ratepayers. Thus, the PSCR does not insulate I&M from the need to finance significant deferred power production and supply costs. Indeed, despite the significant investment of resources to manage power supply procurement, investors are aware that the best that I&M can do is to recover its actual costs.

Q. Does I&M operate under other ongoing cost recovery mechanisms?

A. Yes. The MPSC has approved the Energy Optimization Plan Tracker, which is designed to recover the costs of mandated energy efficiency programs, as well as a surcharge related to the costs of nuclear decommissioning. Also, as discussed in the testimony of other Company witnesses, I&M has proposed several new tracking mechanisms in this case, including the Generation Investment Tracker, the gridSMART^{SM} Tracker, the Net Lost Revenue Recovery Tracker and the Enhanced Distribution Reliability Tracker.

Q. Does the fact that I&M operates under various cost adjustment mechanisms warrant any adjustment in your evaluation of a fair ROE?

A. No. Investors recognize that I&M is exposed to significant risks associated with energy price volatility and rising costs and concerns over these risks have become increasingly pronounced in the industry. The MPSC's cost adjustment mechanisms are a valuable means of mitigating those risks, but they do not eliminate them. As noted above, of particular concern to investors is the impact of regulatory lag and cost-recovery on the utility's ability to earn its authorized return. While the adjustment mechanisms approved for I&M partially attenuate exposure to attrition in an era of rising costs, this leveling of the playing field only serves to address factors that could otherwise impair the Company's opportunity to earn its authorized return, as required by established regulatory standards.

Moreover, adjustment mechanisms and trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as energy conservation, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty through adjustment mechanisms. While not always directly analogous to the specific mechanisms approved for I&M, the objective is similar; namely, to allow the utility an opportunity to earn a fair rate of return and partially attenuate exposure to attrition in an era of rising costs.

Reflective of this industry trend, the companies in the Utility Proxy Group operate under a variety of cost adjustment mechanisms, which range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling and adjustment clauses designed to address the rising costs of environmental compliance measures. Similarly, the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the mitigation in risks associated with utilities' ability to attenuate the risk of cost recovery is already reflected in the cost of equity range determined earlier, and no separate adjustment to I&M's ROE is necessary or warranted.

D. Return on Equity Range Recommendation

Q. Please summarize the results of your analyses.

A. In order to reflect the risks and prospects associated with I&M's jurisdictional utility operations, my analyses focused on a proxy group of twenty other utilities with comparable investment risks. Consistent with the fact that utilities must compete for capital with firms outside their own industry, I also referenced a proxy group of comparable risk companies in the non-utility sectors of the economy. The cost of common equity estimates produced by the various capital market oriented analyses described in my testimony are summarized in Table WEA-4, which is reproduced below:

TABLE WEA-4
SUMMARY OF QUANTITATIVE RESULTS

	Utility	Non-Utility
DCF		
Value Line	10.1%	11.4%
IBES	10.6%	12.4%
First Call	10.4%	12.8%
Zacks	11.1%	13.0%
br+sv	10.8%	12.3%
Stock Price	12.4%	12.4%
CAPM	9.9%	10.3%
Expected Earnings		
Electric Utilities - 2009	10.5%	
Electric Utilities - 2010	11.0%	
Electric Utilities - 2012-14	11.0%	
Utility Proxy Group	11.3%	

As noted earlier, based on my assessment of the relative strengths and weaknesses inherent in each method, I concluded that the cost of common equity indicated by my analyses is in the 10.8 percent to 12.4 percent range. After incorporating a minimum adjustment for flotation costs of 15 basis points to my “bare bones” cost of equity range, I concluded that a fair rate of return on equity for the proxy group of electric utilities is currently in the 10.95 to 12.55 percent range.

Q. What else should be considered in establishing a fair ROE range for I&M?

A. While corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. This implies that the cost of permanent capital, including common equity, will be higher in the upcoming years than it is currently.

Q. How do current interest rates on long-term bonds compare with those projected for the next few of years?

A. Table WEA-5 below compares current interest rates on 30-year Treasury bonds, double-A rated utility bonds, and triple-A rated corporate bonds with those projected for 2008 through 2011 by Value Line,[70] GlobalInsight,[71] , and the EIA:[72]

TABLE WEA-5
INTEREST RATE TRENDS

	2010	**2011**	**2012**	**2013**	**Oct. 2009**
30-Yr. Treasury					
Value Line	4.8%	4.5%	5.1%	5.5%	4.2%
GlobalInsight	3.8%	4.9%	5.0%	5.2%	4.2%
AA Utility					
GlobalInsight	6.2%	6.5%	6.4%	6.7%	5.2%
EIA	6.1%	6.8%	6.6%	6.8%	5.2%
AAA Corporate					
Value Line	5.9%	5.8%	6.2%	6.7%	5.2%
GlobalInsight	5.4%	6.0%	6.0%	6.2%	5.2%

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2010-2013 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

[70] The Value Line Investment Survey, *Forecast for the U.S. Economy* (Aug. 28, 2009).
[71] GlobalInsight, *The U.S. Economy: The 30-Year Focus* (First Quarter 2009).
[72] Energy Information Administration, *Updated Annual Energy Outlook 2009* (Mar. 2009).

Q. What then is your conclusion as to a fair ROE for I&M?

A. Considering capital market expectations, the potential exposures faced by I&M, and the economic requirements necessary to maintain financial integrity and support additional capital investment even under adverse circumstances, it is my opinion that 11.75 percent represents a fair and reasonable ROE for I&M.

My conclusion is reinforced by the need to consider the potential exposures faced by I&M and the economic requirements necessary to maintain financial integrity and support access to capital even under adverse circumstances. Because nuclear power represents a significant portion of the Company's generating capability, I&M is exposed to significant financial threats. In addition, I&M faces ongoing uncertainties related to future emissions legislation. Coupled with the need to provide an ROE that supports I&M's credit standing while funding necessary system investments, these considerations indicate that an ROE from the middle of my recommended range is reasonable. The cost of providing the Company an adequate return is small relative to the potential benefits that a strong utility can have in providing reliable service. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation is crucial.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

RENEE V. HAWKINS

PRE-FILED DIRECT TESTIMONY OF RENEE V. HAWKINS
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Renee V. Hawkins. My business address is One Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by American Electric Power Service Corporation (AEPSC), a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), as Managing Director, Corporate Finance. AEP is the parent company of Indiana-Michigan Power Company (I&M or Company) and AEPSC is I&M's service company. In addition, I am the Assistant Treasurer of I&M as well as AEP, Inc. and the other AEP subsidiaries.

Q. Please briefly describe your educational and business experience.

A. I received a Bachelor's Degree in Finance and International Business from The Ohio State University in Columbus, Ohio in 1987, and a Master's Degree in Business Administration with a Finance concentration from the Simon School at the University of Rochester in Rochester, New York in 1991.

In June 1991, I was employed by General Motors as an analyst for AC Delco, which is now a subsidiary of Delphi East.

In June 1993, I was hired by Cablevision Systems Corporation, first as a Senior Financial Analyst and then promoted to Treasury Manager. My responsibilities included managing capitalization and liquidity for a number of subsidiaries. Included in those responsibilities were raising capital through bank and financial markets, managing compliance, and supporting investor and rating agency relations.

In October 1996, I joined AEPSC as a Corporate Finance Senior Analyst supporting financing activity for the AEP operating companies. In July 1999, I was named Manager, Corporate Finance of AEPSC. In June 2000, I was named Director, Corporate Finance of AEPSC, a position that was renamed Director, Regulated Finance in 2001. In that capacity, I was responsible for capital markets activity for all of the regulated utilities, and such things as establishing dividend recommendations and capitalization targets, supporting the rating agency relationships to maintain credit ratings and assisting in the management of liquidity for the overall AEP System. I was promoted to Managing Director, Corporate Finance in July 2003 and Assistant Treasurer in January 2008.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes, I have presented testimony or testified on behalf of Indiana Michigan Power Company before the Indiana Utility Regulatory Commission. I have presented testimony or testified on behalf of Appalachian Power Company before the Public Service Commission of West Virginia, the Virginia State Corporation Commission and the Federal Energy Regulatory Commission

(FERC). I have presented testimony or testified before the Arkansas Public Service Commission (APSC or Commission), and the Public Utility Commission of Texas on behalf of SWEPCO. Finally, I have testified on behalf of Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to present and support the following:

- Capital structure and overall cost of capital for I&M
- Credit ratings of I&M
- Recent activity between the 2008 Historical period and the projected 2010 test year
- Carrying Costs for 2010

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Projected 2010 Schedules:

- I&M-12 (RVH-1) Schedule D-1 Projected Rate of Return Summary
- I&M-13 (RVH-2) Schedule D-2 Projected Cost of Long-term Debt
- I&M-14 (RVH-3) Schedule D-3 Projected Cost of Short-term Debt
- I&M-15 (RVH-4) Schedule D-4 Projected Cost of Preferred Stock
- I&M-16 (RVH-5) Schedule D-5 Projected Cost of Common

Shareholders' Equity

2008 Historic Schedules:

- I&M-17 (RVH-6) Schedule D-1 Historic Rate of Return Summary
- I&M-18 (RVH-7) Schedule D-2 Historic Cost of Long-term Debt
- I&M-19 (RVH-8) Schedule D-3 Historic Cost of Short-term Debt
- I&M-20 (RVH-9) Schedule D-4 Historic Cost of Preferred Stock
- I&M-21 (RVH-10) Schedule D-5 Historic Cost of Common Shareholders' Equity
- I&M-22 (RVH-11) Financial Metrics
- I&M-23 (RVH-12) Annual Investment Carrying Charge Calculation

Q. Were Exhibits I&M-12 through I&M-23 (RVH-1 through RVH-12) prepared by you or under your direct supervision?

A. Yes.

Q. Please describe Exhibit I&M-12 (RVH-1) Projected Cost of Capital as of December 31, 2010.

A. Schedule D-1 computes the total cost of capital for I&M, with both permanent capital and ratemaking adjustments.

Indiana Michigan Power
Projected 2010 Cost of Capital

Line No.	CAPITAL ELEMENT	13-MONTH AVERAGE BALANCE (1)	% PERMANENT CAPITAL	% WITH RATE BASE ADJUSTMENTS	% COST RATE	% WEIGHTED COST PERMANENT	% WEIGHTED COST RATE BASE
1		$					
2	LONG TERM DEBT	1,697,769,231	49.26	43.95	6.40	3.15	2.81
3	SHORT TERM DEBT	33,955,793	0.99	0.88	1.54	0.02	0.01
4	PREFERRED STOCK	8,076,800	0.23	0.21	7.19	0.02	0.02
5	COMMON EQUITY	1,706,805,806	49.52	44.19	11.75	5.82	5.19
6							
7	TOTAL WITHOUT TAXES	3,446,607,630	100.00			9.01	8.03
8							
9	ACC. DEF. ITC (3%)	0		0.00	0.00		0.00
10	ACC. DEF. FIT	359,636,000		9.31	0.00		0.00
11	ACC. DEF. JDITC	56,560,000		1.46	9.01		0.13
12							
13	TOTAL WITH TAXES	3 862 803 630		100 00			8 16

The thirteen month average balance on line 2 is supported by Exhibit I&M-13 (RVH-2), Schedule D-2 Projected Cost of Long-term Debt. The thirteen month average balance on line 3 is supported by Exhibit I&M-14 (RVH-3), Schedule D-3 Projected Cost of Short-term Debt. The thirteen month average balance on line 4 is supported by Exhibit I&M-15 (RVH-4), Schedule D-4 Projected Cost of Preferred Stock. The thirteen month average balance on line 5 is supported by Exhibit I&M-16 (RVH-5) Projected Cost of Shareholders' Equity. The accumulated deferred income tax calculations are shown at the bottom of the exhibit. The cost rate assigned to Accumulated Deferred Job Development Investment Tax Credits (JDITC) is the thirteen month average cost rate of investor-provided capital. No cost was assigned to the Accumulated Deferred Federal Income Tax (FIT) consistent with past Commission practices.

Witness Avera is supporting a Common Equity cost rate of 11.75%. When weighting these costs against the capital balances at the end of 2010, the weighted average cost of capital is 8.16% after taxes as shown on line 13 in Exhibit I&M-12 (RVH-1).

Q. Please describe Exhibit I&M-13 (RVH-2), Schedule D-2 Projected Cost of Long-term Debt as of December 31, 2010.

A. This schedule identifies all long-term debt projected to be outstanding as of December 31, 2010, and the related annualized costs. The costs include premiums and discounts, issuance expenses, gains or losses recognized on reacquisition of debt, and associated hedging gains and losses. All debt included in this schedule has already been issued and the schedule contains no projected transactions. The calculated embedded cost for long-term debt is 6.40%.

Q. Please describe Exhibit I&M-14 (RVH-3) Schedule D-3 Projected Cost of Short-term Debt as of December 31, 2010.

A. This schedule includes the projected thirteen month average of I&M Consolidated less River Transportation Division, as of December 31, 2010. The thirteen-month average short-term debt level projected for 2010 of $33,955,793 is significantly less than 2008 the thirteen month average of

$229,330,896 and is more representative of the average balance going forward. The short-term debt levels increased significantly during 2008 due to the financial crisis that occurred upon the bankruptcy of Lehman Brothers, which impacted I&M's plans to issue senior notes in 2008. The $50 million Senior Notes Series A matured in 2008 and the Company had to tender in auction rate securities that had failed auctions. New notes were not reissued until 2009 when the market conditions improved. In January 2009, a $475 million unsecured 7% senior note was issued. Rockport pollution control bonds were tendered in May of 2008 and not reissued until 2009 at a rate of 6.25% for a 5-year period. Until these transactions occurred in early 2009, I&M was funded with higher levels of short-term debt than is typical.

Q. Was the historic period calculated consistent with the projected test year?

A. Yes. The historic period calculations included in Exhibits I&M-17 (RVH-6) through Exhibit I&M-21 (RVH-10) which include schedules D-1 through D-5 for the historic period were prepared in a similar manner as discussed above for the projected test year. As noted above, the historic period of year end 2008 is not representative of going forward short term debt levels due to the market disruptions that occurred in that period.

Q. Please provide a summary of the current credit ratings for I&M.

A. I&M is rated Baa2 by Moody's Investor Service (Moody's), BBB by Standard and Poor's (S&P), and BBB- by Fitch Ratings Service (Fitch). The ratings are stable from all three rating agencies and have not changed in the past five years. S&P has taken a family approach to the ratings of all of the AEP System subsidiaries and the bond ratings of I&M are based upon those of the entire family. S&P states the major strengths of the AEP System are the steady utility operating cash flow, large diverse regulated electric utility operations and low cost generation asset portfolio. According to S&P, the weaknesses are the Parent's marketing operations and the leverage, which is considered high for the rating.

Moody's rates each operating company individually but does recognize that each is part of a larger holding company. Moody's has stated that the large capital investment program constrains the rating and that managing the DC Cook nuclear outage represents a near-term risk.

Fitch has stated that the credit strengths for I&M include stable cash flow and its affiliation with the AEP System family. According to Fitch, credit concerns primarily relate to I&M's exposure to industrial customers in local service territories with struggling economies, as well as the potential financial and operational impact of the shutdown of Unit 1 of the Cook nuclear plant.

Q. Please provide a summary of the current credit ratings for AEP, Inc.

A. AEP, Inc. is rated Baa2 by Moody's, BBB by S&P, and BBB by Fitch. The ratings are stable from S&P and Fitch and have not changed in the past five years. AEP was placed on negative outlook from Moody's in February 2009. In addition, AEP, Inc. was upgraded to Baa3 from Baa2 in September 2005 after it was placed on review for upgrade in August of 2005. There were no other rating changes except as noted above in the last five years for AEP, Inc.

Q. What are the credit metrics of I&M on an actual and pro forma basis (without the change in revenue requirements)?

A. There is a significant divergence between Accounting Principles Generally Accepted in the United States (GAAP) capitalization of I&M Consolidated and capitalization as measured by the rating agencies. Each agency has its own capitalization adjustments that are made in published reports, but universally the agencies include all leases as debt and account for the sale of accounts receivable in a similar manner. I will refer to the debt amount including leases as credit-adjusted debt. With these additions, the credit-adjusted debt as a percentage of capitalization for I&M on December 31, 2008, was 61.8%, inclusive of leases of approximately $639 million amount, primarily resulting from the Rockport Unit 2 sale-leaseback. The funds from operations (FFO) interest coverage was 2.9x as shown in exhibit I&M-22 (RVH-11) Financial Metrics. Funds from operations are defined as cash from operations less changes in working capital.

Credit-adjusted debt as a percentage of capitalization for I&M as of December 31, 2010 is projected to be 59.5%. The FFO interest coverage is projected to be 2.7x.

Q. Please describe the recent activity between the historic test year and the projected 2010 cost of capital.

A. As mentioned previously, there was a 7% senior unsecured note for $475 million issued in January 2009 that is an adjustment between the historic test year and projected 2010. A $25 million inter-company note at a rate of 5.375% was also issued in early January 2009 as short term debt neared the maximum allowable amount outstanding. I&M reissued the Rockport bonds in March 2009 when the market conditions improved (Rockport 2009A for $50 million and Rockport 2009B for $50 million, both with a coupon of 6.25%).

Q. Were there any equity contributions to I&M?

A. Yes. In June 2009, AEP contributed $120 million in equity to I&M. This contribution was related to the April 2009 equity issuance by AEP of 69 million shares with the purpose of reducing leverage at AEP and the various utilities. I&M's equity contribution was based upon the need to fund pension expense and to manage to a GAAP equity target in the 45% range.

Q. Are there any other adjustments to the projected test year?

A. Yes. The equity balance has been adjusted for the projected retained capital earnings as of December 31, 2010 prior to receiving rate relief requested in this proceeding.

Q. What is the projected carrying cost for 2010?

A. The carrying cost calculation was based on a pre-tax return of 9.01% and a pre-tax weighted average cost of capital of 3.15%. The carrying costs for 5, 7, 15, 30 and 35 year investments are 32.15%, 27.74%, 19.23%, 16.05%, and 15.57% respectively. See Exhibit I&M-23 (RVH-12) for the calculation. I have provided the carrying cost calculations to Company Witness Roush who discusses them further in his testimony.

Q. Is the projected 2010 test year capital structure appropriate for establishing rates?

A. Yes, the year end 2010 capital structure reflects appropriate long term debt and short term percentages for I&M during the time rates are expected to be in effect. Also, all of the projected transactions in the 2010 cost of capital have already occurred and many were delayed issuances.

Q. Does this complete your direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM A. ALLEN

PRE-FILED DIRECT TESTIMONY OF WILLIAM A. ALLEN
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is William A. Allen, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and what is your position?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as Director of Operating Company Forecasts. AEPSC supplies engineering, financing, accounting, and planning and advisory services to the eleven electric operating companies of the American Electric Power System, one of which is Indiana Michigan Power Company (I&M).

Q. Would you please describe your educational and professional background?

A. Yes. I received a Bachelor of Science in Nuclear Engineering from the University of Cincinnati in 1996 and a Master of Business Administration from the Ohio State University in 2004.

I was employed by AEPSC beginning in 1992 as a Coop Engineer in the Nuclear Fuels, Safety and Analysis department and upon completing my degree in 1996 was hired on a permanent basis in the Nuclear Fuel section of the same department. In January 1997, the Nuclear Fuel section became a part of I&M due to a corporate restructuring. In 1999, I transferred to the Business Planning section of the Nuclear Generation Group as a Financial

Analyst. In 2000, I transferred back to AEPSC into the Regulatory Pricing and Analysis section as a Regulatory Consultant. In 2003, I transferred into the Corporate Financial Forecasting department as a Senior Financial Analyst. I was named to my current position in April 2007.

Q. What are your responsibilities as Director of Operating Company Forecasts?

A. I am primarily responsible for the supervision of the financial forecasting and analysis of the AEP System's eleven operating companies of which I&M is one. In such capacity, I coordinate short- and long-term forecasts for these companies as well as monthly analysis of budget to actual variances. With respect to this filing, I am responsible for development of I&M's financial forecast.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony on behalf of I&M before the Michigan Public Service Commission (MPSC) in I&M's 2007, 2008, 2009 and 2010 Power Supply Cost Recovery (PSCR) Plan Cases and before the Indiana Utility Regulatory Commission (IURC) in Cause Numbers 38702-FAC58, FAC59, FAC60, FAC62 and FAC63; 43774 and 43775. I have also testified on behalf of Appalachian Power Company in fuel related proceedings before the West Virginia Public Service Commission and the Virginia State Corporation Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present I&M's 2010 projected test year, to discuss the forecast methodology and to discuss the reasonableness of the projected test year. I will also support the power supply cost recovery (PSCR) basing point.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

1) Exhibit I&M-24 (WAA-1) 2010 Total Company Projected Revenues and Expenses;
2) Exhibit I&M-25 (WAA-2) Historical and Projected O&M Data;
3) Exhibit I&M-26 (WAA-3) 2010 13-Month Average Total Company Projected Rate Base Items;
4) Exhibit I&M-27 (WAA-4) Historical and Projected Functional Plant Activity;
5) Exhibit I&M-28 (WAA-5) 2010 Total Company Projected PSCR Costs;
6) Exhibit I&M-29 (WAA-6) 2010 Total Company Projected Transmission Costs; and
7) Exhibit I&M-30 (WAA-7) Off-System Sales Margin Accounts.

Forecast Methodology

Q. Please briefly describe the process used to develop a financial forecast for the AEP System and an individual operating company like I&M.

A. The preparation of a financial forecast for the AEP System and an individual operating company is a complex process requiring input from a variety of groups within AEP and I&M. Due to the integrated nature of the AEP System, the preparation of any individual operating company forecast requires a forecast of the entire AEP System. The major components of a forecast are as follows: 1) load and demand forecast; 2) generation forecast; 3) retail and firm wholesale revenue projections; 4) off-system sales forecast; 5) O&M forecast; 6) construction expenditure forecast; and 7) financing plan.

Q. Please discuss each of these major components of the forecast in more detail.

A. Assumptions, such as growth in kilowatt-hour sales, fuel expense, interest rates, and cost projections based on each of the companies' work plans, are made in advance of the preparation of the forecast. These assumptions are reviewed with individuals from the operating companies and within AEPSC to determine the most reasonable set of assumptions to be incorporated into the forecast. The major sequential steps are as follows:

1) Load and Demand Forecast - Because the AEP System is highly integrated, the preparation of any individual company forecast requires an internal load forecast and an off-system sales forecast for all the AEP System companies. The internal load projection is developed by the Economic Forecasting Department in conjunction with various groups across the AEP System including input from the operating companies and reflects an analysis of the economy and the unique factors that influence individual customers or customer classes in each of the regions that AEP serves.

2) Generation Forecast - A generation forecast is developed by the Commercial Operations Division and the Resource Planning and Operational

Analysis Department which together with planned energy purchases, is sufficient to meet the system's anticipated total energy requirements. The cost of fuel consumed is based on the generation forecast for each of the generating units in the AEP System. In addition to fuel costs, AEP incurs other variable costs of production, costs for other consumable materials at our generating stations for the operation of environmental equipment and purchased power costs.

3) Retail and Wholesale Firm Revenue Projections - Revenues for most customers are developed by customer class using base realizations under current rates and fuel adjustment clauses included in the appropriate filed tariffs or contracts. Projections of base realizations reflect actual experience adjusted to be consistent with the projected sales and usage levels. Revenues for large wholesale and other special contract customers are developed in detail in accordance with the terms of the contract, including demand, energy and fuel adjustment charges.

4) Off-System Sales Forecast - The off-system sales projections are developed by the Commercial Operations Division together with the Resource Planning and Operational Analysis Department. Revenues related to known off-system sales arrangements are developed in accordance with the terms of the specific agreements related to such sales. The bulk of the projected off-system sales volume sold to counter-parties is not known when the forecast is developed and, therefore, is priced at expected market rates.

5) O&M Forecast - Operation and maintenance expenses, excluding

energy costs, are based upon current work plans for each of the functional groups. These plans include expenditures for scheduled maintenance programs as well as the cost of operations. These plans take into consideration staffing levels, including budgeted increases in salaries as well as material costs necessary to perform each planned program.

6) Construction Expenditure Forecast - The various engineering and planning groups in each operating company and in the AEP Service Corporation develop the construction expenditure budget. It reflects expenditures and in-service dates of major projects during the year as well as amounts approved to fund blanket work (smaller projects grouped together) which is essential in estimating both book and tax depreciation as well as the allowance for funds used during construction (AFUDC).

7) Financing Plan - The development of the financing program for the forecast is intended to meet the company's working capital requirements. In determining the company's financing program, consideration is given to coverage and other regulatory restrictions, timing of requirements, availability of equity capital, and corporate objectives such as credit metrics, capital structure and short-term debt limitations.

Q. Please discuss I&M's 2010 projected test year and its reasonableness.

A. I will describe the projected values for each of the relevant lines included in Exhibits I&M-24 (WAA-1) and I&M-26 (WAA-3) on a total company basis. I will support the reasonableness of each of the projected values.

Operating Revenues

Q. What are the major components of operating revenues that are included in the forecast?

A. The major components of operating revenues that are included in the forecast are Retail and Firm Sales, Interruptible Sales, Non-Firm Sales, Pool and Interchange Sales, and Other Operating Revenues.

Q. Please discuss the level of Retail and Firm Sales that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Retail and Firm Sales are projected to be $1,517 million for 2010. Retail and Firm Sales is comprised of Michigan retail revenue, Indiana retail revenue, and firm municipal and cooperative revenue. Total Michigan retail revenue, excluding any change in basic rates, is projected to be $210 million based on a load of 3,022 GWH. Total Michigan retail revenue is comprised of $55 million in fuel revenue and $155 million in non-fuel revenue.

Q. How does the projected Michigan retail revenue and load compare to the actual revenue and load for 2008?

A. The projected Michigan retail load is slightly lower than the actual load for 2008. In 2008, the actual Michigan retail revenue was $190 million ($39 million in fuel revenue and $151 million in non-fuel revenue) based on a load of 3,036 GWH. The slight decline in projected retail load is the result of the economic recession of 2008 and 2009. As can be seen in the table below, the reduction in load is directly the result of a projected decline in industrial load partially offset by a small increase in load in all other classes. The effect of weather in 2008 was negligible.

Michigan Retail Load

Class	2008 Actual (GWH)	2008 Normal (GWH)	2010 Projection (GWH)	Change vs Actual (%)
Residential	1,262	1,261	1,271	0.7
Commercial	839	841	849	1.2
Industrial	923	923	890	-3.5
Other	12	12	12	0.4
Total	**3,036**	**3,037**	**3,022**	**-0.5**

The $20 million increase in Michigan retail revenue is primarily the result of an increase in projected PSCR costs using the definition of includable costs used in the Company's 2010 PSCR Plan Case (U-16046).

Q. Please discuss the level of Interruptible Sales that is included in the forecast.

A. Interruptible Sales are sales to Indiana retail customers taking service under interruptible tariffs. As shown on Exhibit I&M-24 (WAA-1), Interruptible Sales are projected to be $107 million for 2010 based on a load of 2,368 GWH. This compares to the $93 million in 2008 based on a load of 2,497 GWH. The major reason for the increase in revenue is increased interruptible rates.

Q. Please discuss the level of Non-Firm Sales that is included in the forecast.

A. Non-Firm Sales include sales to non-affiliates (both cost recovery and margin) and various charges and credits incurred in the PJM market. As shown on Exhibit I&M-24 (WAA-1), Non-Firm Sales are projected to be $228 million for

2010. This compares to $371 million in 2008. The decrease in revenue is primarily due to lower price and sales volume.

Q. Please discuss the level of Pool and Interchange Sales that is included in the forecast.

A. Pool and Interchange Sales include energy and capacity sales to the AEP Pool in accordance with the FERC approved AEP Interconnection Agreement. Under provisions of the agreement, each pool member is responsible for providing its Member Load Ratio (MLR)[1] share of the total primary capacity of the pool. A pool member contributing more than its MLR share of pool capacity is deemed to have a capacity surplus with respect to the pool, while a member contributing less than its MLR share of pool capacity is deemed to have a capacity deficit in the pool. Each company having a capacity surplus is credited on a monthly basis for its surplus and receives payments from the capacity deficit companies at a rate which reflects the embedded investment cost of its own primary capacity and the fixed operating costs of this capacity. Payments made by the capacity deficit companies are made in proportion to their respective capacity deficits at the primary capacity equalization charge which is the weighted average of the member primary capacity investment rates and the member primary capacity fixed operating rates of the surplus companies. The projected capacity settlement amounts in 2010 reflect the fact

[1] Member Load Ratio is defined by the AEP Interconnection agreement as "the ratio of a particular Member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the five MEMBER MAXIMUM DEMANDS in effect for such month" where the MEMBER MAXIMUM DEMAND is "the maximum MEMBER DEMAND experienced by said Member during the twelve consecutive calendar months next preceding such calendar month."

that I&M is projected to be a surplus member of the AEP System Pool and will thereby receive payments from the deficit companies.

In accordance with the Interconnection Agreement, the projected credit that I&M would receive for energy delivered to the pool was based on I&M's projected average variable cost (fuel + one-half maintenance expense) each month and the quantity of energy delivered to the pool.

As shown on Exhibit I&M-24 (WAA-1), Pool and Interchange Sales are projected to be $360 million for 2010 comprised of $281 million in energy sales and $78 million in capacity sales. This compares to 2008 actual Pool and Interchange Sales of $288 million comprised of $240 million in energy sales and $48 million in capacity sales.

Q. Please discuss the level of Other Operating Revenues that is included in the forecast.

A. The major components of Other Operating Revenues are third party transmission revenues, associated business development (ABD) revenues, rent from electric property, gain/(loss) on sale of allowances and forfeited discounts. As shown on Exhibit I&M-24 (WAA-1), Other Operating Revenues are projected to be $33 million for 2010. This compares to 2008 Other Operating Revenues of $30 million.

Q. Do you believe that the level of Operating Revenue included in the forecast that you have provided are reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

Fuel and Purchased Power

Q. Please discuss the level of Fuel expense that is included in the forecast.

A. Fuel expense includes both fossil and nuclear fuel expenses. The cost of fossil fuel consumed was based on the generation forecast for each of I&M's fossil generating units. The cost of fossil fuel consumed for each of I&M's generating units is equal to the number of tons of coal consumed times the average unit cost of coal in fuel inventory ($/ton), Account 151. The cost of fuel consumed was developed on a monthly basis. The average cost of coal was defined as the weighting of the average cost of coal in inventory at the beginning of the month plus the projected cost of fuel delivered during the month. Other non-Account 151 fossil fuel expenses such as fuel handling costs are added and credits such as ash sales proceeds are deducted from this amount.

Nuclear fuel expense was projected for each unit of the Donald C. Cook Nuclear Plant (Cook Plant). The projection of nuclear fuel expense consists of a base fuel component, spent fuel canister costs and post-April 7, 1983 spent nuclear fuel disposal costs. The base fuel component is calculated by multiplying the number of BTUs (British Thermal Units) generated by the nuclear fuel and the BTU charge. Lease finance and administrative charges are then added to this amount. Spent fuel canister costs are based on an amortization of the total projected spent fuel canister costs over the remaining life of the plant. Post-April 7, 1983 spent nuclear fuel disposal costs are calculated based on the rate of one mill per kilowatt-hour of electricity generated and sold in accordance with the Nuclear Waste Policy Act of 1982.

Q. Please discuss the level of Purchased Power expense that is included in the forecast.

A. Purchased Power reflects the costs associated with planned purchases, I&M's share of other purchases and charges for energy received from the Pool.

Q. Would you please describe planned purchases?

A. Yes. Planned purchases include purchases from the Ohio Valley Electric Corporation (OVEC), purchases from the AEP Generating Company (AEG) and purchases of wind power. The projected kilowatt-hours (kWh) purchased from OVEC reflect I&M's share of the anticipated OVEC surplus. The cost associated with these purchases is based on a contractual agreement with OVEC.

Planned purchases from AEG represent the purchase of 910 MW (70%) of the power and energy from AEG's share of Rockport Units 1 & 2. The costs associated with these purchases are composed of both fuel and non-fuel charges.

Planned purchases of wind power represent purchases from the Fowler Ridge Wind Farm consistent with the Commission's Orders in Case Nos. U-15361 and U-15808.

Q. Would you please describe other system purchases?

A. Other system purchases are I&M's share of the unplanned purchases AEP occasionally makes from non-affiliated suppliers to meet its total load. Other system purchases also include PJM Ancillary Services captured in FERC

Accounts 555XXXX, Purchased Power.

Q. Would you please describe charges for energy received from the Pool?

A. Charges for energy received from the Pool reflect the costs of purchases of primary energy from the AEP System Pool and I&M's allocated share of the cost of system sales from the Pool.

<u>**Operations and Maintenance Expenses**</u>

Q. Have you reviewed the level of projected O&M expenses for reasonableness?

A. Yes. I have compared the projected level of O&M expenses to prior actual expenses and in cases when the growth in expenses appeared to exceed historic trends I sought to determine the underlying cause. Exhibit I&M-25 (WAA-2) provides a summary of actual O&M expenses for the years 2004 through 2008 and the projected O&M expenses for 2010. This exhibit also shows the projected growth in O&M by account grouping.

Q. Please explain why you have provided several years of actual data in your exhibit.

A. Annual O&M expenses are dependant upon many factors including specific work plans for each particular year. As such, actual and projected O&M expenses may vary significantly from year to year especially as you drill down to narrower categories. By comparing the projected level of O&M spending to a variety of recent years' actual data I can verify whether the projected level of O&M expense appears reasonable.

Q. What conclusions did you reach as a result of your comparison?

A. The first conclusion that I reached was that the projected level of Power Production and Nuclear Production O&M expenses appeared reasonable as compared to actual expenses. The compound annual growth in projected Power Production O&M expenses (excluding account 501 fuel and account 509 allowances) is less than 3.5% when compared to any of the five most recent years (2004 through 2008) and the projected expenses are less than actually incurred in 2007. The compound annual growth in projected Nuclear Production O&M expenses (excluding account 518 fuel) is less than 4.2% when compared to any of the five most recent years and 2.7% on average.

The second conclusion that I reached was that the projected level of Hydraulic Power Production O&M expenses are increasing significantly, on a percentage basis, in 2010 as compared to any of the five most recent years. Hydraulic Power Production O&M expenses are rising significantly as a result of FERC mandated dam inspections and repairs. These expenses are cyclical in nature and are expected to remain at this elevated level for the next several years.

The third conclusion that I reached was that the projected level of Other Generation O&M expenses continue to decline in the forecast period. This continuing decline is a result of decreases in System Control and Load Dispatching (FERC account 556) and Other Expenses (FERC account 557).

The fourth conclusion that I reached was that the projected level of Transmission O&M expenses cannot be simply evaluated in aggregate. In order to more clearly understand the projected level of Transmission O&M expenses I have disaggregated the total into several components and shown them on Exhibit I&M-25 (WAA-2). The first component, Transmission Equalization varies annually as a function of MLR and Member Bulk Transmission Surplus or Deficit in accordance with the FERC approved Transmission Agreement between I&M and the other major AEP East Operating Companies dated April 1984. A company having an investment in bulk transmission assets greater than their MLR share of the sum of the bulk transmission assets of all the companies receives payments in accordance with the Agreement. I&M has historically received payments as a result of having a surplus of bulk transmission assets. The payments received by I&M are projected to decline in 2010 primarily as a result of an increase in their MLR. The increase in I&M's MLR is largely the result of reductions in industrial load at APCo, CSP and OPCo. Another component of Transmission O&M is PJM administrative fees. In 2004 I&M joined the PJM RTO. As a result, beginning in 2004 I&M began to incur an allocated share of PJM administrative fees. In 2010 these fees are projected to be $3.9 million. In addition, transmission enhancements or the Regional Transmission Expansion Plan (RTEP) are developed annually and the transmission project costs are allocated by PJM in accordance with FERC approved allocation methods. Throughout the remainder of 2009 and 2010 several large RTEP projects will increase spending in order to meet future PJM required in-service dates. These projects have been authorized by FERC to recover construction work in progress (CWIP) and will result in continued increased charges to AEP and I&M. I&M also receives an MLR share of any credits received by AEP related to RTEP projects. In 2010, I&M is projected to incur $15.2 million in PJM transmission enhancement charges and to receive $0.3 million in credits. After removing the three categories of costs previously discussed (Transmission Equalization, PJM administrative fees, and PJM transmission enhancement charges and credits), Transmission O&M Expense has ranged from $13.3 million to $21.1 million, averaging $17.6 million. These costs are projected to be $18.2 million in 2010 which is slightly higher than the average over the most recent five years.

The fifth conclusion that I reached was that the projected level of Distribution O&M expenses appeared reasonable as compared to actual expenses. The compound annual growth in projected Distribution O&M expenses in 2010 is only 0.6% when compared to 2008 and 3.3% on average when compared to the five most recent years (2004 through 2008).

The sixth conclusion that I reached was that the projected level of Customer Service and Information expenses and Sales expenses are consistent with and slightly lower than the levels experienced in the most recent five years.

The final conclusion that I reached was that the projected level of Administrative and General O&M expenses have increased over recent actual levels primarily as a result of a $19 million increase in pension and other post employment benefits (OPEB) expenses and a $6 million increase in net expenses for Nuclear Electric Insurance Limited (NEIL) insurance. Absent these two increases in 2010, Administrative and General O&M expenses would have been approximately $125 million which is consistent with recent actual expense levels.

Company witnesses Peifer, Hruby, Ehler, and Bethel provide further support for the projected level of O&M expenses included in the forecast.

Q. What level of major storm damage restoration expense is included in the Company's projected O&M for 2010?

A. Major distribution storm damage restoration expense of approximately $3.0 million is included in the Company's projected O&M for 2010. Using the distribution plant allocation factor of 0.196453 provided by Company witness Roush, the Company's projected O&M for 2010 includes approximately $596,000[2] on a Michigan jurisdictional basis.

Q. Do you believe that it would be reasonable to just use actual 2008 O&M expenses adjusted for inflation in place of the projected data that you have provided?

A. No I do not. As I stated previously, annual O&M expenses are dependant upon many factors including specific work plans. Simply taking historic data and adjusting it for inflation fails to take into account activities or costs expected to occur in 2010 and beyond that did not occur in 2008. PJM transmission expansion charges that are expected to be $15.2 million in 2010 and did not begin to be incurred by the Company in significant amounts until

[2] $3,033,000 x 0.196453 ≈ $596,000

2009 are an example of such costs.

Q. Have you reviewed inflation rates, both actual and projected, for the period 2008 through 2010?

A. Yes, I have reviewed several measures of inflation over that period. The U.S. Bureau of Labor Statistics (BLS) has various indexes that measure different aspects of inflation. Three of the major categories of indexes of inflation that the BLS reports in are the Consumer Price Indexes (CPI), Producer Price Indexes (PPI) and Employment Cost Trends (ECT). The CPI program produces monthly data on changes in the prices paid by urban consumers for a representative basket of goods and services.[3] The Producer Price Indexes (PPIs) are a family of indexes that measure changes in the selling prices received by domestic producers of goods and services. The ECT program produces a quarterly index measuring change over time in labor costs (Employment Cost Index – ECI). The BLS provides historical data for each of these three categories of indexes. Third party vendors such as Moody's Economy.com provide forecasts of these inflation measures, although they do not provide forecasts of each subset of these categories.

Q. What conclusions did you reach as a result of your review of these various measures of inflation?

A. The first conclusion that I reached was that none of these are perfect measures and therefore should be given limited weight in evaluating projected

[3] Source: www.bls.gov

changes in costs incurred by a utility. An additional conclusion that I reached was that the CPI is not representative of the changes in costs incurred by a utility. As I previously stated, the CPI produces monthly data on changes in the prices paid by urban consumers for a representative basket of goods and services. This basket of goods and services is comprised of the following eight major groups: 1) Food and Beverages; 2) Housing; 3) Apparel; 4) Transportation; 5) Medical Care; 6) Recreation; 7) Education and Communication and 8) Other Goods and Services. Since the utility industry does not consume this basket of goods and services (and to the extent that a utility does, the proportion of each consumed as compared to the urban consumer is quite different) it should not be used when evaluating historical or projected changes in costs incurred by a utility. Producer Price Indexes and Employment Cost Trends are much better measures of inflation to use when evaluating changes in costs incurred by a utility.

Q. Please discuss the PPI.

A. As I previously mentioned, the PPI is a family of indexes. There is no single index within this family of indexes that represents the same basket of goods and in the same proportion as those used by I&M in the generation and delivery of electricity to their Michigan customers. In the absence of such an index, the PPI for Finished Goods less Food and Energy would be a reasonable high level comparator. This index includes a wide variety of goods and services (many of which are used in the generation and delivery of electricity) and is general enough that it is widely forecasted. In 2008 the PPI for Finished Goods less Food and Energy increased by 4.47% (from an index value of 163.3 to 170.6). In the first ten months of 2009 the increase was 0.41% (from an index value of 170.6 to 171.3 (preliminary)[4]). For the last two months of 2009 the increase is projected to be 0.06% (from an index value of 172.6 to 172.7). For 2010 the increase is projected to be 0.52% (from an index value of 172.7 to 173.6). The average increase from 2008 to 2010 is projected to be 2.97%[5].

Q. Please discuss the ECI.

A. Similar to the PPI, the ECI is a family of indexes and no single index is a perfect proxy for employment costs incurred by I&M. Although one could debate which of the many indexes is the best to use, I would recommend the use of the ECI for Private Industry Workers if one were so inclined to use one of these ECI indexes as a comparator. In 2008 the ECI increased by 2.44% (from an index value of 106.5 to 109.1). In the three quarters of 2009 the increase was 0.82% (from an index value of 109.1 to 110.0). For the last quarter of 2009 the increase is projected to be 0.53% (from an index value of 110.0 to 110.6). For 2010 the increase is projected to be 1.19% (from an index value of 110.6 to 111.9). The average increase from 2008 to 2010 is projected to be 3.17%[6].

Q. Are there instances in which costs expected to occur in 2010 and that did not occur in 2008 should not be fully included in the determination of the

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[4] All indexes are subject to revision four months after original publication.
[5] 2.97% = (4.47%/2) + (0.41% + 0.06%) + (0.52%/2)
[6] 3.17% = (2.44%/2) + (0.82% + 0.53%) + (1.19%/2)

Company's annual revenue requirement?

A. Yes there are. An example would be a major maintenance outage planned at the Rockport Plant that caused I&M's total projected O&M expense to significantly exceed a normal on-going level. In that case it may be appropriate to normalize these costs over a period of years in the determination of the company's annual revenue requirement.

Q. Based upon your review of the O&M data, are there any such instances that have been included in I&M's 2010 forecast?

A. No there are not.

Q. Do you believe that the level of O&M expense included in the forecast that you have provided are reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

Depreciation and Amortization

Q. What are the major components of depreciation and amortization expense that are included in the forecast?

A. The major components of depreciation and amortization expense that are included in the forecast are Depreciation Expense, Depreciation Expense Asset Retirement Obligation (ARO), Amortization of Plant, Amortization of Plant Acquisition Adjustments, and Regulatory Debits.

Q. Please discuss the level of Depreciation Expense that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Depreciation Expense is projected to be

$103.5 million for 2010. This projection was developed by applying approved depreciation rates to projected monthly plant in-service balances. The projected 2010 depreciation expense is approximately $10 million higher than the depreciation expense actually incurred in 2008. Over that period I&M's average plant in-service is projected to increase by approximately $550 million. Based upon this projected increase in plant in-service, the approximately $10 million increase in depreciation expense is reasonable.

Q. Please discuss the level of Depreciation Expense ARO that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Depreciation Expense ARO is projected to be $6.0 million for 2010. The projection of Depreciation Expense ARO (asset retirement obligation) is related to legal obligations to perform an asset retirement activity for I&M's ash ponds and asbestos removal. The projected expense is in line with the actual expense incurred in 2008 of $5.5 million.

Q. Please discuss the level of Amortization of Plant that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Amortization of Plant is projected to be $25.6 million for 2010. The projected expense is in line with the actual expense incurred in 2008 of $26.1 million.

Q. Please discuss the level of Amortization of Plant Acquisition Adjustments that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Amortization of Plant Acquisition Adjustments is projected to be zero for 2010. This is a reduction from the

2008 actual expense of $20 thousand. This is related to the acquisition of distribution assets from United REMC in the 1970s. The Plant Acquisition Adjustment was fully amortized in November 2009.

Q. Please discuss the level of Regulatory Debits that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Regulatory Debits is projected to be $8.9 million for 2010. The increase over the 2008 level of $1.9 million is related to the inclusion of amortization of certain Michigan regulatory assets (either currently approved or requested in this case). Company witnesses Krawec, Hayes and Hruby discuss these amortizations in greater detail.

Q. Do you believe that the level of Depreciation and Amortization expense included in the forecast that you have provided are reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

Taxes Other than Income Taxes

Q. What are the major components of taxes other than income taxes that are included in the forecast?

A. The major components of taxes other than income taxes that are included in the forecast are revenue taxes, payroll taxes and property taxes. The projected 2010 expenses are further supported by Company witness Kelly.

Q. Please discuss the level of Revenue Taxes that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Revenue Taxes are projected to be

$16.0 million for 2010. The projected 2010 expense is approximately $2.3 million higher than the expense actually incurred in 2008.

Q. Please discuss the level of Payroll Taxes that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Payroll Taxes are projected to be $15.6 million for 2010. The projected 2010 expense is approximately $3.2 million higher than the expense actually incurred in 2008.

Q. Please discuss the level of Property Taxes that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Property Taxes are projected to be $52.3 million for 2010. The projected 2010 expense is approximately $7.9 million higher than the expense actually incurred in 2008.

<u>Income Taxes</u>

Q. What are the major components of income taxes that are included in the forecast?

A. The major components of income taxes that are included in the forecast are state income taxes and federal income taxes (both current and deferred). The projected 2010 expenses are further supported by Company witness Kelly.

Q. Please discuss the level of Income Taxes that is included in the forecast.

A. As shown on Exhibit I&M-24 (WAA-1), Income Taxes are projected to be $51.3 million for 2010. The projected 2010 expense is approximately $12.0 million lower than the expense actually incurred in 2008.

<u>Plant in Service</u>

Q. Please describe the development of the forecast of Plant in Service.

A. In order to develop a forecast of Plant in Service, completed Construction Work in Progress is added and retirements are subtracted from the beginning Plant in Service balance. The projection of all balance sheet items begins with actual data through March 2009 and forecasted data from April 2009 through December 2010. Throughout my discussion of balance sheet items I will refer to the period prior to and including March 2009 as the actual period and the period after March 2009 as the forecast period. Exhibit I&M-27 (WAA-4) provides a summary of the historical and projected functional plant activity from 2004 though 2010.

Q. Please discuss the average balance of Plant in Service that is included in the forecast.

A. As shown on Exhibit I&M-26 (WAA-3), the average balance of Plant in Service is projected to be $6,557 million for 2010. The $540 million increase in the average balance over 2008 year end is the result of the Plant in Service increasing by $661 between December 2008 and December 2010. $185 million of the increase was in the actual period and $476 million is in the forecast period. The following table provides a summary of the projected activity during the forecast period.

Function	Transfers from CWIP	Retirements	Net
Fossil and Hydro	$132M	($26M)	$106M
Nuclear	$204M	($19M)	$185M
Transmission	$72M	($12M)	$60M
Distribution	$161M	($40M)	$121M
General & Intangible	$34M	($29M)	$5M
Total	**$603M**	**($127M)**	**$476M**

Q. Do you believe that the Plant in Service balance projected in the forecast that you have provided is reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

<u>Plant Held for Future Use</u>

Q. Please describe the development of the forecast of Plant Held for Future Use.

A. There are no expected changes in the Plant Held for Future Use during the forecast period so the balance is held constant. I&M's Plant Held for Future Use primarily made up of Land and Land Rights related to a generating plant project site, Tanners Creek Generating Plant Unit 1-4 and Rockport Generating Plant Unit 1. The average balance of Plant Held for Future Use is projected to be $7.8 million for 2010. There is no change between the 2008 year end and the 2010 average.

Q. Do you believe that the Plant Held for Future Use balance projected in the forecast that you have provided is reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

Plant Acquisition Adjustments

Q. Please discuss the average balance of Plant Acquisition Adjustments that is included in the forecast.

A. As I've discussed previously, the Plant Acquisition Adjustment was fully amortized in November 2009, therefore the projected average balance of Plant Acquisition Adjustments is zero in the forecast.

Q. Do you believe that the Plant Acquisition Adjustment balance projected in the forecast that you have provided is reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

Construction Work in Progress

Q. Please describe the development of the forecast of Construction Work in Progress.

A. In order to develop a forecast of Construction Work in Progress, capital expenditures are added and completed Construction Work in Progress is subtracted from the beginning Construction Work in Progress balance.

Q. Please discuss the average balance of Construction Work in Progress that is included in the forecast.

A. As shown on Exhibit I&M-26 (WAA-3), the average balance of Construction Work in Progress is projected to be $199 million for 2010. The actual Construction Work in Progress balance for March 2009 was $256 million. The table below provides a summary of the projected activity during the forecast period.

Function	Capital Expenditures	AFUDC	Transfers to Plant in Service	Net
Fossil and Hydro	$116M	$5M	($132M)	($11M)
Nuclear	$196M	$12M	($204M)	$4M
Transmission	$43M	$1M	($72M)	($28M)
Distribution	$144M	$1M	($161M)	($16M)
General & Intangible	$14M	$0M	($34M)	($20M)
Total	**$513M**	**$19M**	**($603M)**	**($71M)**

Q. Please discuss the major capital expenditures included in the table above.

A. There are a large number of projects that are included in the forecasted capital expenditures shown above. Company witnesses Peifer, Hruby, and Ehler, provide further support for the projected level of capital expenditures included in the forecast.

Q. Please discuss the transfers to Plant in Service included in the table above.

A. As projects are completed the construction work in progress balance is transferred to Plant in Service.

Q. Do you believe that the Construction Work in Progress balance projected in the forecast that you have provided is reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

Nuclear Fuel Stock

Q. Please describe the development of the forecast of Nuclear Fuel Stock.

A. In order to develop a forecast of Nuclear Fuel Stock I had to take into account a variety of factors including: 1) purchases of nuclear fuel; 2) transfer of nuclear fuel inventory from in process of refinement, conversion, enrichment and fabrication to nuclear fuel assemblies in reactor; 3) amortization of nuclear fuel; 4) transfers of nuclear fuel assemblies in reactor to spent nuclear fuel; 5) retirement of nuclear fuel; and 6) nuclear fuel leases.

Q. For purposes of this filing was leased nuclear fuel treated differently than owned nuclear fuel?

A. Yes. The interest expense and other costs associated with leased nuclear fuel have historically been included for recovery in the PSCR clause. To the extent that financings costs associated with leased nuclear fuel continue to be recovered through the PSCR clause as proposed in this filing, leased nuclear fuel should be excluded from rate base. As such, the projected balance of leased nuclear fuel has been excluded from the Nuclear Fuel Stock presented on Exhibit I&M-26 (WAA-3).

Q. Please describe the leased nuclear fuel that you have excluded from the Nuclear Fuel Stock presented on Exhibit I&M-26 (WAA-3).

A. The leased nuclear fuel that I have excluded is made up of portions of two batches of nuclear fuel that are currently in use in Unit 2 of the Cook Nuclear Plant. These two leases are with Citicorp Leasing and Metlife. I have not projected the leasing of any additional nuclear fuel.

Q. Please discuss the average balance of Nuclear Fuel Stock that is included in the forecast.

A. As shown on Exhibit I&M-26 (WAA-3), average balance of Nuclear Fuel Stock is projected to be $271 million for 2010. The $28 million increase in the average balance over the 2008 year end level is the result of increased nuclear fuel inventory in process of refinement, conversion, enrichment and fabrication of $5 million and increased nuclear fuel assemblies in reactor (net) of $23 million.

Q. Do you believe that the Nuclear Fuel Stock balance projected in the forecast that you have provided is reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

<u>Depreciation Reserve</u>

Q. Please describe the development of the forecast of Depreciation Reserve?

A. In order to develop a forecast of Depreciation Reserve, depreciation and amortization expenses are added and retirements and removal expenditures are subtracted from the beginning Depreciation Reserve balance.

Q. Please discuss the average balance of Depreciation Reserve that is included in the forecast.

A. As shown on Exhibit I&M-26 (WAA-3), the average balance of Depreciation Reserve is projected to be $3,269 million for 2010. The $63 million increase in the average balance over 2008 year end is the result of the Depreciation

Reserve increasing by $89 between December 2008 and December 2010, with $19 million of the increase in the actual period and $70 million in the forecast period. The table below provides a summary of the projected activity during the forecast period.

Function	Depreciation and Amortization Expense	Retirements	Removal Expenditures	Net
Fossil and Hydro	$45M	($26M)	($17M)	$2M
Nuclear	$52M	($19M)	($2M)	$30M
Transmission	$29M	($12M)	($2M)	$15M
Distribution	$59M	($40M)	($17M)	$2M
General & Intangible	$50M	($29M)	$0M	$21M
Total	**$235M**	**($127M)**	**($38M)**	**$70M**

PSCR Basing Point

Q. Have you prepared an exhibit which supports the PSCR basing point proposed by the Company?

A. Yes. Exhibit I&M-28 (WAA-5) shows the power supply costs and net energy requirements that were used to develop the PSCR basing point that the Company is recommending in the proceeding. In addition, it shows the Transmission Factor that has been included in the recommended PSCR basing point.

Q. Would you please provide a general definition of power supply cost utilized in the development of I&M's PSCR basing point?

A. Yes. Power supply costs include the cost of fossil fuel consumed (including SO_2, NO_x, CO_2 and Hg emission costs), nuclear fuel consumed, spent nuclear fuel disposal costs, the cost of purchased power, the charges for energy received from the AEP System Pool and the credits for energy delivered to the AEP System Pool, offset by I&M's share of revenues received from non-firm sales for resale (System Sales), including any relevant impacts on the forecast of AEP's affiliation with the PJM Interconnection LLC (PJM). In addition, as more fully described by Company witness Gregory, certain transmission costs have been included in the determination of the Company's PSCR basing point. These are the types of costs the Commission has previously approved for inclusion in PSCR clauses in other cases.

Q. Was this data prepared in a manner generally consistent with previous I&M PSCR Plan filings?

A. In many respects it was, although there are some significant differences.

Q. Please describe these differences.

A. The first difference is the elimination of the calculation of a separate PSCR factor for the Three Rivers rate area based on the formal FERC Net Energy Cost method. Due to the proposed merging of the St. Joseph and Three Rivers rate areas, if approved, it is no longer necessary to develop separate PSCR factors for each of the rate areas. Exhibit I&M-28 (WAA-5) was developed using the Michigan PSCR basis historically used for the St. Joseph rate area as a starting point.

In addition to merging the rate areas, the costs included in determination of the total power supply cost has been expanded to include all items in accounts 447 and 555 except those related to Indiana jurisdictional trackers and revenues directly related to I&M's wholesale requirements customers. There are also a few items that are not in accounts 447 and 555 that are related to OSS margins that have been included in the Company's proposed PSCR clause. This results in the addition of the following accounts to the PSCR that were previously recovered through basic rates.

Account	Description
4470066	PWR Trading Transmission Expense – Non-Associated
4470093	PJM Implicit Congestion – LSE
4470101	PJM FTR Revenue – LSE
4470207	PJM Transmission Loss Charges – LSE
4470208	PJM Transmission Loss Credits – LSE
4560049	Merchant Generation Financial Realized
4560050	Other Electric Revenue - Coal Trading Realized
4560109	Interest Rate Swaps-Coal
4560112	Realized GL Coal Trading-Affil
5614000	PJM Admin - SSC&DS-OSS
5614008	PJM Admin - Defaults OSS
5618000	PJM Admin - RP&SDS-OSS
5757000	PJM Admin - MAM&SC- OSS

Company witnesses Krawec and Busby provide support for inclusion of these additional items in the Company's proposed PSCR clause.

Q. Please identify the 447 and 555 accounts related to Indiana jurisdictional trackers and revenues directly related to I&M's wholesale requirements customers that have been excluded from the Company's proposed PSCR.

A. The 447 and 555 accounts that continue to be excluded from the Company's proposed PSCR are provided in the following table.

Account	Description
4470027	Wholesale/Municipal/Public Authority Fuel Revenue
4470033	Wholesale/Municipal/Public Authority Base Revenue
4470150	Trans Revenue - Dedicated Wholesale/Municipal
4470171	Over-Under OSS Margin Sharing – Indiana
4470172	Over-recovered PJM Expense – Indiana

There are no 555 accounts that are excluded from the Company's proposed PSCR clause.

Q. Are there any additional changes to the PSCR clause that the Company is proposing?

A. Yes. As described in the testimony of Company witnesses Murray, Gregory, Roush and Busby, the Company is proposing to share off-system sales (OSS) margins and to include certain transmission related costs. The OSS margins included in Exhibit I&M-28 (WAA-5) include a 50% share of OSS margins consistent with the Company's proposal. A listing of the proposed OSS margin accounts is provided in Exhibit I&M-30 (WAA-7). The transmission costs included in Exhibit I&M-29 (WAA-6) have also been calculated consistent with the Company's proposal.

Q. Please discuss the Demand Allocation Adjustment that is shown on Exhibit I&M-29 (WAA-6).

A. Company witness Roush has allocated transmission related costs to the Michigan retail jurisdiction based on a demand allocation factor. The PSCR factor is developed and applied based upon energy and not demand. In order to ensure that costs are properly allocated in the PSCR clause, a demand allocation adjustment must be applied based upon the demand and energy allocation factors approved in this case. The demand and energy allocation factors that the Company has proposed in this case result in a demand allocation adjustment of 0.9876.[7] This factor will remain unchanged until the Commission approves new demand and energy allocation factors for the Company.

Q. Other than the items that you have just described, was the data prepared in a manner generally consistent with previous I&M PSCR Plan filings?

A. Yes it was.

Q. Have you excluded fuel handling and affiliated transportation costs in the determination of the PSCR basing point?

A. Yes. Consistent with Act 304, I have excluded $16.3M in fuel handling costs and $16.5 in affiliated transportation costs.

Q. What are the test year projected power supply costs and net energy requirements?

A. The test year projected power supply costs, on a total Company basis, are estimated to be $490.7M or 19.51 mills per kWh before consideration for any line losses, based on a net energy requirement of 25,158 GWh. After applying the loss correction multiplier of 1.037, the PSCR Fuel Factor Base included in this projection is 20.23 mills per KWh.

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[7] Demand Allocation Adjustment = MI Demand Allocation Factor ÷ MI Energy Allocation Factor
0.9876 = 14.03502% ÷ 14.21165%

Q. What are the test year projected transmission costs that the Company is prosing to include in the PSCR clause?

A. The test year projected transmission costs, on a total Company basis, are estimated to be $127.5M or 5.07 mills per kWh before consideration for any line losses, based on a net energy requirement of 25,158 GWh. After applying the demand allocation adjustment of 0.9876 and the loss correction multiplier of 1.037, the Transmission Factor Base included in this projection is 5.19 mills per KWh.

Q. How was the loss correction multiplier of 1.037 determined?

A. The loss correction multiplier of 1.037 was determined by taking the calendar year 2008 losses (including a transmission loss adjustment) and dividing by the billed energy for the same period. The transmission loss adjustment of 707,034 MWh removes the transmission losses that are settled financially from those reported by the Company in the Michigan P-521 and FERC Form 1. This ensures that the costs associated with transmission losses are not recovered twice.

$$(1{,}879{,}381 \text{ MWh} - 707{,}034 \text{ MWh}) \div 32{,}059{,}394 \text{ MWh} = 3.7\%$$

Q. Was the loss correction multiplier of 1.037 based on a five-year average consistent with the Commission's order in Case No. U-8041 (I&M's 1985 PSCR Plan case)?

A. No, it was not. PJM did not begin to settle transmission losses financially until mid-2007 and as such the first full year of data that the Company has which includes the financial settlement of transmission losses is 2008. As additional years of data are available the Company will include those to develop an average loss factor including up to five years.

Q. Please discuss the Deferred PJM Recovery Factor shown on line 34 of Exhibit I&M-29 (WAA-6).

A. The Deferred PJM Recovery Factor has been designed to provide recovery of previously deferred PJM costs and associated carrying charges. The value included on line 30 of Exhibit I&M 29 (WAA-6) was provided by Company witness Roush. Since these costs and carrying charges are directly related to I&M's Michigan retail jurisdiction they are divided by the projected Michigan retail sales to develop the Deferred PJM Recovery Factor. No loss correction multiplier is necessary.

Q. What is the PSCR basing point that the Company is recommending in this proceeding?

A. The Company is recommending a PSCR basing point of 26.87 mills per kWh based on a PSCR Fuel Factor of 20.23 mills per kWh and a PSCR Transmission Factor of 6.64 mills per kWh.

Trackers

Q. Have you included revenues or expenses associated with any of the trackers (other than the PSCR), proposed by the Company in the projected test year?

A. I have not included revenues or expenses associated with any of the proposed trackers in the projected test year.

Conclusions

Q. Do you believe that the projected values that you have provided are reasonable and accurate and reflect income statement and balance sheet activity reasonably likely to occur in 2010?

A. Yes I do.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

J. EDWARD EHLER

PRE-FILED DIRECT TESTIMONY OF J. EDWARD EHLER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is J. Edward Ehler. My business address is One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as Vice President of Distribution Operations.

Q. Please briefly describe your educational and business experience.

A. I earned a Bachelor of Science degree in Electrical Engineering from Ohio University.

I have 29 years of electric utility experience focusing primarily on distribution operations. I joined I&M in 1980 as a Distribution Engineer in Fort Wayne, Indiana. In 1986, I became Distribution Engineer Senior in Buchanan, Michigan, before being named Distribution Supervising Engineer in 1989, for the St. Joe Division. In 1991, I became Line Supervisor in Muncie, Indiana, for the Muncie Division. In 1995, I became Line Supervisor in Fort Wayne, Indiana, for the Fort Wayne Region. In 1996, I became Engineering Manager for the Indiana Region and in 1997 I became Operations Manager for the Region. In 2000, I became the Fort Wayne District Manager until being named in January 2008 to my present position.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to review the base distribution services I&M provides to its Michigan customers and demonstrate that the costs of providing such services are reasonable. I also summarize numerous programs designed to maintain and enhance the reliability of the distribution system. In addition, I discuss the work accomplished on I&M's distribution system during the 12-months ended December 31, 2008, historical period. I also support the forecasted test year amounts for the 12-months ending December 31, 2010. I also discuss the value of incremental distribution reliability related work and the costs associated with completing these incremental programs. I also support the ongoing level of major storm related operation and maintenance (O&M) expense.

The final topic that I discuss includes a description of the I&M and AEP transmission systems, the AEP transmission organization, the necessity and reasonableness of transmission costs and investments, and transmission reliability programs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, Exhibit I&M-31 (JEE-1), Summary Table of I&M Michigan Year to Date Residential Benchmarking Performance On Positive Ratings, which shows the summary table of I&M's customer satisfaction benchmarking performance for residential customers in Michigan. Exhibit I&M-32 (JEE-2), Summary Table of I&M-Michigan YTD's Commercial Benchmarking Performance on Positive Ratings, which shows the summary table of I&M's customer satisfaction benchmarking performance for small commercial customers in Michigan.

III. I&M DISTRIBUTION SYSTEM, SERVICE AND STANDARDS

Q. Please describe I&M's distribution system that serves Michigan customers.

A. I&M serves approximately 128,000 customers in southwestern Michigan in a service area that covers approximately 2,200 operational square miles and includes 46 cities and communities and 6 counties. Our distribution system includes nearly 5,300 miles of lower voltage distribution lines.

Q. Would you please describe the organizational structure of I&M's distribution organization?

A. The Michigan District within I&M's Distribution organization is divided into four geographic operating areas: Benton Harbor, Buchanan, New Buffalo and Three Rivers. Additionally, the organization includes three functional departments: Distribution Operation and Dispatch, Distribution Planning and Reliability, and Distribution Support.

The Michigan District is responsible for the day-to-day planning and construction of new distribution facilities, maintenance of existing facilities, work scheduling, right-of-way procurement, and outage response and restoration activities.

The Distribution Operation and Dispatch group is responsible for monitoring and controlling the day-to-day operation of the distribution system.

The Distribution Planning and Reliability group is responsible for system design and reliability programs, including investigating and resolving specific capacity and system reliability problems.

The Distribution Support group is responsible for providing the district's functional support including contract construction services, underground locates, and vegetation management services.

Q. What kind of activities are involved in providing distribution services to I&M's customers in Michigan?

A. To provide distribution service to customers, I&M's distribution organization includes engineering services, including distribution system design and distribution customer service engineering, as well as distribution line services that include the construction of new distribution lines; maintenance or upgrading existing distribution lines; reliability and outage management; and employee and public safety. I&M also provides distribution facility upgrades, alternative feed services, power quality evaluation, and underground networks.

Q. Please describe I&M's distribution engineering services?

A. The engineering function consists primarily of two areas: distribution system design and distribution customer service engineering.

The distribution system design function provides engineering designs for specific projects identified by the distribution planning function, by governmental agencies, and by major commercial and residential developers. This work consists of reconductoring of circuits and relocation and extension of distribution facilities as dictated by these internal and external requirements. In addition, distribution system design monitors the distribution system for adequacy and performance to determine if the system must be upgraded and/or expanded.

The distribution customer service engineering function performs engineering design work associated with maintaining and upgrading existing service and providing new service to industrial, commercial, and residential customers. This work involves planning and engineering of local circuit/feeder reliability improvements, selecting the routing of new lines, and sizing of transformers and conductors to provide reliable service to these customers.

Q. To what standards does I&M design its distribution system?

A. I&M's goal is to design a distribution system at a reasonable cost to provide safe, reliable service to its customers. In achieving this goal, I&M must comply with several electrical standards applicable to the electric utility industry. These standards which are revised and published periodically include; the Occupational Safety and Health Administration (OSHA), the

American National Standards Institute (ANSI), Institute for Electrical and Electronic Engineers (IEEE), and the National Electric Safety Code (NESC). It is the intent of the American Electric Power (AEP) System's distribution design guidelines, which I&M follows in designing its distribution system, to ensure compliance with these external standards. In addition, I&M includes in the design of its distribution system all rules contained in the MPSC's Service Quality and Reliability Standards for Electric Distribution Systems and any applicable state and local codes, laws and ordinances.

Q. Would you please describe distribution line services?

A. Distribution line services include the construction of new distribution lines; maintenance or upgrading existing distribution lines; reliability and outage management; and employee and public safety.

The primary purpose for construction of new distribution lines is to serve new customers. Construction also is required for projects including public highway and road widening, NESC compliance, customer requests, and system improvements.

I&M's primary distribution maintenance programs, referred to as Asset Management Programs, consist of ongoing inspections of facilities and repair or replacement of deficient facilities. In addition, maintenance includes repair and replacement of facilities that are reported by employees and identified through outage reports. These Asset Management Programs are described in greater detail later in my testimony.

Distribution line personnel also are dedicated to outage management and restoration. When customers experience service interruptions, line personnel are directed to the location of the outage to diagnose and repair the problem and restore electric service. This workload varies considerably with the seasons and the level of storm activity; therefore, it is necessary to adjust work shifts and schedules to match the dynamic outage restoration demands and to minimize the duration of outages.

IV. AEP SERVICE CORPORATION (AEPSC) SUPPORT

Q. Please list the services provided by the AEPSC Customer and Distribution Services organization and why these services are necessary.

A. The AEPSC Customer and Distribution Services (C&DS) organization provides specialized energy delivery support services and expertise across the AEP System. C&DS is made up of seven groups: Billing and Credit Operations, Business & Performance Management, Customer Services, Distribution Operations Support, Distribution Reliability Planning & Engineering, Market Research & Development, and Utility Group Systems. Within each group are centralized subgroups that provide dedicated resources to AEP's eleven operating companies[1].

[1] AEP's eleven operating companies are Appalachian Power Company in West Virginia and Virginia, Indiana Michigan Power Company in Indiana and Michigan, Kentucky Power Company in Kentucky, Kingsport Power Company in Tennessee, Columbus Southern Power Company and Ohio Power Company in Ohio, Wheeling Power Company in West Virginia, AEP Texas Central Company in Texas, AEP Texas North Company in Texas, Southwestern Electric Power Company in Louisiana, Arkansas, and Texas, and Public Service Company of Oklahoma in Oklahoma.

Q. Why does the AEPSC provide the above-listed Distribution services through this centralized manner?

A. The services provided by the AEPSC C&DS organization are required by each operating company and generally are not unique to local areas. It thus makes sense to avoid duplicating the expertise and resources required to provide these services. This centralized structure reduces costs for customers and allows I&M to leverage the entire AEP System in the provision of electric services through standardization of systems and processes as well as sharing of employees with specialized skills and expertise.

Q. How do I&M and the AEPSC C&DS organization work together?

A. The AEPSC asset planning employees located in Benton Harbor, Michigan and Fort Wayne, Indiana operate as if they are a part of the I&M distribution organization. They regularly attend staff meetings and conference calls and function as integral parts of the team. During regularly scheduled meetings and conference calls of the operating company vice presidents and the AEPSC C&DS organization leadership, service issues are discussed and resolved. Additionally, the central organization's leadership team travels to each operating company periodically to discuss operating company specific issues or problems and to obtain feedback on the quality of service being provided to the operating company.

Q. Do these services duplicate services provided by personnel within I&M or by any other entity?

A. No.

V. I&M's DISTRIBUTION BASELINE OPERATIONS

Q. What periods are put forth by the Company as being representative of the Michigan jurisdiction's annual distribution expenses?

A. The historical period is the twelve-month period ended December 31, 2008 for actual expenditures. The forecasted test year period is the twelve-month period ending December 31, 2010.

A. O&M Expense, Historical Period and Forecasted Test Year

Q. What level of distribution O&M expenses did I&M incur in the historical period?

A. The Company's historical calendar year 2008 O&M expenses for distribution activities necessary to provide safe, reliable distribution services was $70.8 million, as indicated by Company witness Allen.

Q. What is the I&M distribution O&M expense that is projected for 2010?

A. I&M's projected distribution O&M expenses for 2010 are $71.6 million, as indicated in the testimony of Company witness Allen.

Q. Describe the Company's distribution O&M expense trend since 2004.

A. Figure 1 show's the Company's distribution O&M expenditures for the 2008 historical period and four previous periods. Additionally, Figure 1 includes the projected O&M expense level for calendar year 2010.

The Company's distribution O&M expense in the forecasted test year period increase by $837,000 or 1.2 percent in 2010 as compared to the historical year of 2008.

Figure 1
I&M Total Company Distribution O&M Expenses by Year ($000)

Year	I&M Amount ($000)
2004	$52,384
2005	$71,370
2006	$59,599
2007	$60,548
2008	$70,805
Projected (2010)	$71,642

Q. Why does the forecasted test year period indicate an increase in the Company's distribution expenses compared to the historical year of 2008?

A. The small 1.2 percent increase from 2008 to 2010 is reasonable, and it is consistent with the normal inflationary trends, as discussed by Company witness Allen.

Q. Indicate the major components of the distribution O&M expenses.

A. Refer to Figure 2, which indicates the major O&M expenditure categories and amounts for the historical period and the forecasted test year.

Figure 2
I&M Total Company – Distribution O&M Expenses by Activity

Category	**2008 Actual ($000)**	**2010 Forecasted ($000)**
Supervision, Engineering, and Support Functions	$27,745	$21,295
Restoration	$21,769	$17,058
Vegetation Management	$10,104	$11,534
Distribution Line Asset Improvement	$4,120	$10,877
Distribution Station Asset Improvement	$4,305	$5,559
Customer Service & Other	$2,762	$5,319
Total	$70,805	$71,642

Q. Is the forecasted test year level of distribution O&M expense reflected in the Company's filing representative of the distribution O&M expense necessary to provide ongoing safe and reliable service?

A. Yes. The forecasted test year level of O&M expense is representative of distribution service activities that are necessary to serve I&M's customer base.

Several factors affect the costs that are incurred by the Company on an ongoing basis. These include safety, customer growth, customer satisfaction, reliability, employee training, planning and engineering standards, and the impact of weather, environment, and terrain on the distribution system. These factors are interrelated, affecting all areas of the business, and must be balanced with each other to achieve a safe, reliable system. The forecasted test year level of O&M expense represents an ongoing level necessary to provide safe and reliable service.

Q. Does the forecasted test year level of distribution O&M expense contain

an amount for expected major storm restoration?

A. Yes it does. This amount will be further discussed later in my testimony.

Q. Do you believe that the level of O&M expense included in the forecasted test year that you have referenced are reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

<u>B. Capital Expenditures</u>

Q. Please discuss the projected distribution capital expenditures for the forecasted period of April 2009 through December 2010.

A. The total 21 month projected amount from April 2009 through December 2010 is $144.037 million.

Q. Please describe what the projected distribution capital expenditures from April 2009 through December 2010 represent?

A. The Company's distribution capital expenditures predominantly fall into five categories, all of which ensure continued safe and reliable operation of the distribution system:

- <u>Distribution Asset Improvement</u> – The Company utilizes industry research and internal system and equipment performance analyses to develop and implement targeted reliability mitigation programs. Continuing research, development and testing of new materials and equipment are providing new opportunities for increasing the performance and life of distribution assets. The Distribution Asset Programs are designed to optimize expenditures and system performance. These programs consist of two basic components: periodic inspection and maintenance programs and targeted mitigation programs. Periodic inspection and maintenance programs are designed to assess the condition of assets to assure compliance with NESC, state utility regulatory requirements, and AEP System requirements, as well as to maintain and improve system performance. Targeted mitigation programs are designed to improve equipment reliability. This work is necessary and meets the Company's obligation to provide safe and adequate service.

- Customer Service – The initial construction of overhead and underground facilities follows AEP's material and construction standards (except as modified to comply with other codes and standards established by local regulatory authority). AEP's material and construction standards incorporate NESC requirements and other industry standards and were adopted to safely and reliably operate AEP's extensive distribution system. This work is necessary and also meets the Company's obligation to provide the public with adequate and safe service.
- Vegetation Management – The program used for pruning and clearing

vegetation along the Company's distribution circuits at the proper time to protect our lines in an environmentally sound and cost-effective manner. Effective vegetation management is an important factor in the success of any utility providing reliable service, and meets the Company's obligation to provide service while avoiding an unacceptable level of performance.

- Other / Third Party Requests – This category includes several job types, including make-ready, joint use, public project relocations, underground locates, facilities projects, and building projects. This work is necessary and meets the Company's obligation to provide the public with safe and adequate service.
- Storm Restoration - Work related to outage management and restoration of the distribution electrical system. When customers experience service interruptions, line personnel are directed to the location of the outage to diagnose and repair the problem and restore electric service. This workload varies considerably with the seasons and the level of storm activity. This work is necessary and also meets the Company's obligation to provide service while avoiding an unacceptable level of performance.

Q. Please provide more detail on the investment that I&M projects to add to distribution plant during the forecast period.

A. Figure 3 provides additional detail regarding project types that are projected to be undertaken during the 21-month forecasted period:

Figure 3

I&M – Total Company
Projected Distribution Capital Projects
(April 2009 – December 2010)

Category	**Project Description (For project types > $2 million)**	**Estimated Amount ($000)**
Distribution Asset Improvement	Capacity Additions	$15,271
	Reliability	$12,105
	Asset Improvement	$10,274
	Small Local Asset Improvement	$6,934
	Preventive Maintenance	$6,846
	Station Equipment, Other	$4,218
	Other	$1,693
Distribution Asset Improvement Total		$57,341
Customer Service	Customer Service Commercial & Industrial	$16,024
	Transformer	$11,832
	Customer Service Residential New	$5,782
	Customer Meter	$5,743
	Support Customer Service	$3,593
	Customer Upgrade & Relocates	$4,303
Customer Service Total		$47,278
Vegetation Management	Forestry Right of Way	$16,839
Vegetation Management Total		$16,839
Other - Third Party Requests	Public Project Relocation	$7,536
	Facility Relocation	$4,383
	Facilities Building Projects	$2,807
	Damage by Outside Parties and Make Ready	$1,049
Other - Third Party Requests Total		$15,775
Storm Restoration	Failed Equipment	$2,663
	Major Event	$2,077
	NonMajor Event Service Restoration	$2,065
Storm Restoration Total		$6,805
Grand Total		$144,037

Q. Is the projected level of distribution capital investment reflected in the Company's filing representative of the distribution expense necessary to provide ongoing customer service?

A. Yes. The projected level of capital investment is representative of distribution service activities that are necessary to serve I&M's customer base.

Several factors affect the investment levels that are incurred by the Company on an ongoing basis. These include many of the same factors mentioned in the O&M section. Similarly, these factors are interrelated, affecting all areas of the business, and must be balanced with each other to achieve a safe, reliable system. The projected level of investment represents an ongoing level necessary to provide safe and reliable service.

Q. Do you believe that the level of distribution capital investment projected in the forecast period is reasonable and accurate and reasonably likely to occur by the end of 2010?

A. Yes I do.

C. Distribution Programs

Q. What are the principal causes of service interruptions?

A. The principal causes of customer minutes of interruption on I&M's system in the Michigan jurisdiction, excluding unusual events such as major storms, are tree contacts, equipment failures, and outages originating on the transmission system.

Tree related outages accounted for approximately 30 percent of the System Average Interruption Duration Index (SAIDI) on I&M's system in the Michigan jurisdiction during the 12-months ended December 2009. Short momentary interruptions occur when a tree branch is blown against a line causing conductors to come together. Longer sustained interruptions can occur when a tree limb falls into a line. Trees falling into the distribution right-of-way can also damage distribution poles and conductors.

Distribution line equipment failures caused approximately 22 percent of the Michigan SAIDI. Other major causes included transmission related outages at approximately 14 percent and weather related events at approximately 14 percent. The remaining 20 percent of SAIDI was due to miscellaneous causes.

Q. How does I&M maintain reliability on its distribution system?

A. Customer expectations and changing distribution system conditions have helped form I&M's efforts to maintain service reliability. The Company's work has been beneficial in maintaining and improving reliability by reducing the number of customers interrupted on our distribution system. The work can be divided into three major categories which are Distribution Asset Management Programs, the Major Distribution Reliability Programs and Distribution Vegetation Management Program.

Distribution Asset Management Programs

Q. Please describe the Distribution Asset Management programs.

A. Industry research and the Company's experience in the construction, operation and maintenance of distribution systems in varied geographic and demographic areas are applied to manage and maintain the Company's assets. I&M develops objectives and plans to achieve optimal performance in a safe and reliable manner over the expected life of the asset, while at the same time balancing costs and benefits. An example of this type of planning is the Distribution Asset Management Programs, of which, I&M has ten ongoing preventative maintenance programs.

The Distribution Asset Management Programs are designed to optimize expenditures and system performance. These programs consist of two basic components: 1) periodic inspection and maintenance programs and 2) targeted mitigation programs. Periodic inspection and maintenance programs are designed to assess the condition of assets to assure compliance with NESC, state utility regulatory requirements and I&M requirements and to maintain and improve system performance. Targeted mitigation programs are designed to improve equipment reliability and safety performance and maintain and improve system reliability and performance.

The ten I&M Distribution Asset Management Programs and their roles with respect to distribution system reliability are as follows:

1. Overhead Circuit Facilities Inspection and Maintenance Program

Under this Asset Program, I&M visually inspects its overhead facilities to identify and correct potential problems before they cause service interruptions. To assist in these inspections, I&M recently began using Electromagnetic Interference (EMI) devices, infrared devices, and Spectrum Analyzers, a technology employed to identify problems that are not always apparent from a visual inspection. Through these inspections, I&M can identify and repair such things as broken insulators and blown lightning arresters. As a result of identifying and repairing such problems before they cause an outage, I&M's customers may experience fewer and shorter service interruptions.

2. Animal Mitigation Program

The objective of this Asset Program is to reduce the number of animal caused outages by installing animal guards on line transformers and other line equipment at locations that have, or potentially have, a high risk of animal-caused outages.

3. Underground Facilities Inspection and Maintenance Program

Under this Asset Program, I&M visually inspects the external, above-ground portions of underground distribution facilities on an approximate five-year cycle to identify and correct problems before they happen. Through these inspections, I&M identifies and repairs equipment such as defective transformers, pedestals, and switchgear to avoid outages.

4. Pole Inspection and Maintenance Program

The primary objective of this Asset Program is to maintain and prolong the structural integrity of I&M's wood poles. As necessary, poles are treated and reinforced, or replaced. With pole inspection and replacement, small wire replacement has allowed proactive spot maintenance, and has provided a healthier infrastructure. This program helps us identify and replace poles that might otherwise fail and cause power interruptions.

5. Recloser Maintenance / Replacement Program

The objective of this program is to identify the need to perform preventive maintenance, or to replace, as needed, recloser units that are not operating properly. When a recloser device senses a fault, the device will automatically open and allow a brief period of time for the cause of the fault to clear from the line. The reclosing equipment will then automatically reclose and re-energize the circuit. A recloser that does not open and close properly can turn a momentary interruption into a sustained interruption of service, which then requires a crew to be dispatched to correct the problem.

6. Overhead Conductor Program

This program minimizes primary and secondary conductor failures by replacing overhead conductors that show signs of deterioration. This program focuses on areas that are experiencing above-average interruptions.

7. Underground Cable Program

The objective of this program is to correct primary cable deficiencies by restoring the integrity of cable through either cable injection or cable replacement. As is the case with I&M's Overhead Conductor Program, this program targets areas experiencing above-average interruptions and lessens the likelihood of future interruptions to our customers. Cable treatment is a benefit to customers because it is a less intrusive process.

8. Capacitor Inspection and Maintenance Program

The objective of this program is to visually inspect all switched capacitor banks for proper operation twice annually and all fixed capacitor banks once annually to identify and correct deficiencies necessary for system reliability to include an emphasis on capacitor bank availability during summer and winter peak loading seasons.

9. Lightning Mitigation Program

The objective of this program is to reduce the number of lightning-caused outages through the installation of new lightning arresters at locations within areas known to be prone to lightning-caused outages.

10. Sectionalizing Program

This program improves the performance of I&M's distribution circuits by adding new, modifying existing or replacing sectionalizing devices. This enhanced sectionalizing enables smaller circuit segments and fewer customers to be interrupted due to faults that may occur on distribution circuits.

Major Distribution Reliability Programs

Q. Please describe what is included in the major distribution reliability improvement category.

A. Each year, I&M completes various major Distribution reliability improvements that are not included in the Asset Programs category that I described above. During 2008, for instance, I&M completed improvements to prevent overloading of equipment and to improve our ability to restore power to customers. These improvements range from comparatively minor distribution circuit reconfigurations within a residential area to complex additions of new substations and associated transmission lines to establish new distribution circuits to better serve our customers.

A couple of examples of this type of work include the following:

<u>New distribution stations:</u>

- Moore Park (2008) - Installed a 20 MVA transformer and three circuits to relieve the Three Rivers station.
- Saulk Trails (2008).- Built a new 20 MVA station and two circuits to relieve and replace the Edwardsburg station. The new station is fed by

two 138 kV sources, whereas Edwardsburg station was fed by one 34.5 kV line, thus, reliability is much improved.

Expansion of existing stations:

- New Buffalo (2009) - Replaced a 9.4 MVA transformer with a 20 MVA unit to serve load growth in and around the Four Winds Casino.
- Sister Lakes (2008) - Added a second transformer to relieve projected overload and improve reliability to this remote station.

Distribution Vegetation Management Program

Q. Please describe I&M's third major category, the distribution vegetation management program.

A. I&M's existing Distribution Vegetation Management Program is a performance-based vegetation management program for pruning and clearing vegetation along I&M's distribution circuits as required to protect its lines in an environmentally sound and cost-effective manner. Performance-based vegetation management is the method that I&M uses to address circuits with the greatest need for vegetation management. Each fall, the following year's annual vegetation plan is developed based on current circuit performance. The annual vegetation management work plans are flexible and dynamic. Inputs into the work plan include historical reliability data, line inspections, customer density, circuit performance, weather, customer complaints, and time elapsed since vegetation management was last performed.

I&M uses a variety of vegetation management practices to control vegetation along its distribution rights-of-way, such as aerial sawing, mechanized trimming, manual trimming (roping, hand climbing), mechanized clearing, manual clearing and herbicide and growth regulator applications. I&M's distribution vegetation management practices are conducted in accordance with standards established by the ANSI, OSHA, and the NESC.

Q. Is I&M's existing vegetation management program sufficient to provide I&M's customers with the level of reliability they expect?

A. While our performance-based approach limits the number of tree-related outages, given I&M's service area, it is important that we move to a more regular four-year vegetation management cycle to significantly reduce these outages. To achieve this result, I discuss in a later section of my testimony, our plan to enhance our vegetation management effort by moving to a four-year management cycle.

Other Programs

Q. In addition to the programs mentioned previously, what other activities has I&M performed to improve reliability?

A. I&M endeavors to be proactive with regard to replacing or rebuilding distribution infrastructure and installing automated switches on both overhead and underground three-phase lines. This work has helped prevent outages caused by aged equipment and, where possible, has minimized the impact of outages on Michigan customers.

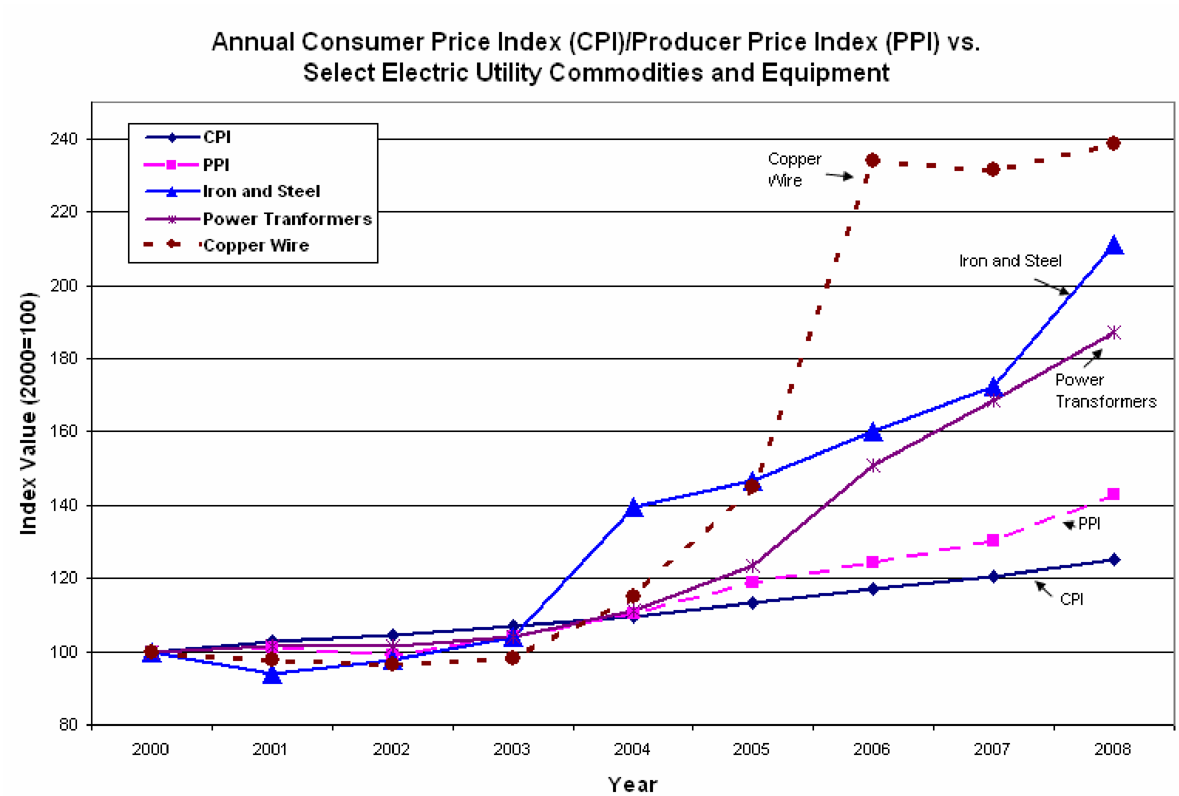
I&M also has installed automated switches on three-phase lines. When an interruption occurs, automated switches segment a circuit by automatically opening (de-energizing) or closing (re-energizing), depending on their location. Customers not directly affected by the fault are immediately transferred to another source, if available. Distribution automation also allows for the faster restoration of customers affected by an outage. I&M has begun this effort in Michigan and so far, has installed one distribution automation scheme on two circuits.

In addition to these initiatives, I&M also addressed summer capacity issues in 2007 and 2008 after experiencing high summer load peaks in many parts of Michigan in summer of 2006. Each affected area was analyzed and as a result, in-service dates and associated project timelines for several major initiatives were moved to ensure solutions were in place before the next summer peak season. Through a collaborative effort, completion dates were met and the number of load related problems was greatly reduced during the summer 2008 load peaks.

Q. Is the Company able to maintain its level of service reliability at current spending levels?

A. No. Absent an increase in spending, the total number of trees trimmed or removed in the Company's Michigan service area will decrease in future years, given inflation and the rise in labor and commodity pricing. The Company has incurred, and will continue to incur, cost escalations in material and contract labor related to providing distribution service. One of the examples noted above is exemplified in Figure 4 below. Since the year 2000, commodity prices for items like copper, iron, and steel have increased dramatically.

Figure 4



All Data Extracted from United States' Bureau of Labor Statistics Website
Data Extracted October 19, 2009
Indices Set to = 100 at Year 2000 for Basis of Comparison

D. Distribution Performance

Q. Please explain how I&M measures the results of the programs you have

described to provide reliable service to its Michigan customers?

A. The indices that I&M uses to gauge service reliability are the System Average Interruption Frequency Index (SAIFI), the System Average Interruption Duration Index (SAIDI),and the Customer Average Interruption Duration Index (CAIDI). These indices are described as follows in the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003:

- SAIFI indicates how often the average customer experiences a sustained interruption over a predefined period of time. It is the total number of customers interrupted divided by the total number of customers served.
- SAIDI indicates the total time the average customer is without service due to sustained interruptions during the specified period. It is the sum of customer-minutes of interruption from each outage divided by the number of customers served.
- CAIDI represents the average time required to restore service. It is the sum of customer-minutes of interruption from each outage divided by the total number of customers interrupted.

These indices provide insight into how well we are minimizing service interruptions. I&M calculates its SAIFI, SAIDI, and CAIDI indices excluding major events to provide a more realistic view of how the system operates during normal operating conditions. Major events represent conditions that exceed reasonable design and/or operational limits of the electric power system. I&M identifies major events using the major event day methodology detailed in "IEEE Std 1366 -2003, IEEE Guide for Electric Power Distribution Reliability Indices". Major event days are determined by considering the entire Michigan jurisdiction. Outages that begin on the identified days are categorized as occurring during major events.

Q. Please provide and discuss the Company's recent SAIFI, SAIDI and CAIDI indices.

A. I&M's (Michigan jurisdiction) SAIFI, SAIDI, and CAIDI indices including major events and excluding major events are shown in Figures 5 and 6 below.

Figure 5
I&M Reliability Indices (including major events)

12 Months End	SAIFI	SAIDI (minutes)	CAIDI (minutes)
Dec-04	2.537	1880.7*	741.5*
Dec-05	1.281	229.6	179.2
Dec-06	1.604	291.2	181.5
Dec-07	2.045	1008.3*	493*
Dec-08	1.259	207.5	164.8
Dec-09	1.309	361.8	276.4

** Increase in SAIDI and CAIDI due to ice storms.*

Figure 6

I&M Reliability Indices
(excluding major events; IEEE 1366-2003 methodology)

12 Months End	SAIFI	SAIDI (minutes)	CAIDI (minutes)
Dec-04	1.811	333.3	184.0
Dec-05	1.170	185.1	158.3
Dec-06	1.504	248.2	165.0
Dec-07	1.304	202.6	155.4
Dec-08	1.259	207.5	164.8
Dec-09	1.130	186.8	165.3

I&M also uses SAIDI data to direct its reliability enhancement program. A good example of the results of these efforts was the Company's 2008 review of two very similar storms that mostly affected I&M's Muncie, Indiana territory, one in 2004 and another in 2007, and their affect on our service delivery. After reviewing the data, we found we were able to restore service to customers significantly faster in 2007 because of the work we had accomplished prior to 2007. The SAIDI attributed to the 2007 storm was nearly half of that from the 2004 storm. When compared to the 2007 storm, that number dropped 50 percent to 105 million minutes. In addition, we found 22 fewer circuits locked out due to tree damage during the 2007 storm, and there was an 89 percent reduction in tree-caused SAIDI.

Q. What other measures does I&M track to gauge the reliability of its T&D system?

A. I&M conducts quarterly customer satisfaction tracking studies for both its residential and small commercial customers. These studies are conducted by Market Strategies, International (MSI). Using this unaffiliated survey research firm assures the integrity and quality of the data and provides comparative national benchmarking data on standardized questions included in these surveys.

Please refer to Exhibit I&M-31 (JEE-1), which shows the summary table of I&M's benchmarking performance for residential customers in Michigan during 2008. Please refer to Exhibit I&M-32 (JEE-2), which shows the summary table of I&M's benchmarking performance for small commercial customers in Michigan during 2008. Overall customer satisfaction with I&M's operations in Michigan was very high in the residential segment, ranking third out of 106 utilities. I&M, Michigan jurisdiction, ranked 17th overall out of 91 for small commercial customers.

Although the overall customer satisfaction survey includes a multitude of questions related to all aspects of the customer's experience with the Company, the Distribution organization focuses mainly on those questions that are reliability focused.

From our 2008 Michigan reliability-related customer satisfaction results included in the exhibits noted above, I&M placed above the MSI-supplied national benchmarks as follows:

- Overall reliability satisfaction levels for both (residential = 88 percent, small commercial = 91 percent) customer segments scored two and three points above their respective MSI national benchmarks.
- Overall power quality satisfaction for both (residential = 86 percent, small commercial = 86 percent) customer segments scored six and five point above their corresponding MSI national benchmarks.
- Outage restoration satisfaction for both (residential = 83 percent, small commercial = 87 percent) customer segments scored six and eight point above their corresponding MSI national benchmarks.

Q. Have customer expectations for service reliability changed over time?

A. Yes. The demand for electricity continues to increase in the United States, along with the expectation of consumers for more reliable and cost-effective distribution of electricity. In large part, this increasing expectation is driven by the growing dependence on electronic technology within all customer groups. Customers today are becoming more sensitive to momentary interruptions (interruptions lasting five minutes or less) in their service delivery; and they are not disassociating momentary interruptions from sustained outages (lasting greater than five minutes). As a result, momentary interruptions (although always present in the past, but not considered an issue by customers) are now more likely to be perceived by customers as degradation in service reliability. Ironically, these interruptions are actually occurring through a series of recloser operations to clear objects from the line to avoid sustained outages.

In 2008 I&M added a question to its customer satisfaction survey addressing customer reliability expectations. When asked how their expectations related to having reliable electric service delivered had changed over the past five years, the majority of I&M's (Michigan jurisdiction) residential (65 percent) and small commercial (74 percent) customers surveyed in 2008 indicated that those expectations had stayed about the same. However, 25 percent of residential and 23 percent of small commercial customers indicated that those expectations had actually increased (either somewhat or significantly) in the past five years as opposed to the 9 percent of residential customers and 3 percent of small commercial customers who indicated that those expectations had actually decreased over the past five years.

This expectation has been growing within all customer groups over the past 10 years and has been fueled by the proliferation of microelectronics, home-based computers, and industrial process controllers. Today, almost every low- and high-power type of equipment from light dimmers to adjustable speed drives, uses some type of power electronic device to convert AC to DC. Unfortunately, manufacturers have been slow in responding to design features that let sensitive equipment ride through momentary interruptions, and even some sustained interruptions, thus leaving the device to be reset or re-programmed, which is an irritant to customers. Though the increased use of technology has delivered promising opportunities for many customers, it has created a challenge for electric utilities to improve an infrastructure that was not initially designed for today's digital world.

Q. Overall, how would you rate I&M's performance in regard to distribution reliability in Michigan service territory?

A. I believe we have been doing a good job. This is confirmed by I&M's reliability indices that have generally gotten better as well as the customer satisfaction results noted earlier.

VI. I&M's INCREMENTAL ENHANCED DISTRIBUTION RELIABILITY PROGRAM

Q. How can I&M's service reliability be improved in Michigan?

A. As previously discussed in my testimony, I&M's current programs have proven successful in increasing customer satisfaction and improving system reliability indices. Our results show that through prudent planning and efficient use of available resources, I&M has been able to produce positive reliability results. However, customers' demand for ongoing service quality is growing, so incremental work above and beyond the base forecast is required to further improve customer reliability and power quality.

To further improve reliability, our focus is on addressing the leading causes of outages, which are vegetation both in and out of right of ways. Increased vegetation management efforts will lead to an improvement in SAIDI, thereby meeting our customers' growing demand for improved reliability.

Q. What incremental program does I&M propose to address future reliability

needs?

To reach the next level of reliability, I&M is focused on an incremental reliability initiative to address I&M's vegetation management needs and our customers' demand for increased quality of service. Continued focus on current level of distribution reliability programs can take the reliability of a distribution system only so far. Vegetation will continue to grow and absent an increase in spending, the number of total trees trimmed or removed in I&M's service territory in Michigan will decrease in future years, given inflation and the rise in labor and commodity prices. Low cost opportunities to improve reliability, such as sectionalizing, are of high value but often have been fully utilized. In addition, as costs for current programs continue to escalate, the value and amount of work performed potentially declines.

Q. Does the I&M service territory in Michigan exhibit characteristics that indicate a need for enhanced vegetation management?

A. Yes. Trees have caused nearly 37 percent of the sustained, non-major event customer service outages from 2004 through December 2009. This is the highest percentage of all the recorded outage cause types. Tree outages are caused by vegetation both in and out of the right-of-way.

The major causes of customer service outages in I&M's service territory in Michigan are shown in Figure 7.

Figure 7
Principal Outage Causes in I&M's service territory in Michigan

12 Months End	Tree Inside / Outside ROW	Distribution Equipment	Transmission	Weather	Other
Dec-04	37.0%	10.8%	6.3%	22.0%	23.9%
Dec-05	34.4%	19.7%	7.2%	16.9%	21.8%
Dec-06	44.2%	12.4%	6.9%	17.8%	18.7%
Dec-07	38.5%	21.0%	6.4%	8.7%	25.4%
Dec-08	30.3%	22.7%	23.5%	13.4%	10.1%
Dec-09	30.1%	21.8%	14.1%	14.2%	19.8%
Weighted Average	36.7%	17.1%	10.2%	16.2%	19.8%

Data based upon SAIDI data, excluding Jurisdictional Major Event Day (IEEE 1366-2003 methodology)

Q. Please describe the proposed incremental program.

A. I&M proposes an incremental vegetation management program for its Michigan territory that is in addition to the base amount that will be spent on vegetation management. In order to more aggressively maintain and further manage vegetation growth on its entire distribution system, I&M plans to move to a four-year cycle vegetation management program in the Michigan service territory. As noted previously in my testimony, over the past several years, I&M has focused on a performance-based management approach and has found this approach to be a prudent way to manage its vegetation-caused outages.

Performance-based vegetation management is a reactionary method where typically, the worst performing circuits are trimmed in an effort to provide better reliability to the customers who have experienced more frequent or lengthier outages than other customers. Although this method has been effective and prudent, it has also allowed some circuits to remain untrimmed for several years.

The proposed four-year vegetation management cycle is proactive in nature and once it is in place, provides for the increased likelihood that all customers will experience better reliability since all circuits will be reviewed on schedule and the proper treatment determined accordingly.

I&M's in-service distribution plant includes approximately 4,500 miles of primary overhead distribution lines. As shown earlier, one principal cause of service interruptions on I&M's system is contact between a line and a tree or other vegetation. Therefore, an effective way to reduce outages would be to increase the level of vegetation management performed so that all of the distribution rights-of-way would be inspected and/or maintained at least once over a four-year period.

With the projected additional funding, I&M would be able to move from a reactive vegetation management program that is based on specific historical performance of a given line, to a more proactive vegetation management program. With a four-year cycle, I&M would evaluate every mile of its Michigan distribution system within a four-year period. Evaluating every line mile would allow a more systematic, data-driven approach to maintaining the system from a vegetation management viewpoint.

This evaluation process would allow I&M to achieve a cyclic vegetation management program to perform the necessary vegetation clearing on the system dictated by the evaluation process. With this plan, identified areas would be trimmed as needed and an inspection and analysis of each line mile would be conducted over a four-year period.

The projected four-year cycle approach would be deployed in I&M's service area in Michigan during a four-year transition period. I&M would create a vegetation profile to collect, store, predict, and analyze specific vegetation data. For instance, the location of vegetation in proximity to the conductors, accessibility, density, vegetation coverage (e.g., vines), and vegetation growth rates are all input variables which are critical in the planning process. This vegetation profile would be used to establish detailed work plans for each circuit (or portions of a circuit) to predict and schedule annual vegetation management cycles. Some locations would require more frequent trimming, while trimming in other areas may be less frequent, depending on a number of factors. This profiling effort would provide sufficient information for trimming between distribution power lines and trees so that within the cycle period (four years) tree vegetation would not grow back into power lines, thus reducing outages and increasing overall reliability.

To illustrate the scope of the Incremental Vegetation Management Program, Figures 8 and 9 have been prepared. Figure 8 shows the Company's historical base vegetation management activity as well as the projected amounts for 2010. Figure 9 shows the incremental amount of work that will be accomplished through increased spending and effort, which is in addition to the base amounts.

Figure 8

I&M's Historical and Projected Base Vegetation Management Program in Michigan

Year	2006		2007		2008		Projected 2009		Projected 2010	
Trees Trimmed	184,191		300,872		72,502		91,000		74,000	
Trees Removed	29,497		17,060		21,047		15,000		12,000	
Acres of Brush Cleared	1,963		926		1,121		850		700	
Circuit Miles Addressed	1,745		2,093		3,081		1,000		850	
Current Vegetation Cost ($ Millions)	**O&M**	**Cap**	**O&M**	**Cap**	**O&M**	**Cap**	**O&M**	**Cap**	**O&M**	**Cap**
	$5.93	$4.31	$5.61	$3.01	$3.90	$4.93	$3.29	$2.38	$2.65	$2.31

Figure 9 shows projections for the same activities that would escalate as a result of the incremental spending in Program Years 1 through 4. These values are in addition to the amounts that will be achieved through the base program values in the projected test year column of 2010 in Figure 8. Once the distribution system has been more effectively managed, I&M expects the number of tree crews to decrease as the four-year cycle is continued at a more moderate ongoing maintenance level.

Figure 9

I&M's Incremental Vegetation Management Program in Michigan

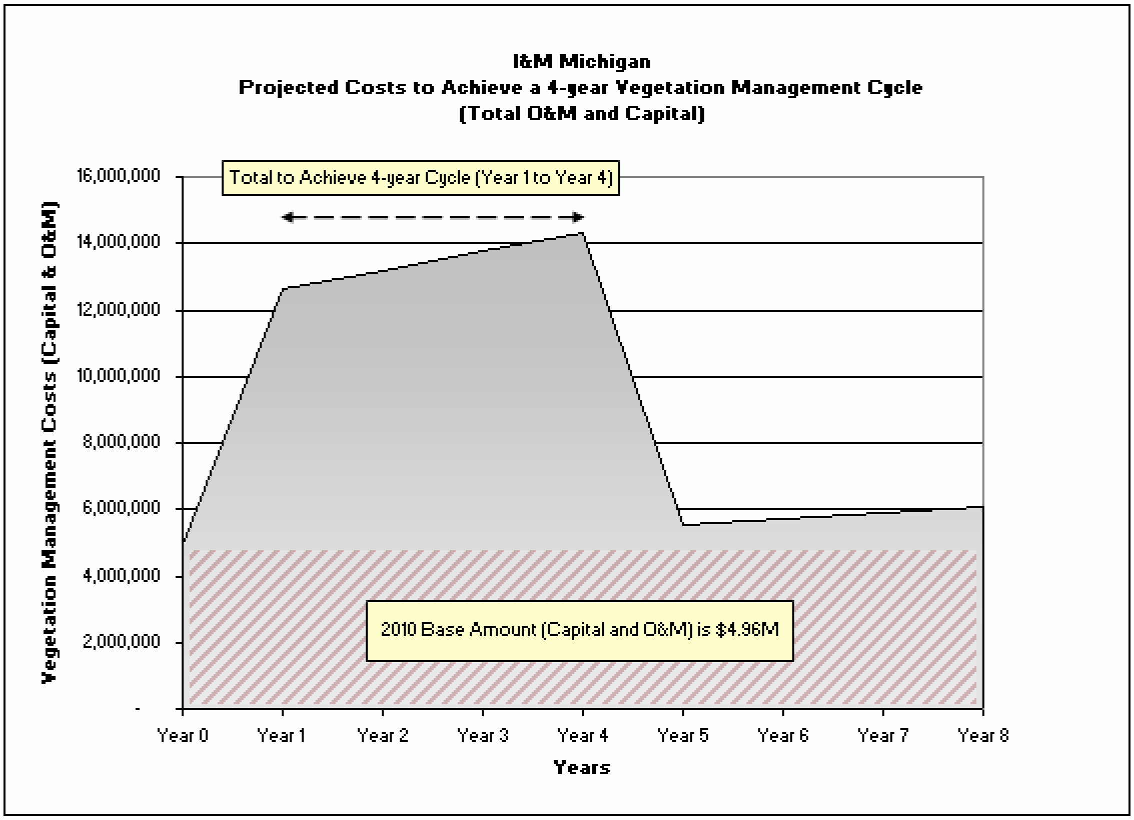
Program Year*	**Year 1**		**Year 2**		**Year 3**		**Year 4**	
Trees Trimmed	115,000		125,000		135,000		140,000	
Trees Removed	18,000		18,000		18,000		23,000	
Acres of Brush Cleared	1,100		1,100		1,200		1,300	
Circuit Miles Addressed	1,125		1,125		1,125		1,125	
Incremental Vegetation Cost ($ Millions)	**O&M**	**Cap**	**O&M**	**Cap**	**O&M**	**Cap**	**O&M**	**Cap**
	$2.12	$5.57	$2.27	$5.96	$2.41	$6.38	$2.57	$6.81

** Program Year is based upon implementation date, not necessarily calendar year.*

Q. What are the long-term cost projections associated with this proposal?

A. The long-term projections demonstrate that the projected enhancement program will allow I&M to maintain reliability at a decreased ongoing cost once a four-year cycle is achieved. Figure 10 depicts the projected base and incremental O&M costs associated with implementing the proposed Enhanced Distribution Reliability Tracker.

Figure 10



Q. What are the key customer benefits from achieving a four-year vegetation management cycle program?

A. The key benefits for I&M's customers in Michigan are reduction in sustained tree-caused outages, improved power quality with fewer momentary interruptions, faster restoration after major storm outages, and improved communications with customers about the enhanced vegetation management plan.

Since I&M will be addressing all Michigan circuits on a regular cycle, tree-caused outages from inside and outside the right of way (ROW) will be reduced by a projected 54 percent. Danger trees outside the ROW will be addressed through identification and removal, improving reliability. As circuits are trimmed and cleared on a cycle, the power quality for customers will improve, as customers experience fewer momentary outages due to reduced momentary tree contact with power lines.

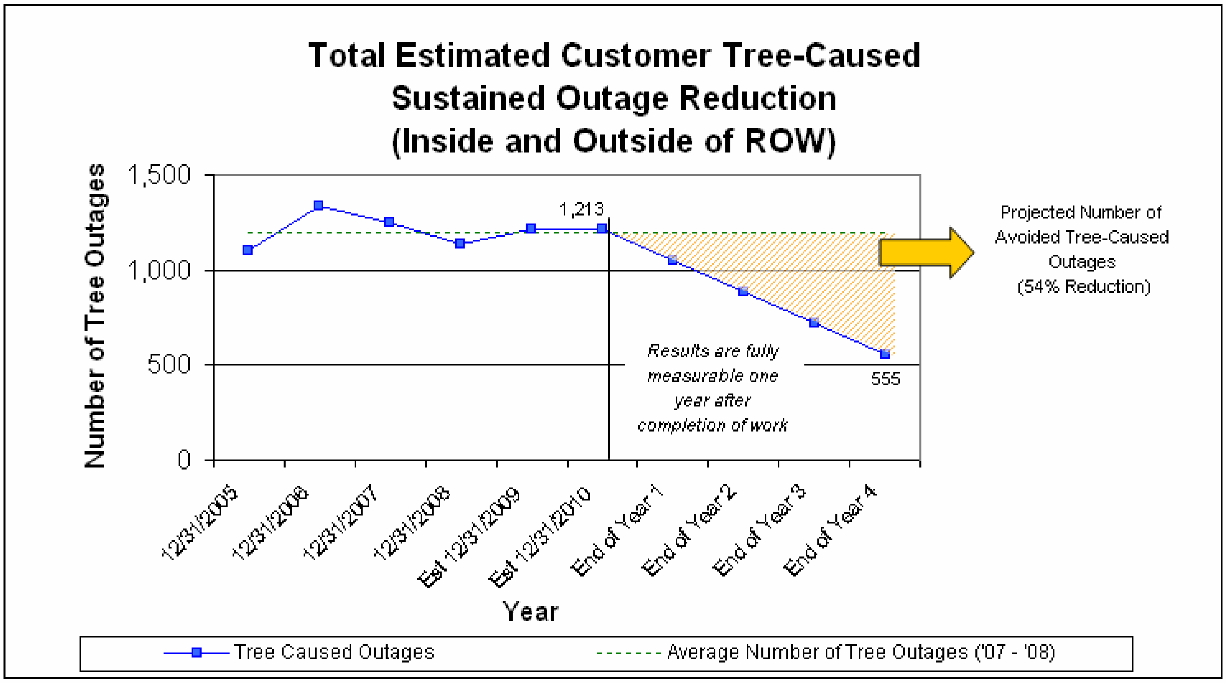
Customers will also benefit from faster restoration after major storms. As the ROWs are widened and trees and brush are removed, crews will have improved access to address the cause of the outage.

The vegetation profile compiled for all of I&M's circuits in Michigan will provide data that will feed into the creation of annual work plans used on all circuits, especially to target troublesome circuits. The vegetation profile, coupled with the mapping capability, will allow a greater means of communication with the customer and crews. Communication with customers will further their understanding of the need for and the benefits of an enhanced vegetation management program.

Q. What is the time frame in which customers will realize these benefits?

A. Figure 11 shows total estimated customer tree-caused sustained outage reductions for the circuits cleared under the enhanced program. The benefits of the Enhanced Distribution Reliability Plan can be measured approximately one year after the mitigation work has been completed. However, customers will recognize the power quality and reliability benefits immediately once the work has been completed on their circuit. The enhanced vegetation initiative will proactively reduce tree-caused outages and improve customers' overall service experience.

Figure 11



Q. Will I&M customers in Michigan experience the benefits of I&M's incremental enhanced distribution reliability program in the near term?

A. Yes. It is expected that Michigan customers will experience improvement as soon as the work is completed on individual feeders. However, since reliability indices are measured on a rolling 12-month average, improvement efforts will not be immediately reflected in these indices.

Q. Has the customer benefit of a four-year vegetation cycle been demonstrated in any other AEP System service territories?

A. Yes, it has. The customer benefit of such a plan is demonstrated by the experience of Public Service Company of Oklahoma (PSO), an AEP affiliate, which is progressing towards a four-year trimming cycle. PSO's efforts are funded through a reliability rider similar to the one being proposed in this case. PSO is on track to complete its first four-year tree trimming cycle by late 2010. PSO has completed vegetation management activities on approximately 87 percent of its existing overhead distribution system, which represents work either completed or in progress on 622 circuits and 10,841 line miles. Since PSO began this effort, reliability has improved significantly. For the 12-months ending June 2009, PSO experienced a 58 percent reduction in customer outages due to sustained, non-major-event tree-related outages, compared to the 12-months ending December 2004, which was the year before the reliability program was initiated.

Q. Are you aware of any studies that show a four-year vegetation management cycle is becoming an industry practice?

A. Yes. In 2005, the Edison Electric Institute sponsored a survey and study by Davies Consulting regarding state reliability regulation in the United States. The Davies review of vegetation practices by 18 investor-owned utilities serving customers in 39 states showed a four-year tree trimming cycle to be a common benchmark for vegetation management programs.

Q. Does I&M anticipate any challenges to implementing its incremental vegetation management plan in Michigan?

A. I&M's overall reliability strategy is ongoing and remains flexible in order to allow for the introduction of new technology and industry advancements, as well as new reliability challenges not yet identified or addressed. Implementation of the plan may be impacted by labor availability, material resource constraints or other emerging issues. Key to the implementation of this plan will be Commission support and approval. It is our belief that the time is right to go beyond base level of service reliability by moving to a proactive four-year cycle.

Q. How does I&M propose to recognize the costs of the incremental vegetation management program for ratemaking purposes?

A. I&M proposes the implementation of an Enhanced Distribution Reliability Tracker to recover the costs associated with the Distribution reliability improvement work I previously described. Company witness Krawec explains and supports in his testimony the application of a tracker and projected recovery mechanism.

VII. TRANSMISSION BASELINE OPERATIONS

Q. Please provide an overview of the existing AEP East Companies'[2] transmission system.

A. The AEP East Companies' transmission system is centrally located within the

[2] The AEP East Companies include Appalachian Power Company in West Virginia and Virginia, Indiana Michigan Power Company in Indiana and Michigan, Kentucky Power Company in Kentucky, Kingsport Power Company in Tennessee, Columbus Southern Power Company and Ohio Power Company in Ohio, and Wheeling Power Company in West Virginia.

Eastern Interconnection, extends throughout portions of seven states, and is interconnected with systems serving numerous heavily populated areas, including, among others, Chicago, St. Louis, Detroit, Cleveland, Cincinnati and Pittsburgh. The system extends more than 500 miles from Indiana to Virginia, west to east, and from Michigan to Tennessee, over 400 miles, north to south. The longest individual transmission lines are 150 to 200 miles in length.

The AEP East Companies' transmission system is comprised of nearly 15,000 miles of circuits operating at or above 138 kV. Included in this total are nearly 6,000 miles of extra high voltage (EHV) transmission lines, including about 2,100 miles of 765 kV lines, and about 3,800 miles of 345 kV lines. This expansive system allows AEP to economically and reliably deliver electric power to approximately 24,200 MW of zonal customer demand, and other loads served under the PJM Open Access Transmission Tariff (OATT). The EHV system also connects more than 26,000 MW of generation to the grid, including approximately 5,300 MW of generation operated by other utilities and independent power producers. In addition, the AEP East Companies' transmission system is directly connected to 19 neighboring utility transmission systems at 144 interconnection points.

Q. Please describe the I&M transmission system.

A. The I&M transmission system is a highly networked grid that delivers electric energy from generation sources to the retail and wholesale consumers served by I&M. I&M's transmission system serves I&M's own distribution systems and large retail loads, as well as the distribution systems of other utilities, co-ops, and municipalities. The I&M transmission system delivers energy to approximately 164 transmission and 258 distribution stations that provide the necessary voltage transformation to serve I&M customers. Of the I&M station total, there are approximately 39 transmission stations and 52 distribution stations in the state of Michigan.

I&M's transmission system can be divided into three categories based on voltage level: EHV, transmission, and sub-transmission. There are approximately 5,343 circuit miles of transmission lines in I&M, 938 circuit miles in Michigan, with the approximate number of circuit miles at each voltage level shown in Figure 12.

Figure 12

I&M Transmission Circuit Miles by Voltage (as of 12/31/08)

Voltage	I&M Total Circuit Miles	I&M Michigan Total Circuit Miles	Voltage Category
765 kV	615	16	EHV
345 kV	1,614	234	EHV
138 kV	1,668	242	Transmission
69 kV	707	298	Sub-transmission
34.5 kV	739	148	Sub-transmission
Total	**5,343**	**938**	

The I&M sub-transmission system, which represents approximately 27 percent of the total transmission circuit miles, plays an important role in providing reliable service to I&M's customers because it provides energy directly to approximately 76 percent of the 258 distribution stations located in I&M. Consequently, sub-transmission system reliability improvements translate directly to improved distribution station reliability and hence improved customer reliability.

Q. Please describe the transmission planning process used to determine the reliability needs of the I&M transmission system.

A. Since AEP transferred functional control of the AEP East Companies' transmission system to the PJM RTO in October 2004, AEPSC has conducted the planning activities described below in coordination with and under the oversight of PJM. PJM has assumed the responsibility and is registered with North American Electric Reliability Corporation (NERC) as a Transmission Planner for the PJM footprint. Coordination and oversight of transmission planning by PJM ensures that the expansion and improvement of the AEP East Companies' transmission system, and transmission systems of other transmission owners within the PJM footprint, meet the needs of PJM regional customers, and that all stakeholders can interact with the planning process through participation in various PJM regional activities in compliance with the requirements of FERC Order 890.

Historically, AEPSC has developed annual base case power flow models to perform system reliability studies, as needed, in order to determine future system additions and modifications. AEPSC studies its transmission system applying NERC and ReliabilityFirst Corporation (RFC) Reliability Standards, PJM Reliability Criteria[3], and AEP Transmission Planning Criteria and Assessment Practices to determine capacities, constraints, and limitations of the transmission lines and station equipment, such as wave traps and transformers.

AEPSC conducts power flow studies to simulate the performance of the I&M transmission system during normal peak loading conditions and also with key transmission facilities out-of-service. AEPSC also conducts short circuit studies to analyze fault current interrupting capabilities of circuit breakers with proposed transmission facilities in service, and conducts stability studies as necessary. AEPSC identifies capital improvements to meet reliability needs for the I&M transmission system based on the results of the above studies.

Q. Does PJM coordinate with neighboring systems to address transmission planning?

A. Yes. PJM coordinates with interconnected systems via formal agreements and coordinated efforts. PJM has formal agreements with the Midwest Independent Transmission System Operator (MISO), New York ISO, ISO New England, TVA, and Progress Energy Carolinas that address coordinated system planning.

[3] Schedule 6 of the Operating Agreement and Manual 14 Series Documents

Q. Is the I&M transmission system currently adequate to serve its customers' load reliably?

A. Yes, the I&M transmission system currently has adequate capacity to serve its retail and wholesale loads reliably.

Q. Will I&M transmission continue to provide reliable service for its customers in the future?

A. Yes. I&M transmission will continue to make the necessary transmission capital investments to provide reliable service.

VIII. I&M TRANSMISSION O&M EXPENSES

Q. Please describe the forecasting, planning, and cost review processes that are used to control transmission O&M costs.

A. AEPSC's transmission planning and forecasting is a cohesive and dynamic planning process that is linked to the AEP annual business planning process. Each department within AEPSC Transmission provides input for the business plan and the related expenses and capital requirements, including inputs specific to I&M. After the business plan is approved by executive management, a ten-year capital forecast and a two-year O&M forecast are prepared that describe capital and O&M expenditures necessary for AEPSC Transmission to perform its primary functions of planning, engineering, constructing, operating and maintaining the transmission network. An annual work plan based on the approved forecast, which includes projected costs to support the plan, is then prepared and implemented. During the work plan year, the status of the work plan and the related costs are monitored by AEPSC Transmission management on an on-going basis, and work plan adjustments are made as necessary to address emerging needs. Transmission management reviews any variances versus forecast for O&M expenses and the capital expenditures as discussed later in order to keep such expenses within the forecast. Additionally, I&M management reviews AEPSC billings related to these expenses.

Q. What level of transmission O&M expenses were incurred for I&M in 2008?

A. As indicated by Company witness Allen, total I&M incurred $21.1 million of transmission O&M expenses during 2008. These costs are the sum of the Transmission Operation Accounts 560 – 567 and the sum of Transmission Maintenance Accounts 568 – 573, less Account 565 (Transmission of Electricity by Others) and the PJM costs included in Account 561 (Load Dispatching). These accounts are used to track and identify the I&M transmission O&M expenses. Account 565 is excluded for discussion purposes because the Transmission Equalization credit and PJM Transmission Enhancement costs contained in Account 565 obscure the historic trend in the I&M total transmission O&M costs. Similarly, the PJM costs included in Account 561 are excluded because these costs are not directly related to the operation and maintenance of I&M's transmission assets and similarly obscure the historic trend. As I discuss transmission O&M expenses throughout my testimony, I will be referring to this subset of expenses.

Q. What level of transmission O&M expenses are projected to be incurred in 2010?

A As indicated by Company witness Allen in Exhibit I&M-25 (WAA-2), the I&M total transmission O&M expenditures projected for the 2010 are $18,191,000. These expenditures are required to fund the Transmission Asset Management programs that are necessary to maintain and ensure the reliable operation of the transmission system. The expenditures also includes the I&M Transmission Vegetation Management Program. Figure 13 provides a forecast estimate of the 2010 transmission O&M expenditures for I&M:

Figure 13
I&M 2010 Transmission O&M Expense Forecast

Description of O&M Expense	I&M ($000's)
Overheads and Expenses	$6,640
Station Programs	$3,150
Line Programs	$2,169
Protection & Control Programs	$1,200
Vegetation Mgt Programs	$3,207
Other	$1,825
Total	**$18,191**

Q. Please describe the Transmission Asset Management Programs.

A. The Transmission Asset Management Programs fall into the following three broad functional areas: Station Programs, Transmission Line Programs, and Protection & Control (P&C) Programs. The objective of these programs is to identify potential situations that could cause an interruption of service and implement proactive corrective actions to maintain the reliable operation of the transmission equipment.

The Station Programs include the inspection and maintenance of I&M's station equipment such as circuit breakers, transformers, switches, reactive power devices, station batteries, control buildings, structural steel and associated facilities.

The Transmission Line Programs provide for the inspection and maintenance of line equipment, which includes structures, conductors, switches, insulators, hardware and rights-of-way. The Transmission Line Programs can be divided into two parts: The Line Inspection Programs include walking, climbing, aerial, infrared and emergency inspections. The Line Maintenance Programs address conductor, structural or hardware problems, and include such things as steel structure corrosion control and groundline treatment for wood poles.

The P&C Programs primarily involve the testing and calibration of protective relays, Supervisory Control and Data Acquisition (SCADA) systems, remote terminal units, power line carrier and pilot wire equipment.

Q. Please describe I&M's Transmission Vegetation Management Program.

A. I&M performs aerial patrols of its transmission facilities at least once a year where allowed, and conducts ground-based inspections in those areas where aerial inspections are not allowed, such as I&M's D. C. Cook Nuclear Plant. Vegetation maintenance on transmission lines is done on an ongoing basis, depending upon the rate of growth of the vegetation and the voltage of specific transmission lines. However, with new NERC requirements, I&M is moving towards a cycle basis, which would schedule circuits for trimming based upon the time elapsed since the last trimming. I&M will continue to conduct routine inspections and correct any compromising situations found regardless of the timing of the last trimming or scheduled cycle.

Q. Do you believe that the projected level of O&M expense is reasonable and accurate and reasonably likely to occur in 2010?

A. Yes I do.

IX. I&M TRANSMISSION CAPITAL EXPENDITURES

Q. What is the total amount of transmission capital expenditures that I&M expects to make from April 2009 through December 2010?

A. As described in the testimony of Company witness Allen, I&M expects to make approximately $43 Million in capital expenditures during the period from April 2009 through December 2010. These investments include expansion projects and rehabilitation projects that are needed to ensure compliance with all NERC and PJM reliability standards and requirements and to ensure continued safe and reliable operation. Figure 14 provides a summary of the types of projects that are expected to be undertaken during this period.

Figure 14

I&M Transmission Capital Expenditures

(April 2009 – December 2010)

Project Description	**Estimated Amount (000's)**
Stand-alone project to replace poles, cross arms, insulators & conductors on multiple circuits	$4,640
Stand-alone project to replace relay equipment on multiple line terminals	$1,779
Stand-alone project to purchase spare transformers, reactors and circuit breakers	$1,347
Stand-alone project to improve the Twin Branch area to meet NERC Standards	$1,087
Line Rehabilitation Blanket for maintenance of transmission lines	$1,862
Emerging Work Blanket to support the engineering and development of new projects	$1,435
Vegetation Management Blanket to maintain and improve line Rights-of-Way	$1,097
System Rehabilitation Blanket, which includes station equipment such as transformers, circuit breakers and relays	$20,969
Pole Rehabilitation/Replacement Blanket for replacing end-of-life poles and hardware	$4,646
Sum of other projects or Blankets	$4,449
Total I&M	**$43,310**

Q. Do you believe that the level of projected capital expenditures is reasonable and accurate and reasonably likely to occur?

A. Yes I do.

X. MICHIGAN MAJOR STORM DAMAGE RESTORATION RESERVE

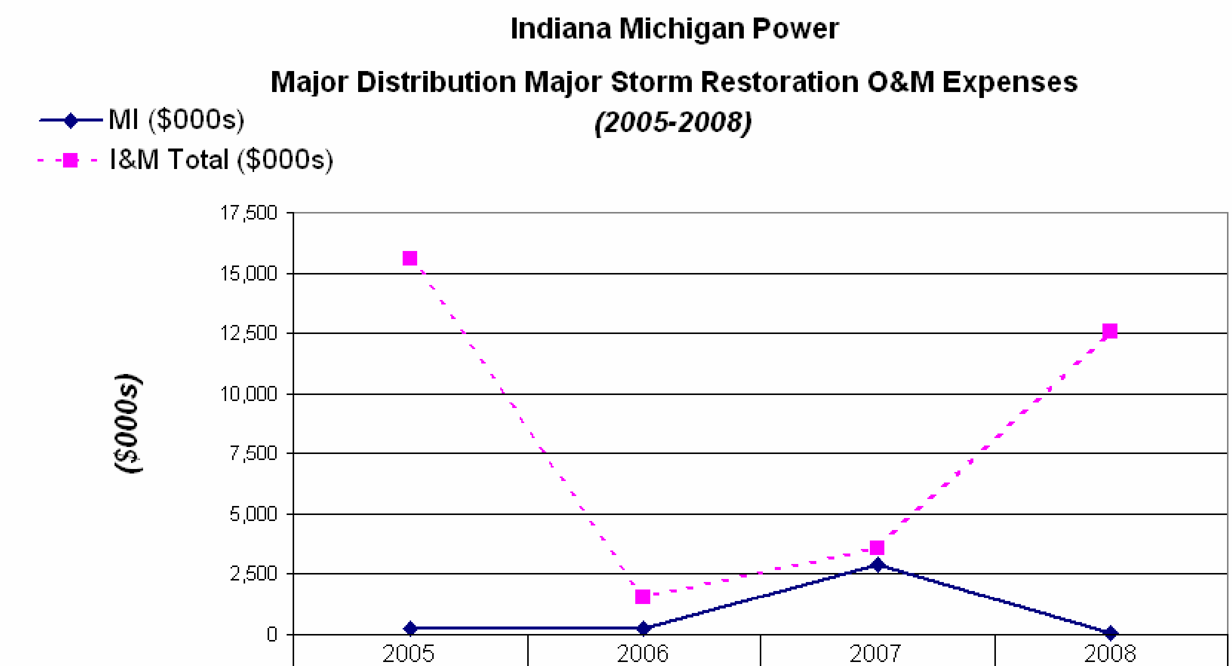
Q. What is the amount of major storm damage restoration O&M expense included in the test year?

A. I&M has included $3 million (total Company) in the 2010 forecasted test year for major storm damage restoration O&M expenses. Major storms are classified as a period of time when the electric delivery system is faced with challenges beyond its normal design criteria. Major storms are determined based on the methodology outlined in IEEE Standard 1366 - 2003, IEEE Guide for Electric Power Distribution Reliability Indices.

Q. Why is I&M proposing a major storm damage restoration reserve?

A. Given the volatility of major storm damage restoration O&M expenses from year to year, I&M is proposing that a restoration reserve be created. This mechanism is further discussed by Company witnesses Krawec and Hayes. Figure 15 shows the volatility in Michigan's major distribution storm damage restoration O&M expenses from 2005 to 2008.

Figure 15



	2005	2006	2007	2008
MI ($000s)	242	276	2,900	49
I&M Total ($000s)	15,579	1,528	3,572	12,551

Over the four-year period ending 2008, the average major distribution storm restoration expense for the Michigan jurisdiction is approximately $867,000.

Q. Would the major storm damage restoration mechanism include capital costs incurred as a result of a major storm?

A. No. Capital costs would become a component of rate base in the next general rate proceeding.

XI. CONCLUSION

Q. Please summarize your testimony.

A. I&M provides reliable distribution service to customers in its Michigan service territory through prudent planning, efficient use of available resources and implementation of cost-effective solutions. My testimony shows that I&M has improved our customers' overall electric distribution service experience by implementing proactive maintenance programs, targeting aging infrastructure and improving system response to outages.

Although this work has produced positive results in the short term, we anticipate these programs alone will not be enough to sustain and/or improve continued reliability. Nor, will these programs address the growing trend of outage cases in I&M's service territory in Michigan. Customer expectations regarding service reliability are changing. With an increase in home-based businesses, advanced electronics and more sensitive technologies, customers' demand for ongoing service quality is growing. When this demand is coupled with an aging distribution infrastructure, we anticipate that special efforts are needed to reduce the risk of outage.

In my testimony, I&M proposes incremental programs and associated costs that tackle additional performance objectives over an identified period of time to arrest these trends. As I describe earlier, our ongoing or "base" programs target overall system reliability improvements. At the current level of spending provided in the 2008 historical period and 2010 forecasted test year costs, these programs have been maximized to their fullest potential and we do not anticipate this level of spending to be enough to further improve reliability. However, the incremental programs we propose go to the next level and aim at improving areas of concern by using proven practices, such as capacity deficiency, system renewal, vegetation management, and system automation. By doing so, I&M intends to be even more proactive on preventing outage causes and further develop the capabilities and performance of the distribution system by adapting the current infrastructure utilizing new technologies that can meet customers' growing demand for improved reliability. My testimony includes a description of the work to be done and the capital and O&M costs associated with doing the work.

My testimony supports a baseline amount of major storm damage restoration O&M expense included in the 2010 forecast and the need for a reserve due to the volatile nature of major storm damage expenses.

I&M provides reliable transmission service to customers through effective planning and efficient use of its resources. In maintaining a reliable transmission system, I&M has been able to maintain a reasonable level of spending and provide access to competitive sources of generation through our participation in PJM. Through the use of ongoing proactive reliability programs including the transmission asset management and vegetation management programs, we have been able to ensure a safe, efficient, and reliable transmission system to serve our customers in Indiana and Michigan.

Q. Are the expenditures projected for the 2010 forecasted test year reasonably necessary to provide safe, reliable and adequate service?

A. Yes.

Q. Does this conclude your pre-filed direct testimony?
A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

JON C. WALTER

PRE-FILED DIRECT TESTIMONY OF JON C. WALTER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Jon C. Walter. My business address is One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as Manager of Regulatory Support.

Q. Please briefly describe your educational and business experience.

A. I am a graduate of I am a 1989 graduate of Purdue University with a Bachelor of Science degree in Electrical Technology, and am a 1996 graduate of Indiana University with a Masters of Business Administration.

I have worked for I&M and AEP for 20 years, and have had several different roles of increasing responsibility. I began my career as a Station Relay Engineer in South Bend, Indiana, and have held the following positions, Distribution Engineering Supervisor, Key Accounts Engineer, National Accounts Engineer, Customer Design Supervisor, Supervisor Distribution Systems, Circuit Performance Improvement Manager, Distribution Reliability & Engineering Manager, and Manager of Distribution Dispatch.

Q. What are your responsibilities as I&M's Manager of Regulatory Support?

A. I am responsible for I&M's Demand Side Management / Energy Efficiency

(DSM/EE), gridSMART^{sm}, and Demand Response strategies and program implementation.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss and support the phased-in implementation of I&M's gridSMART^{sm} initiatives in I&M's Michigan service territory. The gridSMART^{sm} concept is described later in my testimony; furthermore, I explain the technology associated with this effort, anticipated costs, and the expected benefits.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring:

- Exhibit I&M-33 (JCW-1), gridSMART^{sm} I&M Michigan Total Estimated Net Costs, which provides a total four-year summary of net O&M and Capital costs related to the Company's gridSMART^{sm} initiative.
- Exhibit I&M-34 (JCW-2), gridSMART^{sm} I&M Michigan Four-Year Overview of Net Costs, which provides a yearly overview of net O&M and Capital costs related to the Company's gridSMART^{sm} initiative.
- Exhibit I&M-35 (JCW-3), gridSMART^{sm} I&M Michigan Obsolete Meters, which provides a summary of obsolete meter costs related to the Company's gridSMART^{sm} initiative.

- Exhibit I&M-36 (JCW-4), gridSMART^sm I&M Michigan AMI Operational Benefits, which provides an overview of AMI operational benefits related to the Company's gridSMART^sm initiative.

Q. Would you please explain the term "gridSMART^sm?"

A. In 2007, gridSMART^sm begun as a multi-year initiative of AEP and its operating companies that includes a suite of customer programs and advanced technology initiatives that will move I&M into a new era of energy delivery and customer service by achieving energy efficiency and demand reduction, improving reliability, and positioning the distribution grid to accommodate and optimize new sources and storage options. It includes consumer-facing technologies and programs that can further enable energy efficiency and demand reduction. It also includes new grid management technologies that can improve reliability, achieve energy efficiency and demand reduction via actions that I&M can implement, and provide the operating processes and systems that will be required to integrate future generation and storage device efficiencies.

The gridSMART^sm initiative includes integrating the information technology systems used for the programs and technologies to improve operating efficiencies and information available for customers. The technologies and integration are utilizing interoperability concepts consistent with the standards being developed by the National Institute of Science and

Technology (NIST), as directed by the U.S. Department of Energy.

Q. Why is I&M proposing the gridSMART^{sm} initiative?

A. Several converging factors make the timing right for these types of advances. These include the following:

- Equipment maintenance needs, replacement of aging facilities, more stringent environmental requirements, and increasing fuel and other costs of production are increasing at an unprecedented rate. The various options provided through gridSMART^{sm} will help enable customers to become more energy efficient, reduce demand, and manage costs.
- The gridSMART^{sm} initiative would support Governor Granholm's goal of supporting and attracting high-tech companies to Michigan.
- Advanced communications and control technologies are becoming more affordable, more accessible, and easier to use than ever before.
- A new generation of customers is becoming increasingly comfortable with new technology. The types of communication systems included in the gridSMART^{sm} effort can provide customers greater control with pricing information to facilitate usage decisions for energy efficiency options.

- Advanced communications to and from the consumer in near real-time can enable both new consumer-facing and utility-activated options for the more efficient management of power generation and use. The two-way communication network required for consumer-facing technologies can also be leveraged to permit the utility to achieve demand reduction and energy efficiency via utility-activated grid management equipment. It will also enable the Company to more efficiently manage generation and distribution of power. Utility-activated grid management can lower demand and energy consumption by customers, with no action on our customer's part, and with no impact on the level of service they receive.
- Consumers are becoming increasingly aware of greenhouse gas emissions and, like I&M, are concerned about sustainable action to address global climate change. Energy efficiency and conservation initiatives are facilitated by the gridSMART^{sm} effort.
- Existing equipment needs to be updated to accommodate new grid management technologies. gridSMART^{sm} enables the Company to install new technologies and advanced data and communications systems that better respond to energy needs, enable more effective energy efficiency, and increase service reliability expectations.

- Customers' expectations concerning reliability are changing as further described by Company witness Ehler. Adoption of sensitive electronics through all levels of society have increased the need and expectation for a reliable supply of high quality electric power. New grid management technologies associated with gridSMARTsm will help improve service reliability to better match customer expectations.
- Customers also are interested in having greater control over their energy usage. The gridSMARTsm capabilities provide more accurate information to facilitate usage decisions, as well as programs and pricing options focused on energy efficiency and demand reduction.
- Demand response initiatives will be needed in order to meet increasing load growth requirements while deferring the need for new base load generation. Advanced Meter Infrastructure (AMI) and Home Area Network (HAN) will enable customers or the Company to reduce demand by turning off or cycling appliances.
- Utility-controlled grid management technologies that will permit the optimization of voltage delivered from each distribution station and improvement of power factor through var control will also assist I&M

with its energy efficiency and demand reduction goals without requiring active customer participation.

These factors alone and in any combination are helping drive I&M's response to what is a dramatically changing landscape of electricity distribution. As another significant benefit of gridSMART^{sm}, these initiatives will help minimize employees' exposure to the threat of injuries.

Q. How is I&M planning to implement gridSMART^{sm} in Michigan?

A. I&M is planning to implement gridSMART^{sm} initiatives throughout its Michigan service territory over a four-year period, if the Commission approves full cost recovery, as proposed. To effectively install and implement the technologies associated with this effort, I&M is proposing a phased-in approach to implementing specific gridSMART^{sm} initiatives. These initiatives, which will be described in greater detail later in my testimony, focus on three main components. These include AMI, grid management technology deployment, and HAN. These components individually have specific Company and customer benefits. However, when combined, gridSMART^{sm} will offer customers the flexibility to control their energy usage by receiving timely energy and pricing information, while allowing the Company to improve safety, reliability, grid energy efficiency and demand reduction, and customer service efficiencies.

Q. What does I&M expect to achieve through the implementation of gridSMART^{sm}?

A. I&M anticipates customers will receive the following benefits:

- Better information concerning their electricity usage, both on a real-time and historical basis via a 24 hour, seven days a week web portal accessible on I&M's home web page.
- Greater control over their energy usage decisions allowing them to conserve energy, save money and help to protect the environment.
- Improved meter reading accuracy.
- Lower long-term energy usage through utility-activated energy efficiency, power factor improvement, and demand reduction initiatives.
- More efficient and modernized service delivery which leads to a higher quality customer experience.
- Fewer outages and shorter outage durations through automated grid management and remote control of distribution equipment.
- Improved knowledge of energy costs and technology benefits.

Through implementation of gridSMART^{sm}, I&M expects to achieve;

- Improved safety for our employees through reduced exposure to potential threats and hazards.
- Reduced outage events and duration through automated grid management and remote control of distribution equipment.

- Real-time information for system operation efficiency.
- Enhanced outage restoration ability due to real-time system information.
- Demand reduction, power factor improvement and energy efficiency capabilities via utility-activated technologies.
- Demand reduction through new tariff offerings that would take advantage of gridSMART^{sm} capabilities. These tariffs will be filed in a separate proceeding after the base case, closer to the time that meters are being installed.

Q. How does I&M accomplish this work today?

A. Much of the work associated with meter reading, electricity usage, grid management, and outage restoration is performed manually and often prompted by customer notification. Although technology has allowed us to improve our processes and procedures, the Company has had limited capability to provide real-time information to our customers and our employees regarding demand and energy usage and outage events.

Today, the only means for customers to see their usage pattern is through a monthly bill. To get that information, I&M employees have to physically read the meters each month. This involves driving approximately 17,000 miles each month to read customer meters. Although the Company strives to read every customer's meter each month, certain impediments, such as dogs, fences, or weather can prohibit us from reaching that goal. On average, the Company reads approximately 95 percent of the meters each month in Michigan.

Another manual process involves connecting and disconnecting meters. On average, our employees disconnect and reconnect nearly 1,000 meters each month for Michigan's service territory by driving to the customers' premises and physically performing the work.

Grid management activities today are mostly focused on maintenance and service restoration efforts that are additional processes involving extensive manual intervention. These include public notification of a service interruption, manual assessment of facilities to locate the cause of an outage, manual assessment of the distribution system prior to restoration via circuit ties, manual step-restoration, visual inspections of capacitor status and manual capacitor switching.

Q. How will gridSMART^{sm} change these processes?

A. Through the implementation of gridSMART^{sm} components, much of the work I described earlier will move from manual and reactive to automated and proactive. Meters will be read, disconnected and reconnected remotely, improving meter reading accuracy. On-demand meter reading and service requests will be available, while reducing vehicle accidents and employee exposure to injuries.

Grid operation, grid monitoring and control, grid planning, and service restoration will become more efficient through the application of automated and remote switching capability of devices, automated grid management capability with enhanced fault detection and system reconfiguration, and improved system information for engineering and planning back-office functions.

Additionally, utility-owned distributed generation installations are increasing throughout the I&M footprint and through the implementation of gridSMART^{sm} the Company will become fully prepared to monitor and control such facilities.

Q. Would you please describe each component of I&M's gridSMART^{sm} initiative being proposed and related benefits?

A. There are three main components of gridSMART^{sm}. These are AMI, grid management technology deployment, and HAN, as mentioned previously.

<u>Advanced Meter Infrastructure (AMI)</u>

Three features comprise the AMI system: "smart" meters, two-way communications networks, and the information technology systems to support their interaction. AMI uses internal communications systems to convey real-time energy use and load information to both I&M and to the customer.

AMI provides the capability to monitor equipment and can quickly convey information about certain malfunctions and operating conditions. It also facilitates our customers' ability to achieve benefits related to certain future customer-owned advanced technologies and appliances.

AMI, when paired with tariff options and the HAN, can empower our customers to control their energy usage by providing real-time information and usage data, allowing them to better understand their energy consumption and potentially reduce their electricity bill. In addition, AMI can help speed service restoration through better information about the facilities involved. Customers also can receive faster response to service requests, including meter reading and service connection, due to the remote execution of those activities.

Because AMI allows for remote connect or disconnect, I&M is able to improve service response and worker safety. Power quality monitoring can improve customer satisfaction while tamper detection capability deters energy theft. Less personal interaction with energized equipment also improves employee and public safety.

Grid Management

Grid management technologies are an integral part of the gridSMART^{sm} initiative due to their ability to provide overall grid control. The new technologies also provide improved ability for voltage optimization, demand reduction, and reliability benefits to customers through the use of advanced distribution automation (DA) restoration equipment.

The Company's experience gained through the I&M South Bend, Indiana Smart Meter pilot will be leveraged when expanding the existing distribution management system (DMS) under this gridSMART^{sm} application. The DMS will be further integrated with I&M's Distribution Supervisory Control And Data Acquisition (SCADA) system. SCADA is a system operator tool used to remotely control and monitor station and line equipment. SCADA improves reliability by providing system operators with remote control and monitoring capability over a transmission or distribution network. Utilization of this system shortens outage restoration times for customers and provides data and intelligence to sense abnormal or evolving system conditions. I&M is currently able to communicate with AMI meters that are installed in Indiana both from a call center as well as through the DMS to determine whether power has been restored during power outages. This same capability will be provided for in Michigan.

The gridSMART^{sm} plan for Michigan will incorporate a voltage optimization and power factor control system known as Integrated Volt Var[1] Control (IVVC). This system will be monitored via the DMS and enable utility-activated energy efficiency and demand reduction technologies to help I&M achieve energy efficiency and demand reduction goals.

[1] Volt-ampere reactive (var) is a unit used to measure reactive power in an AC electric power system.

Further, the DMS will permit the monitoring, and in the future, direct control of distribution automation DA equipment that provides real-time control and monitoring of selected electrical components within the distribution system. The electrical components to be controlled and monitored include capacitor banks, voltage regulators, reclosers, and automated line switches. These electrical components will be connected via a two-way wireless communication system to I&M's dispatch operations center. The capacitor banks, voltage regulators, and reclosers will be equipped with sensors, which provide information on operational status and analog data such as voltage or current. When an interruption occurs, automated switches isolate a circuit by automatically opening (de-energizing) or closing (re-energizing), depending on its location. Customers not directly affected by the fault are immediately transferred to another source, if available, thereby restoring their service sooner. The communication system used by DA also will allow for a pathway for the customers' meters to communicate real-time information.

DA can help minimize sustained outages experienced by customers and reduce durations of those outages that do occur through advanced detection and isolation of certain system faults. In addition, DA can improve power quality through remote monitoring and control of power regulating equipment.

DA capabilities allow I&M to monitor equipment status, detect faults in the distribution system, notify controllers about a fault location and optimize service restoration activities. The technology used provides faster identification of outage locations and equipment involved, automates switching to reroute the flow of power when the normal route has been interrupted, monitors grid conditions with voltage fluctuation alerts, improves system efficiency through automated load management and supply and demand matching, and enhances public and employee safety due to less exposure to energized equipment.

Voltage optimization improves energy efficiency by reducing losses on the system and can improve reliability by relieving congestion on the transmission system. Voltage optimization can also allow a reduction of system voltage that still maintains minimum levels needed by customers but will cause a corresponding reduction in energy consumption. AEP is participating with the Electric Power Research Institute (EPRI) as well as conducting its own pilot installations to evaluate response rates of energy reduction and power factor improvement. Early results indicate a range of 0.5% to 1% of energy demand reduction for a 1% voltage reduction, with power factors near unity possible. I&M anticipates that energy demand and consumption by customers on these circuits can be reduced by approximately 2% with no impact on the level of service and no action required to participate by customers.

Home Area Network (HAN)

The HAN, located within customers' homes, allows customers to conserve energy and potentially save money through increased information and control of their electric usage. Customers would receive a programmable communicating thermostat (PCT) in their homes or businesses. PCTs have the ability to receive electrical energy consumption data from the meter, store the data, and provide the customer with real-time and historical energy usage. The PCT can receive price signals from electric meters and be programmed to regulate temperature accordingly, allowing the customer to regulate their indoor temperature in response to daily or seasonal electric price fluctuations while maintaining an acceptable level of comfort. Advanced PCTs available today also have the capability to cycle air conditioning on and off upon receiving a critical peak signal from the electric meter.

Another HAN enabled component is a Load Control Switch (LCS). An LCS is a device installed ahead of a major electrical appliance that can either turn the appliance on or off or cycle the appliance on and off as in the case of an air conditioning unit. For customers on a direct load control or interruptible tariff, the LCS would receive commands from the electric meter, respond accordingly, and send a signal back to the meter to confirm action has been taken.

Today, customers can only determine energy usage after the fact through their monthly bill. The HAN can provide real-time and historical electrical usage, providing the customer with the knowledge and opportunity to control usage, conserve energy and save money. In addition, HAN enables I&M to provide the customer pricing options including time-differentiated rates. Data collected by the HAN can help I&M shape future pricing programs to suit customers' needs. In addition, as customers save money by shifting load to off-peak hours, it helps I&M reduce demand and potentially defers the need for new generation.

Q. Would you please describe the implementation plan for gridSMART^{sm}?

A. I&M proposes to implement gridSMART^{sm} in Michigan over a four-year period. The 48-month timeframe is necessary in order to effectively install the technology and equipment. The proposed area includes the entire Michigan service territory: Benton Harbor, Buchanan, New Buffalo and Three Rivers. This area includes approximately 132,000 meters, 126 distribution circuits and 2,200 operational square miles. A four-year summary of the net O&M and Capital costs related to the Company's gridSMART^{sm} initiative are shown in Exhibit IM-33 (JCW-1).

Q. Will the components you described be installed throughout the four-year period?

A. Yes, I&M will use a staged deployment strategy for the gridSMART^{sm} roll out in the Michigan jurisdiction. Deployment will begin in the Benton Harbor/St Joseph area first and will be implemented on a distribution station/circuit basis. Distribution circuits will be prioritized largely by customer density (customer per square mile) for both AMI/HAN and grid management technologies, but AMI will not be deployed strictly by circuit boundaries due to customer tie issues in the Geographic Information System (GIS).

Grid Management technologies will be deployed by implementation of an initial voltage optimization and power factor improvement project in the Three Rivers area that is consistent with the AMI communications infrastructure. DA will be deployed on a station/circuit basis that is based upon AEP's gridSMART^{sm} DA circuit ratings, past reliability performance, the presence of existing SCADA, and the degree of diverse-source load recoverability options.

For more information regarding the implementation, see Exhibit IM-34 (JCW-2), which shows the year-to-year implementation costs of each major gridSMART^{sm} component as well as associated work papers for each major component.

Q. Does I&M plan to offer new pricing options associated with the gridSMART^{sm} installation?

A. Yes, I&M is developing time-differentiated pricing options for customers that will take advantage of gridSMART^{sm} capabilities, which is further explained in the testimony of Company witness Roush.

Q. What are the net costs associated with implementing gridSMART^{sm}?

A. As shown in Exhibit IM-33 (JCW-1), the estimated net cost is approximately $79 million over a four-year period. Company witness Roush supports the revenue requirement associated with the gridSMART^{sm} capital and O&M

proposal.

Q. What will happen to the meters that are replaced as part of the gridSMART^{sm} implementation?

A. I&M plans to replace all meters associated with this initiative. Those that can be reused will be redeployed in other parts of I&M's service territory as well as at other AEP operating companies, to the extent possible. Once the meters have been removed and placed back into inventory, if and when those meters are transferred to a sister operating companies, net book value will be credited to I&M rate base. Meters that are obsolete will be retired. The Company estimates that 14.5 percent or 19,000 meters of the 132,000 meters will be obsolete and retired upon removal. Exhibit IM-35 (JCW-3) reflects the net book value of the 19,000 meters that were estimated to be retired at $480,720 over the four-year implementation period, which is included in the net cost estimate for recovery. Also please refer to Company witness Hayes' testimony regarding the accounting treatment of major gridSMART^{sm} components.

Q. Does the cost estimate shown in Exhibit IM-36 (JCW-4) include AMI operational savings that will accrue to I&M upon implementation gridSMART^{sm}?

A. Yes. Exhibit IM-36 (JCW-4) reflects our estimate of operational savings associated with gridSMART^{sm} AMI deployment. With a four-year phased approach to implementation, not all of the operational savings materialize in the initial phase and some additional savings will occur as full implementation is pursued. For example, additional savings will occur after the initial phase as a result of improved planning and investments for distribution improvements that will be based on operational performance data obtained during the third year of the implementation period and in subsequent years. As meter reading is fully automated within I&M's territory, call volume related to billing estimates will decrease, and billing analysis and rebilling will not be required to the extent that it is today. I&M anticipates AMI operational savings of $2.2 million between years two and four of the gridSMART℠ implementation, which helps to reduce the net cost of the initiative.

Q. How soon will this gridSMART℠ technology be replaced?

A. Like computers, wireless phones and cell phones, smart metering equipment is state of the art equipment in an area where technology is expected to improve rapidly and as such, like computers and cell phones, the smart meters will have to be replaced before the expiration of their physical life to upgrade to the second or third generation of smart metering technology. This is routinely true for computers and cell phones and our engineers believe it will also be the case for the smart meter which is a computer/communication device. Refer to Exhibit IM-34 (JCW-2) for details regarding the specific asset life for each major gridSMART℠ component. Also please refer to Company witness Hayes' testimony regarding the accounting treatment of major gridSMART℠ components.

Q. What is the asset life of smart meters and the other major gridSMART℠

components?

A. The current smart meters have two separate components, a communication/computer component with an expected seven-year useful life and a basic meter component with a fifteen-year physical life (per the manufacturer). The current smart meters will be capitalized when acquired as one retirement unit with a seven-year life. This is appropriate because by the time the meters are replaced in five to seven years with more advanced smart meters, the new advanced smart meters are expected to be one integrated meter. This would then require the entire meter be replaced and not just the communication/computer component of the original smart meter. As such, we are proposing to continue to have one retirement unit for the initial smart meters with an expected useful life of seven years.

HAN devices, described earlier as PCTs or also as In-Home Devices (IHDs) are computerized electronic devices that have a limited asset life. Such devices, similar to smart meters, have a shorter asset life of five years.

Grid management devices, such as recloser controls, capacitor controls, and centralized DA control units are subject to the same type of upgrade requirements due to their computerized electronic components. These devices are defined as having a fifteen year asset life due to a less dynamic performance requirement profile. Again, please refer to Company witness Hayes' testimony regarding the accounting treatment of major gridSMART^{sm} components.

Q. What is the role of societal benefits, including customer benefits, when evaluating smart metering implementation?

A. There are varying opinions on this subject. I&M believes there are substantial customer and societal benefits associated with smart metering and smart grid deployment by an electric utility. Some benefits accrue directly to customers of the utility such as bill savings and some are more indirect such as the development of a more robust energy market. Other benefits accrue to society as a whole such as environmental benefits and assumed improved national security.

Q. Did I&M attempt to quantify the customer and societal benefits as part of its proposal in this case?

A. No, it did not. From the above discussion, it quickly becomes apparent that some societal and customer benefits can be quantified and others are very difficult to quantify. Beyond the difficulty of that exercise, however, I&M does not believe it is necessary for the Commission to make specific findings about the quantification of customer and societal benefits as part of approving gridSMART^{sm} in this case. Smart metering deployment will clearly empower customers with information and capabilities that will help them use energy more wisely and ultimately control their energy bills, while also improving reliability. To that end, the customer and societal benefits of smart metering are already sufficiently evident to support a decision to deploy the technology without imposing a requirement that all such quantified benefits be specifically monetized and mathematically shown to equal or exceed the net costs. Stated differently, I&M believes the proposed deployment is a prudent investment to make and it stands ready to undertake gridSMART^{sm} implementation subject to the Commission verifying that the deployment promotes the policies of the State of Michigan and authorizing appropriate regulatory recovery.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

MARK A. PEIFER

PRE-FILED DIRECT TESTIMONY OF MARK A. PEIFER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction

Q. Please state your name and business address.

A. My name is Mark A. Peifer. My business address is 110 East Wayne Street, Fort Wayne, Indiana.

Q. By whom are you employed and in what capacity?

A. I am Vice President - Generating Assets for Indiana Michigan Power Company (I&M or Company). I&M is a subsidiary of American Electric Power Company, Inc. (AEP). I am responsible for the safe, reliable, efficient and environmentally-compliant performance of I&M's generating assets. More specifically, I oversee and direct the operations and maintenance (O&M) and capital budget expenditures with responsibility for allocation of budget resources to ensure the financial optimization of those generating assets. I collaborate with I&M executive leadership, AEP's Fossil & Hydro Generation group, AEP's Commercial Operations group, and the American Electric Power Service Corporation (AEPSC) organization to optimize the effectiveness and reliability of I&M's generation assets.

Q. Please briefly describe your educational and business experience.

A. I hold a degree in analytical management from the U.S. Naval Academy, and I have also completed the Advanced Management Program at Harvard University.

I held executive positions with the Nuclear Management Company (NMC) and with the Institute of Nuclear Power Operations (INPO) prior to joining I&M in 2005. I most recently served as the Site Vice President at the D.C. Cook Nuclear Plant (Cook Plant), prior to accepting my current role as Vice President - Generating Assets in 2008. Prior to joining I&M I was the Site Vice President at NMC/Alliant Energy's Duane Arnold Energy Center (Nuclear Plant). Before that I was with INPO in various jobs of increasing scope and responsibility, leaving there in 2003 as the Vice President of Training and Accreditation. Prior to my time at INPO I served in the United States Navy on nuclear submarines.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to describe I&M's fossil fuel-fired and hydroelectric (Fossil & Hydro) generating assets, and to support the forecasted levels of operation and maintenance (O&M) and capital expenses associated with the operation of those generating assets. All historical and forecasted capital and O&M expenses that I present in my testimony are total I&M expenses, and are not representative of the Michigan jurisdictional share of the expenses. Company witness Roush describes the Michigan jurisdictional allocation of the I&M expenses.

I will also discuss the planned future environmental retrofits for the

Rockport Plant. These future retrofits require significant investment and will be designed and constructed over a period of years. I&M is proposing that the capital investment and O&M associated with these projects be recovered in future regulatory proceedings through the Generation Investment Tracker (GIT) filings, as described by Company witness Krawec.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

1) Exhibit I&M-37 (MAP-1) Selective Catalytic Reduction (SCR) Fact Sheet and

2) Exhibit I&M-38 (MAP-2) Flue Gas Desulfurization (FGD) Fact Sheet

II. I&M Generation Fleet

Q. Please describe I&M's Fossil & Hydro fleet of generating plants.

A. I&M's fleet of Fossil & Hydro generating plants consists of two coal-fired power plants and six hydroelectric power plants and two coal-fired power plants.

I&M's coal-fired power plants consist of two units at the Rockport Plant and four units at the Tanners Creek Plant.

The Rockport Plant is located in Rockport, Indiana. The plant consists of two similar 1300 MW boilers, which I&M operates and in which I&M has a 50% interest as discussed by Company witness Krawec. Units 1 and 2 at the Rockport plant were placed in service in 1984 and 1989, respectively. Each unit is equipped with an Electrostatic Precipitator (ESP) for particulate collection, low-NO_x burners and overfire air (OFA) to minimize nitrogen oxide (NO_x) formation, and each unit also currently burns a nominally 85% Powder River Basin (PRB – 15% eastern bituminous (EB) coal blend, resulting in lower emission rates of sulfur dioxide (SO_2) and NO_x than burning a higher-sulfur coal.

The Tanners Creek Plant is located in Lawrenceburg, Indiana and consists of four generating units. Units 1 and 2 are each rated at 145 megawatts (MW), and were put into service in 1951 and 1952. These units are roof-fired units that burn pulverized coal and are equipped with ESPs to capture particulate (also referred to as flyash), and utilize a staged combustion system to minimize the formation of NO_x.

Unit 3 was put into service in 1954, and is capable of producing 205 MW. This roof-fired unit is equipped with an ESP for particulate control and minimizes NO_x formation through the staged combustion of coal.

Units 1, 2, and 3 at the Tanners Creek Plant minimize SO_2 emissions by burning low-sulfur coal that is compatible with the safe and reliable operation of each of the respective units. Also, during 2009, Tanners Creek Units 1 through 3 were retrofitted with selective non-catalytic reduction (SNCR) systems to reduce NO_x emissions. These systems inject water and urea into the combustion zone in the furnace where the urea reacts with NO_x to form nitrogen gas (N_2) and water.

Unit 4, a cyclone-fired unit, was put into service in 1964 and can produce up to 500 MW. Unit 4 is capable of burning a high percentage blend of PRB coal to minimize NO_x and SO_2 emissions, and is also equipped with an OFA system that allows the units to stage combustion to minimize NO_x formation.

None of the units at the Tanners Creek Plant are equipped with post-combustion Air Pollution Control Devices (APCDs) specifically designed to minimize emissions of SO_2.

I&M's six hydroelectric facilities include the 10-unit Berrien Springs Plant (MI), the 10-unit Buchanan Plant (MI), the 4-unit Constantine Plant (MI), the 4-unit Mottville Plant (MI), the 3-unit Elkhart Plant (IN), and the 8-unit Twin Branch Plant (IN). These plants combine for a total of 22.4 megawatts (MW) of installed capacity.

III. Operation and Maintenance (O&M) Expenses

Q. Please describe the major areas of generation O&M expense for I&M's Fossil & Hydro generating plants.

A. There are several major categories into which I&M's Fossil & Hydro generation O&M can be divided. The largest portion of non-fuel generation O&M for I&M's coal-fired power plants is the base operations category. These costs fall into categories involving normal operation and maintenance that are relatively consistent from year-to-year. These activities are things such as routine maintenance on parts and equipment that is typically routine and predictable. Base operations account for almost 61% of the projected Steam Generation expenses in the forecasted 2010 test year.

While base operations constitutes the largest portion of I&M's projected O&M, planned outages are also a significant portion of I&M's projected O&M at over 13% of the total planned O&M expenses for the forecasted 2010 test year. Planned outages are those outages that can include major overhaul work to the boiler or other key steam and electric generating equipment. Planned outages are scheduled well ahead of time, and often require long lead times on equipment and engineering of new or replacement parts. Planned outage costs can vary significantly from year to year, depending on the needs of each individual operating unit, but are necessary to maintain the safe and reliable operation of I&M's Fossil & Hydro generating units.

Non-outage maintenance constitutes over 11% of I&M's non-fuel generation O&M costs for the forecasted 2010 test year. These costs represent major O&M work that can be done while the generating units are in service.

Forced outages are planned to constitute approximately 10% of the forecasted 2010 test year O&M. These funds are projected under the assumption that there will be some unforeseen issues that will cause some units to need outage repairs during the forecasted year, and are necessary to quickly bring the units back to operating conditions as expeditiously as possible.

Another significant cost that is included in the O&M costs for I&M's Fossil & Hydro generating fleet is the Rockport Plant lease. This cost, approximately $70.1 million per year, constitutes a large portion of I&M's Fossil & Hydro O&M. However, because this cost is very consistent from year to year, and is not similar to the other O&M costs described above in that it is not directly associated with the operation of a power plant. Therefore, this lease cost was not included in the percentages presented above with regard to the total fossil-fired O&M costs.

Q. Are the operating costs for I&M's generating fleet of Fossil & Hydro plants relatively evenly distributed among its coal-fired and hydroelectric units?

A. No. The vast majority of I&M's power generation comes from its fossil-fired plants, and the vast majority of O&M dollars are spent at its fossil-fired plants. The hydro plants, in total, will incur approximately 5% of the forecasted 2010 test year O&M expenses (excluding the Rockport lease cost).

Q. What level of non-fuel Fossil & Hydro generation O&M expenses for I&M were incurred during the historical period?

A. The Company’s 2008 calendar year historical non-fuel Fossil & Hydro generation O&M expenses for activities necessary to generate electricity safely and reliably were $131,976,000 (including the Rockport lease expense) for fossil fuel-fired power plants and $2,630,000 for I&M's hydroelectric power plants, as supported by Company witness Allen.

Q. What is the level of increase from the historical 2008 Fossil & Hydro generation O&M expense to the forecasted level for 2010?

A. The 2010 forecasted level of O&M is $138,691,000, which is 3.0% higher than the 2008 level of $134,607,000.

Q. Why are the Company's Fossil & Hydro generation O&M expenses projected to increase from 2008 to 2010?

A. The 2010 forecasted test year includes increases of approximately $5 million dollars for planned outages for Tanners Creek compared to 2008 historical costs. These costs are associated with planned outages of 72 days and 23 days for Tanners Creek Units 1 and 2, respectively. There is also an increase of approximately $3.9 million in non-outage maintenance spending for the Rockport and Tanners Creek Plants. These increases are associated with a painting program and planned harbor infrastructure maintenance scheduled for 2010 at the Tanners Creek Plant, along with planned low-pressure and intermediate pressure turbine work on Rockport Unit 1.

There are also reductions in O&M planned for the test year in base operations, forced outages, and major projects compared to historical spending levels, but these reductions do not completely offset the increases in O&M that is due to the changes previously described.

Q. Is the forecasted period level of Fossil & Hydro generation O&M expense representative of the activities and expenses necessary to provide for

the safe and reliable generation of electricity for I&M's customers?

A. Yes. I&M has a long history of operating its Fossil & Hydro plants, which allows for reasonable forecasting of O&M expenditures. Although there are some significant increases in outage costs for the forecasted 2010 test year, these increases are offset by decreases in other categories, and lead to a reasonable level of O&M costs for I&M's Fossil & Hydro plants going forward. These projected O&M expenses have been scrutinized at a plant, operating company, and corporate level, and are representative of I&M's Fossil & Hydro O&M expenses in the foreseeable future.

IV. Forecasted Level of Capital Costs

Q. With respect to I&M's planned capital investments, what is the forecast period considered in this filing?

A. The forecast period with respect to capital investment is the period from April 1, 2009 through December 31, 2010. This 21 month period includes all of the projected capital investment that is included Company witness Allen's forecast.

Q. Is the amount of capital to be spent in the forecast period reasonable?

A. Yes. The amount of capital investment forecasted to be made in the final 9 months of 2009 and the 2010 calendar year has been closely scrutinized by I&M and AEPSC management. The total estimated capital investment for I&M's Fossil & Hydro generating fleet over the 21-month forecast period is $115,857,000.

Q. How is the total amount of capital investment to be made in I&M's Fossil & Hydro fleet reviewed for approval?

A. I&M works collaboratively with AEPSC leadership and engineering management teams to evaluate the needs of each generating unit with respect to capital projects to improve reliability, safety, environmental performance, or a number of other unit performance parameters. The decision and timing in which capital investments are made depends on the immediacy of the need of the investment, comparison of economic evaluations of many projects across many plants, and regulatory or safety compliance requirements. All of these factors serve as input to the management teams that are responsible for approving capital projects and allocating the necessary funding to I&M's Fossil & Hydro generating plants.

Q. Please briefly describe each of the individual capital investments greater than $2 million that I&M intends to make in the Fossil & Hydro generating fleet during the forecasted period, and the amount included in the forecast.

A. The individual capital investments greater than $2 million, including the amount planned to be spent during the forecast period, are shown below.

- Funds are forecasted to be spent to complete Phase 2, comprised of final engineering, design, construction and land procurement for a new flyash landfill at the Tanners Creek Plant. Landfills are necessary to provide a disposal location for combustion byproducts, and the existing landfill at the Tanners Creek Plant was originally estimated to run out of capacity in late 2008. The total capital expenditure estimated for the forecast period is $17.5 million.

- Selective non-catalytic reduction (SNCR) systems were selected for installation on Units 1 through 3 at I&M's Tanners Creek Plant as a low-capital method for reducing emissions of nitrogen oxides (NO_x). The estimated expenditure over the forecast period is $6.0 million.

- Plans were made to replace to Lower Furnace Waterwall sections of the Tanners Creek Unit 4 boiler in the fall of 2009. The existing waterwalls, of which a significant portion was below the recommended replacement thickness, were replaced with material that will be able to better withstand the fireside corrosion that affected the previous material. Approximately $5.8 million is planned to be spent on this project during the forecast period.

- Approximately $5.5 million is forecasted to be spent to order materials to completely rewind the high pressure generator stator on Tanners Creek Unit 4. This stator has undergone a number of repairs and patches over its lifetime, and more failures are expected to occur as the stator ages. These new parts will ultimately be used to completely rewind the stator, which will greatly reduce the rate of failure that this piece of equipment is currently exhibiting.

- During the spring outage of 2009 I&M replaces multiple sidewall tube panels in the furnace of Rockport Unit 2. These panels were approaching the end of their useful lives due to the addition of NO_x controls at the Rockport Plant, and are being replaced with another alloy that is more resistant to the type of corrosion that the current panels are experiencing. This work is projected to require approximately $4.9 million during the forecast period.

- From 2008 through 2010 work is being performed to rewind the 4 north Generator Step-Up (4N GSU) transformer at the Tanners Creek Plant. The 4N GSU is currently operating, due to a failure in the 4 South (4S) GSU, but is also a system spare that is 30 years old and has been used at various plants across the AEP fleet as a spare. Rewinding of this GSU was determined to be less expensive that purchasing a new spare GSU. This rewinding is estimated to require $4.1 million during the forecast period.

- During the Rockport Unit 1 Spring 2010 outage work is planned to replace the furnace ash hopper slope tube panels and support trusses. These sloped panels, which are located near the bottom of the furnace, have become damaged from falling slag due to changing fuel supplies and the addition of combustion controls to reduce NO_x emissions. It is expected that this replacement will reduce the rate at which the current panels are failing, and will cost approximately $3.8 million during the forecast period.

- As described above with the 4N GSU, the 4S GSU at Tanners Creek Unit 4 had previously failed and it was determined to be less expensive to rewind the generator than to purchase a new GSU. The 4S GSU returned to service during the fall 2009 outage at Tanners Creek Unit 4. The total estimate cost to be incurred during the forecast period is $3.6 million.

- Approximately $3.3 million is planned to be spent during the forecast period on the replacement of the economizer section of the boiler on Rockport Unit 2. This section of the boiler has been in service since the units entered commercial operation, and economic analysis shows that replacement in the near future has the potential to reduce future forced outage rates associated with failures of sections of the economizer.

- Activated Carbon Injection (ACI) systems were retrofitted on both units of the Rockport Plant in 2009. Gaseous mercury adsorbs to the activated carbon, which is removed in existing pollution control devices. This installation is estimated to require $2.6 million during the forecast period.

- Leaks due to corrosion fatigue and oxygen pitting were first found in the horizontal reheater section of Rockport Unit 1 in 2003. Recent leaks have been in harder to reach areas, which add to the amount of outage time required to address these failures. Approximately $2.6 million is estimated to be spent on this replacement during the forecast period.

- As previously described with respect to Rockport Unit 2, the economizer section of the boiler for Rockport Unit 1 is scheduled to be replaced during the spring 2010 outage. The estimated cost to be incurred during the forecast period for the Rockport Unit 1 economizer replacement is approximately $2.6 million.

- Approximately $2.5 million is planned to be spent during the forecast period in order to replace the turbine controls on Tanners Creek Unit 4. This project will replace an aging mechanical hydraulic system with a modern digital control system and high-pressure fluid system. This projected is expected to increase reliability of Unit 4.

- Much as the expansion of the Tanners Creek landfill was described previously, approximately $2.0 million will also be spent during the forecast period to expand the existing landfill at the Rockport Plant. The existing landfill uses the environmentally best available technology for the disposal of flyash, and the expansion of the existing landfill is a lower-cost option than developing a new landfill.

- Approximately $2.0 million is planned to be spent during the forecast period to replace both banks of the secondary superheater section of the furnace at Tanners Creek Unit 3. These parts are at the end of their life, and the poor condition of the existing equipment makes it difficult to replace failed supports. It was determined that equipment purchase, and subsequent installation during the 2011 outage is the best replacement option for this equipment.

- Finally, approximately $2.0 million is expected to be spent during the forecast period replacing the reheat outlet header section of the Tanners Creek Unit 1 furnace.

Q. Please summarize your testimony regarding forecasted capital expenditures.

A. I&M and AEPSC have efficient processes developed for the approval and allocation of funds to make capital improvements to I&M's fleet of Fossil & Hydro generating plants. The projects that I have described above also account for a significant portion of I&M's planned capital investment in its Fossil & Hydro fleet over the forecast period. All of this evidence demonstrates that I&M is effectively managing its level of capital investment to provide reasonable investments for its plants and its customers.

V. Future Projects

Q. Aside from the generation O&M and capital expenditures that you support, are there any other projects to which you will testify?

A. Yes. I will also discuss future environmental retrofits to be made the Rockport Plant. These projects have not commenced, and are not required to be in service for almost 8 years. The capital investment and O&M associated with these projects is proposed to be recovered in future regulatory proceedings through the Generation Investment Tracker, which is described in detail by Company witness Krawec.

Q. With respect to I&M's Fossil & Hydro generating fleet, what future potential projects will you discuss?

A. I will discuss two future projects; the planned future addition of selective catalytic reduction (SCR) to control emissions of NO_x at the Rockport Plant, and the planned future addition of flue gas desulfurization (FGD) systems at the Rockport Plant to control emissions of SO_2.

Q. Please describe the SCR retrofit proposed for the Rockport Plant.

A. SCR systems use a catalyst to reduce NOx emissions from coal-fired power plants. Prior to passing through a bed of catalyst, ammonia (NH_3) is injected into the flue gas stream. Then, as the flue gas passes through the catalyst, NH_3 reacts with NO_x to form nitrogen (N_2) and water (H_2O). The NH_3 can either be purchased and stored on-site, or it can be made on-site using urea (a common fertilizer) and a system such as an Ammonia-on-Demand (AOD) system or a Urea-to-Ammonia (U2A) system. In these instances where NH_3 is produced at the site, urea is delivered to the site, dissolved in water, and then undergoes a reaction with steam to form NH_3 vapor. Although there is a parasitic load associated with the on-site production of NH_3, it eliminates the need to store large amounts of NH_3 at the plant site. Exhibit I&M-37 (MAP-1) is a fact sheet produced by AEP to describe SCR technology.

Q. Where in the current configuration of the Rockport Plant would SCRs be installed?

A. SCRs at the Rockport Plant would be installed downstream of the existing economizer section of the convection pass, and upstream of the air heaters. Flue gas in the part of the generation process is typically between 700°F and 800°F, which is approximately the design temperature for the catalyst.

Q. What type of equipment additions are necessary for an SCR installation?

A. The installation of an SCR requires adding duct work that houses the catalyst. This added duct work requires support from the ground, and internal mixing devices to ensure that the NO_x and NH_3 are well-mixed prior to passing through the catalyst. Aside from the duct work, the addition of the AOD or U2A systems is necessary, and typically consists of multiple hydrolyzers, which are the pressurized vessels in which NH_3 is produced from urea liquor and steam. The installation will usually allow for a spare hydrolyzer, in case one vessel becomes inoperable, and the spare will allow either unit at the plant to continue reducing NO_x while repairs can be made to the out-of-service hydrolyzer.

Q. Are SCR systems proven as commercial pollution control technology?

A. Yes. AEP installed the first SCR system in its fleet in 2001 at Ohio Power Company's Gavin Plant. Including that first installation, AEP has installed SCRs on a total of over 11,000 MW of AEP-owned and operated coal-fired generation. SCR is a well-understood technology that can be supplied by multiple vendors able to guarantee performance for the installed system at a NO_x removal rate of up to 90%.

Q. Please describe the FGD retrofits planned for the Rockport Plant.

A. FGD systems are utilized by passing the flue gas from a coal-fired power plant through an absorber vessel, where the gas is contacted by calcium-containing slurry (typically the calcium comes from lime or limestone). As the flue gas passes through the absorber liquid, the SO_2 in the flue gas dissolves in the liquid, and then reacts to form calcium sulfite ($CaSO_3$) or calcium sulfate ($CaSO_4$).

Q. Is there more than one type of FGD system that can be used to reduce SO_2 emissions from a coal-fired power plant?

A. Yes. FGD systems can be characterized as either "wet" or "dry". Wet FGD systems use caustic slurries to react with flue gas, and the reaction takes place in the slurry in a reaction vessel. Dry FGD systems inject caustic slurry that evaporates in the flue gas, and the reaction between the SO_2 and the reagent takes place on the surface of a fabric filter, which also captures particulate matter.

Q. Has a decision been made as to what type of FGD system will be installed at the Rockport Plant?

A. At this time it is assumed that the Rockport Plant will be retrofitted with a wet FGD system. AEP has experience retrofitting plants of Rockport's size with FGD systems. Installing a wet FGD will also give the Rockport Plant more fuel flexibility, since a wet FGD system can be designed to scrub the flue gas generated by burning higher sulfur coals than a dry FGD system. A fact sheet created by AEP to describe wet FGD technology is included as Exhibit I&M-38 (MAP-2).

Q. What type of equipment additions are necessary for a wet FGD installation?

A. The installation of a wet FGD requires added duct work, fans, an absorber vessel, and the addition of a wet stack. Duct work additions are necessary to divert flue gas through the absorber vessel, as the current configuration includes duct work that goes immediately from the ESP outlet to the existing stack. The installation of added fans is necessary to overcome the pressure drop added by the additional duct work and the absorber tower.

The absorber tower itself is where the reaction between the SO_2 and the calcium takes place, removing the SO_2 from the flue gas. Absorber towers are offered from multiple vendors in many different configurations. In some instances the gas travels upward through the absorber tower as the scrubber liquor is sprayed downward. In other absorber configurations the gas is bubbled through a liquid layer, providing the same reaction.

As previously mentioned, the installation of a wet FGD at the Rockport Plant would also require the installation of a "wet stack". The current design of the stack at the Rockport Plant accommodates "dry" flue gas in that it does not have free moisture. A wet stack conversion is necessary when installing a wet FGD system because moisture particles will be entrained in the flue gas and these particles must be removed from the gas and drained from the stack prior to their emission. Wet stacks also use different lining materials that are not susceptible to corrosion, so that they can withstand the conditions presented in the flue gas downstream of a wet FGD.

Q. Where in the current configuration of the Rockport Plant would the wet FGD be installed?

A. The FGD at the Rockport Plant would be installed downstream of the existing ESPs. Duct work would then be used to take the flue gas through the added absorber vessel and to the new stack that would be required.

Q. Are FGD systems proven as commercial pollution control technology?

A. Yes. AEP installed the first FGD system in its fleet in 1994 at Ohio Power's Gavin Plant. Including that first installation, AEP has installed FGDs on a total of 9,530 MW[1] of AEP operated coal-fired generation in the AEP System-East Zone[2]. FGD is a well-understood technology that can be supplied by multiple vendors able to guarantee performance for the installed system at SO_2 removal rates up to 98%.

VI. Summary

Q. Please provide a summary of your testimony in this proceeding.

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[1] As of October 2009. This MW total includes all FGD-retrofitted AEP-operated generation in the AEP-East Zone.

[2] The AEP System - East Zone consist of the following operating companies with generation capabilities of Indiana Michigan Power Company serving portions of Indiana and Michigan, Columbus Southern Power Company, serving portions of central and southern Ohio; Appalachian Power Company, serving portions of West Virginia and Virginia; Kentucky Power Company, serving portions of eastern Kentucky; and Ohio Power Company serving portions of Ohio. In addition, two operating companies residing in this AEP System – East Zone, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo) represent non-generating affiliates.

A. In my testimony I have described the 2010 forecasted test year level of O&M. This amount of O&M represents the normal Fossil & Hydro generation O&M that I&M expects to continue incurring in future years. O&M is reviewed at the I&M and AEPSC level, and the expenses to be incurred are reasonable.

I have described the level of capital investment that I&M plans to make with respect to its Fossil & Hydro generating fleet of power plants during the 21-month capital forecast period from April 2009 through December 2010. These capital investments are reviewed at various levels within the I&M and AEPSC organizations, and represent a reasonable level of investment in I&M's Fossil & Hydro generating assets.

I also have discussed the future retrofit of SCR and FGD technology at the Rockport Plant for reduction of NO_x and SO_2 emissions, respectively. While I&M is not seeking recovery of costs associated with these projects as part of this proceeding, these are the types of projects for which I&M is proposing to recover costs in future GIT filings, which are described by Company witness Krawec.

Q. Does this complete your prefiled direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

RAYMOND A. HRUBY, JR.

PRE-FILED DIRECT TESTIMONY OF RAYMOND A. HRUBY, JR.
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. Introduction

Q. Please state your name and business address.

A. My name is Raymond A. Hruby, Jr. My business address is One Cook Place, Bridgman, Michigan 49106.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as the Vice-President of Site Support Services at the Donald C. Cook Nuclear Power Plant (Cook Plant) in Bridgman, Michigan. I was promoted to this position in January of 2009, having previously served as a Project Director at the Cook Plant.

Q. Please briefly describe your educational and business experience.

A. I graduated from the Pennsylvania State University in 1982 with a Bachelor of Science degree in Nuclear Engineering. I also completed the Management of Managers program at the University of Michigan Ross School of Business. I joined I&M in March 2008. Prior to joining I&M, I was the Fleet Oversight Manager, and more recently the Regulatory Compliance Manager, at FirstEnergy's Davis-Besse Nuclear Power Station. Prior to my assignment at Davis-Besse I worked at the Beaver Valley Power Station from 1982 until 2004 and held various technical and management positions. Overall, I have 27 years of experience in nuclear plant management, engineering, project management, operations, oversight, and regulatory affairs. I also received a Senior Reactor Operator's License while at Beaver Valley.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I submitted written testimony on behalf of I&M before the Michigan Public Service Commission in Case No. U-15416-R, I&M's Power Supply Cost Recovery Reconciliation Case and before the Indiana Utility Regulatory Commission in Cause No. 38702-FAC63.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to describe the Cook Plant, its operation and maintenance, and how costs for both are affected by Nuclear Regulatory Commission (NRC) regulations and industry standards. My testimony will also support the projected levels of Operation and Maintenance (O&M) and capital expense associated with the operation of the Cook Plant that are presented by Company witness Allen in this proceeding.

I will also discuss the Cook Improvement Project (CIP). This potential future project requires significant investment and will be designed and constructed over a period of years. I&M is proposing that the capital investment and O&M associated with this project be recovered in future regulatory proceedings through the Generation Investment Tracker (GIT) filings, as described by Company witness Krawec.

Finally, I will discuss Cook Plant expenses related to enhanced security in response to the events surrounding September 11, 2001.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am supporting Exhibit I&M-39 (RAH-1), which includes a diagram of the Cook Plant.

II. Cook Nuclear Plant

Q. Please describe the Cook Plant.

A. The Cook Plant is a two unit nuclear power plant located along the eastern shore of Lake Michigan in Bridgman, Michigan. Units 1 and 2 are both pressurized water reactors (PWRs) with a 4-loop Westinghouse nuclear steam supply system (i.e., reactor systems), with a combined nominally-rated net electrical output of 2,160 megawatts. The design of each unit was based upon proven concepts that had been developed and successfully applied in the construction of other pressurized water reactor systems. Unit 1 began commercial operation in 1975 with Unit 2 following in 1978. Unit 1 and Unit 2 are licensed to operate by the NRC until 2034 and 2037, respectively, having received approval from the NRC in 2004 of a twenty-year extension of their license lives.

Unlike a traditional fossil-fueled generating plant, which produces steam through a combustion process involving coal, oil, or natural gas, the

Cook Plant creates the heat needed to produce steam by the fissioning (splitting) of uranium atoms, as shown in Exhibit I&M-39 (RAH-1). Each reactor (one per unit) has 193 fuel assemblies containing uranium. The design, manufacture, and handling of the fuel assemblies are strictly engineered to ensure nuclear safety while providing the best fuel efficiency from generating electricity in the unit.

The NRC has provided specific technical requirements through regulations regarding the components and systems that must be incorporated into the design of the systems to ensure that the fission products do not reach the environment. The NRC defines compliance with these regulations during facility operation, in part, by incorporating certain Technical Specifications into the facility Operating License. These Technical Specifications provide Limiting Conditions for Operation that must be met on a continuous basis to operate the plant. If a Limiting Condition for Operation is not met within a specific timeframe, the Plant must be shut down until the Condition is satisfied.

Approximately 1400 I&M and contract employees work at the Cook Plant, and 150 I&M and contract employees work at the Buchanan, MI engineering office located twenty miles from the plant, which also houses some of the nuclear plant's emergency plan facilities. In addition, I&M requires the services of approximately 600-1000 temporary contract workers for planned and unplanned outages at the Cook plant.

III. Cook Plant Operation and Maintenance (O&M) Expenses

Q. Please describe the major components of the nuclear generation O&M expenses.

A. The operation and maintenance of the Cook Plant involves the control and management of a number of technically complex systems and components. Practically all of the activities associated with the operation and maintenance of the Cook Plant are under the comprehensive regulation and continuous inspection of the NRC. These regulations include requirements for equipment reliability including periodic equipment testing.

The Cook Plant Technical Specifications provide the specific testing requirements for components at Cook Plant. This testing may be conducted daily, weekly, monthly, quarterly, or a longer periodicity. Additionally, maintenance is regulated, inspected, and monitored under the NRC Maintenance Rule regulation 10 CFR 50.65 which establishes strict requirements for monitoring equipment performance and maintenance to maximize equipment availability and reliability while addressing operational risk.

Cook Plant uses a work management process to schedule corrective and preventive maintenance, and equipment testing in a manner that maximizes equipment availability and reliability, manages risk impacts, and efficiently and effectively uses plant resources.

This work management process relies on a scheduling template/timeline with major work windows scheduled at two-year intervals. The process further utilizes a thirteen week template/timeline to schedule equipment maintenance and testing. Within a thirteen week cycle each system is assigned to a work week. The thirteen week planning process ensures that all corrective and preventive maintenance and testing for a system are scheduled during its respective week. This planning process ensures that appropriate personnel and material are available to support the work in a given week in the most efficient manner.

Each unit of Cook Plant provides safe, low-cost, emission-free baseload generation to I&M's customers for approximately 18 months at a time before a refueling outage is required. Maintaining that type of operation takes careful planning to ensure that components are replaced and refurbished at the correct periodicity.

The I&M Nuclear Generation Group is organized to ensure that each activity required to operate and maintain the plant is accomplished in a safe and efficient manner. The Nuclear Generation Group is organized by those functions directly involved in operations, namely Site Operations, and those functions that support operations, namely Site Support Services.

Site Operations is made up of Operations, Maintenance, Radiation Protection, Work Control, Outage Management, Chemistry, Environmental, Safety & Health, Regulatory Affairs, Emergency Planning, and Site Protective Services departments.

The departments included in Site Support Services are Plant Engineering, Design Engineering, Project Management, Training, Learning Organization (maintains the corrective action program), Information Management, and the Cook Improvement Project.

Supporting both of these organizations are our Human Resources, Employee Concerns Program, Performance Assurance and Business Services departments.

Station O&M expenses are mainly divided as follows: Base operating expenditures are approximately 93% of O&M expenses while non-outage equipment reliability expenditures are approximately 7%. Included in the base O&M costs are refueling outage amortizations. Refueling outages could have a significant impact on the overall expenditures for the Cook Plant depending on the refueling outage cycle that is occurring during any given year. Deferring and amortizing these costs limits year-to-year changes in O&M expenses and was approved by the MPSC in Case No. U-10003[1].

Q. How is a projection of O&M expenses developed for the Cook Plant?

[1] In the matter of the application of INDIANA MICHIGAN POWER COMPANY for accounting authority to levelize costs associated with refueling outages at the Donald C. Cook Nuclear Plant, May 6, 1992.

A. Projections of O&M expenses are performed on an annual basis for the Cook Plant, using a collaborative process that involves Cook Plant management, I&M management, and also management from the American Electric Power Service Corporation (AEPSC). Each year Cook Plant employees must perform condition assessments for the equipment at the Cook Plant to ensure that operation will continue safely and reliably. This may include replacement of equipment as it reaches the end of its useful life, or planning for some unforeseen failures (such as forced outages). Historical trends can also be used to determine reasonable levels of O&M expenses. These trends are based on detailed project plans that are used to determine the need for regular maintenance items.

After developing an O&M projection at the plant level, Cook Plant employees work with I&M management and AEPSC management to review work, and determine what work can be performed at a reasonable cost to both the company and the customer, while maintaining reliability and safety for continued plant operation.

Q. What level of non-fuel nuclear generation O&M expenses were incurred in the historical period?

A. The Company's non-fuel nuclear generation O&M expenses in 2008 were approximately $230,208,000, as shown on Exhibit I&M-25 (WAA-2).

Q. What is the projected level of O&M for the Cook Plant in 2010?

A. The projected level of O&M for the Cook Plant in 2010 is approximately

$246,165,000, as shown in Exhibit I&M-25 (WAA-2).

Q. What are the major reasons for the increase in projected nuclear O&M expenditures from 2008 to 2010?

A. The projected increase in O&M expenditures from 2008 to 2010 can be attributed to projected cost increases in the following areas:

1. Workforce Planning – Hiring of new employees is needed to support long term plant operation and vital to have trained and experienced engineering, operations, and maintenance workers available. Maintaining such expertise will be a challenge as the current workforce ages.
2. Station Materials – The estimated increase in station materials due to aging plant equipment and higher material costs.
3. Incremental Projects - Due to the Unit 1 turbine event on September 20, 2008, plant projects that were scheduled for the fourth quarter of 2008 were postponed to future years. This resulted in significantly lower O&M costs in 2008. Examples of these initiatives would be:
   - Turbine Lube Oil Vapor Extractor (Nuclear Margin Initiative)
   - North Essential Service Water Pump Overhaul (Nuclear Margin Initiative)
   - Elevator Doors (Safety Initiative)
   - Lower Containment Coatings (Housekeeping Initiative)
   - Emergency Diesel Generator Load Reduction (Safety Initiative)
   - Update of ASME Code section XI (Regulatory Initiative)

Q. Is the projected level of nuclear generation O&M expense representative of the activities and expenses that I&M expects to experience to generate electricity for I&M's customers in 2010?

A. Yes.

IV. Nuclear Generation Capital Expenditures

Q. What capital expenditures do you support in your testimony?

A. I support the capital expenditures projected to be spent in the 21-month forecast period from April 1, 2009 through December 31, 2010.

Q. What is the amount of capital estimated to be spent during the forecast period at the Cook Plant?

A. The projected amount of capital expenditures for the Cook Plant is approximately $196,269,000 for the 21-month forecast period.

Q. Is the amount of capital to be spent in the forecast period reasonable?

A. Yes. The projects included in the 21-month forecast period represent planned projects. Cook Plant management has the ability to reallocate capital dollars on an as needed basis as circumstances warrant, however the overall projected level of capital expenditures is reasonable and reasonably likely to occur in the forecast period.

Q. How is the amount of capital investment to be made in the Cook Plant reviewed for approval?

A. Cook Plant staff works collaboratively with AEPSC leadership and engineering management teams to evaluate the needs of the Cook Plant with respect to capital projects to improve reliability, safety, environmental performance, or a number of other unit performance parameters. The decision and timing in which capital investments are made depends on the immediacy of the need of the investment, comparison of economic evaluations of many projects across many plants, and regulatory or safety compliance requirements. All of these factors serve as input to the management teams that are responsible for approving capital projects and allocating the necessary funds to the Cook Plant.

Q. Please describe the nature of the Company's major nuclear capital expenditures for the forecast period.

A. The following table contains a breakdown of the forecasted capital expenditures.

Project Description	I&M Total Company Forecast Period Expense (thousands)
Cook Improvement Project (CIP) Study	$ 44,094
Dry Cask Nuclear Fuel Storage	$ 25,049
Unit 1 Secondary System Water Chemistry Improvement Project	$ 6,721
Unit 2 Secondary System Water Chemistry Improvement Project	$ 6,691
Unit 2 Moisture Separator Reheater Replacement Project	$ 6,427
Plant Heating Boiler Replacement Project	$ 5,423
Unit 1 Reactor Coolant Pump Upgrade Project	$ 5,023
Security Computer Replacement Project	$ 4,109
Installation of Additional Transformer TR-5 Equivalent Project	$ 3,764
Unit 2 Supplemental Containment Cooling Project	$ 3,226
Ice Condenser Glycol Chiller Replacement Project	$ 2,510
Fuel Transfer Equipment Replacement Project	$ 2,214
Nuclear Production Plant Blanket (PPB) Projects*	$ 42,466
Other Projects**	$ 38,551
TOTAL	**$ 196,269**

*Comprised of multiple projects, each with total costs under $500,000.
**Comprised of 73 projects that are forecasted to incur under $2 million each in costs during the forecast period.

Q. Please describe the 12 major capital projects that are forecasted to incur over $2 million each in costs during the forecast period.

A. Following is a description of each of the projects:

- The CIP Study is an extensive study of substantial improvements to both units of the Cook Plant that will extend their operating lives, improve nuclear safety margins and potentially increase the capacity of the plant, as discussed in detail in Section V of my testimony.
- The Dry Cask Storage project will support the ongoing operations of the Cook Plant by providing required space in the Spent Fuel Pool to permit loading and unloading of fuel for the reactor. If additional fuel storage space is not made available, the Spent Fuel Pool will reach

full capacity and the ability to offload spent fuel and permit new fuel loading of the reactor will be lost resulting in the shutdown of the two units in approximately 2015.

- The Unit 1 and Unit 2 Secondary System Water Chemistry Improvement projects include installation of permanent chemistry polishing systems on each unit to manage system water quality. Currently, the Cook Plant is meeting its chemistry requirements by using other systems over extended periods of time beyond its original design. The new polishing systems will enable Cook Plant to avoid forced derates or shutdowns due to poor chemistry.
- The Unit 2 Moisture Separator Reheater (MSR) will be refurbished during the 2010 fall refueling outage. The Unit 2 MSR system has exhibited chronic degradation in availability, functionality, and efficiency. Currently the MSR's have been removed from service which impacts station efficiency by reducing electrical output and increasing the potential for erosion of the Low Pressure Turbine components.
- The Plant Heating Boiler project includes the permanent installation of a heating boiler capable of providing plant heating steam in the event both units are removed from service at the same time. The installation of the permanent heating boiler replaced a temporary backup heating boiler that had been installed under a temporary modification for an extended period of time.
- The Unit 1 Reactor Coolant Pump Upgrade project involves the upgrading of flow controllers and instrumentation on the reactor coolant pumps. This upgrade project will provide plant operators with better controls for reactor coolant system water flow along with enhanced control room instrumentation.

- The Security Computer Replacement Project includes replacement of the Security Computer, and associated equipment at the Cook Plant. The replacement is required because the software and the hardware are out of date, there were few replacement parts available, and the system is difficult to maintain because vendor support of both the hardware and software are being discontinued.
- The Installation of Additional Transformer TR-5 Equivalent Project involves a spare transformer for the 345KV/34.5KV reserve feed transformer which was procured and installed in the Cook Plant's Switchyard as an onsite replacement to be used in the event of a failure of the installed transformer. The existing transformer has been in service for over 20 years and AEP does not have a spare replacement transformer for use in the event of failure.
- The Unit 2 Supplemental Containment Cooling Upgrade Project involves the installation of an additional water cooling system to supplement the Containment Ventilation Systems on each unit. The installation of closed loop water cooled chiller systems will eliminate operational problems associated with elevated Lake Michigan water temperature during the summer months (when electrical demand is at its highest) and eliminate sand, silt, and debris intrusion in the current cooling system during storms.
- The Ice Condenser Glycol Chiller Replacement Project involves the replacement of refrigerant chillers used to maintain both unit's containment ice condensers at required Technical Specification temperatures. The existing chillers are original installed plant equipment and are obsolete and use refrigerant that is no longer available.
- The Fuel Transfer Equipment Replacement Project involves the

replacement and upgrade of equipment used to transfer new and used nuclear fuel into and out of the reactor from the spent fuel pool and new fuel storage vault. The existing equipment is original installed plant equipment and is obsolete and unreliable.

Q. Please describe the Production Plant Blanket (PPB) Projects line item included in the table.

A. The Production Plant Blanket process is used to manage projects with a total cost below $500,000. Some examples of PPB projects included in the forecast include emergent plant component replacements, outage related minor design changes, plant computer system infrastructure upgrades, and replacement of equipment and tools used to support plant operation.

Q. Please summarize your testimony regarding forecasted capital expenditures.

A. I&M, the Cook Plant, and AEPSC have efficient processes developed for the approval and allocation of funds to make capital improvements to the Cook Plant. The projects that I have described account for a significant portion of I&M's planned capital investment in the Cook Plant over the forecast period. This demonstrates that I&M is effectively managing its level of capital investments to support the safe and reliable operation of the Cook Plant.

V. Future Projects

Q. Are there future capital improvement projects planned for the Cook Plant that will be subject to the Generation Investment Tracker (GIT) if approved by the Commission?

A. Yes. For example, we currently have underway a comprehensive study of potential significant improvements to both units of the Cook Plant that will allow the Cook Plant to operate safely and reliably for the extended operating life and increase the electrical output of the plant (Cook Improvement Project or CIP). I&M intends to file shortly with the Commission a separate petition requesting appropriate regulatory approvals of the CIP that will provide the Commission and any interested parties an opportunity to review the CIP in detail. For the purpose of this testimony, I will preview the CIP to illustrate a project that would be included in the GIT if approved by the Commission.

Q. Please generally describe the Cook Improvement Project.

A. The Cook Improvement Project is actually a series of projects that will be performed over multiple years (through 2017) that may ultimately increase the electrical output of the Cook Plant by approximately 400 MW. The CIP can generally be categorized in three basic groups: Life Cycle Management (LCM), Nuclear Safety Margin Improvement (NSMI), and the Extended Power Uprate (EPU).

LCM work refers to those projects that must be performed to keep the plant in normal operating condition. LCM projects typically consist of in-kind equipment replacement to ensure overall plant reliability, and must occur in order to maintain the plant in an as-is safe, operable condition. NSMI projects are projects that either regain nuclear safety margin or improve the nuclear safety margin of the plant, and are typically achieved through the addition of redundant equipment (redundant equipment is generally designed to provide backup capability should the primary equipment fail to operate properly similar to the alternate feed service that some customers request) or the replacement of existing equipment with equipment of improved design that allows the plant to operate more efficiently or more effectively. EPU projects are those projects that allow the plant to increase its electrical output through the addition of improved equipment as compared to the existing equipment.

It is important to note that projects associated with either the LCM, the NSMI, or the EPU work cannot always be discretely separated between those three categories. Each of the three categories of projects overlap to some extent, and as a result it is difficult to precisely calculate the cost of each portion of the CIP.

Q. What is the status of the CIP?

A. The CIP has undergone engineering reviews and scope assessment and a more thorough and detailed conceptual design study (CIP study) is underway. The CIP Study is scheduled for completion during the fourth quarter of 2010 and will allow management to understand the various combinations of specific projects and options available for its consideration and approval. The CIP Study will cost approximately $67.8 million, of which $12.7 million has been spent through March 31, 2009, and another $44.1 million is forecasted to be spent by the end of 2010. The study results will provide a detailed cost estimate and timeline for all aspects of the CIP, including major capital expenditures over a multi-year period for CIP implementation.

CIP Study Spending Timeframe	Through 3/31/2009	4/1/2009 to 12/31/2010	1/1/2011 through end of study	Total
$ (millions)	12.7	44.1	11.0	**67.8**

VI. Enhanced Security Costs

Q. Are there any other expenses you are supporting in this case?

A. Yes. Cook Plant incurred expenses during calendar years 2002 through 2005 related to enhanced security in response to the events surrounding September 11, 2001. These expenses include capital expenditures totaling approximately $12.8 million, security officer costs of approximately $2.5 million, and additional O&M expenditures of approximately $109,000. Company witness Hayes discusses the Total Company amount of these enhanced security costs, including depreciation and return on the capital expenditures. These Total Company amounts were provided to Company witness Roush who developed the Michigan jurisdictional revenue requirement. Company witness Krawec further discusses the recovery requested for the enhanced security costs.

VII. Summary

Q. Please summarize your testimony in this proceeding.

A. I have described I&M's Cook Plant, as well as the O&M and Capital projections for the Cook Plant associated with the 2010 forecasted test year proposed in this proceeding. Both the O&M and capital projections are reasonable and have undergone significant review by AEPSC, I&M, and Cook Plant management.

I also previewed the CIP and CIP Study, which is expected to be complete in the fourth quarter of 2010. The CIP would require a significant capital investment over a period of many years. For these reasons, I&M proposes to include the CIP costs, after review and approval in a separate proceeding, in the Generation Investment Tracker described by Company witness Krawec, if such a rate mechanism is approved by the Commission in this proceeding.

I have also described Cook Plant expenses related to enhanced security in response to the events surrounding September 11, 2001.

Q. Does this complete your pre-filed direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

TESTIMONY

OF

INDIANA MICHIGAN POWER COMPANY

VOLUME II

CONTENTS:

DIANA L. GREGORY
DENNIS W. BETEL
TODD D. BUSBY
MICHAEL N. KELLY
DONALD E. HAYES

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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INDIANA MICHIGAN POWER COMPANY	)	
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PRE-FILED DIRECT TESTIMONY

OF

DIANA L. GREGORY

PRE-FILED DIRECT TESTIMONY OF DIANA L. GREGORY
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Diana L. Gregory. My business address is 700 Morrison Road, Gahanna, Ohio 43230-6642. I am the Director of Transmission Accounting for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. AEP is the parent company of Indiana Michigan Power Company (I&M or Company).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND.

A. I received a Bachelor of Science in Business Administration degree, majoring in Accounting, in 1994, from Miami University. I was employed by Worthington Cylinders in 1994 as a plant controller. I joined AEPSC in 2000 as a financial analyst. I briefly worked in human resources before returning to accounting as a Supervisor in Investment accounting and then Manager of Investment accounting in 2004. In 2007 I became the Manager of East Power Pool Settlements. In this role I had access to information directly related to how PJM bills costs. In 2008, I assumed my current position as the Director of Transmission Accounting.

I am a Certified Public Accountant licensed in Ohio.

Q. WHAT ARE YOUR RESPONSIBILITIES AS THE DIRECTOR OF TRANSMISSION ACCOUNTING?

A. As the Director of Transmission Accounting I am responsible for the accounting for transmission settlements and certain transmission joint ventures.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my pre-filed direct testimony is to describe the billing and allocation of costs and credits for transmission services provided to AEP by PJM Interconnection L.L.C. (PJM), the regional transmission organization (RTO) of which the Company is a member. The costs and credits are billed according to applicable rates, terms and conditions previously approved by the Federal Energy Regulatory Commission (FERC) under the PJM Open Access Transmission Tariff (PJM OATT) and are included in the proposed unified PSCR clause. More specifically with respect to the PJM charges and credits, I will describe the billing for and allocation of: (1) FERC approved Network Integration Transmission Service (NITS) charges; (2) firm and non-firm point-to-point (PTP) transmission revenues; (3) ancillary service charges designed to recover transmission costs (Schedule 1A); (4) PJM transmission enhancement charges for transmission projects approved in the PJM Regional Transmission Expansion Plan (RTEP); (5) PJM administrative charges for operating PJM and for funding various organizations through schedules included in the PJM OATT; (6) RTO formation cost recovery charges and PJM expansion cost recovery charges; and (7) PJM default allocation assessments. These charges are described in greater detail in the direct testimony of Company witness Bethel. My testimony will explain, in general, how the aforementioned charges and credits are billed to AEP, assigned between the native load (i.e., Load Serving Entity or LSE) and off-system sales (OSS) related activities and then allocated to the AEP System – East Zone [1] (AEP), including I&M, using the appropriate allocation basis. I will also explain how the PJM OATT charges and credits (hereinafter referred to as PJM OATT net costs) are recorded in I&M's general ledger and describe I&M's proposed deferral accounting for over/under recovery through the PSCR.

Q. WOULD YOU PLEASE DESCRIBE THE INVOICES THAT AEP RECEIVES FROM PJM RELATING TO GENERATION RESOURCES AND LOAD RESPONSIBILITIES?

A. AEP East Zone Operating Companies are represented in the PJM market as a single account for generation resources and load responsibilities. PJM provides AEP invoices with Billing Line items which detail the charges and credits applicable to the PJM Operating Agreement and Open Access Transmission Tariff. PJM does not, however, designate charges and credits

[1] The AEP System - East Zone (AEP) consists of the following operating companies with generation capabilities: Indiana Michigan Power Company serving portions of Indiana and Michigan, Columbus Southern Power Company, serving portions of central and southern Ohio; Appalachian Power Company, serving portions of West Virginia and Virginia; Kentucky Power Company, serving portions of eastern Kentucky; and Ohio Power Company serving portions of Ohio. In addition, two operating companies residing in this AEP System – East Zone, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo) represent non-generating affiliates.

between the LSE and OSS; this responsibility belongs to AEPSC and will be discussed later in my testimony.

Q. WOULD YOU PLEASE GENERALLY DESCRIBE HOW PJM ASSESSES OATT CHARGES AND CREDITS TO AEP?

A. The costs of providing services to PJM market participants are charged according to the FERC- approved PJM OATT as discussed by Company witness Bethel. PJM applies the tariff rates to the various generation, load, and transmission billing determinants specified in the PJM OATT. Likewise, AEP receives credits in return for services that AEP provides under the PJM OATT and PJM Operating Agreement. As a part of the PJM Settlement Process, PJM charges AEP for services provided and credits AEP for services provided by AEP on behalf of its retail and wholesale customers.

Q. DOES AEPSC HAVE A PROCESS FOR REVIEWING PJM BILLS AND RESOLVING ANY BILLING DISCREPANCIES?

A. Yes. AEPSC Commercial Operations group estimates PJM charges and credits concurrently with PJM through their “shadow settlement” process to help ensure the accuracy of PJM invoices. The shadow settlement estimate uses data supplied by PJM that relates to the charges and credits identified on the PJM invoice. In the event of a discrepancy, AEPSC will contact PJM’s market settlement operations group. PJM, after an assessment of the data provided by AEP, will make any appropriate adjustments to the bill in the current or subsequent month, depending on the timing of when the bill is published.

Q. HOW ARE THE OATT CHARGES AND CREDITS ASSIGNED BETWEEN NATIVE LOAD AND OSS FROM THE PJM INVOICES?

A. Hourly MWh information from PJM is the basis for reconstructing the resources (both generation and purchased energy) used to serve the native load requirements and to fulfill OSS obligations. The reconstruction of the hourly data is completed using AEP's internal Energy Costing and Reporting (ECR) process. The ECR process assigns generation resources and market purchases (resources) with the highest hourly cost to OSS, resulting in the least cost resources serving the native load customers[2]. Based on this reconstruction, PJM administrative charges and default allocation assessments are assigned proportionally, based on Load Ratio Share (LRS), to the native load and OSS. The LRS is the ratio of native load and OSS load obligations to the total load. The costs assigned to OSS are included in the calculation of OSS margins. OSS margins are discussed in the testimony of Company witness Busby and the forecast of OSS margins is discussed in the testimony of Company witness Allen. The remaining charges and credits are assigned directly to the LSE.

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[2] ECR is an internal AEP application used for assigning and reporting the cost and revenues associated with OSS for pool settlements of the Eastern AEP operating companies. ECR calculates costs, demand and energy charges and provides reporting on these results. Using an economic dispatch model, ECR determines the costs associated with OSS on an hourly basis. The ECR process assigns generation and market purchases with the highest price to these off system sales. Once all OSS activity has been covered by the higher cost generation and market purchases, the remaining lower cost resources are assigned to AEP's native load customers.

Q. HOW ARE THE LSE AND OSS CHARGES AND CREDITS FROM THE PJM INVOICES ALLOCATED TO I&M AND THE OTHER AEP SYSTEM-EAST ZONE COMPANIES?

A. Once the PJM charges and credits have been assigned to either the LSE or OSS, they are then allocated to the AEP System – East Zone Operating Companies, including I&M, based on each company's Member Load Ratio (MLR) percentage or transmission pole miles[3]. The MLR allocation methodology is discussed by Company witness Allen.

The charges and credits related to NITS, PTP Transmission Revenues, Transmission owner scheduling, system control and dispatch service (Schedule 1A), PJM Transmission Enhancement charges, PJM administrative charges and default allocation assessments are allocated to the AEP East Zone operating companies based on their respective MLRs. Charges related to RTO formation cost recovery and PJM expansion cost recovery are allocated to the operating companies based on each company's transmission pole miles.

Q. PLEASE DESCRIBE HOW THE PJM OATT CHARGES AND CREDITS ARE RECORDED IN I&M'S GENERAL LEDGER.

A. Since the actual PJM OATT invoices are received after AEP's month-end settlement and closing have been completed, an estimate of OATT charges

[3] Transmission pole miles are calculated using the pole miles for each separate AEP system company as the numerator, and the total company pole miles as the denominator. The resulting ratios are applied to the total cost to be allocated based on the formula.

and credits for the current month is recorded, based on information received from PJM. The following month, an adjustment is made to true-up the estimate amount to the actual invoice amount. Both the estimate and the actual settlement are received on a total AEP basis. The amounts recorded to I&M's general ledger reflect I&M's allocated share of those settlements. Most of these OATT charges and credits are allocated to I&M based on MLR.

Q. WOULD YOU PLEASE DESCRIBE THE CATEGORIES OF FERC-APPROVED ACCOUNTS IN WHICH THESE PJM OATT CHARGES AND CREDITS ARE RECORDED?

A. A schedule of the PJM OATT charges and credits to be recovered through the PSCR and the accounts to which they are recorded is set forth in Exhibit I&M-40 (DLG-1). The majority of the PJM OATT charges and credits are charged 100% to a specific FERC account. Company witness Hayes explains that these specific FERC accounts are not in the current MPSC Uniform System of Accounts (USofA). The exceptions to charging or crediting 100% to one account are certain PJM administrative charges, which are charged to Account 561.4, Scheduling, System Control and Dispatching Services, Account 561.8, Reliability Planning and Standards Development Services, and Account 575.7, Market Facilitation, Monitoring and Compliance Services, in accordance with FERC Order 668, but are assigned among these accounts based on instructions from PJM.

Q. WOULD YOU PLEASE DESCRIBE I&M'S PROPOSED TRUE-UP OVER/UNDER RECOVERY DEFERRAL ACCOUNTING FOR THE DIFFERENCE BETWEEN PJM OATT NET COSTS AND PSCR OATT REVENUES?

A. When recovery of PJM OATT net costs through the PSCR is implemented, by being an authorized component of the PSCR factor, I&M will be comparing the PSCR OATT revenues to its PJM OATT net costs. PSCR OATT revenues in excess of allowable PJM OATT net costs will constitute an over recovery. PJM OATT net costs in excess of the PSCR OATT revenues will constitute an under recovery.

Q. IS I&M PROPOSING TO EMPLOY TRUE-UP OVER/UNDER RECOVERY ACCOUNTING, CONSISTENT WITH THE CURRENT ACCOUNTING FOR THE PSCR, FOR THE COLLECTION OF PJM OATT NET COSTS?

A. Yes. Company witness Krawec will describe the proposed PJM OATT net cost recovery process to be included in the PSCR. I&M will record a regulatory liability for any over recovery of PJM OATT net costs or a regulatory asset for any under recovery of PJM OATT net costs effective with the implementation of recovery of PJM OATT net costs as a component of the PSCR. At the end of the initial PSCR OATT collection period, and subsequent collection periods, the cumulative over/under recoveries would result in either a net regulatory liability recorded in Account 254, Other Regulatory Liabilities, or a net regulatory asset recorded in Account 182.3, Other Regulatory Assets. This net regulatory liability or asset would be included in the development of the next PJM OATT net costs PSCR component to either be refunded or recovered.

Q. HOW WILL THE PJM OATT NET COST OVER/UNDER RECOVERIES BE CALCULATED ONCE THE PJM OATT COMPONENT OF THE PSCR IS IMPLEMENTED?

A. The PSCR OATT revenues (i.e., the Michigan jurisdictional revenues collected as a separate component of the PSCR factor) will be compared to the total of Michigan jurisdictional PJM OATT net costs incurred for that period. The difference between these revenues and PJM OATT net costs will be deferred as either a net regulatory liability for an over recovery to be refunded through the PSCR or a net regulatory asset for an under recovery to be recovered through the PSCR.

Q. WILL I&M'S ACTUAL OVER/UNDER RECOVERY OF PJM OATT NET COSTS BE DEFERRED UNTIL CREDITED TO /RECOVERED FROM CUSTOMERS, RESPECTIVELY?

A. Yes. I&M plans to record deferrals of its actual over/under recovered PJM OATT net costs, based on the types of costs identified in this application, until over-collections are credited to customers or under collections are recovered from customers in a future PSCR period.

Q. WHAT IS THE BASIS IN ACCOUNTING PRINCIPLES GENERALLY ACCEPTED IN THE UNITED STATES OF AMERICA (GAAP) FOR I&M

DEFERRING AS A REGULATORY ASSET PJM OATT NET COSTS IN EXCESS OF PSCR OATT REVENUES?

A. Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 980-340-25-1, formerly Paragraph 9 of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, as adopted by the FERC in its Order 390 and used in the FERC USofA, states the following: “An enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: a.) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes. b.) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.” FASB ASC 980 defines “capitalize” as cost that would be recorded as an asset and this resulting asset is commonly known as a deferred cost or a regulatory asset. The term “probable” is defined as a future event that is likely to occur but is not certain consistent with its use in FASB ASC 450, formerly SFAS No. 5, *Accounting for Contingencies*.

Q. WHAT IS NEEDED TO ESTABLISH PROBABILITY OF RECOVERY?

A. The final order in this proceeding should clearly provide for the future recovery of any PJM OATT net costs in excess of applicable PSCR OATT revenues in the next PSCR proceeding.

Q. HOW WILL THE TWO CRITERIA OF FASB ASC 980 BE MET TO ENABLE I&M TO CAPITALIZE OR DEFER UNDER-RECOVERED PJM OATT NET COSTS AS A REGULATORY ASSET?

A. If an Order from the Commission approves the recovery of under-recovered PJM OATT net costs, then the two criteria of FASB ASC 980 for capitalizing or deferring net under-recovered PJM OATT net costs as a regulatory asset will be met.

Q. DOES THE DEFERRAL ACCOUNTING TREATMENT YOU PROPOSE FOR RECORDING A REGULATORY LIABILITY IN THE INSTANCE WHERE I&M HAS AN OVER RECOVERY OF PJM OATT NET COSTS COMPLY WITH GAAP?

A. Yes. FASB ASC 980-405 defines accounting for instances when a regulator imposes a liability on a cost based regulated enterprise, such as I&M. One of the instances in which a liability can be imposed on a regulated enterprise occurs when a regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced. If the regulator requires that any over collection of such recoverable costs be returned to customers, any over recovery shall be recognized as a regulatory liability, or if a net cumulative under recovery exists in the form of a regulatory asset, a subsequent over recovery would be accounted for as a reduction in such net cumulative under recovery regulatory asset until the regulatory asset is eliminated.

Q. IN ADDITION TO THE REQUIREMENTS OF FASB ASC 980, ARE THERE UNDERLYING REASONS THAT SUPPORT I&M PRACTICING OVER/UNDER RECOVERY DEFERRAL ACCOUNTING FOR ITS ACTUAL PJM OATT NET COSTS?

A. Yes. The proper matching of costs with their recovery in revenues in the same accounting period necessitates that I&M's actual unrecovered PJM OATT net costs be deferred since they will be recovered in a future period. Failure to practice deferral accounting for unrecovered actual PJM OATT net costs recoverable through the PSCR would understate I&M's earnings in the periods prior to their recovery and overstate earnings in the periods in which they are recovered through the PSCR.

Q. ARE YOU REQUESTING THAT PJM OATT NET COSTS OVER/UNDER RECOVERY BALANCES ACCRUE INTEREST?

A. Yes. The Company is proposing to apply interest to the over or under recovery with these costs consistent with the current PSCR practice.

Q. WHAT ACCOUNTING WOULD I&M EMPLOY TO RECORD THE PJM OATT NET COST OVER OR UNDER RECOVERIES AND THE RELATED INTEREST DEFERRALS?

A. PSCR OATT revenues will be recorded in the appropriate revenue Accounts 440 through 446 while the credit to or recovery from customers for related interest will be recorded in Interest Expense (Account 431) or Interest Income (Account 419) as appropriate. The PSCR OATT revenues will be compared to total PJM OATT net costs.

If, within a given month, PSCR OATT revenues are greater than the PJM OATT net costs, I&M will record the over recovery as a decrease (charge) to Account 456.1, Revenues from Transmission of Electricity and a credit to Account 254, Other Regulatory Liabilities, if the cumulative balance is an over recovery. If the cumulative balance is an under recovery, the charge will be to Account 566, Miscellaneous Transmission Expense and Account 182.3, Other Regulatory Assets, will be credited until the under recovery balance is eliminated.

If the monthly PSCR OATT revenues are less than the monthly PJM OATT net costs, I&M will record the under recovery as a decrease (credit) to Account 566, Miscellaneous Transmission Expense, with a corresponding debit recorded to Account 182.3, Other Regulatory Assets, if the cumulative balance is an under recovery. If the cumulative balance is an over recovery the credit will be to Account 456.1, Revenues from Transmission of Electricity, and Account 254, Other Regulatory Liabilities, will be debited until the over recovery balance is eliminated. On an annual basis any over or under recovered balance will be included as a reconciliation item to either reduce for an over recovery or increase for an under recovery the amount to be collected in the next PSCR rate.

Q. DOES THIS CONCLUDE YOUR PRE-FILED TESTIMONY?
A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	**)**	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

DENNIS W. BETHEL

PRE-FILED DIRECT TESTIMONY
OF
DENNIS W. BETHEL
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Dennis W. Bethel. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am the Managing Director – Regulated Tariffs for the American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company Inc. (AEP). AEP is the parent company of Indiana Michigan Power Company (I&M or the Company).

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. As Managing Director- Regulated Tariffs, I direct a staff that is responsible for cost of service studies, rate design, agreements and tariffs for retail and regulated wholesale services throughout the eleven-state AEP service area. I participate on AEP's behalf in Regional Transmission Organization (RTO) forums, particularly relating to the transmission tariffs, rate design, and related committee matters in the Southwest Power Pool (SPP) and the PJM Interconnection, L.L.C. (PJM).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. In 1973, I earned a Bachelor of Science Degree in Electrical Engineering from the University of Evansville (Indiana). In July of 1973, I began my utility career at

I&M, as a commercial and industrial customer service engineer. In 1977 I transferred to I&M's rate department. In 1980 I transferred to AEPSC, where I have held positions in Rate Research and Design, System Transactions, Transmission Operations, and Regulated Tariffs. At I&M I worked directly with customers on new and expanded service, was responsible for retail and wholesale contract development and administration, cost of service studies, rate design, fuel clause adjustments and other regulatory analyses. In the AEPSC Rate Research and Design Division, from 1980 to 1988, I performed and supervised cost of service and rate design studies and testified in a number of retail rate cases on those topics for several of the AEP East Companies[1]. In 1988 I transferred to the System Transactions Department where I was responsible for power, interconnection and transmission-related agreements and tariffs and in 1991 was promoted to Manager – Interconnection Agreements. During this time I helped to develop and support AEP's first Open Access Transmission Tariff (OATT) filed in Docket No. ER93-540-000. In 1997 I moved to the Transmission Operations Department as Manager – Transmission Contracts and Regulatory Support, a position that was functionally separated from the merchant operations function. In June 2000, I was named Director – Transmission and Interconnection Services in the AEPSC Regulatory Services Department. In that position I was responsible for the development and implementation of transmission, interconnection and related agreements, tariffs and policies on behalf of the AEP companies in the three regions where we

[1] The AEP East Companies include Indiana Michigan Power Company, Appalachian Power Company, Columbus Southern Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company.

provide service, SPP, PJM and the Electric Reliability Council of Texas (ERCOT). I assumed my present position in July 2005.

Q. DO YOU HOLD ANY PROFESSIONAL LICENSES?

A. Yes, I am registered as a Professional Engineer in the States of Indiana and Ohio.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN REGULATORY PROCEEDINGS?

A. Yes. I have provided expert testimony on various electric cost-of-service and rate design issues before this Commission, and the utility regulatory commissions of Kentucky, Ohio, Tennessee, Virginia, and West Virginia.

I have also previously submitted testimony before the Federal Energy Regulatory Commission (FERC) in Dockets ER93-540, ER98-2786, EL02-111, et al, EL01-73, EL05-74, EL05-121, EL07-101, and ER05-751, all of which involved transmission rate issues, some of them involving transmission service under the PJM OATT. In FERC Dockets ER07-1069 and ER08-1329, I sponsored AEP's formula rates and protocols for inclusion in, respectively, the SPP OATT, on behalf of Public Service Company of Oklahoma and Southwestern Electric Power Company, and in the PJM OATT, on behalf of the AEP East Companies. I have also recently filed testimony in FERC Docket No. ER09-1279, in support of changes to the AEP Transmission Agreement, a transmission cost sharing arrangement among the AEP East Companies, and in Docket No. ER10-355 , in support of formula rates for transmission service over facilities to be constructed by subsidiaries of AEP Transmission Company, LLC. (AEPTCo)

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony describes the transmission related costs and credits billed to AEP by PJM, as identified by Company witness Gregory, and supports the transmission component of the unified Power Supply Cost Recovery Clause (PSCR) proposed by Company witness Krawec to collect the portion of those costs identified by Company witness Roush as being related to I&M's responsibility as an load serving entity (LSE) providing retail electric service in Michigan. Specifically I will describe the following transmission cost components included in the PSCR.

1. Network Integration Transmission Service (NITS), pursuant to PJM OATT Attachment H-14;
2. Transmission Owner Scheduling, System Control and Dispatch Service, pursuant to PJM OATT Schedule 1A;
3. PJM RTO Administration fees and other charges, pursuant to PJM OATT Schedules 9 and 10;
4. PJM Regional Transmission Enhancement charges, pursuant to PJM OATT Schedule 12;
5. PJM Expansion Cost Recovery Charges (ECRC), pursuant to PJM OATT Schedule 13;
6. AEP RTO Start-up Cost Recovery Charges, pursuant to PJM OATT Attachment H-14; and
7. Default Allocation Assessments, and any refunds of such assessments, pursuant to Section 15.2 of the PJM Operating Agreement.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

1. Exhibit I&M - 41 (DWB-1), AEP East Companies PJM Administrative Tariff Rates and Actual Charges Twelve Month Ended November 30, 2009, a Summary of current PJM charges applicable to PJM NITS customers, such as I&M and the other AEP East Companies, in the AEP Zone of PJM; and

2. Exhibit I&M - 42 (DWB-2), PJM RTEP Project Cumulative Costs Based on Assumed Construction Schedules and Estimated Charges to AEP for PJM Socialized RTEP Projects, bar charts illustrating the trend in costs for new transmission facilities being constructed and charged on a load share basis to all PJM NITS customers through OATT Schedule 12.

Q. WHY IS IT APPROPRIATE FOR TRANSMISSION-RELATED CHARGES FROM THE RTO TO BE RECOVERED THROUGH THE PSCR?

A. Transmission and related services are necessary components of the power supply function, without which I&M could not deliver power and energy to its Michigan retail customers. The charges for transmission and related services are determined by FERC-approved rates, and they are increasing. AEPSC vigorously represents the interests of I&M and the other AEP East Companies through participation in the various RTO Stakeholder forums, and in proceedings before the FERC. The RTO's budgets, policies and rate designs, however, reflect the wishes of a majority of the stakeholders, the will of the RTO Board of Directors and Management, and the decisions of the FERC. The AEP East and SPP Companies were directed by FERC to join RTOs as a condition of the merger between AEP and the Central and Southwest Corporation (CSW). In addition, I am advised by legal counsel that Michigan law directed Michigan utilities to either join a FERC approved multistate regional transmission organization or independent transmission organization or divest its transmission facilities to an independent transmission organization. Further, by potentially reducing the frequency with which I&M may need to file costly general rate proceedings, as transmission-related costs change, the transmission component of the PSCR factor creates the opportunity, over time, to reduce costs for I&M's customers. Given all these circumstances, I believe that it is appropriate that I&M be permitted to adjust its rates periodically through the transmission component of the PSCR, in order to maintain a balance between its transmission and related costs and the revenues its Michigan retail rates pay for those services.

Finally, in cases involving other Michigan electric utilities, Consumers Energy Company and The Detroit Edison Company, the Commission has found that recovery through the PSCR is appropriate for comparable services provided by the Midwest Independent System Operator, Inc. (MISO).

Q. YOU MENTIONED THAT YOU HAVE SUBMITTED TESTIMONY IN FERC DOCKET ER09-1279. HOW AND WHEN WILL THE CHANGES TO THE AEP TRANSMISSION AGREEMENT PROPOSED IN THAT CASE IMPACT I&M'S COSTS FOR TRANSMISSION SERVICE?

A. The AEP Transmission Agreement (AEPTA), executed by the AEP East Companies in 1984, specifies a method by which the signatories (Members) share costs related to certain transmission (Bulk Transmission) investments that they have made. The AEPTA defines Bulk Transmission investments as the original cost, less investment tax credits, of transmission lines operated at 138 kV or higher, and transmission stations that contain extra-high voltage facilities. In Docket No. ER09-1279, the AEP East Companies have proposed to make changes to the transmission costs that are shared, and to the cost sharing mechanism. As it presently stands, the AEPTA provides that Members with Bulk Transmission investments that exceed their member load ratio (MLR) share of the total of such investments by the Members (Surplus Members) receive payments from Members that have invested less than their MLR share of the total in such facilities (Deficit Members). I&M has been a Surplus Member under the AEPTA since its inception, and has received significant amounts, approximately $3 million per month in recent years, from the Deficit Members. These receipts have been flowed through to I&M's customers in the form of reduced retail and wholesale rates. When the AEP East Companies joined PJM, a new cost sharing mechanism, the PJM OATT, came into play. PJM charges the AEP East Companies for transmission service over the combined transmission facilities owned by the AEP East Companies. Under the OATT rate design, the costs of all transmission facilities owned by the AEP East Companies (Rolled-In Cost), not just the Bulk Transmission facility costs, are shared by all the LSEs in the AEP Zone of PJM.

The formula used to determine the Rolled-In costs, including the rate of return allowed on investments under the OATT, is different than under the AEPTA, and as I mentioned earlier, in Docket No. ER09-1279, the AEP East

Companies propose to replace the present Bulk Transmission investment sharing mechanism under the AEPTA with one based on the OATT. The proposed changes to the AEPTA allocate the Rolled-in Cost reflected in the OATT using the average of the prior year monthly coincident peaks (12 CP) instead of the MLR, and specify how the AEP Companies will share other PJM transmission-related charges and revenues that were not addressed by the original AEPTA.

If the changes proposed by the AEP East Companies are approved by the FERC, I&M will experience a cost increase; however, no adjustments have been included in this proceeding to recognize the proposed changes since the FERC approved an indefinite delay in the effective date until after it issues a final order, set the proposed changes for hearing, and is holding that process in abeyance while the interested parties pursue settlement discussions. The settlement discussions are privileged, and at this stage in the process it is not possible to predict what the outcome might be.

Inclusion of transmission costs in the PSCR, as proposed by I&M in this proceeding, will provide a mechanism to promptly adjust retail rates when a final FERC order is approved after settlement or hearings in Docket ER09-1279.

II. PJM NETWORK INTEGRATION TRANSMISSION SERVICE

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH NETWORK INTEGRATION TRANSMISSION SERVICE.

A. The charges incurred by I&M for PJM NITS recover I&M's load share of the AEP East Companies' FERC approved Annual Transmission Revenue Requirement (ATRR) for transmission facilities in the AEP Zone of PJM. There are a number of additional charges associated with NITS, all of which are summarized in my Exhibit I&M - 41 (DWB-1). The AEP Zone ATRR presently consists of the cost of transmission facilities owned by the AEP East Companies, and is computed by applying a formula rate specified in Attachment H-14 of the PJM OATT.

Q. IS AEP's FORMULA RATE IN THE PJM OATT CURRENTLY AUTHORIZED BY FERC?

A. Yes, the formula rate was accepted for filing by the FERC in Docket No. ER08-1329, and is presently being collected, subject to refund after issuance of a final order in that proceeding.

Q. PLEASE EXPLAIN THE STATUS OF FERC DOCKET NO. ER08-1329-000.

A. In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM, and to implement a formula rate allowing annual adjustments reflecting future changes in cost of service. In September 2008, the FERC issued an order accepting AEP's proposed formula rate, subject to a compliance filing, and suspended the rate until March 1, 2009. In addition, the order established settlement proceedings with an Administrative Law Judge. Those settlement negotiations are on going. Per the FERC's order, the formula rate became effective on March 1, 2009, subject to refund, and in May 2009 AEP posted the first annual update for the twelve month period July 1, 2009 through June 30, 2010. Company witness Roush has applied the charges that are being billed for service beginning July 1, 2009, to estimate I&M's cost of transmission service for purposes of the PSCR. The NITS charge effective July 1, 2009 is $69.42 per MW per day, a 4.5% increase from the initial charge under the formula rate ($66.41), and a 20% increase from the rate that had been effective prior to March 1, 2009 ($57.78). As previously mentioned, the charges under the formula rate are presently subject to refund, with interest at a FERC defined rate.

Q. ARE THERE CREDITS ASSOCIATED WITH PJM POINT-TO-POINT TRANSMISSION SERVICE ON THE AEP ZONAL NETWORK INTEGRATION TRANSMISSION SERVICE BILLS?

A. Yes. Each month, PJM allocates revenues for both firm and non-firm point-to-point (PTP) transmission service to the various PJM Transmission Zones, proportionate to the revenue requirements for NITS in each zone. In addition, the NITS formula rate includes credits within the formula rate ATRR calculation for PTP revenues under AEP-administered "grandfathered" or "pre-RTO" transmission service contracts, and for transmission construction-related services that the AEP East Companies provide to third parties, net of the costs to provide those services. PJM allocates the AEP Zone share of PJM PTP revenues directly to AEP and other NITS customers in the AEP Zone each month, whereas the other credits are built into the NITS rate as credits to the ATRR in the formula rate.

III. TRANSMISSION OWNER SCHEDULING, SYSTEM CONTROL & DISPATCH SERVICE (SCHEDULE 1A)

Q. PLEASE DESCRIBE THE CHARGES PURSUANT TO PJM OATT SCHEDULE 1A, TRANSMISSION OWNER SCHEDULING SYSTEM CONTROL AND DISPATCH SERVICE.

A. PJM OATT Schedule 1A contains a rate, specified in $/MWh, for Scheduling, System Control and Dispatch (Scheduling) Service provided by PJM Transmission Owners in each PJM Zone. The AEP East Companies' rate for that service is updated annually with the NITS formula rate update discussed above. Prior to March 1, 2009, the rate was $0.0686/MWh. From March 1 through June 31, 2009 it was $0.0555/MWh. The 2009 Annual Update resulted in an increase to $0.0711/MWh effective July 1, 2009.

Company witness Roush has used the July 1, 2009 rate to estimate I&M's Schedule 1A costs for 2010 under the transmission component of the PSCR.

IV. PJM RTO ADMINISTRATION FEES OVERVIEW

Q. WHAT ARE THE TYPES OF PJM ADMINISTRATION AND RELATED FEES THAT ARE INCLUDED IN THE PSCR?

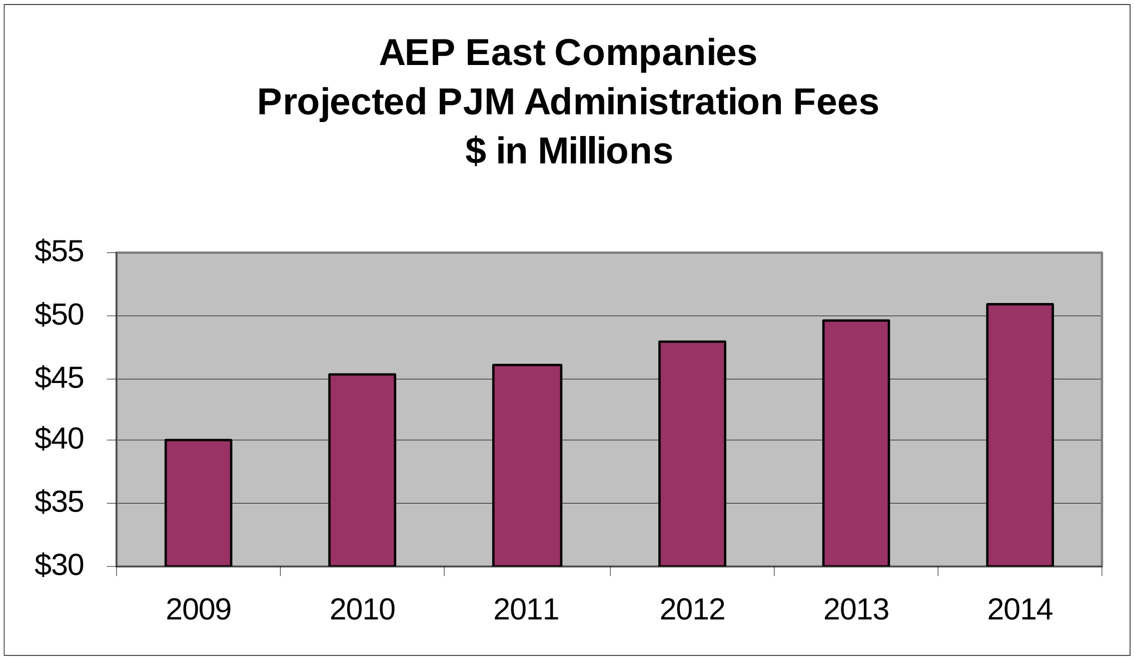
A. PJM charges each market participant on a monthly basis a number of fees to recover its operating and administration costs. PJM also charges fees to transmission customers and other market participants to fund the operation of FERC and certain other organizations that are involved in management of transmission reliability and regulation. These fees are defined in PJM OATT

Schedules 9 and 10, and are approved by the FERC. The components of these administration fees, by PJM OATT Schedule number, are:

- 9-1, Control Area Administration Service;
- 9-2, Financial Transmission Rights (FTR) Administration Service;
- 9-3, Market Support Service;
- 9-4, Regulation and Frequency Response Administration Service;
- 9-5, Capacity Resource and Obligation Management Service;
- 9-6, Formula Rate for Costs of Advanced Second Control Center;
- 9-FERC, FERC Annual Charge Recovery;
- 9-OPSI, Funding for the Organization of PJM States, Inc. (OPSI);
- 9-FINCON, Finance Committee Retained Outside Consultant charges;
- 9-MMU, Market Monitoring Unit funding charge;
- 10-NERC, North American Electric Reliability Corporation Charge; and,
- 10-RFC, ReliabilityFirst Corporation Charge.

Q. HOW ARE THE PJM ADMINISTRATION COSTS EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. The PJM and other RTO-related administration charges (Schedules 9 and 10) billed to the AEP East Companies for service to all their retail and wholesale customers totaled about $40 million during 2009. Based on preliminary budgets released by PJM, AEPSC estimates that those charges will increase to about $51 million by 2014, a 26% increase over the next five years. The expected year to year change is illustrated in the following chart:



Q. WHAT IS PJM SCHEDULE 9-1, CONTROL AREA ADMINISTRATION SERVICE AND HOW IS IT BILLED?

A. Control Area Administration Service comprises all of the activities of PJM associated with preserving the reliability of the PJM Region and administering point-to-point transmission service and network integration transmission service. This service is billed to each user, including AEP, based on MWhs of energy delivered.

Q. WHAT IS PJM SCHEDULE 9-2, FTR ADMINISTRATION SERVICE AND HOW IS IT BILLED?

A. The FTR Administration Service comprises all of the activities of PJM associated with administering financial transmission rights, including coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's online internet-based eFTR tool, and FTR award analyses. FTR Administration Service is billed to each FTR market participant based on three components:

- the quantity of FTR MWhs of all FTRs held by the market participant times the tariff rate,
- the number of hours in all bids to buy FTR obligations during the annual auction and all monthly auctions, multiplied by the tariff rate, and
- five times the number of hours in all bids to buy FTR options during the annual auction and all monthly auctions, multiplied by the tariff rate.

Q. WHAT IS PJM SCHEDULE 9-3, MARKET SUPPORT SERVICE AND HOW IS IT BILLED?

A. Market Support Service comprises all of the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions, including market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, support of PJM's internet-based customer interactive tool known as eSchedules, and market monitoring. PJM bills each market participant a Market Support charge equal to the sum of the following components:

- MWhs of energy delivered to load in the PJM Region or for export, plus MWhs of energy input into the transmission system, plus MWhs of all accepted increment and decrement bids times the tariff rate.
- The number of bid/offer segments submitted during the period times the tariff rate. A bid/offer segment is each price/quantity pair submitted into the day-ahead energy market.

Q. WHAT IS PJM SCHEDULE 9-4, REGULATION AND FREQUENCY RESPONSE ADMINISTRATION SERVICE, AND HOW IS IT BILLED?

A. Regulation and Frequency Response Administration Service comprises all of the activities of PJM associated with administering the provision of regulation and frequency response service. Regulation and frequency response service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled frequency at sixty Hertz. PJM administration costs associated with the provision of Regulation and Frequency Response Administration Service are billed to LSEs and generators based on MWhs of regulation service.

Q. WHAT IS PJM SCHEDULE 9-5, CAPACITY RESOURCE AND OBLIGATION MANAGEMENT SERVICE, AND HOW IS IT BILLED?

A. This service comprises the activities of PJM associated with assuring that customers have arranged for sufficient generating capacity to meet their capacity obligations. This service is billed to LSEs, generators and other market participants based on the MW-days of resource or obligation provided.

Q. PLEASE EXPLAIN PJM SCHEDULE 9-6, FORMULA RATE FOR COSTS OF ADVANCED SECOND CONTROL CENTER.

A. This formula rate recovers the costs of PJM's advanced second control center, as set forth in Schedule 9-6. Monthly charges are assessed to all users of services under PJM OATT Schedules 9-1 through 9-5. The charges are based on the applicable billing determinants set forth in Schedules 9-1 through 9-5.

Q. WHAT CHARGES ARE CONTAINED IN PJM SCHEDULE 9–FERC?

A. PJM is subject to an annual charge assessed by the FERC to cover the costs of that agency. PJM bills this charge to transmission customers based on their total MWhs of electric energy delivered.

Q. PLEASE EXPLAIN THE ORGANIZATION OF PJM STATES AND ITS FUNDING, PJM SCHEDULE 9-OPSI.

A. The Organization of PJM States (OPSI) was established during 2005. The purpose of OPSI is to maintain an organization of electric utility regulatory agencies in the 13 states and the District of Columbia within which PJM operates. OPSI Member Regulatory Agencies' activities include, but are not limited to, coordinating activities such as data collection, issues analyses, and policy formulation related to PJM, its operations, its market monitor, and related FERC matters. The Schedule 9-OPSI charge to each transmission customer is based on the MWhs of energy delivered to load.

Q. WHAT IS THE PJM FINANCE COMMITTEE RETAINED OUTSIDE CONSULTANT CHARGE, PJM SCHEDULE 9-FINCON?

A. PJM anticipates retaining consultants to assist the PJM Finance Committee, and has created Schedule 9-FINCON to collect financial consultant costs. PJM has not yet begun to collect costs for this activity, but when PJM incurs such costs they will be recovered through the Schedule 9-FINCON charge, and thus it is appropriate now to establish a place for those costs in the PSCR.

Q. WHAT IS THE PJM SCHEDULE 9-MMU FEE AND HOW IS IT BILLED?

A. In order to ensure independence and identify potential or actual market manipulation, PJM, per FERC order, receives oversight from a Market Monitoring

Unit (MMU). This fee funds this market monitoring service. Schedule 9-MMU collects the MMU's cost from all transmission service customers, generators and other energy market bidders based upon MWh of service provided, bid or taken.

Q. WHAT IS THE PJM SCHEDULE 10-NERC FEE AND HOW IS IT BILLED?

A. The North American Electric Reliability Corporation (NERC) develops and enforces reliability standards for the bulk power system in North America. PJM Schedule 9-FERC recovers NERC operations costs for the PJM Region. The fee is charged in all PJM zones other than the Duquesne and Dominion Zones and is assessed to LSEs and others based on MWh of energy deliveries.

Q. WHAT IS THE PJM SCHEDULE 10-RFC FEE AND HOW IS IT BILLED?

A. ReliabilityFirst Corporation (RFC) operates under the NERC umbrella; its mission being to preserve and enhance electric service reliability and security for the interconnected electric systems within the ReliabilityFirst geographic area. This area encompasses all of PJM except the Duquesne and Dominion Zones. The fee is assessed based upon MWh of load, including losses.

Q. DOES PJM MAKE ADJUSTMENTS TO TRUE-UP THE PJM ADMINISTRATIVE FEES?

A. Yes. PJM uses stated rates to fund the activities covered by Schedules 9-1 through 9-5 and then computes an after-the-fact adjustment, based upon actual revenues recovered and actual costs for these services. Exhibit I&M- 41 (DWB-1) summarizes the PJM and related administrative charges billed to the AEP East Companies for their firm power customers during the twelve months ended November 30, 2009, showing the breakdown of the charges by PJM Tariff component. The summary shows that, taking into account the cost true-up adjustments, PJM charged significantly less than the maximum stated rates contained in OATT Schedules 9-1 through 9-5 during 2009. For example, the stated rate for Schedule 9-1, Control Area Services, is $0.1809/ MWh, but PJM's actual charges were 68% of the allowed level at $0.1237/ MWh. The charges under Schedules 9-2 through 9-5 vary from the maximum stated levels by similar amounts ranging from 53% to 78% of the maximum rates.

The PSCR has been designed to capture these adjustments to the PJM Administrative charges.

Q. HOW DO PJM'S ADMINISRATIVE COSTS COMPARE TO THOSE OF OTHER RTOS?

A. Exhibit I&M-41 (DWB-1) shows that the AEP East Companies' PJM and related administrative charges averaged about $0.29/MWh during 2009. A report published for the American Public Power Association by GDS Associates in February 2007, *Electric Market Reform Initiative (EMRI) Task 2, Analysis of Operational and Administrative Cost of RTOs* [2], indicates that PJM Administration costs in 2005 were the lowest among five RTOs that operate markets as well as transmission. More recently, data filed in Michigan Public Service Commission Case No. U-15677 by The Detroit Edison Company indicates that Edison's costs for MidWest ISO administrative charges average about $0.40/MWh.

[2] http://www.appanet.org/files/PDFs/ExecutiveSummaryCostofRTOs20507GDS.pdf

V. PJM TRANSMISSION ENHANCEMENT CHARGES (SCHEDULE 12)

Q. PLEASE PROVIDE AN OVERVIEW OF THE PJM REGIONAL TRANSMISSION ENHANCEMENT PROCESS AND SCHEDULE 12 OF THE PJM OATT.

A. PJM has implemented a regional transmission planning process. Transmission enhancements or the Regional Transmission Expansion Plan (RTEP) are developed annually pursuant to Schedule 6 of the PJM Operating Agreement. The RTEP project costs are allocated by PJM in accordance with FERC approved allocation methods. The allocation factors are set forth in Schedule 12 of the PJM OATT. The transmission owners that build RTEP projects establish their annual revenue requirements either through a formula rate or a separate rate filing approved by FERC.

Q. HOW DOES PJM ALLOCATE COSTS FOR RTEP PROJECTS?

A. PJM allocates the revenue requirements for RTEP projects by one of two methods, depending on the scope of the project. PJM uses a beneficiary pays approach for new facilities that operate below 500 kV (Lower Voltage Facilities) and allocates on a region wide basis, i.e., “socializes”, the cost of new facilities that operate at or above 500 kV (Regional Facilities). The costs of certain lower voltage facilities necessary to support the new Regional Facilities (Necessary Lower Voltage Facilities) are also allocated on a region-wide basis. PJM designates, in Schedule 12-Appendix, the zonal cost responsibility for Regional Facilities and other facilities allocated using the beneficiary pays method. The Regional Facilities’ costs are allocated among the PJM Zones on an annual load-ratio share basis. The cost responsibility allocated to each zone for all RTEP projects is charged to NITS customers based on their respective Network Service Peak Load (NSPL) shares of the zonal load. As of December 2009, PJM Schedule 12 Appendix shows that the AEP Zone share of socialized Regional and Required Lower Voltage Facilities costs will be 17.97% in 2010, of which 86.7% will be charged to AEP for its retail loads. Based on project revenue requirements being billed currently, AEP expects to be charged at least $19 million during 2010 for Schedule 12 projects.

Q. PLEASE DISCUSS THE LEVELS OF TRANSMISSION CONSTRUCTION AND SCHEDULE 12 CHARGES BEING INCURRED BY AEP, AND THE TREND EXPECTED IN THOSE CHARGES OVER THE NEXT FEW YEARS.

A. My Exhibit I&M - 42 (DWB-2) contains two bar graphs. The first (top) graph shows the annual transmission capital expenditures that I estimate the various facility builders will incur through 2014, based on PJM's currently approved RTEP. The second (bottom) bar graph shows the annual cost I estimate PJM will bill to the AEP East Companies for those projects. These graphs show the annual capital expenditures increasing from about $700 million in 2008 to nearly $7 billion in 2014, causing AEP's charges to increase sharply from $4.6 million in 2008 to approximately $160 million in 2014. The estimated annual charges increase in-step with construction spending because the builders of the largest projects have received FERC approval of formula rates that include collection of a current return on construction work in progress (CWIP). The 2007 through 2009 charges are based on AEP's actual bills, while the 2010 through 2014 projections reflect the total project costs published by PJM, estimated annual construction spending, and a 15% annual carrying charge rate, which represents an estimate of the return, taxes, O&M and other costs of service.

Q. HOW WILL THE U.S. COURT OF APPEALS, 7TH CIRCUIT, REMAND OF FERC'S DECISION TO SOCIALIZE NEW REGIONAL FACILITIES IMPACT I&M'S COSTS FOR TRANSMISSION SERVICE?

A. How or even whether the remand will impact I&M's costs for PJM transmission service is not known. The Court basically said that FERC, in its Order approving socialization of costs for Regional Facilities, did not identify the evidence needed to support its decision. There are a number of possible outcomes. FERC might determine that the record needs to be supplemented, in which case it would permit parties to submit evidence for and against the socialization before issuing a new decision. FERC might also decide that the record already contains the evidence needed to support the prior or a revised decision, and proceed to address the remand without taking in additional evidence. In any case, I&M will be subject to the present charges in the meanwhile, and should have the opportunity to recover the costs. Until a final un-appealable order (Final Order) is approved, the Schedule 12 charges will be subject to refund. Tracking of the Schedule 12 charges through the PSCR process is especially appropriate, given that a Final Order may be some time away. Inclusion of these costs in the PSCR means that I&M and the MPSC will have a method already in-place by which to make adjustments to Michigan retail customer bills, should the FERC change the allocation of the RTEP facility costs in such a Final Order.

VI. PJM EXPANSION AND RTO START UP COST RECOVERY CHARGES

Q. WHAT COSTS ARE BEING COLLECTED THROUGH THE PJM EXPANSION COST RECOVERY CHARGES?

A. The PJM expansion cost recovery charges (ECRC) that are billed by PJM, recover costs that PJM originally incurred to expand the RTO's capability to accommodate the addition of new zones that were added during 2004 and 2005. Although PJM incurred these costs, the AEP East Companies, Commonwealth Edison Company (ComEd), the Dayton Power and Light Company (Dayton), and Dominion Virginia Power (Dominion) were required to reimburse PJM. AEP, ComEd and Dayton filed a proposal at the FERC to recover the expansion costs over a ten-year period from all customers of the RTO. The outcome of that case was a settlement pursuant to which customers in all PJM zones except the Dominion Zone pay ECRC rates. Dominion elected not to include its expansion costs in the ECRC charges and was exempted from paying the ECRC charges that implement region-wide recovery of the AEP, ComEd and Dayton costs. The ECRC rates will be collected for ten years, through April 2015, coinciding with the FERC-approved amortization period for the PJM expansion costs.

Q. WHAT COSTS ARE BEING COLLECTED THROUGH THERTO START-UP COST RECOVERY CHARGES?

A. The RTO Start-Up Cost Recovery Charges (SCRC) recover the AEP East Companies' direct costs for RTO development and start-up. That charge is only billed to AEP and other NITS customers in the AEP Zone. The SCRC rate collects the AEP RTO start-up costs and FERC-approved carrying costs over a fifteen-year amortization period.

VII. DEFAULT ALLOCATIONS ASSESSMENTS

Q. WHAT ARE THE DEFAULT ALLOCATION ASSESSMENTS?

A. Default allocation charges occur when PJM has uncollectible accounts; these amounts are allocated under Section 15.2 of the PJM operating agreement. When PJM allocates such costs to AEP, recovery of I&M's share of those costs allocated to the Michigan jurisdiction through the PSCR is appropriate.

Q. DOES THAT CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

TODD D. BUSBY

PRE-FILED DIRECT TESTIMONY OF TODD D. BUSBY
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Todd D. Busby. My business address is 155 W. Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by American Electric Power Service Corporation (AEPSC) as Senior Vice President – Commercial Operations, for American Electric Power Service Corporation (AEPSC). AEPSC is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Indiana Michigan Power Company (I&M, or "Company"). AEPSC supplies engineering, financing, accounting and similar planning and advisory services to AEP's eleven electric operating companies, including I&M. As Senior Vice President – Commercial Operations, I am responsible for wholesale energy marketing, energy trading, and market operations, as well as commercial and financial analysis. Commercial Operations offers AEP's generating units into the PJM Interconnection, L.L.C. RTO (PJM[1]), dispatches its generating fleet in coordination with PJM, and engages in market operations, first in order to

[1] PJM Interconnection, LLC is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. AEP is both a transmission provider and a market participant in the PJM energy market. Charges and credits associated with serving AEP's native load and off-system sales are invoiced ("settled") to AEP by PJM.

produce energy for AEP native load customers, and then in support of Off-System Sales (OSS) margins. In addition, Commercial Operations engages in trading of energy commodities.

Q. Please briefly describe your educational and business experience.

A. I graduated from Stephen F. Austin State University in Nacogdoches, Texas with a Bachelor of Business Administration. Prior to joining AEP, I worked for a subsidiary of Enron Corporation, in various risk management, structuring, and accounting positions. In 2001 I was employed by AEP in Commercial Operations, with management duties that included overseeing structuring, portfolio and margin analysis, RTO (Regional Transmission Organization) and commodity settlements, contract administration, and generation forecasting. Prior to being assigned my current position, I was Vice President, Energy Trading and Marketing, with responsibility for managing AEP's economic risk associated with electricity, coal, natural gas, and emissions positions, as well as electricity marketing, within and adjacent to AEP's service territory. I was promoted to my present position in January, 2010.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support I&M's proposed treatment of OSS margins under the Power Supply Cost Recovery (PSCR) clause in Michigan and to describe Commercial Operations' role in managing and optimizing OSS margins. More specifically, my testimony will describe the following:

- The proposed treatment of OSS margins under the sharing mechanism.

- The reasons why a sharing mechanism for OSS margins makes sense, and why it provides a balance of risk and reward, along with appropriate incentives, to the benefit of both customers and shareholders.
- A description of OSS margins, the manner in which they are produced, the various trading instruments used, and the different markets in which Commercial Operations is actively involved.
- How the wholesale market has substantially changed since the time of I&M's last rate case nearly 20 years ago, and how the character and magnitude of those changes has fundamentally transformed the way in which OSS are produced and managed.
- The complexities and risks of operating in the competitive wholesale environment that exists today, and how, by actively managing those risks, AEPSC creates significantly more OSS value for the customer than would be created if it did not manage the risk.
- The benefits that customers receive as a result of Commercial Operations' activities, and the appropriateness and fairness of I&M's 50%-50% sharing proposal in the PSCR clause.

My testimony will demonstrate that price volatility in the current wholesale power markets, and the associated risks, warrant that OSS margins be shared fairly and equally between I&M's Michigan customers and I&M.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits.

- Exhibit I&M-43 (TDB-1): Different Types of Risk Managed by AEPSC.
- Exhibit I&M-44 (TDB-2): Cumulative Change in Net Summer Capacity from Natural Gas (1995-2007).
- Exhibit I&M-45 (TDB-3): Type of Fuel Used by Marginal PJM Unit (January 1999-September 2009).
- Exhibit I&M-46 (TDB-4): Historical Price of NYMEX[2] Natural Gas Contracts and Volatility (April 1990-October 2009).
- Exhibit I&M-47 (TDB-5): Historical Price of NYMEX Coal Contracts and Volatility (July 2001-October 2009).

These exhibits were prepared by me, or under my direction and supervision.

I. Current OSS Treatment and Proposed Sharing Mechanism

Q. What is the present treatment of OSS Margins?

A. **Table 1** below summarizes the current OSS Margin treatment for I&M Michigan rate areas.

Table 1: Current Treatment of OSS Margins:

St. Joseph	100% to Customers	OSS Margins are currently part of the PSCR clause, and thus 100% of the margins are returned to customers. Established at the time of the Settlement Agreement February 12, 1991, Case No. U-9656
Three Rivers	100% to Company	OSS Margins are not in the PSCR, and thus 100% of OSS margins are retained by I&M. (Settlement Agreement was March 9, 1989, Case No. U-9205.)

[2] New York Mercantile Exchange is the world's largest physical commodity futures exchange. NYMEX-quoted prices for transactions on the exchange are the basis for prices paid for various commodities throughout the world.

As **Table 1** illustrates, OSS margins are presently treated in entirely opposite manners in each of the I&M Michigan jurisdictions: 100% of OSS margins offset fuel costs in St. Joseph, while all margins are retained by I&M in Three Rivers.

Q. What is the Company's proposed treatment of OSS Margins?

A. With this filing, in conjunction with unifying the treatment of I&M's St. Joseph and Three Rivers service territories under the PSCR clause, as described by Company witnesses Murray and Krawec, I&M is proposing to implement an OSS sharing mechanism to the PSCR clause for St. Joseph and to expand the mechanism to Three Rivers as well, with the OSS components of the PSCR to be shared equally (50%-50%) between I&M's St. Joseph/Three Rivers jurisdictional customers and the Company. Greater detail concerning the mechanics of how the OSS sharing proposal will work is provided by Company witness Krawec.

As mentioned in the testimony of Company witness Krawec, the ratemaking treatment of the Company's 50% share of OSS margins will serve as an incentive for continued optimization of these margins. I will further explain the need for an incentive later in my testimony. In order to reflect the proposed 50%-50% sharing, the 2010 projected test year PSCR costs, as described by Company witness Allen, include 50% of forecasted OSS margins. On an I&M total company basis, the amount is $35.7M, as presented in Company witness Allen's Exhibit I&M-28 (WAA-5), Line 26 Company witness

Allen provides a list of the current OSS margin accounts subject to sharing that the Company proposes to include.

II. Rationale for Sharing of OSS Margins

Q. Why does the situation today need a rate treatment that is different from the traditional ratemaking treatment?

A. In the past, the underlying rationale for the traditional wholesale energy marketplace was reliability-focused, and based on energy that physically flowed. OSS transactions were not as significant and carried very little risk or volatility. As I will describe in greater detail later in my testimony, changes in the wholesale market have introduced risk into many parts of the utility business; and these risks exist whether they are actively managed or not. As part of the AEP System, AEPSC, on behalf of I&M, has taken the initiative, incurring both the cost and the risk, to build a group called Commercial Operations. This group participates in the wholesale electricity market by blending the traditional physical OSS view with proactive management of the significant amount of risk in these new operational and wholesale markets. With the proposed modification, the Company receives a reasonable benefit for its contributions, as well as a reasonable incentive to continue to optimize OSS margins by effectively managing the risks and volatility inherent in the wholesale power markets as they exist today.

Q. Why does the current treatment of OSS Margins within the PSCR clause fall short of addressing the current realities?

A. There are two core aspects of I&M's Michigan OSS margins that need to be addressed; the PSCR does a good job of handling the first, but currently fails to address the second. The first issue is the volatility and materiality of the OSS margins. OSS margins are a much larger component of revenue than in the past, and, as the recent economic downturn shows, changes in the wholesale energy market are largely beyond the utility's control. In order to support the financial strength of I&M, for the benefit of both customers and the Company, OSS margins are most effectively accounted for through a tracking mechanism, The purpose of a tracker mechanism is generally to mitigate the effects of a cost component that is significant, volatile, and largely outside the control of the utility, and the PSCR successfully fills such a role.

The second issue is the equitable distribution of OSS margins between customers and the Company. As the PSCR currently functions for St. Joseph, the Company is provided no financial incentive for the continued optimization of OSS margins, and receive no recognition for the creation and development of the integrated and highly successful Commercial Operations function. Therefore, a tracker alone does not provide the balance of incentive and reward that a 50%-50% sharing mechanism offers.

Q. Can you explain further the reasons why sharing of the OSS margins balances risk and reward?

A. Just to operate in today's wholesale energy market, AEPSC must manage a significant amount of risk. AEPSC engages in energy transactions, and hedges the output of its economic generation in order to optimize OSS margins and manage the associated risks. I&M benefits from AEPSC's Commercial Operations organization, which has invested in systems and personnel to manage these risks while continuing to optimize OSS margins. But for AEPSC to continue to assume the incremental risk necessary to optimize OSS margins, it is logical to conclude that it must be able to continue to participate in the margin created by this activity in a way that makes sense for both customers and the Company. It is important to remember that the path to the formation of Commercial Operations was not the only path available. Had AEPSC not taken the initiative to establish that expertise, the level of OSS margins that have been experienced in the period since I&M's last case would likely have been much lower. Had Commercial Operations' efforts in the market failed, then the OSS customer benefits that have been realized since would not exist, and AEPSC would have suffered a loss of any resources invested in establishing the group.

Q. Could you please summarize the Company's rationale, and some of the benefits of sharing the margins from OSS on a 50%-50% basis?

A. The proposed OSS Sharing mechanism provides a fair incentive, and is the best way to balance the risks and rewards associated with the wholesale power markets. A level of OSS margins cannot be guaranteed, and a rate treatment must recognize the potential impact of a situation where the customers do, in part, share responsibility for the uncertainty and potential shortfall of a component that is so closely linked to the volatility of the wholesale power market. It is important to have an OSS mechanism that does not expose I&M to unreasonable financial risks which could vastly outweigh any potential benefits.

Examples of the benefits of a 50%-50% sharing of OSS margins include:

- **Volatility Management:** The sharing mechanism within the PSCR helps to mitigate the effects of a cost component that is significant and volatile. Risks are shared equally in a sustainable way, whether the level of margins is high or low.
- **Appropriate Incentives:** The existing PSCR mechanism compensates for the risk associated with provision of retail service only. Commercial Operations' activities extend beyond the obligation I&M has as a retail utility. Activities which optimize assets that present corresponding benefits to the customers deserve to be encouraged, with the benefits shared by both customers and Company. Referring back to **Table 1**, the present treatment of OSS margins in St. Joseph does not provide any incentive for a utility to take on added risk in order to optimize OSS margin, and allows I&M's retail customers to participate in wholesale market gains simply because they are users of the retail service. Incentives are likewise distorted by comparing the treatment in Three Rivers, where 100% of OSS margins remain with the Company, failing to recognize that activities that produce OSS margins are

inherently integrated with the optimization of the generating fleet in the wholesale market, as I will describe in my testimony. In Three Rivers, the customer does not share in margins, yet the risk that the utility takes in creating those margins is still there. Neither of these approaches is fair or sustainable.

- **Materiality:** OSS margins are material to the financial health of the Company. The 50%-50% sharing proposal balances the risk of fixing retail rates that are tied to OSS margins that may not be sustained. As recent history has shown, there is no guarantee of OSS margins, and for the reasons explained earlier, it is not good ratemaking policy to create a dependence on a fixed cost in the retail rate structure that could harm the financial health of I&M, and which could also put at risk the operating cash flow needed to provide reliable service to customers. **Table 2** illustrates that, based on projected 2010 I&M OSS margins and Net Operating Income identified in Company witness Allen's Exhibits I&M-24 (WAA-1) and I&M-28 (WAA-5), 50% of I&M's OSS margins represent 16% of Net Operating Income.

Table 2: Impact of OSS Margins
Relative to Projected I&M Net Operating Income: 2010 ($M)

Projected 2010 I&M Net Operating Income (from Company witness Allen's Exhibit I&M- 24 (WAA-1), Page 2, Line 19)	$221.1
Projected 2010 Total I&M OSS Margin (based on 50% OSS Margin, Company witness Allen's Exhibit I&M-28 (WAA-5), Line 26)	$71.4
Projected 2010 I&M OSS Margin (50%) (from Company witness Allen's Exhibit I&M-28 (WAA-5), Line 26)	$35.7
% of Net Operating Income (Based on 50% of OSS Margins	16%

Total OSS margins that represent about one-third the magnitude of Net Operating Income is a reminder that any shortfall in earnings could raise the cost of capital for I&M, which can negatively impact customers through future rate increases. The proposed OSS sharing mechanism provides a prudent incentive for AEPSC to achieve a level of OSS margins while providing an equal benefit to the customer. Both customers and the Company have a mutually shared interest in reducing the impacts of a shortfall in OSS margins.

- **Fair and Sound Rate Design:** OSS include not only the sale of electricity from all AEP generating units, but also the resale of power purchased from non-AEP companies, and the margins from trading activities. Thus, OSS margins include both asset-based and non asset-based transactions. The provision of retail electric service should reflect the cost of providing that service, and margins based on wholesale energy transactions should not be used to mask those retail costs. In recognition of the integrated nature and mutual benefit of OSS activity, as I will further describe in my testimony, a 50%-50% sharing mechanism is a just and fair way to ensure that base rates for retail service are based on the cost of providing that service. Customers retain the advantages of OSS margins, while being shielded against a negative outcome.

Q. Is there a limit on the OSS margins that can be credited to the I&M customer?

A. No. Equal sharing of the OSS margins provides AEPSC with an incentive mechanism to optimize the margins in a manner that will benefit I&M customers and provide a reasonable reward to the Company as well.

Q. Are there other reasons why the proposed 50%-50% OSS modification to the PSCR is appropriate?

A. One of the greatest challenges arising over this past year has been managing the current downturn in the economy, which has resulted in the thinning of creditworthy counterparties in the market. AEPSC, as agent on behalf of I&M is tasked with managing and optimizing the value of the Company's generating assets while simultaneously confronting significant and volatile costs. OSS can potentially be a large component of revenue. But, as the recent economic downturn has shown, there are still many factors that are beyond the control of the utility even though AEPSC actively manages the risk associated with the wholesale power market. For example, even though PJM has forecast an economic rebound in 2010, even given that assumption, PJM's most recent

(2009) load forecast estimates that peak load will not recover to above 2008 levels until 2011.

III. Detailed Description of OSS Margins

Q. Having generally discussed the Company's proposal, could you go back and provide a detailed description of OSS Margins?

A. OSS margins are the net profit that results after taking the total revenue from all sales made to non-affiliated counterparties, and subtracting out the variable costs of making those sales. For example, sales to non-affiliated counterparties may include the sale of electricity from AEP generating units, the re-sale of purchased power, or margins from financial products such as swaps[3]. Variable costs may include the cost of fuel, variable operating and maintenance (O&M) costs, purchased power, emissions credits, or costs associated with entering into a financial product.

Q. Are OSS margins created simply from selling surplus energy into the wholesale power market?

A. No. As I will describe further in my testimony, sales of surplus energy are just one way that OSS margins are produced. Even that activity, selling surplus energy, requires a complex skill set and is much more complicated in today's competitive wholesale markets than it was at the time of I&M's last rate case in Michigan. As I will further explain, the growth of Regional Transmission

[3] A swap, also known as a "contract for differences" or as a "fixed-for-floating" contract, is a financial trading instrument in which the two counterparties exchange one stream of cash flow for another stream. Swaps can be used for hedging purposes or for trading.

Organizations (RTOs), and of non-traditional and non-utility participants (that do not seek physical electricity for either their own, or their customer's needs) have resulted in an array of market impacts that must be known and understood. The risks of the wholesale market cannot be entirely avoided, but they can be prudently managed.

Q. Please describe physical OSS margins.

A. Physical OSS margins are best defined as the difference between AEP's cost of electricity sold and the revenue received for electricity that physically flows. The cost of electricity sold can be either the cost of AEP's generation (these costs would include the variable costs of operating, plus any PJM charges and credits), or purchased power costs. The revenues are derived from wholesale energy sales, hedging activities associated with AEP's generation, and trading and marketing efforts that settle physically. Therefore, as I will further explain, sales of surplus energy from the AEP generation fleet are but one way that OSS margins are generated.

Q. Do all OSS transactions result in the physical flow of electricity?

A. No. Many of the megawatt-hours (MWh) involved in AEPSC's OSS trading transactions are never physically delivered, but are simply transactions, either buying or selling, in the wholesale electric energy market. These may include physical transactions that are "booked out", as well as purely financial transactions that do not contemplate physical flow. A "booked out" transaction occurs when AEP has a purchase and sale of the same quantity for the same specific delivery period at the same specific delivery point. The offsetting sale and purchase transactions are financially settled rather than physically delivered resulting in "booked out" transactions. These transactions underscore the fact that it is extremely difficult to separate the impact of physical transactions versus financial transactions.

Q. Can you provide examples of activities that can have both physical and financial components?

A. Many hedging transactions or short-term transactions are based on AEP's load and generating unit commitment profiles. The rationale for the transactions includes both a physical and a financial aspect, such as in the following examples:

Example 1: Hourly Trading: Within the trading group, Hourly Trading is responsible for managing AEP's intraday financial exposure to PJM's real-time Locational Marginal Price (LMP) in order to optimize margin. For example, if a generating unit is suddenly lost, PJM will settle the deviation financially at the real-time LMP. Hourly Trading is essentially responsible for managing the resulting "short" position by estimating LMP throughout the day and, if necessary, making spot market purchases of available energy from counterparties, in close coordination with Generation Dispatch, Production Optimization, and others within Commercial Operations.

Example 2: Managing Risk of the Fleet Due to Outages: Day-today operational strategies rely on input from the trading group. For example, are real-time prices expected to be higher or lower than day-ahead prices? Are there adequate "hedge" Megawatt-hours (MWhs) if there is an unexpected unit outage? What is the aggregate risk of the fleet regarding outages or curtailments? The confidence of having a solid expectation of market prices, and the transactions that trading may implement, are an essential part of the integrated nature of the financial and physical decisions.

Example 3: Selling Forward: The ability to financially "sell forward" economic generation provides the opportunity to lock in positive margins associated with price spikes in the forward market that could not be captured otherwise. Periodically, power price anomalies may occur, due to weather or natural gas storage volumes, for example. If, based on experienced analysis, prices are not supported by fundamentals, margins from physical generation may be captured for future periods through either physical or financial forward sales. Selling forward also lessens the volume of AEPSC's physical generation exposed to real-time price volatility, decreasing exposure to short-term market prices.

Again, it is extremely difficult to separate the impact of physical transactions versus financial transactions. Because AEPSC transacts both physically and financially, looking at solely physical or financial transactions does not provide an accurate indication of impact of Commercial Operations' activity. However, when the physical and financial transactions are considered as a whole, it results in a situation where "the sum is greater than the parts".

Q. How does Commercial Operations create OSS Margins in the Wholesale Power Market?

A. AEPSC's Commercial Operations group utilizes trading instruments such as swaps and options, actively following the developments in other commodity markets and other factors that influence the price of electricity. Commercial Operations also participates in competitive energy auctions outside of AEP's service territory in PJM and in the Midwest Independent Transmission System Operator, Inc. (MISO). This provides an additional revenue stream and additional margins that I&M would forego without Commercial Operations' trading and marketing capabilities within AEPSC. The following list identifies the broad set of activities that contribute to OSS margins, and shows how AEPSC's role has expanded beyond merely selling surplus energy, to a broader scope of employing various methods to create OSS margins.

- Optimizing effective operation in PJM
- Auction Participation
- Basis Trading
- Time-Spread Trading

- Trading Spark Spreads[4]
- Physical Sales of Surplus Energy (which now includes Hedging)

As mentioned, in Michigan and elsewhere, many utilities are less active than AEP. While others have spun off their trading and marketing arm into a separate, deregulated entity, AEP chose its integrated path based on the view that a coordinated approach between jurisdictional and non-jurisdictional activities would result in significant synergies. Today, physical sales of surplus energy are but one way that OSS margins are created.

IV. Changes in the Wholesale Market and Impacts

Q. What was the environment like at the time of I&M's last base rate case in Michigan?

A. During the time period of I&M's last rate case, the trend was that OSS margins were a much smaller piece of the Company's total revenue, and there was significantly lower price volatility and much less volume in the markets where these transactions occurred. The traditional marketplace in which OSS were made had the following important characteristics:

- Limited competitive wholesale market. Most utilities managed hourly and emergency energy sales with a focus on the reliability of their own control area operations.

[4] Spark spread indicates whether it makes economic sense for power to be produced, *i.e.* the theoretical gross margin of a power plant per MWh, based on production costs of fuel alone. All other costs (operation and maintenance, capital and other financial costs) must be covered from the spark spread. Spark Spread = Price of Electricity - [(Cost of Fuel) * (Heat Rate)] = $/MWh - [($/MMBtu) * (MMBtu/MWh)]

- Virtually all transactions were conducted between utilities that had direct interconnections with one another.
- Sales were made from a utility's excess physical generation.
- There was much greater price stability.
- Energy sales were generally contracted over very short timeframes.
- Transactions could be cancelled without penalty if the seller needed to retain the energy for system load.
- Economy sales were conducted using the "golden rule" – if you could help out a neighboring utility by selling them some excess energy, at a split between your current marginal cost and their current marginal cost, then the transaction was made.

Simply comparing sales made in the 1990s and the wholesale transactions made today would greatly distort the realities of the current marketplace. The character and magnitude of the changes in the wholesale power market have fundamentally altered the way in which OSS are produced and managed. Correspondingly, the ratemaking treatment should recognize the differences.

Q. How did the wholesale power market evolve into what exists today?

A. The Energy Policy Act (EPAct) of 1992 triggered a series of Federal Energy Regulatory Commission (FERC) actions and orders aimed at developing a fully competitive market for wholesale transactions. FERC issued Orders 888 and

889 in 1996, which dramatically opened access to the transmission system to whole new classes of generation providers. Later, FERC issued Order 2000 which further expanded the process of opening up the nation's transmission grids, and called for the creation of RTOs throughout the United States. Today, RTOs and Independent System Operators (ISOs) cover all or part of 35 states. The RTOs/ ISO's in the Eastern Interconnection serve a total of 124 million customers. PJM, of which I&M is a member, is the largest centrally dispatched electric grid in North America. The growth of RTOs has fundamentally changed the way member utilities handle day-to-day operations, including OSS. **Table 3** contrasts the major factors that have changed since I&M's last rate case in Michigan.

Table 3: Significant Changes in the Wholesale Energy Environment

Factor	**I&M Michigan's Last Rate Case**	⇨	**I&M Michigan's Current Rate Case**
1) Role of Physical Generation	Virtually 100% of OSS margins were from sales of surplus energy	⇨	AEP East OSS volume (on a MWh basis) from surplus energy varied from 2 to 17% of OSS activity from 2000-2008
2) Volatility	Very Low	⇨	Very High
3) Role of RTOs	Did not exist-transactions were focused on reliability of own control area	⇨	RTOs now cover all or part of 35 States. In addition to coordinated planning and operation of the transmission system, the RTO coordinates economic and reliable dispatch of generation, manages transmission congestion for efficient operation of the grid, and provides markets for capacity, energy, and ancillary services for the reliable operation of the grid
4) Modes of Conduct	The "Golden Rule"	⇨	Economically Competitive Markets – Optimization of Margins
5) Potential Counterparties	Primarily Neighboring Utilities	⇨	Traditional wholesale market, plus: Merchant generators, power marketers, banks, and hedge funds
6) Generation Capacity Compared to Peak Demand	I&M Internal Peak Load (3,306 MW) was 66% of I&M Primary Capacity in 1990.	⇨	I&M Internal Peak Load (4,264 MW) was 83% of I&M Primary Capacity in 2009
7) OSS Margins	OSS margins were not a significant component of revenue. OSS Margins from Three Rivers, which owned minimal generation, did not exist at the time of the last rate case in 1991.	⇨	50% of OSS margins ($35.7M) represents 7% of total Power Supply Costs (based on 2010 forecast year PSCR costs identified in Company witness Allen's Exhibit I&M 28 (WAA-5)

As a more competitive nature in the wholesale power markets began to emerge, it led to the growth of non-traditional and non-utility market participants. These participants included merchant generators, power marketers, and later, hedge funds and banks. These non-traditional market participants sought to make profits by trading wholesale electricity in volatile markets. They did not seek physical electricity merely for meeting their own, or their customers' end use requirements. Trading energy for profit was the primary goal of many of these market participants. Many liquid trading hubs arose, and volume of energy traded increased enormously after 1996, with the final FERC Order No. 888.

Today, non-traditional market participants, financial products, and RTO-created markets affect the wholesale electricity markets. As new markets have formed, new trading hubs and energy-related trading products have developed, and new market participants have continued to multiply. The markets have matured greatly since their inception, but so has their complexity and volatility. Ultimately, today's marketplace offers a greater amount of risk and reward, but to capitalize on the potential value, a participant must have an organization with the capability to compete effectively and to properly handle the associated risks.

V. Complexities and Risks of the Wholesale Market

Q. What are some of the risks that AEPSC must face in current wholesale power markets?

A. Not only is there the extreme volatility of electricity inputs, which I will further detail, but with the multitude of new market participants, the increase in non-creditworthy market participants, the growth of RTOs/ISOs, the development of various trading hubs, the introduction and rising importance of financial trading instruments, and the changing market rules, there is an array of forces that tend to increase the level of risk associated with the wholesale power markets. Exhibit I&M-43 (TDB-1) identifies the different types of risk encountered and appropriately managed by AEPSC. I will explain how, by actively managing those risks, AEPSC creates significantly more OSS value than would be created if it did not manage the risk. Having the appropriate risk measures in place limits the downside risk exposure to the customer and the Company.

Q. Can you provide examples of the volatility that occurs in today's competitive wholesale market?

A. Price volatility ("Price Risk") is but one example of a market risk that AEPSC's Commercial Operations group manages. Volatility, referring to price changes over time, is a reflection of the degree of price risk faced by a company. Observing the volatility of the components that drive electricity prices, such as natural gas, coal, and emissions allowances, as well as market demand, is one of the easiest ways to see how much things have changed in the wholesale electricity markets in the last two decades. Natural gas-fired generation increased, and began to have a greater influence on the price of electricity in the Midwest in the early 2000s. Exhibit I&M-44 (TDB-2) shows a graph of the cumulative change in capacity from natural gas compared to all sources over the years 1995-2007. As shown by the graph in this exhibit, nearly all new capacity being brought on line was natural gas-fired. Increasingly natural gas fired generation was “on the margin”; that is, the marginal cost of supplying the next increment of power demand was determined by a natural gas-fired generating unit. Exhibit I&M-45 (TDB-3) illustrates that the percentage of gas units setting the marginal price in PJM has grown since 2000, peaked in 2004, and has remained high since then. The sustained high level of gas-fired generation has caused the wholesale price of electricity in PJM and other RTOs to be heavily dependent on the volatile pricing of natural gas. Exhibit I&M-46 (TDB-4) provides the dollar per MMBtu at which natural gas contracts were traded from April 1990 through October 2009 along with the volatility of these prices. The natural gas contract prices shown in the exhibit, have ranged from a low of $1.05/MMBtu in 1992 to a high of $15.38/MMBtu in 2005.

NYMEX Coal prices have also shown a high degree of volatility. Exhibit I&M-47 (TDB-5) provides the dollar per ton at which coal contracts were traded from July 2001 through October 2009 along with the volatility of these prices. Coal contract prices shown in the exhibit, have ranged from a low of $23.10/ton in 2002 to a high of $143.25/ton in 2008.

Volatility provides clearer signals for what issues are impacting the cost of electricity now, and the expectations of those impacts in the future. However, volatility needs to be evaluated constantly to understand the reasons behind it, and the best means to mitigate its effects. The lack of ”storability”, namely, that the supply and demand of electricity must be perfectly balanced at all times, makes it unique among commodities. One of the key ways that Commercial Operations optimizes OSS margins is by anticipating and reacting to the factors that cause volatility. Changes in the input components that might make our surplus energy less competitive in the wholesale market can create opportunities for other areas that contribute to OSS margins, such as trading financial derivatives associated with those inputs.

Q. In addition to volatility, what are some specific examples of how risk affects operations in the wholesale market?

A. Referring to Exhibit I&M-43 (TDB-1), other Market Risks include:

Credit: As the transaction will involve two counterparties, there is the risk that the counterparty may not have the ability to pay its obligations. AEPSC employs extensive and stringent credit analysis in order to manage credit risk. AEPSC's Credit Risk group independently monitors Commercial Operations' exposure to counterparty credit risk on a daily basis.

Counterparty Performance: The specific counterparty may not be able to deliver on a contracted transaction, such as in the case where an independent power producer's generating facility experiences a forced outage. Or, transmission congestion may prevent the delivery of contracted energy.

Volumetric Risk: Relative to the wholesale power market, there is volumetric risk associated with unanticipated variations in load obligations, or in the availability of generation. AEPSC manages these variations through its trading activity.

Basis Risk: Prices are based at numerous and liquid trading hubs. Thus, the basis risk results from the possibility that the market price will vary as a result of associated congestion costs, for example, between the generation source and the delivery point.

Although this does not constitute an exhaustive list of the risks that are confronted in the wholesale power market, these are the primary risks that AEPSC faces on a daily basis.

VI. Responses of Utilities to the Wholesale Market

Q. How has the changing environment of the wholesale market affected AEP?

A. Prior to the expansion of the wholesale power markets, AEP performed traditional activities such as unit dispatch, accounting, and settlements of physical transactions. However, in the changed environment of the energy market, activities such as unit dispatch and coordination of generation now carry considerable financial consequences, due to the risks I have described, and the added complexity of participation in PJM which I will further describe.

Q. Has AEP has chosen an integrated approach to the expanding wholesale power market?

A. Yes. Currently, instead of creating an entirely separate organization to take on the risks and rewards of the changing markets, AEP leverages its existing operating expertise, in conjunction with traditional knowledge, to provide an optimized benefit. In order to successfully compete against non-traditional market participants and address continually evolving market conditions, AEPSC has transformed the traditional commercial skill set of those engaged in OSS transactions. The presence of commodity traders, risk management experts, as well as accounting, credit, and legal experts who are versed in the contractually-based commodity environment makes Commercial Operations an experienced trading and marketing organization. To enhance this organization, AEPSC has purchased and built sophisticated risk management, market risk oversight, as well as scheduling and trading capture information technology systems. AEP also uses an independent market risk oversight staff to monitor the implementation and adherence to Commercial Operations risk policies, procedures, and risk levels on a daily basis. As the markets have evolved, the Commercial Operations organization has continuously been structured to meet the ever-changing environments of the wholesale power markets.

The different ways in which individual utilities have responded to those external changes also added layers of complexity. AEPSC's structure for Commercial Operations is just one of a variety of ways utilities around the country manage OSS. AEP chose its path, based on the optimization of OSS margins through integration, believing that leveraging existing operating expertise in traditional utility activities with active participation in the competitive market would provide the greatest benefit. The belief then, as it is now, is that "the whole is greater than the sum of its parts".

Q. What was the response of other utilities to the changing environment of the wholesale market?

A. In contrast to AEP's integrated approach, other utilities in Michigan took different paths. DTE Energy Company, the parent company of Detroit Edison Company, has spun off their trading and marketing activities entirely into an unregulated arm. DTE Energy Trading, a wholly-owned subsidiary of DTE Energy, is an active participant in the physical and financial market for energy and natural gas in the Midwest, Northeast, and Texas markets. However, unlike I&M's approach, the margins from these activities benefit DTE, not customers.

CMS Energy Corporation, although it owns and operates significant independent power generation, exists primarily as a regulated utility in Michigan, through its subsidiary, Consumers Energy. It does not extensively engage in trading activities, having exited the speculative wholesale energy-trading business. Its former trading unit, now known as CMS Energy Resource Management, continues to market wholesale energy from assets owned by the parent company.

AEP, with this request, believes that our approach incorporates the best of both options, and ultimately provides the most benefit to the customer, given the realities of the wholesale energy market as it exists today. The activities of

Commercial Operations not only impact OSS margins, but are also closely linked with the optimization of the entire generating fleet, as I will explain further. In order to perpetuate this model, however, there needs to be a fair and equitable sharing of OSS margins.

VII. Managing and Optimizing OSS Margins in the PJM RTO

Q. How has AEP's participation in PJM increased the complexity of producing OSS margins?

A. Joining PJM has added another layer of complexity to the marketplace in which AEP must operate. PJM's operation of AEP's (and other utilities') high voltage transmission system and PJM's dispatch instructions to AEP units are based on a reliability-constrained, economic approach for the entire PJM footprint. From an operational standpoint, by joining PJM, Commercial Operations must evaluate complexities in order to deliver reliable, reasonably-priced electricity for AEP's customers and to optimize OSS margins. Demand for energy, and the amount and price of energy available to be purchased from the marketplace (*i.e.*, the PJM RTO) impacts the security-constrained, economic dispatch of the AEP generating fleet by backing down (or keeping off-line) units that are not economic. This is the basis for the PJM market awards, and an overall benefit to customers, in that it reduces the collective cost of generation. However, the impact of PJM market awards relative to MWhs available to meet load obligations, and energy available for sale in the forward and spot energy markets, results in a significant amount of risk, which must be understood and managed.

Q. Please explain how AEPSC applies the trading and risk management skills it has developed to the PJM market.

A. PJM operates what is referred to as a "two settlement" system. This means that market participants must indicate by noon the day prior to the operating day what their PJM load and generation resource mix will be the following day. Companies submitting such a load and resource mix to PJM will receive the results of PJM's reliability-constrained economic dispatch run and will become financially committed to abide by the price and volume commitments they receive from PJM at 4:00 p.m. on the day prior to the operating day. PJM will then settle with market participants against their day-ahead commitments for volume and price based on their actual volume relative to the price that is realized during the operating day. Thus, the term "two settlement" is used.

An example of the direct application of AEPSC's trading and risk management acumen to operations in the PJM environment would be how AEPSC sets itself up for an operating day. AEPSC must consider where the expected daily bilateral prices are trading for the next day, PJM's expected load forecast relative to AEP's own load forecast, and AEP's related expectation of weather for the following day. Further, Commercial Operations must understand the expected availabilities of AEP's generating units, and the impacts of being "short" or "long" in the real time market.

To highlight additional complexity in the above example, suppose that as AEP entered into the operating day, but then lost two large units, driving up the expectation for prices for the balance of the day. Using its trading expertise, and related position management ability, AEPSC could purchase additional energy (length) in the financial "balance of the day" product in order minimize the impact of its "short" position.

Q. What are some of the ways that AEPSC manages its assets within the complexities of the PJM market?

A. OSS margins from PJM markets are not simply the result of bidding all excess energy that can be sold on an hourly or day-ahead basis into the market with little or no effort by AEP. Rather, to maximize margins in this short-term (*i.e.*, hourly or day-ahead) market, AEPSC utilizes its Commercial Operations group to leverage "traditional" utility expertise, such as engineers with power plant experience, with teams that may consist of PhDs in operations research, financial performance analysts, energy marketers and traders who understand commodity markets, skilled energy market analysts, meteorologists to forecast weather impacts, economists to forecast load/demand, and transmission specialists that can understand physical transmission limitations and congestion. Examples of some issues that are specific to the short-term markets are the: 1) relationship of day-ahead to real-time pricing, 2) generation availability, 3) load variability, 4) unit start-up and shut-down risks, and 5) financial impacts associated with not following the PJM dispatch instructions.

Offering in surplus energy related to short-term physical transactions to optimize OSS margin is much more complex than simply offering the units into the PJM market. As I mentioned above, PJM does not dispatch generating units to maximize OSS for AEP. The dispatch performed by PJM is designed to reliably serve the load within the entire PJM footprint in a least-cost manner for PJM. Therefore, PJM looks to minimize the cost, without sacrificing reliability, across the entire footprint and does not attempt to optimize revenues for individual market participants. It is AEPSC's responsibility to optimize the Company's margins for OSS. Commercial Operations must line up all available resources from a cost standpoint to determine if they will be selected in the market on a daily and forward basis. This is accomplished in multiple ways; traders provide a forward market view, while simulation tools are used to project market prices. All available resources are offered into the market, while keeping in mind the likelihood that PJM will select those units on a day-ahead basis, and considering those units which may have physical constraints that would make it costly to shut down. In addition, Commercial Operations continually evaluates AEP's generating resources on a rolling weekly basis and beyond to avoid costly shut downs and start-ups to ensure lower overall cost to our customers. Commercial Operations has in place real-time monitoring of dispatch accuracy to ensure plants are performing as requested and that dispatchers are optimizing a unit's energy output to relative to market price.

Q. You stated earlier that AEPSC participates in energy auctions. Please explain what is meant by that.

A. Energy auctions are competitive procurement processes to secure the lowest possible market price for the load requirement. Energy auctions can be held for utility customers, aggregated groups such as cities, or even entire states. There are a variety of auction types, and different possible contract provisions sought, such as load-following. AEPSC participates in energy auctions both inside and outside of AEP's service territory in both MISO and PJM, in which AEP's generation is not used as a hedge. These efforts require the extensive coordinated work of various parts of AEPSC, such as trading, marketing, fundamentals analysis, legal, and credit analysis in order to formulate an initial bid. Commercial Operations must analyze the time period of the auction and the requested products for 1) forward capacity and electricity prices, 2) load shape, 3) customer migration risks, 4) volatility of other energy and energy-related markets (natural gas, coal, emissions, etc.) and 5) any other events that may influence price. In the event that AEPSC is awarded a portion of the auction load, it must be hedged with market purchases and managed by the Energy Trading and Marketing group. These auction revenues provide additional OSS margin unrelated to AEP's generation, which is an incremental positive margin that AEPSC would forego without the trading-based ability to appropriately price the transaction and offer at a price that locks in the margin. AEPSC manages the risks and benefits of the obligation to deliver energy at a given volume and price in future periods. This activity is clearly above and beyond simply offering surplus economic energy into the wholesale power market, and this margin is only made possible by the knowledge of market fundamentals.

Q. Explain hedging as it relates to trading.

A. When AEPSC uses the term “hedging” in regard to its trading activity, it primarily means that it is entering into transactions for which AEPSC has an existing “open” position (*i.e.*, an obligation to purchase or sell energy in the future without a matching obligation in the other direction that protects from effects of change in the price of the asset) and wants to lock in the margin on that position. An example of a hedge transaction would be one in which AEPSC “sells forward” (at an agreed-upon future time) surplus energy that it has for a particular period. In this example, the surplus energy would be AEPSC’s “open long” position. By entering into a sale for that same period, AEPSC would be “closing” its position. Hedging is a way to mitigate risk; however, not all risk can be eliminated. For example, in the event that several additional units needed to come off-line during the "hedge" period, then AEPSC would have an open position to manage. Even hedge transactions must be constantly monitored and appropriate actions taken when faced with a fundamental change in the generation portfolio, and/or market conditions.

Prior to the growth of the wholesale energy markets over the past decade, AEP and other utilities would hedge uncommitted generation to some degree, primarily through long-term firm or monthly physical sales to traditional municipal, cooperative, and investor-owned utility customers. These physical transactions were often limited by the number and location of counterparties interested in entering into physical transactions at the same time as AEP. The development of the financial electricity market has given Commercial Operations a new avenue in which to hedge generation assets. A new category of financial intermediaries, which includes high credit quality investment banks and hedge funds, are willing and able to enter into financial transactions through newer electronic trading exchanges, such as ICE[5]. By entering into such transactions and by employing proper trading-based risk management and accounting treatment, AEP is able to financially sell forward surplus energy to counterparties who were not active in the electricity market 20 years ago.

An example of this occurred in late 2005, when electricity prices were driven up due to a surge in natural gas prices caused by supply disruptions associated with hurricanes Rita and Katrina. AEPSC saw the 2006 on-peak price for power in the AEP/Dayton trading hub (a key price reference point) increase from $63/MWh before the hurricanes to a high of $79/MWh. AEPSC

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[5] Intercontinental Exchange (ICE) is a leading electronic marketplace for energy trading and price discovery. ICE allows market participants direct access to energy futures and Over-the-Counter commodity products for oil and refined products, natural gas, power and emissions.

wanted to sell some of its surplus energy for certain periods of the 2006 on-peak period, but had only limited opportunities to do so with traditional physical customers. By employing position management techniques that AEP had honed through its risk management functions associated with its trading activities, AEP was able to determine certain quantities during particular periods that it desired to hedge. AEP then transacted in the financial swap market on ICE in order to hedge surplus energy. Subsequently, the hurricane-related price increases receded, but AEP was able to realize OSS margins associated with the higher prices because AEP engaged in this financial hedging. Had AEP not financially hedged its generation forward and simply sold its generation at current lower spot prices, it would have realized lower margins.

Q. What are some other opportunities where AEP is able to use trading to respond to price anomalies?

A. An example would be a trade related to market fundamentals that AEP might enter into based on observations about an upcoming outage season. In the past, AEP has observed that during a particular outage season, not only did AEP have significant outages planned, but that other generators also had significant planned outages. AEP compared market prices for that season to previous outage seasons and believed that the market price of electricity for the planned outage season did not adequately reflect the amount of capacity expected to be unavailable (*i.e.* AEP believed the forward price of power for that period was lower than what would normally be expected during the outage season). In such a situation, AEP would buy forward financial power and thus realize positive margins on the trade when future prices rise as anticipated.

Q. Are there some additional benefits of these trading activities?

A. An additional benefit of AEP's trading activity that distinguishes it from the physically-based activity of the past is that this activity affords greater opportunity to respond to changing market conditions. If AEPSC had to rely only on physical transactions, the universe of potential counterparties would be greatly diminished, as would the ability to quickly change positions (from being long to being short or flat and vice versa). Ultimately, AEP's trading activity provides incremental positive margin that would not be available without the capabilities of its Energy Trading and Marketing group.

AEPSC believes that its physical positions of generation and purchased resources ("length") and load and sales commitments ("shorts") provides its traders with unique insights into the fundamentals of its own footprint as well as surrounding areas. AEP believes by employing that fundamental insight it can make better and quicker judgments about the movement of the prices of forward electricity than can counterparties without such insights. Traders also consider a wide range of additional data in other regions and in areas such as new construction, unit efficiencies, environmental regulations, weather trends, and economic conditions in order to analyze the markets and devise appropriate trading strategies.

AEPSC also uses the same skill sets and resources to secure power from the spot energy market, which is required periodically to meet native load requirements. Power purchased from the market is used to serve native load customers when the cost of the purchase is less than the variable cost of AEP's internal generation. The Commercial Operations group makes targeted purchases from the market that directly benefit the Company's customers. Because AEPSC is an active market participant for both hedging and trading purposes, other market participants are not able to determine whether AEPSC is hedging a significant amount of generation, or simply adjusting a trading position. Such instances, with no clear sign to the market that AEPSC is in an unfavorable position and needs to buy, result in AEPSC's ability to "buy better", which helps to keep the component of purchased power that is used to serve native load customers as low as possible. By contrast, when AEPSC is selling in the market, lack of a clear market signal to other market participants allows AEPSC to gain additional OSS margins compared to an energy company with surplus energy that is only a seller in the wholesale electricity markets.

Q. Could you please summarize the role of Commercial Operations?

A. The Commercial Operations business unit currently is part of AEPSC and performs activities on behalf of I&M and other AEP companies. That structure was established based on the symbiotic relationship between the functions of Commercial Operations necessary to serve native load customers and the non-traditional opportunities available in the wholesale markets. Such activity makes it possible for AEP to buy and sell at better prices in the wholesale market than if it were only entering the market based on the physical needs of its retail load. The existing wholesale power market has introduced additional risks into many parts of the utility business. Commercial Operations serves as an "energy portfolio manager" responsible for choosing and allocating the appropriate "investment" mix of generation, trading, and marketing as tools to balance risk versus performance.

VIII. Conclusion: Balance of Risks and Incentives

Q. Could you please summarize your testimony, and explain why the OSS margin sharing proposal provides the best balance of incentives?

A. Yes. Careful balancing of the interests of utilities and their customers is a long-standing principle when evaluating any rate case. Although AEP has proactively created Commercial Operations to actively manage risks within the wholesale power market, there are still many risks that are beyond the control of the Company. Therefore, to actively meet the challenges posed by these risks, AEP must continually evaluate its structure and activities to determine an optimal balance between market risks and rewards.

The best way to ensure that the risk/reward relationship is kept in balance for I&M customers is to align the interests of both customers and

Company by having the rate treatment reflect equitable sharing of OSS margins. This treatment recognizes the volatility that is inherent in the market, the level of margins achieved (whether high or low), their material effect on the financial health of the Company, and the integrated manner in which Commercial Operations optimizes OSS margins. **Table 4** illustrates how I&M's proposed sharing mechanism aligns the results of OSS activities in a way that balances the needs of customers and Company.

Table 4: Balancing of Common Goals

<table>
<tr><th colspan="2">Common Goal: OSS Margin Maximization</th></tr>
<tr><td rowspan="2">Because OSS margins are shared 50%-50%, both customers and the Company directly benefit from increased margins.</td><td><u>Customers</u>: Customers want the largest OSS margins possible because it will directly lead to lower rates.</td></tr>
<tr><td><u>Company</u>: The Company wants the largest OSS margins possible because it will benefit total earnings.</td></tr>
<tr><th colspan="2">Common Goal: Strict Risk Management</th></tr>
<tr><td rowspan="2">Because the Company has the daily responsibility to actively manage OSS risks, the distribution of risk places the greatest exposure on the Company, thus directly aligning both parties' desire for prudent risk management.</td><td><u>Customers</u>: Customers want strict risk management procedures in place because a smaller, steady credit from OSS margins is vastly preferable to no credit at all.</td></tr>
<tr><td><u>Company</u>: The Company wants strict risk management procedures in place because while they share equally in the upside of OSS margins, they retain the responsibility for any downside.</td></tr>
</table>

With I&M's proposed sharing mechanism, the Company will continue to have an incentive mechanism to optimize assets and pursue opportunities in the vibrant wholesale market for electricity, and the I&M Michigan customer in both St. Joseph and Three Rivers will continue to receive benefit from the opportunities for OSS margins. The Company's financial health is protected from the potentially material earnings swings that are an inherent risk in this volatile, rapidly changing environment, potentially helping to avoid or delay future rate increases that would otherwise be caused due to increased costs of providing service.

I&M's sharing proposal is consistent with the Commission's principles of balancing the interests of the customers and the Company, and it protects the financial well-being of the Company while also shielding the customers from losses or volatility associated with the wholesale energy market. The 50%-50% OSS sharing mechanism within the PSCR takes all these factors into account and lays the foundation for promoting the continued benefits of maximizing OSS margins, while aligning incentives for customers and the Company.

Q. Does this complete your pre-filed direct testimony?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

MICHAEL N. KELLY

PRE-FILED DIRECT TESTIMONY OF MICHAEL N. KELLY
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name, position, and business address.

A. My name is Michael N. Kelly. I am the Manager of Taxes - Tax Accounting and Regulatory Support for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent company of Indiana Michigan Power Company (IMPCo or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. Please briefly describe your educational and business experience.

A. I earned a Bachelor of Science Degree in Accounting from Virginia Polytechnic Institute and State University in 1984. I have been a Certified Public Accountant since 1987. I joined APCo, a subsidiary of American Electric Power in April 1984 as an Associate Staff Accountant. I was promoted to Staff Accountant in 1986, Accounting Staff Assistant II in 1989, Accounting Staff Assistant in 1992, General Records Supervising Accountant in January 1996 and General Records Supervisor in December 1996. I was promoted to Administrator of Regulated Accounting in May 1998 and transferred to the AEPSC. In 2000, I transferred to Corporate Development as the Principal Financial Coordinator and in 2001 transferred to the Tax Department as Tax

Project Manager. I was promoted to my current position effective January 1, 2005.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have filed testimony before the Federal Energy Regulatory Commission in a transmission rate case for the AEP System – East[1]. I have also filed testimony before the Virginia State Corporation Commission on behalf of Appalachian Power Company.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to present and support the federal, state and local income taxes to which I&M is subject to for the historical period ended December 31, 2008 with normalization adjustments and for the forecasted test year ended December 31, 2010 related to these income taxes. I am also responsible for the calculation of the Gross Revenue Conversion Factor (GRCF) and adjustments for certain taxes other than income taxes.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring Exhibit I&M-48 (MNK-1) (A-3, Schedule C2) (Computation

[1] The AEP System - East consist of the following operating companies with generation capabilities of Indiana Michigan Power Company serving portions of Indiana and Michigan, Columbus Southern Power Company, serving portions of central and southern Ohio; Appalachian Power Company, serving portions of West Virginia and Virginia; Kentucky Power Company, serving portions of eastern Kentucky; and Ohio Power Company serving portions of Ohio. In addition, two operating companies residing in this AEP System – East, Kingsport Power Company (KgP) and Wheeling Power Company (WPCo) represent non-generating affiliates.

of GRCF). I am also sponsoring Exhibits I&M-49 through I&M-52 (MNK-2 through 5) (A-3, Schedules C7 through C10). Company witness Roush is responsible for all jurisdictional amounts shown on these exhibits, unless otherwise noted. In addition, I am sponsoring Exhibit I&M-53 (MNK-6) (A-3, Schedule C12) and Exhibit I&M-54 (MNK-7) (A-3, Schedule 13), which shows the Calculation of Interest Synchronization for Federal Income Tax and the Interest Synchronization Adjustment, respectively, and Exhibit I&M-55 (MNK-8) (A-3, Schedule C17). I am also presenting WP-MNK-1 through 47, which shows the calculation of taxes other than income taxes, the calculation of current and deferred federal and state income taxes, and the Calculation of the Effective State Income Tax Rate.

Q. Were the exhibits or portions of the exhibits that you are sponsoring prepared by you or under your direct supervision?

A. Yes.

Q. Please describe Exhibit I&M-48 (MNK-1) (A-3, Schedule C2) – GRCF.

A. Exhibit I&M-48 (MNK-1) (A-3, Schedule C2) shows the calculation of the factor necessary to determine the incremental amount of gross revenue required to generate an additional dollar of operating income after payment of all public utility assessment fees and federal and state income taxes.

Q. Can you briefly describe Exhibits I&M-49 through I&M-52 (MNK-2 through MNK-5) (A-3, Schedules C7 through C10)?

A. On Exhibits I&M-49 through I&M 52 (MNK-2 through MNK-5) (A-3, Schedules C7 through C10), amounts are presented for the historical period ended December 31, 2008 and the 2010 forecasted test year, on a total company basis and on a Michigan Retail jurisdictional basis. Company witness Roush is responsible for the jurisdictional amounts shown on these Schedules. Exhibit I&M-49 (MNK-2) (Schedule C7) reflects taxes other than income taxes; Exhibit I&M-50 (MNK-3), (Schedule C8) indicates the total federal income tax expense; Exhibit I&M-51 (MNK 4), (Schedule C9) reflects the total state income tax expense and Exhibit I&M-52 (MNK-5) (Schedule C10) indicates local or other income tax expense.

Q. Please describe Exhibit I&M-53 (MNK-6) (A-3, Schedule C12) – Income Tax Effect of Interest Allowed For in the Ratemaking Formula.

A. Exhibit I&M-53 (MNK-6) (A-3, Schedule C12) shows the calculation of the amount of interest expense deduction used by the Company for purposes of computing income tax expense. This amount is calculated by multiplying the adjusted rate base by the weighted cost of long-term and short-term debt. This interest expense deduction methodology is consistent with past Commission practice.

Q. Please describe Exhibit I&M-54 (MNK-7) (A-3, Schedule C13) – Interest Synchronization Adjustment.

A. Exhibit I&M-54 (MNK-7) (A-3, Schedule C13) shows the calculation of the amount of interest expense deduction associated with the portion of rate base which is funded by Job Development Investment Tax Credits (JDITC) in computing income tax expense. This amount is calculated by multiplying the portion of adjusted rate base funded by JDITC by the weighted cost of long-term and short-term debt. This interest expense deduction methodology is consistent with past Commission practice.

Q. Please describe Exhibit I&M-55 (MNK-8) (A-3, Schedule C17).

A. Exhibit I&M-55 (MNK-8) (A-3, Schedule C17) indicates the tax related normalization adjustments to the 2008 historical period. These normalization adjustments remove tax expense associated with prior period adjustments and non-applicable items. In addition, WP-MNK-1 through WP-MNK-26 also indicate the normalization adjustments. WP-MNK-21 through WP-MNK-26 also reflect the removal of non-utility amounts since the total company per books contained both utility and non-utility amounts.

Q. Please describe WP-MNK-1 through WP-MNK-26 and WP-MNK-28 through WP-MNK-46 – Calculation of Taxes Other than Income Taxes and Federal and State Income Taxes.

A. WP-MNK-1 through WP-MNK-20 and WP-MNK-28 through 40 indicate the calculations for taxes other than income taxes for the 2008 historical period and the 2010 forecasted test year. WP-MNK-21 through 26 and WP-MNK-41 through WP-MNK-46 also indicate the calculation of current and deferred federal and state income tax expense for the two periods. Also included is a calculation of the Company's effective federal income tax rate after taking into consideration permanent and flow-through timing differences, excess deferred federal income taxes and deferred investment tax credit amortization. The overall total company and Michigan jurisdictional effective federal income tax rate before rate relief for the 2008 historical period is 31.24% and 30.00%, respectively and the overall total company and Michigan jurisdictional effective federal income tax rate before rate relief for the 2010 forecasted test year is 27.03% and -45.77%, respectively. The effective federal income tax rate is calculated by dividing total federal income tax expense by pre-tax electric operating income including interest expense.

Q. Please describe WP-MNK-27 and MNK-47 - Calculation of the Effective State Income Tax Rate.

A. WP-MNK-27 and WP-MNK-47 show the composite state income tax rates for the 2008 historical period and the 2010 forecasted test year developed by using the appropriate state income tax rates and apportionment factors. This composite rate is used to compute current state income tax expense and is used in the development of the GRCF.

Q. Please explain the methodology used to develop federal and state income tax expense for the 2010 forecasted test year as presented in WP-MNK-41 through 46.

A. WP-MNK-41 through 46, summarize the computation of the Company's federal and state income tax expense which is stated on an electric utility, current year basis. Consistent with prior Commission Orders, current federal income tax expense has been reduced by I&M's share of the tax loss benefit of the AEP (the parent company) tax loss as a result of the Company's participation in the AEP consolidated Federal income tax return. The Company's income tax expense is based to a large part on Company witness Allen's components of pre-tax book income and expense and the forecast of other various Schedule M items that would impact the computation of current and deferred income tax expense for the 2010 forecasted test year. The computations also include reversals of deferred taxes and amortization of deferred investment tax credits utilized in prior years. WP-MNK-43, indicates the calculation of forecasted current federal income tax expense, based primarily upon the Schedule M's as mentioned above. WP-MNK-44 and WP-MNK-46 summarize all deferred federal income taxes included in the cost-of-service. All deferred federal income taxes were computed based upon the related Schedule M items as presented in WP-MNK-43 and other adjustments as previously described. WP-MNK-45 shows the calculation of the current state income tax expense which was developed, as mentioned above, and by using the appropriate state income tax rates and apportionment factors applicable to I&M as applied to state taxable income.

Q. Please describe Statement of Financial Accounting Standards (SFAS 109) now known as Financial Accounting Standards Board's Accounting Standards Codification (FASB ASC 740), Accounting for Income Taxes.

A. SFAS 109 (ASC 740) establishes financial accounting and reporting standards for recording the effects of income taxes resulting from an entity's activities during the current and preceding years. It requires recognition of the amount of taxes payable or refundable for the current year and deferred tax assets and liabilities for future tax consequences of events that have been recognized in an entity's financial statements or tax returns.

Q. When did the AEP System's operating companies, including I&M, adopt SFAS 109?

A. The AEP System's operating companies, including I&M, adopted SFAS 109 effective January 1, 1993.

Q. Has the Company filed any base rate cases before the Michigan Public Service Commission reflecting the adoption of SFAS 109?

A. No.

Q. Does SFAS 109 specifically address tax accounting for regulated entities?

A. Yes. While SFAS 109 provides guidance for accounting for income taxes for both regulated and nonregulated enterprises, paragraph 29 addresses accounting for income taxes by regulated enterprises and specifically:

- Prohibits net-of-tax accounting and reporting.
- Requires recognition of a deferred tax liability for: 1) tax benefits that are flowed through to customers when temporary differences originate and 2) for the equity component of the allowance for funds used during construction.

- Requires adjustment of a deferred tax liability or asset for an enacted change in tax laws or rates.

Additionally, if the regulated entity is allowed to recover from or return to customers the future increase or decrease in taxes payable for items mentioned above, a regulatory asset or liability is recognized for that probable future revenue or reduction in future revenue. This asset or liability also is a temporary difference for which deferred taxes are recognized.

The net impact of a regulated utility to accounting for SFAS 109 is to record additional deferred income taxes with an offsetting amount recorded as a regulatory asset or liability, resulting in no effect on net income.

Q. Could you briefly describe why the Company has SFAS 109 Regulatory Assets?

A. 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 Michigan in which the current tax benefits of temporary book/tax differences were immediately passed-through to customers. This type of "flow-through" accounting was permitted under SFAS 71, Accounting for the Effects of Certain Types of Regulation (now known as FASB ASC 980). 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 SFAS 71, are not exempt from the requirements of Statement 71. 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 SFAS 71. That asset or liability is a temporary difference for which a deferred tax liability or asset shall be recognized."

In this instance, the customers' 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 customers' 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.

Q. Has the MPSC historically allowed the recovery of SFAS 109 Regulatory Assets in setting rates?

A. Yes. 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.

Q. Can you explain the impacts of SFAS 109 on a regulated company in a rate proceeding?

A. SFAS 109 should have no impact in a rate proceeding provided that the SFAS 109 Accumulated Deferred Federal Income Taxes, as well as the SFAS 109 regulated assets and liabilities of the Company, are properly excluded from rate base or cost of capital. Since these account balances should offset one another, they should have no impact on rate base, cost of capital or the return on rate base. As a result, the Company did not include any of the SFAS 109 Regulatory Asset/Liability balances or the SFAS 109 Deferred Income Tax

Asset/Liability balances in this proceeding.

Q. Please summarize your direct testimony.

A. The 2008 historical period and the 2010 forecasted test year's level of Taxes Other Than Income Tax expense recorded on I&M's books is representative of these types of ongoing tax expenses. The 2010 forecasted test year level of other tax expense is appropriate and necessary and reflects the proper amount of going-level expense. The Company's state and federal income tax expense has been properly recomputed to eliminate all non-recurring, out-of-period and non-utility items, to reflect I&M's share of any tax loss benefits of participating in AEP consolidated income tax returns, and to reflect the appropriate tax effects resulting from the 2010 forecasted income and expense data supported in this case. The GRCF calculated on Exhibit I&M-48 (MNK-1) (A-3, Schedule C2) indicates the appropriate factor that should be applied to the income deficiency in order to determine the amount of incremental revenue needed to obtain the required level of operating income. It is necessary to apply this factor to the income deficiency in order to provide sufficient revenues to cover the additional federal and state income tax expense and the public utility assessment fees. And finally, the accounting required by SFAS 109 does not and should not have any impact on ratemaking or on the determination of utility income tax expense in this proceeding.

Q. Does this complete your pre-filed direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

DONALD E. HAYES

PRE-FILED DIRECT TESTIMONY OF DONALD E. HAYES
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is Donald E. Hayes. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by American Electric Power Service Corporation (AEPSC) as Manager of Regulatory Accounting Services. AEPSC, a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP), provides centralized professional and other services to subsidiaries of AEP. AEP is the parent company of Indiana Michigan Power Company (I&M or the Company).

Q. Please briefly describe your educational background, professional qualifications and business experience.

A. I graduated with a Bachelor of Science in Business Administration Degree with a Major in Accounting from The Ohio State University in June 1983. I have been a Certified Public Accountant, licensed in the state of Ohio, since 1987. I am a member of the American Institute of Certified Public Accountants.

I joined Columbus Southern Power Company, a subsidiary of AEP, in December 1981 as a Business Student Co-Op. Upon completing my degree I was hired permanently by AEPSC in June 1983 as an Assistant Consolidation Accountant. I was promoted to Consolidation Accountant in 1985, Senior Consolidation Accountant in 1987 and Supervisor of Financial Reporting in

1989. In May 1998 I was promoted to Administrator of Regulated Accounting and in 2001 I was promoted to Manager of Regulated Accounting for I&M, Kentucky Power Company (KPCo), and AEP Generating Company (AEG). As Administrator and as Manager of Regulated Accounting my duties included maintaining I&M, KPCo and AEG's General Ledgers, which included the preparation and review of accounting entries to the General Ledgers, supervision of the monthly closing process, analysis of financial results and compilation and review of various financial reports including the Annual Report on Form P-521 (P-521) to the Michigan Public Service Commission (MPSC or the Commission) and the Annual Report on Form 1 to the Federal Energy Regulatory Commission (FERC). I transferred to my current position in August 2008. As a result of my experience I have extensive knowledge of I&M's books and records and its financial and regulatory reporting. I am also very familiar with the FERC Uniform System of Accounts (USofA) and Accounting Principles Generally Accepted in the United States of America (GAAP).

Q. What are your principal areas of responsibility as Manager of Regulatory Accounting Services?

A. My primary responsibilities include providing the AEP electric operating subsidiaries, such as I&M, with regulatory and general accounting expertise in support of regulatory filings, including the preparation of cost of service adjustments, accounting schedules and accounting testimony. Also, I monitor regulatory proceedings, settlements, orders and legislation for accounting implications and participate in determining the appropriate regulatory accounting and financial reporting treatment of regulatory transactions.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I filed testimony on behalf of I&M before the Indiana Utility Regulatory Commission in support of accounting matters related to recovery of Clean Coal Technology Projects. I also filed accounting testimony on behalf of AEP Transmission Company, LLC before the FERC in support of accounting matters related to its request for transmission formula rates.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my pre-filed direct testimony in this proceeding is to support certain of the 2008 Historical Period Schedules, to discuss and support regulatory asset treatment and recovery for certain Michigan jurisdictional items that I&M is requesting to recover, and to address the regulatory accounting to be used by I&M, under GAAP and the FERC USofA, to properly account for 1) net lost revenues resulting from I&M's Energy Optimization Program; 2) the Company's proposed phase-in of the planned gridSMART^{SM} program; 3) the Company's proposed Enhanced Distribution Reliability Tracker; 4) I&M’s proposed Generation Investment Tracker; and 5) I&M's proposed Major Storm Damage Restoration Reserve.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. My exhibits show I&M's Total Company 2008 historical period data required by the standard filing instructions in Case No. U-15895. The Total Company historical data required in the standard filing schedules "Part 1 A-2 Schedules B1 through B4" and "Part 1 A-3 Schedules C1, C3 through C6, and C11" are included in the following exhibits:

1) Exhibit I&M-56 (DEH-1) 2008 End of Year Total Company Rate Base Items;
2) Exhibit I&M-57 (DEH-2) 2008 Total Company Utility Plant and Accumulated Provision for Depreciation;
3) Exhibit I&M-58 (DEH-3) 2008 Total Company 13-Month Working Capital;
4) Exhibit I&M-59 (DEH-4) 2008 Total Company Revenues, Expenses and Operating and Maintenance (O&M) Expense Detail; and
5) Exhibit I&M-60 (DEH-5) 2008 Allowance For Funds Used During Construction.

I also sponsor Exhibit I&M-61 (DEH-6) Chart of Accounts Comparison, described later in my testimony.

Q. Please describe the preparation of the schedules in the exhibits that you sponsor.

A. Each exhibit that I sponsor was prepared under my supervision and represents I&M's Total Company amounts. The source of the historical data is I&M's books and records, which are kept in conformity with the FERC USofA, producing results consistent with the MPSC USofA. The major differences between FERC and MPSC USofA evident in this filing will be discussed below and shown in Exhibit I&M-61 (DEH-6) Chart of Accounts Comparison.

<u>2008 Total Company Historical Period Schedules</u>

Q. Please describe Exhibit I&M-56 (DEH-1) 2008 End of Year Total Company Rate Base Items.

A. Exhibit I&M-56 (DEH-1) contains the Historical Total Company information required by the standard filing requirements Part 1 A-2 Schedule B1. This summary schedule of rate base items is based upon the actual Total Company December 31, 2008 balances, except for working capital which is based upon 13-month averages, as required.

Q. Were any adjustments made to the 2008 Total Company Balances?

A. Yes, the balances related to the Rockport Plant Unit 2 Unit Power Sale to Progress Energy (a wholesale customer) have been removed from the Total Company balances as shown in column (d) "Rockport 2 Unit Power Sale." This adjustment is necessary since the costs related to that unit power sale (which ended December 31, 2009) were recovered from Progress Energy and not from Michigan jurisdictional customers through 2009. Also, the original cost of assets related to legal Asset Retirement Obligations (ARO), along with the accumulated depreciation thereon, have been removed from Total Company Rate Base since these net ARO assets are non-cash plant assets. I will explain these ARO assets later in my testimony. Additionally, I adjusted Total Company Construction Work In Progress by removing non-utility project balances. I also made adjustments to Electric Plant In Service and Accumulated Provision for Depreciation to reflect Commission directives in previous cases (U-6148 and U-7791) related to test energy credit and pollution control equipment allowance for funds used during construction. Finally, I have adjusted the accumulated provision for depreciation balances to reflect the Commission approved Michigan depreciation rates rather than I&M's multi-jurisdiction composite rates used in the per books financial statements.

Q. Please describe Exhibit I&M-57 (DEH-2) 2008 Total Company Utility Plant and Accumulated Provision for Depreciation.

A. Exhibit I&M-57 (DEH-2) contains the Total Company December 31, 2008 balances required by the standard filing requirements Part 1 A-2 Schedules B2 and B3. Exhibit line numbers 1 through 20 contain the information for Schedule B2 and line numbers 22 through 29 contain the information for Schedule B3.

Q. Please describe Exhibit I&M-58 (DEH-3) 2008 Total Company 13-Month Working Capital.

A. Exhibit I&M-58 (DEH-3) contains the Total Company's 13-month average balance sheet required by the standard filing requirements Part 1 A-2 Schedule B4. Each account was analyzed to determine the portion included in working capital, utilizing the balance sheet methodology in accordance with

Case No. U-7350. Each working capital item was further analyzed to determine if the balance could be direct assigned to a jurisdiction or should be allocated.

Q. Please describe Exhibit I&M-59 (DEH-4) 2008 Total Company Revenues, Expenses and O&M Detail.

A. Exhibit I&M-59 (DEH-4) provides the detailed income statement information for the historical test year ended December 31, 2008 and contains the Total Company details making up standard filing requirements Part 1 A-2 Schedules C1 and C3 through C6.

Q. Please describe Exhibit I&M-60 (DEH-5) 2008 Allowance for Funds Used During Construction.

A. Exhibit I&M-60 (DEH-5) 2008 Allowance for Funds Used During Construction (AFUDC) provides the standard filing requirements Part 1 A-2 Schedule C11 related to Total Company AFUDC per books and adjusted for environmental AFUDC.

Q. Please describe Exhibit I&M-61 (DEH-6) Chart of Accounts Comparison.

A. Examples of the FERC vs MPSC differences found in this filing are listed on Exhibit I&M-61 (DEH-6) Comparison of FERC and MPSC USofA. This exhibit is not intended to be an exhaustive list of all differences but rather the main differences evident in the instant filing such as the accounts used later in my testimony for regulatory assets and regulatory liabilities as well as the accounts used by Company witness Gregory in her testimony for transmission revenues and expenses.

Q. Please discuss the differences between the FERC USofA and the MPSC USofA as seen in I&M's historical data.

A. The FERC, in its Order 390 effective January 1, 1984, amended its USofA, fully incorporating Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation,* (now know as Financial Accounting Standards Board's Accounting Standards Codification (FASB ASC) 980) and established new account numbers to reflect this accounting pronouncement. The MPSC did not change its USofA at that time, and generally has not changed it when the FERC has amended its USofA, resulting in different account numbers used in Michigan compared to the FERC USofA. As a multi-jurisdiction utility, I&M continues to use the account numbers from the FERC USofA, as amended. The transmission revenue and expense accounts discussed by Company witness Gregory were established by FERC Order 668 but also have not yet been adopted by the MPSC.

Q. Are you aware that these FERC vs MPSC account number differences will be eliminated if the Commission adopts the FERC USofA as result of the pending Cases U-14811 and U-14812?

A. Yes. I&M supports the Commission's efforts to adopt the FERC USofA as a component of MPSC accounting rules.

Discussion of Regulatory Asset Treatment for Certain Michigan Jurisdictional Items

Q. Please identify the items, that have not been included previously in I&M's rates, for which I&M requests Regulatory Asset treatment and recovery of in this case.

A. The Michigan jurisdictional items not previously included in I&M's rates that I&M is requesting regulatory asset treatment and recovery of in this case are:

Asset Description
Deferred Customer Choice Implementation Costs (including carrying costs)
Deferred PJM Administration Fees
Deferred VEBA Trust Contributions
Deferred Asset Retirement Obligations
Enhanced Security Costs
Rate Case Expenses
Nuclear Decommissioning Study Expenses

Company witness Allen has included amortization expense for each of these items in his Total Company forecast and Company witness Roush has included the Michigan jurisdictional amortization expense in the development of the Michigan jurisdictional revenue requirement. I will discuss and identify the historical balances of these items in my testimony.

Q. Please describe I&M's regulatory asset for Deferred Customer Choice Implementation Costs.

A. In Case No. U-12652, the Commission authorized I&M "to account for implementation costs on a deferred basis in the following manner:

implementation costs incurred after June 19, 2000 shall be debited to Account 186-miscellaneous deferred debits and shall accrue a carrying charge on the unamortized balance at a rate of 7%." This regulatory asset represents costs necessary to implement customer choice deferred for future recovery with carrying charges according to the above authorization. I've been advised by counsel that these are the same type of costs covered in MCL 460.10a (16). The balance of this regulatory asset, including carrying costs, at December 31, 2008 was $5,885,333.

Q. Please describe I&M's regulatory asset for PJM Administration Fees.

A. In Case No. U-12652, the Commission approved the settlement agreement where "the parties agree that deferred accounting treatment is an appropriate methodology" for the regulatory assets identified, which included administrative costs related to I&M's participation in a regional transmission organization. I&M integrated into PJM on October 1, 2004 and has been incurring and deferring the Michigan portion of these incremental administrative costs since then according to the authorization in Case No. U-12652. The balance of this regulatory asset at December 31, 2008 was $5,296,408.

Q. Please describe I&M's regulatory asset for VEBA trust contributions.

A. I&M's VEBA trust contributions for postretirement benefits relate to pre-1995 contributions that were deferred for future recovery. This regulatory asset was authorized for continued deferral in Case No. U-12652 and contemplated to be requested for recovery in I&M's next base rate case. This filing is that next base case. The balance of this regulatory asset at December 31, 2008 was $354,500.

Q. Before discussing the Asset Retirement Obligations (ARO) regulatory asset, please briefly describe the GAAP applicable to AROs.

A. Financial Accounting Standards Board's Accounting Standards Codification (FASB ASC) 410-20, (formerly Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting For Asset Retirement Obligations*), which applies to all entities including rate-regulated companies, requires that the fair value of a liability for a legal ARO associated with the retirement of a long-lived asset be recognized in the period in which it is incurred. FASB ASC 410-20 defines a legal obligation as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel". Upon initial recognition of a liability at the present value of an ARO, the entity will capitalize an asset retirement cost (ARO asset) in the same amount as the ARO liability. This ARO asset is allocated to expense over the useful life of the underlying long-lived asset. The present value of the ARO liability accretes (increases) due to the passage of time and this change is recognized by increasing the carrying amount of the ARO liability and by recording an equal amount of "accretion" expense on the income statement.

At the required implementation of FASB ASC 410-20 ARO Accounting, an entity, such as I&M, that is cost-based regulated and meets the criteria for applying FASB ASC 980, (formerly SFAS 71, *Accounting for the Effects of Certain Types of Regulation*) should establish a regulatory asset or liability for the difference between the amount of any accumulated depreciation of the ARO asset and accumulated accretion of the ARO liability recognized for financial reporting purposes and the amount of any related removal costs reflected for ratemaking purposes.

Q. When did I&M implement the ARO accounting required by FASB ASC 410-20?

A. The Company implemented FASB ASC 410-20 ARO accounting in the first quarter of 2003 as required by the new ARO accounting standard.

Q. Did I&M record any ARO-related assets and liabilities upon the required implementation of FASB ASC 410-20 in 2003?

A. Yes. Based upon a review of I&M's asset retirement obligations, the Company determined that it had legal AROs related to the removal of the Rockport Plant ash ponds and for the decommissioning of the Cook Nuclear Plant. Therefore, I&M established in the first quarter of 2003 the following FASB ASC 410-20 ARO-related assets and liabilities related to the Rockport Plant ash ponds and nuclear decommissioning costs: 1) a liability recorded in FERC Account 230, Asset Retirement Obligations, for the present value of the ARO for ash ponds and nuclear decommissioning costs adjusted for accumulated accretion through the date of adoption of FASB ASC 410-20, 2) a capitalized asset retirement cost (ARO asset) recorded in Account 101, Electric Plant In-Service (FERC Electric Plant Account 317 for ash ponds and FERC Electric Plant Account 326 for nuclear decommissioning), to increase the carrying amount of the associated long-lived asset by the amount of the initial ARO liability, and 3) accumulated depreciation of the ARO asset recorded in Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. Since the Company's nuclear decommissioning costs and existing liabilities recorded for such nuclear retirement obligations were previously recognized for ratemaking purposes, I&M made a reclassification entry that recognized the ARO liability in FERC Account 230 and reduced the existing liabilities, which were recorded in FERC Account 228.4, Accumulated Miscellaneous Operating Provisions. The Michigan jurisdictional nuclear decommissioning liabilities are reported in the P-521 in Account 108, Accumulated Provision for Depreciation, per MPSC reporting requirements.

Q. Has I&M previously included removal costs related to its ash ponds in its depreciation rates?

A. No, I&M has never reflected removal costs on its ash ponds in depreciation rates approved by the MPSC.

Q. Has I&M recognized any AROs other than those for ash ponds and nuclear decommissioning since the required implementation of FASB ASC 410-20 in 2003?

A. Yes. I&M recognized conditional AROs related to asbestos removal in the fourth quarter of 2005 upon the initial application of FASB ASC 410-20-25 (formerly FASB Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations – An Interpretation of FASB Statement No. 143*). FASB ASC 410-20-25, issued by the FASB in 2005, clarified that all entities are required to recognize a liability for the fair value of a conditional ARO when incurred. A conditional ARO is an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Based on a review of I&M's conditional AROs, the Company concluded that conditional legal liabilities exist for asbestos removal and disposal in I&M's general buildings and generating plants. I&M made a reclassification entry that recognized the ARO liability in FERC Account 230 and reduced the existing Account 108 balance.

Q. Please describe I&M's deferred ARO regulatory asset for which I&M is seeking rate recovery and amortization.

A. Since the first quarter of 2003 I&M has been deferring, for future rate recovery, the ARO depreciation and accretion related to the Rockport Plant ash ponds. The Michigan jurisdictional portion of those deferrals comprise the balance of the ARO regulatory asset being requested for recovery in this rate case. The balance of this regulatory asset at December 31, 2008 was $245,915. Beginning in January 2009, I&M also began to defer as a regulatory asset the ARO depreciation and accretion related to the Tanners Creek Plant ash ponds.

Q. Are there other ARO expenses, incurred by I&M as a result of implementing FASB ASC 410-20, that are not included in the ARO regulatory asset?

A. Yes. Nuclear decommissioning expenses have historically been included in I&M's cost of service and revenue requirements for ratemaking purposes and those expenses are included in the projected test year level of expenses. Asbestos removal and disposal costs have historically been included in the Company's depreciation rates. Thus, there are no deferred balances to recover for either nuclear decommissioning or asbestos removal in the ARO regulatory asset being requested for rate recovery.

Q. Does I&M propose the MPSC approve a carrying charge on the deferred regulatory assets discussed above?

A. Since the deferred PJM Administration Fees, the deferred VEBA Trust Contributions and the deferred Asset Retirement Obligations are included in I&M's working capital, and thus are part of rate base, I&M is not requesting a carrying charge on those Regulatory Assets. As previously ordered, I&M currently accrues an approved carrying charge on the deferred Customer Choice Implementation costs at a fixed rate of 7%, which was approximately the short-term debt rate at the time the asset was approved for deferral in Case U-12652. Therefore, the deferred Customer Choice Implementation Regulatory Asset has not been included in working capital and the unamortized balance will continue to accrue carrying charges.

Q. Please identify the expenditures for enhanced security costs that I&M is requesting recovery of as a regulatory asset in this case.

A. I&M is requesting recovery of costs incurred and expensed during calendar years 2002 through 2005 related to enhanced security at its nuclear facility in response to the events surrounding September 11, 2001. These costs, including capital expenditures and O&M expenses supported by Company witness Hruby, are the type of costs identified in MCL 460.10d(3) - (9) as being recoverable. The Total Company amount of these enhanced security costs was $4,219,515 including the O&M expenses, depreciation expense of $425,375 and a calculated return of $1,187,033 on the capital expenditures. These Total Company amounts were provided to Company witness Roush who developed the Michigan jurisdictional revenue requirement. Company witness Krawec further discusses the recovery requested for the enhanced security costs.

Q. Please identify the expenditures for rate case costs that I&M is requesting recovery of as a regulatory asset in this case.

A. I&M is requesting recovery of costs incurred and expensed during 2009 and estimated for 2010, totaling $245,238, related to this rate case as supported by Company witness Krawec.

Q. Please identify the expenditures for nuclear decommissioning study costs that I&M is requesting recovery of as a regulatory asset in this case.

A. I&M is requesting recovery of costs incurred and expensed during 2009 related to the nuclear decommissioning study required by Case No. U-6150, as supported by Company witness Krawec. The Total Company amount of this study was $85,500.

Q. How does I&M propose to account for the amortization of these existing and proposed regulatory assets?

A. I&M proposes to amortize these existing and proposed regulatory assets over the periods approved by the MPSC and will record the amortization as credits to the regulatory asset accounts and charges to the appropriate expense accounts. The expense accounts charged will be the same accounts credited when the regulatory assets were established, which will reflect the nature of the items that were originally deferred.

<u>Accounting for Net Lost Revenues resulting from I&M's Energy Optimization Plan</u>

Q. Is I&M participating in an Energy Optimization Plan (EOP)?

A. Yes, as authorized in Case No. U-15808, I&M is contracting with a State approved EOP administrator to meet its statutory requirements. I&M has a current two year commitment with the EOP administrator and an option to renew.

Q. Is the Company recovering the EOP program costs in a current surcharge?

A. Yes, as authorized in Case No. U-15808, I&M is currently collecting a surcharge to recover the EOP program costs. I&M is using traditional regulatory deferral over/under recovery true-up accounting for any over/under recovery of EOP program costs, along with a short-term debt carrying cost on the over or under recovery regulatory liability/asset balance as authorized by the MPSC in Case No. U-15808.

Q. How will I&M account for the net lost revenues resulting from the EOP that are proposed to be included in the new Net Lost Revenue Recovery (NLRR) Rider sponsored by Company witness Roush?

A. I&M is requesting to record a regulatory asset and recognize revenues for the under recovery of net lost revenues in the accounting period that the revenues are actually lost. One requirement of FASB ASC 980-340-25-1 (formerly SFAS 71) is that a cost must be incurred to be capitalized as a regulatory asset. Net lost revenues are not an incurred cost and thus in order to record a regulatory asset for net lost revenues, the requirements of FASB ASC 980-605-25 (formerly Emerging Issues Task Force (EITF) Issue No. 92-7, *Accounting by Rate-Regulated Utilities for the Effects of Certain Alternative Revenue Programs*) must be met. FASB ASC 980-605-25 provides an exception to the incurred cost requirement of FASB ASC 980-340-25-1 for the recognition as a regulatory asset of future revenues to be collected through an alternative revenue program including programs that adjust billings to compensate the utility for demand side management initiatives.

Q. What are the requirements of FASB ASC 980-605-25 that must be met in order for I&M to recognize the additional revenues to be billed in the future?

A. In accordance with FASB ASC 980-605-25, I&M can recognize revenues to be billed in the future as a regulatory asset even though they are not an incurred cost if all of the following conditions are met: 1) the demand side management (DSM) program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates to recover net lost revenues. Verification (an audit) of the computation of lost revenues and the adjustment to future rates by the regulator or its staff would not preclude the adjustment from being considered automatic; 2) the amount of recoverable net lost revenues for the period is objectively determinable and is probable of recovery and 3) the additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

Q. Does I&M currently qualify for this exception?

A. No. Recovery would have to be through an automatic rider with no further adjudication of the recovery request. Since I&M does not currently have an automatic rider it does not qualify.

Q. Is I&M currently recording a regulatory asset to recognize the additional net lost revenues to be billed in the future?

A. No. Due to its failure to qualify, under FASB ASC 980-605-25, for an exception, I&M is not currently recording a regulatory asset to recognize the additional net lost revenues to be billed in the future.

Q. Do the requirements of FASB ASC 980-605-25 apply to all components included in the NLRR Rider for which I&M will be using deferral accounting?

A. No, the requirements of FASB ASC 980-605-25 apply only to the net lost revenues but not to incurred costs, i.e. the program costs. The incurred EOP program costs are deferrable as a regulatory asset if under-recovered or if over-recovered as a regulatory liability in accordance with FASB ASC 980-10-15-2 (formerly SFAS 71 paragraph 5) if it is probable that the resultant deferred incurred cost regulatory assets or regulatory liabilities will be recovered, or returned to customers, through future rates. The deferral of incurred EOP program costs does not have to meet the conditions of FASB ASC 980-605-25. However, in order to recognize, through a regulatory asset, any under-recovered net lost revenues to be recovered under a DSM program, which are not an incurred cost, the conditions of FASB ASC 980-605-25 must be met.

Q. If the proposed changes to the rates under the NLRR Rider are approved as filed, would the changes meet the requirements of FASB ASC 980-605-25 in order for I&M to recognize any under recovery of lost revenues to be recovered in the future as a regulatory asset?

A. Yes, the proposed changes to the rates under the NLRR Rider proposed by Company witness Roush meet the requirements of FASB ASC 980-605-25.

The proposed changes to the rates under the NLRR Rider include an annual reconciliation that will automatically include net lost revenues in the amount to be collected in the next annual rate adjustment to the rider. As such, it will be recovered in less than 24 months without further adjudication. Thus, I&M would meet the above stated requirements of FASB ASC 980-605-25 and, as such, would be able to record a regulatory asset and recognize revenues for any under recovery of net lost revenues in the accounting period that the revenues are actually lost, using traditional regulatory deferral over/under recovery true-up accounting.

Q. Does I&M propose the MPSC approve a carrying charge on the net lost revenue regulatory asset or regulatory liability?

A. Yes, given the short-term nature of net lost revenues, Company witness Krawec recommends that carrying charges be computed by applying I&M's monthly weighted average cost of short-term debt to the prior month under recovery balance or over recovery balance of the net lost revenues.

Accounting for the I&M's proposed phase-in of the gridSMART^{SM} program

Q. Please describe the gridSMART^{SM} program that I&M will be initiating.

A. Company witness Walter describes the gridSMART^{SM} program in his testimony and includes the estimated costs of the program including the cost associated with the early retirement of existing meters and other equipment to be replaced by smart meters and smart equipment that can communicate with the smart meters. Briefly as it relates to my accounting testimony, I&M will be installing Advanced Metering equipment or smart meters in its gridSMART^{SM} program. The four year phase-in of the gridSMART^{SM} program is proposed to begin commensurate with rate recovery. Presently smart meters have two components: a plug in communications/computer component and a basic meter component. In the near future it is expected that smart meters will be one integrated device. The new smart meters will be owned by I&M. If the program is successful, I&M expects to also be placing, in the near future, with the customer's permission, programmable communicating thermostats (PCT's) and other home area network devices, such as load control switches (LCSs) in the customer's premises to control the use of certain major appliances and to provide customers with real time information regarding energy costs and use. With the possible exception of the PCTs, these in home devices will probably also be owned by I&M. Since the PCT will be attached to the customer's walls and wired to the customer's electrical and heating and cooling systems, the customer may own the PCT device. I&M will also be installing two-way wireless communication systems, and replacement reclosures, switches and voltage regulators with communication capability. The smart meters will be able to communicate with the home area network devices and with the two-way wireless communication systems. As Company witness Walter testifies, it is expected that in the next five to seven years, the initially installed smart meters plus some of the communication equipment and home area network devices will be replaced with upgraded technology with greater functionality and benefit to both the customer and I&M.

Q. How does I&M propose to recover the gridSMART^{SM} program expenditures?

A. I&M is proposing to recover the gridSMART^{SM} O&M expenses and capital costs, including a return on gridSMART^{SM} investments, as well as the cost of non-reusable meters and other replaced equipment, if any, (collectively referred to hereinafter as gridSMART^{SM} costs) through a gridSMART^{SM} tracker as explained by Company witnesses Krawec and Walter.

Q. How does I&M propose to account for the gridSMART^{SM} tracker?

A. I&M will use traditional regulatory deferral over/under recovery true-up accounting for the difference between actual incurred gridSMART^{SM} costs and the gridSMART^{SM} tracker revenues, which will be based on projected gridSMART^{SM} costs.

Q. Is the deferral accounting treatment I&M proposes in accordance with GAAP and the FERC USofA?

A. Yes. FASB ASC 980 (formerly SFAS 71) requires deferral accounting when certain conditions are met. FASB ASC 980-340-25-1 requires that when incurred costs are probable of future recovery, from inclusion of that incurred cost in allowable future costs for ratemaking purposes, the unrecovered costs should be capitalized (deferred) as a regulatory asset and amortized to expense when recovered in revenues. The Statement recognizes that a regulator can provide reasonable assurance of the existence of an asset, if the regulator provides for the future recovery through cost-based rates, of a currently incurred cost that would otherwise have been charged to expense. When that occurs the regulator-created asset, or regulatory asset, must be recorded by deferring the incurred cost to be recovered in the future. The deferral as a regulatory asset of unrecovered incurred costs to be recovered in the future allows I&M to properly match such costs with the revenues recovering such costs in the same accounting period. The matching of cost and revenue is a long-standing utility accounting concept, which produces meaningful financial statements especially for cost-based regulated operations.

FASB ASC 980-405-25-1 addresses how a regulator can impose a liability on a regulated enterprise. One of the ways in which a liability can be imposed on a regulated enterprise occurs when a regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced. If the regulator requires that any over collection of such recoverable costs be returned to customers, any over-recovery must be recognized as a regulatory liability, or if a net under-recovery regulatory asset balance currently exists, it must be recognized as a reduction in such net under recovery regulatory asset until the regulatory asset is eliminated.

The FERC amended its USofA, incorporating FASB ASC 980 (SFAS 71) in the USofA, in its Order 390 effective January 1, 1984. As such, I&M's proposed deferral accounting is consistent with both GAAP and the FERC USofA.

Q. How does I&M propose to account for the gridSMART^{SM} program's capital expenditures?

A. As discussed by Company witness Walter, the smart meters have a useful life of seven years. As such, I&M will have a retirement unit for the initial smart meters with an expected useful life of seven years.

I&M is also proposing that the purchase cost of the smart meter plus its installation cost be recorded in Subaccount 370, Meters, of Account 101, Electric Plant In Service, and be depreciated on a composite depreciation method over that same seven years.

When I&M purchases home area network devices (PCTs and LCSs) that will be placed in the customers' premises, I&M is proposing to initially record them in Account 154, Plant Materials and Operating Supplies, (M&S inventory). When installed, they will be removed from the M&S inventory account and capitalized in Subaccount 371, Installations on Customers' Premises, along with the installation costs if the home area network devices are to be owned by I&M. If the home area network devices are to be owned by the customer, such as may be the case for smart thermostats (PCTs), it will be removed from the M&S inventory account and expensed in Account 586, Meter Expenses (which includes devices associated with meters), to be recovered with other non-capital gridSMART^{SM} program costs through the gridSMART^{SM} tracker. The cost of the wireless communication equipment will be in Subaccount 397, Communication Equipment, and will have a seven year life, its expected useful life, as supported by Company witness Walter.

Central software will be purchased and installed to allow the smart meters to function and provide beneficial information and controls to both I&M and the customers. This software will be recorded in Subaccount 303, Miscellaneous Intangible Plant, and depreciated over the traditional five-year life for software.

Finally, certain older distribution equipment such as switches, reclosures, and voltage regulators, will have to be upgraded or replaced to facilitate the addition of new communication devices. The cost of the new switches and reclosures will be recorded in Subaccount 365, Overhead Conductors and Devices, and voltage regulators will be recorded in Subaccount 368, Line Transformers, and depreciated over the existing long lives for these existing accounts. The cost of upgrading existing distribution equipment, if a maintenance expense, would be expensed for recovery through the gridSMART^{SM} tracker. The cost of new switches, reclosures and voltage regulators will be depreciated over the existing thirty-year life for the Conductor account, Account 365 and the existing thirty five year life for the Line Transformer account, Account 368. The cost of the replaced equipment has not been included in the gridSMART^{SM} program costs included in Company witness Walter's testimony, under the assumption that they are fully depreciated when replaced.

Q. Why is I&M proposing to use a seven year depreciation life for the smart meters?

A. As Company witness Walter explains, a seven year expected useful life is reasonable. FASB ASC 360-10-35-4 (formerly "*Accounting Research Bulletin (ARB) 43: Restatement and Revision of ARBs Chapter 9 Section C Paragraph 4*") requires that depreciable assets be depreciated over their expected useful life and not their physical lives. To depreciate the smart meter equipment over its physical life or an arbitrary longer life instead of its expected useful life will result in an undepreciated balance when as expected, to upgrade the technology, the smart meters are replaced in five to seven years.

Q. How is I&M proposing to account for the early retirement and removal of the existing traditional long lived meters, under I&M's gridSMART^{SM} program?

A. If a mass plant asset, such as a meter, is retired and removed from service early in the normal course of business, its remaining book value is traditionally charged to the Account 108, Accumulated Provision for Depreciation of Electric Plant, along with the net removal cost (net of any salvage) for cost based regulated companies. Charging the Account 108 reserve for early retirements in the normal course of business provides for recovery of the undepreciated balance and the net cost of removal over the remaining life of the assets in the mass property account by causing a small increase in the on-going composite depreciation rates in the next Depreciation Study. However, a mass early retirement of the existing meters to be replaced with smart meters is not a retirement in the normal course of business and as such it would distort the reserve and must be expensed unless it is recoverable through future rates as a regulatory asset. As a result, I&M is proposing that the estimated remaining book value of the existing meters replaced, and retired in mass in the gridSMART^{SM} program together with the net removal cost (removal cost net of salvage recoveries) be recovered through the gridSMART^{SM} tracker as a program expense. Company witness Walter has included an estimate in his testimony for this mass retirement cost to be included in the total gridSMART^{SM} program costs to be recovered through the proposed gridSMART^{SM} tracker.

Q. How does I&M propose to recover the depreciation expense and other fixed costs associated with the gridSMART^{SM} program including the cost to finance the investment, the additional property taxes, and other fixed costs associated with the gridSMART^{SM} program?

A. I&M proposes to recover the depreciation expense and other fixed costs associated with the new gridSMART^{SM} program through the gridSMART^{SM} tracker. The estimated gridSMART^{SM} cost recovery revenue requirement will include a capital carrying cost on the undepreciated balances in the gridSMART^{SM} subaccounts of Accounts 370, 371, 397, 365, 303, 368 and 154 computed at a capital carrying cost rate developed by Company witness Hawkins and used by Company witness Roush to develop the annual cost associated with the new gridSMART^{SM} program equipment. This capital carrying cost rate includes a weighted average cost of capital (WACC) rate and other capital related costs like depreciation, property taxes, other taxes, income taxes etc. A capital carrying cost rate is appropriate to provide a return of and a return on gridSMART^{SM} program capital expenditures. I&M is proposing to use an approximate 50/50 debt to equity ratio, actual debt costs and an ROE of 11.75% to compute the WACC rate component of the capital carrying cost rate. Company witness Roush employed a capital carrying cost rate provided to him by Company witness Hawkins to apply to the net gridSMART^{SM} plant balances estimated by Company witness Walter to arrive at the capital cost component of the revenue requirement to be recovered together with all other gridSMART^{SM} program costs through the gridSMART^{SM} tracker. Company witness Hawkins also supports the use of the 50/50 capital structure including an 11.75% ROE rate, supported by Company witness Avera, and the other components of her capital carrying cost rate.

Q. Does I&M propose the MPSC approve a carrying charge on the gridSMART^{SM} tracker over/under recovery balance?

A. Yes, given the nature of the gridSMART^{SM} tracker program expenditures, I&M recommends that carrying charges be computed by applying I&M's monthly weighted average cost of short term debt rate to the prior month cumulative under recovery regulatory asset balance or cumulative over recovery regulatory liability balance of the gridSMART^{SM} tracker.

Q. What will be I&M's monthly accounting for the gridSMART^{SM} tracker after the proposed gridSMART^{SM} tracker is effective?

A. If gridSMART^{SM} tracker is approved by the MPSC, effective with the implementation of the gridSMART^{SM} tracker, I&M will perform traditional over/under recovery true-up accounting by calculating, monthly, any over-recovery or under-recovery of the gridSMART^{SM} program costs. I&M will compare the current month gridSMART^{SM} tracker revenues to the current month actual gridSMART^{SM} tracker costs including a carrying cost on previously deferred gridSMART^{SM} tracker costs.

If the monthly gridSMART^{SM} tracker revenues are less than the monthly actual gridSMART^{SM} tracker costs, I&M will record the under-recovery as a decrease (credit) to the appropriate distribution expense accounts, with a corresponding debit recorded to either Regulatory Assets or Regulatory Liabilities. (A Regulatory Asset will be debited if the cumulative balance is an under-recovery and a Regulatory Liability will be debited if the cumulative balance is an over-recovery until the over recovery balance is eliminated.)

Similarly, if monthly gridSMART^{SM} tracker revenues are more than the monthly actual gridSMART^{SM} tracker costs, I&M will record the over-recovery as an increase (charge) to the appropriate distribution expense accounts, with a corresponding credit recorded to either Regulatory Liabilities or Regulatory Assets. (A Regulatory Liability will be credited if the cumulative balance is an over-recovery and a Regulatory Asset will be credited if the cumulative balance is an under-recovery until the under-recovery balance is eliminated.) On an annual basis any over or under recovered balance will be included as a reconciliation item to either reduce, for an over-recovery, or increase, for an under-recovery the amount of unrecovered gridSMART^{SM} tracker costs to be collected in the next gridSMART^{SM} tracker rate period. This process will allow I&M to true up gridSMART^{SM} tracker revenues to actual gridSMART^{SM} tracker costs.

<u>Accounting for an Incremental Enhanced Distribution Reliability Tracker (EDRT)</u>

Q. Please explain the accounting for I&M's requested incremental EDRT program costs.

A. Company witness Ehler discusses the plans and supports the incremental capital and O&M program costs to be incurred in connection with distribution reliability improvement work to be performed by I&M. Company witness Krawec proposes an EDRT to provide timely and full recovery of the actual EDRT costs (O&M expense, depreciation expense, carrying charges on the capital investments and carrying charges on any over/under recovered EDRT costs). Specific projects, such as the vegetation management program, will be identified as a part of the reliability improvement program and I&M will record actual costs incurred in the appropriate capital or expense accounts as described in detail later in my testimony. If approved, concurrently, I&M would recover from customers an amount approved by the Commission based on forecasted EDRT costs and record the revenues in the normal revenue accounts. I&M will then compare the current EDRT revenues to its actual incremental EDRT costs including a carrying charge on the over/under recovery balance in order to true-up the EDRT revenues to the actual incremental EDRT costs. EDRT revenues in excess of EDRT costs will constitute an over recovery. EDRT costs in excess of the EDRT revenues will constitute an under recovery. The difference in EDRT incremental costs and EDRT revenues will be deferred as a regulatory liability if there is an over recovery, or as a regulatory asset if there is an under recovery.

Q. What costs will be considered qualifying incremental EDRT costs and thus qualify for the EDRT recovery?

A. To be considered an incremental EDRT cost and thus qualify for deferral accounting, the incurred O&M costs and capital costs must be related to the activities identified in the projections made with this filing, or subsequent EDRT filings, such as the projects discussed by Company witness Ehler. Also in order to qualify as an EDRT cost the identified projects must be incremental reliability, i.e. the costs must exceed the reliability costs being recovered in base rates. After the EDRT rates are effective the incremental EDRT costs, and any true-up over or under recovery deferral balance, along with the carrying costs on any deferred over or under recovered balance, will be considered EDRT costs.

Q. How will the qualifying EDRT costs be recorded by I&M?

A. Qualifying EDRT O&M costs, supported by Company witness Ehler, will be recorded as O&M expenses and will be charged to the appropriate functional distribution expense accounts in the 580-598 series using a project number and work order. Likewise, qualifying EDRT capital costs, supported by Company witness Ehler, will be recorded as incurred and will be charged to the appropriate functional electric plant accounts using a project number and work order. The project/work order number will allow I&M to identify qualifying EDRT costs attributable to qualifying activities in order to include them in the over/under recovery true-up determination.

Q. What will be I&M's monthly accounting for EDRT qualifying projects after the proposed EDRT is effective?

A. If over/under recovery deferral accounting is approved by the MPSC for EDRT, in accordance with FASB ASC 980, as previously discussed in my testimony, effective with the implementation of the EDRT, I&M will perform traditional regulatory deferral over/under recovery true-up accounting by calculating, monthly, any over-recovery or under-recovery of the incremental projects' costs. I&M will compare the current month EDRT revenues collected to the current month actual incremental EDRT project costs including a return on the capital costs calculated using the rate supported by Company witness Hawkins related to gridSMART^{SM} (as discussed earlier in my testimony) as well as a carrying cost on previously deferred over/under recoveries of EDRT costs.

If the monthly qualifying incremental EDRT revenues are less than the monthly actual EDRT costs, I&M will record the under-recovery as a decrease (credit) to the appropriate expense accounts, with a corresponding debit recorded to either a Regulatory Asset or a Regulatory Liability. (A Regulatory Asset will be debited if the cumulative balance is an under-recovery and a Regulatory Liability will be debited if the cumulative balance is an over-recovery until the over recovery balance is eliminated.)

Similarly, if monthly EDRT revenues are more than the monthly qualifying incremental actual EDRT costs, I&M will record the over-recovery as an increase (charge) to the appropriate expense accounts, with a corresponding credit recorded to either a Regulatory Liability or a Regulatory Asset. (A Regulatory Liability will be credited if the cumulative balance is an over-recovery and a Regulatory Asset will be credited if the cumulative balance is an under-recovery until the under recovery balance is eliminated.) On an annual basis any over or under recovered balance will be included as a reconciliation item to either reduce, for an over-recovery, or increase, for an under-recovery the amount of incremental unrecovered EDRT costs to be collected in the next EDRT rate period. This process will allow I&M to true up

EDRT revenues to actual EDRT costs.

Q. How will I&M calculate a carrying cost related to the EDRT?

A. Whenever I&M experiences an over or under recovery of EDRT costs I&M will calculate and defer a carrying cost on the over or under recovered balances computed at a short-term debt carrying cost (STDCC) rate updated monthly. The deferred carrying cost will be a component of the determination of the EDRT over or under recovery true-up. This accrual of STDCC on the deferred balance of over or under recovered qualifying incremental EDRT expenses will continue until the balance is fully recovered through the new EDRT rates. The resulting regulatory liability or regulatory asset will be recovered over the next 12 month EDRT rate period.

Accounting For the Proposed Generation Investment Tracker

Q. Has I&M included the forecasted balance of Construction Work in Progress (CWIP) in its average rate base in this case?

A. Yes, as shown on Exhibit I&M-26 (WAA-3), a forecasted level of CWIP is included in average rate base for I&M's 2010 projected test year, the 12 months ended December 31, 2010, as presented by Company witness Allen.

Q. Since I&M has included CWIP in rate base, does I&M intend to capitalize AFUDC on CWIP expenditures in rate base?

A. Yes. Although I&M has included a level of CWIP in rate base, I&M capitalizes

AFUDC on CWIP based on the authorization obtained in Case No. U-6910. That authorization allowed I&M, as a multi-state jurisdiction company, to record AFUDC per the FERC accounting requirements. However, consistent with the traditional procedure in Michigan, the Michigan jurisdictional portion of AFUDC related to CWIP is treated as income in the revenue requirement determination by Company witness Roush.

Q. Please explain generally how the accounting for I&M's requested GIT will work for these major projects?

A. Company witnesses Hruby and Peifer, respectively, describe the Cook Improvement Project (CIP) and the installation of selective catalytic reduction (SCR) and flue gas desulfurization (FGD) equipment at the Rockport Plant, i.e. proposed qualifying projects which will accumulate annually to a balance significantly in excess of the plant balances included in I&M's requested rate base in 2010. Company witness Krawec proposes a Generation Investment Tracker (GIT) to provide timely and full recovery of actual CWIP financing costs on these major construction projects without having to adjust base rates. As these qualifying major projects are constructed and subsequently placed in-service in the near future, I&M will record actual costs incurred in the normal asset and expense accounts as described in detail later in my testimony. Concurrently, I&M proposes to recover from customers an amount of cost on these qualifying major projects approved by the Commission and record the revenues in the normal revenue accounts. I&M will then compare the GIT revenues to its actual GIT costs, including approved carrying costs, and record a true-up over recovery regulatory liability in the amount that GIT revenues exceed actual GIT costs or record a true-up regulatory asset in the amount that actual qualifying GIT costs exceed the GIT revenues.

Q. What costs will be considered qualifying GIT costs and thus be eligible for recovery through the GIT rider?

A. To be considered a qualifying GIT cost, and thus be eligible for recovery through the GIT rider and eligible for traditional regulatory deferral over/under recovery true-up accounting, the incurred cost must be a construction financing cost calculated on the amount by which the balance of qualifying major project construction expenditures exceeds the $57 million Total Company balance (hereinafter referred to as the eligible GIT project costs) included in the net plant shown on Exhibit I&M-26 (WAA-3) or a post in-service cost related specifically to the CIP as supported by Company witness Hruby. As explained by Company witness Hruby, components of the CIP will be placed in-service as those projects are completed over the next few years. When a project is placed in-service, I&M will also incur post in-service costs, which include depreciation on the newly in-service investment and operating and maintenance expenses on the new assets. Therefore those in-service costs, along with a carrying cost (return) on the newly in-service investment related to these major projects will also qualify as GIT costs. In addition, the previous GIT period's over or under recoveries of qualifying GIT costs, plus a return, will be considered qualifying GIT costs.

Accounting For The GIT Projects During Construction

Q. In what account will the construction expenditures on these qualifying major projects initially be recorded?

A. During construction, these costs are recorded in Account 107, Construction Work in Progress.

Q. Please explain how I&M will record and segregate construction costs associated with the projects.

A. I&M assigns a project number to each project so that all capital costs associated with a specific project may be recorded and separately identified in the accounting system.

Q. If the MPSC approves the GIT, as proposed to include a cash return calculated at a full WACC rate, will I&M accrue AFUDC on the GIT qualifying construction balances in excess of the GIT CWIP balances included in I&M's projected 2010 rate base?

A. No, although Case U-6910 allows the accrual of AFUDC on CWIP balances, no AFUDC should be accrued since I&M has proposed to recover a WACC return on the GIT CWIP balances that will be recognized through the GIT, as explained by Company witness Krawec, and has also proposed traditional regulatory deferral over/under recovery true-up accounting.

Accounting For GIT Project Post In-service Costs

Q. What accounting will I&M do upon the in-service and completion of construction of the GIT qualifying projects?

A. When the GIT qualifying major projects are placed in-service, I&M will transfer the costs from Account 107, CWIP, to Account 106, Completed Construction Not Classified. The construction costs will be transferred into Account 101, Electric Plant in Service, when classified by appropriate 300 level plant sub-accounts provided in the USofA. Once the GIT qualifying projects are in-service, I&M will start recording depreciation, and begin incurring and recording the operating and maintenance expenses of the qualifying assets.

Q. Please explain I&M's accounting for depreciation expense on the projects.

A. Depreciation expense will be computed using the recent Commission-approved depreciation rates, in Case No. U-15162, and recorded by charging Account 403, Depreciation Expense, and crediting Account 108, Accumulated Provision For Depreciation of Electric Plant. The specific asset location and depreciation group assigned to each project will permit the depreciation of each qualifying asset to be tracked.

Q. How will I&M account for operation and maintenance expenses related to these projects?

A. Post in-service O&M costs on these projects, supported by Company witnesses Hruby and Peifer, will be charged using a project number and work order to the appropriate functional generation expense accounts in the 500-532 series. The project/work order number will allow I&M to identify qualifying GIT post in-service costs attributable to qualifying assets.

<u>Deferral Accounting for GIT Projects</u>

Q. Is the deferral accounting treatment I&M proposes in accordance with GAAP and the FERC USofA?

A. Yes, as discussed previously in my testimony, FASB ASC 980 (formerly SFAS 71) requires deferral accounting when certain conditions are met such that incurred costs are probable of future recovery. Also, as previously discussed, FASB ASC 980-405-25-1 addresses how a regulator can impose a liability on a regulated enterprise including when a regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced.

The FERC fully incorporated FASB ASC 980 in the USofA. As such, I&M's proposed deferral accounting is consistent with GAAP and the FERC USofA.

Q. Please explain I&M's monthly accounting for the over/under recovery of GIT qualifying projects.

A. Effective with the implementation of the GIT, I&M will perform traditional over/under recovery true-up accounting by calculating, monthly, any over-recovery or under-recovery of the projects' costs. I&M will compare the current month GIT revenues to the current month actual eligible GIT project costs including the GIT WACC carrying cost, as discussed later in my testimony.

If the monthly GIT revenues are less than the monthly actual eligible GIT project costs I&M will record the under-recovery as a decrease (credit) to the appropriate expense accounts, with a corresponding debit recorded to either a Regulatory Asset or a Regulatory Liability. (A Regulatory Asset will be debited if the cumulative balance is an under-recovery while a Regulatory Liability will be debited if the cumulative balance is an over-recovery until the over-recovery balance is eliminated.)

Similarly, if monthly GIT revenues are more than the monthly eligible GIT project costs, I&M will record the over-recovery as an increase (charge) to the appropriate expense accounts, with a corresponding credit recorded to either a Regulatory Liability or a Regulatory Asset. (A Regulatory Liability will be credited if the cumulative balance is an over-recovery while a Regulatory Asset will be credited if the cumulative balance is an under-recovery.)

On an annual basis any over or under recovery balance will be included as a reconciliation item to either reduce, for an over-recovery, or increase, for an under-recovery the amount to be collected in the next GIT rate. This process will allow I&M to true up GIT revenues to actual eligible GIT project costs and comply with the matching of cost and revenue inherent in FASB ASC 980's required deferral accounting.

Discussion of GIT Carrying Costs

Q. Under what circumstances will I&M record a carrying cost related to the GIT and how will it be calculated?

A. As previously discussed, I&M proposes to use a WACC return as the carrying cost rate in the determination of actual costs used in the reconciliation of over/under recovery of GIT project costs. A WACC rate will be used due to the long-term nature of qualifying GIT project expenditures and the need to finance these expenditures on a long term basis with both debt and equity. The deferred carrying cost will be a component of the determination of the GIT over or under recovery. As a result, I&M will continue to earn a return on a qualifying project's investment balances included in the then current GIT factor, collected in GIT revenues. However, the difference between the GIT costs authorized and included in the GIT rider as of the effective date of the final Commission rate order (or as of any future MPSC approval date) and the total actual GIT cost of the qualifying projects including a WACC based carrying cost will result in carrying costs on qualifying assets being deferred and recorded as a regulatory asset or as a component of a regulatory liability for collection or refund in the next GIT reconciliation proceeding. This deferral of a WACC based carrying cost on qualifying plant investment balances will continue until the balances are included in the GIT investment base for computing a WACC based return in the GIT factor or included in new base rates, whichever comes first. This regulatory asset will be recovered over the next 12 month GIT recovery period.

Q. What carrying cost rates will I&M use in the calculation of the WACC return on GIT project expenditures in the calculation of the GIT over/under recovery?

A. I&M will use the ROE rate approved in this base case and the WACC rate will be updated for changes in I&M's weighted average cost of debt.

Q. How often will the WACC rate be updated for changes in I&M's weighted average cost of debt?

A. I&M will update its weighted average cost of debt monthly.

Q. Will the equity rate be updated?

A. An update to the equity rate will only be made if I&M has a change in its base rates in a base rate proceeding before this Commission which revises the ROE rate.

Q. Please discuss the accounting related to I&M being able to recognize an equity carrying cost.

A. FASB ASC 980 allows I&M to recognize an equity carrying cost while the assets are under construction. However, if the carrying cost relates to a qualifying asset that is no longer under construction, i.e. a qualifying post in-service asset, I&M cannot recognize the equity component of a WACC based in-service carrying cost as a regulatory asset.

The debt portion of a carrying charge on in-service plant can be recognized as income as it is deferred for future recovery, however, in accordance with FASB ASC 980-340-25-5 (formerly SFAS 92 paragraph 9) if the item upon which the carrying cost is being earned is not construction expenditures, the equity portion of the WACC based carrying charges can be recognized as income only when it is included in rates and billed to customers. The equity component of the post in-service carrying cost cannot be deferred as a regulatory asset even though it is recoverable in the future because it is not an incurred cost. FASB ASC 980-10-15-2 (formerly SFAS 71 paragraph 5) requires that incurred costs be deferred as a regulatory asset when the cost is to be recovered in the future through cost based regulated rates. This is reaffirmed by FASB ASC 980-340-25-5 which prohibits the recognition of equity costs except during construction. However, in order to track the currently non-recognizable equity portion, I&M will record a regulatory asset in the full amount of the WACC carrying cost and credit, as a contra regulatory asset, the equity portion of the post in-service WACC carrying cost to be recovered and recognized in the future. As a result, the equity component of the post in-service carrying cost not yet recovered will be tracked by this contra regulatory asset account for accounting purposes until it can be recognized when recovered in rates and the resulting net regulatory asset will only equal the debt component of the non-construction (in-service) WACC-based carrying cost. This procedure will result in only the debt component of the post in-service carrying charge being reflected as a net credit monthly to income.

Q. Is I&M also proposing to calculate carrying charges on the over/under

recovery regulatory liability or regulatory asset balances?

A. Yes, given the expected short-term nature of the over/under recovery balances, I&M recommends that carrying charges be computed and deferred for future recovery by applying I&M's monthly weighted average cost of short term debt to the prior month cumulative GIT over recovery balance or cumulative GIT under recovery balance.

<u>Accounting for I&M's Proposed Major Storm Damage Restoration Reserve</u>

Q. Please summarize the accounting for I&M's Proposed Major Storm Damage Restoration Reserve.

A. As discussed by Company witness Krawec, and supported by Company witnesses Allen and Ehler, I&M is proposing to implement a Major Storm Damage Restoration Reserve. If approved, I&M will use traditional regulatory deferral over/under recovery true-up accounting to match the Michigan base revenues intended to recover the restoration expenses to the incurred major storm damage restoration O&M expenses (see Company witness Ehler's discussion of how I&M defines major storm damage), beginning with the effective date of a final order in this case. If there is an over recovery from such matching, I&M will record a regulatory liability. If there is an under recovery I&M will record a regulatory asset. The true-up of the resulting net balance of the monthly over and under recoveries will be included in the next

I&M Michigan base rate case.

Q. Will the over/under recovery of the Major Storm Damage Restoration Reserve include both distribution and transmission major storm costs?

A. As proposed, I&M's projected Major Storm Damage Restoration Reserve expenses supported by Company witness Allen includes only major storm damage distribution expenses since the major storm damage transmission expenses would be included in I&M's proposed Open Access Transmission Tariff (OATT) charges in the proposed unified PSCR clause. The inclusion of OATT charges in the unified PSCR clause is more fully discussed by Company witnesses Krawec, Gregory and Bethel. However, if the MPSC does not approve I&M's proposed inclusion of the OATT charges in the proposed unified PSCR clause, then I&M proposes to include actual transmission major storm restoration expenses as well as distribution major storm restoration expenses in the proposed Major Storm Damage Restoration Reserve.

Q. After Commission approval, what monthly accounting will I&M use to match its base rate recovery to its actual incurred major storm damage restoration expenses?

A. Beginning with the effective date of a final order in this case, I&M proposes to begin recording monthly an over or under recovery regulatory liability or asset calculated by comparing the approved Michigan jurisdictional base revenues ($596,000 annually as proposed by Company witness Allen) intended to recover major storm damage restoration O&M expenses with the actual incurred major storm damage restoration expenses. If the monthly actual incurred major storm damage restoration expenses are less than the monthly approved major storm damage restoration base revenue ($49,667 as proposed, i.e. one twelfth of the annual $596,000), I&M will credit a regulatory liability and charge the appropriate distribution and transmission O&M expense accounts. Similarly, if the monthly actual incurred major storm damage restoration expenses are more than the monthly approved major storm damage restoration base revenues ($49,667 as proposed), I&M will charge a regulatory asset while crediting the appropriate distribution and transmission O&M expense accounts.

Q. Is I&M requesting a carrying charge be applied to the major storm damage restoration reserve regulatory liability or regulatory asset?

A. Yes, as discussed by Company witness Krawec, given the potential long-term nature of the over/under recovery balances, I&M recommends that carrying charges be computed and deferred for future recovery by applying I&M's WACC return rate to the prior month cumulative over/under recovery balance.

Q. What carrying cost rates will I&M use in the calculation of the WACC return on over/under recovery balances?

A. I&M will use the ROE rate approved in this base case and the WACC rate will be updated for changes in I&M's weighted average cost of debt.

Q. How often will the WACC rate be updated for changes in I&M's weighted average cost of debt?

A. I&M will update its weighted average cost of debt monthly.

Q. Will the equity rate be updated?

A. An update to the equity rate will only be made if I&M has a change in its base rates in a base rate proceeding before this Commission which revises the ROE rate.

Q. Please discuss the accounting related to I&M being able to recognize an equity carrying cost.

A. FASB ASC 980-340-25-5 (formerly SFAS 92 paragraph 9) does not allow I&M to recognize, as a regulatory asset, an equity component of a WACC based carrying cost on assets that are not under construction.

The debt portion of a carrying charge on under recovered regulatory assets can be recognized as income as it is deferred for future recovery, however, in accordance with FASB ASC 980-340-25-5 if the item upon which the carrying cost is being earned is not construction expenditures, the equity portion of the WACC based carrying charges can be recognized as income only when it is included in rates and billed to customers. The equity component of the carrying cost on under recovered regulatory assets cannot be deferred as a regulatory asset even though it is recoverable in the future because it is not an incurred cost. However, in order to track the currently non-recognizable equity portion, I&M will record a regulatory asset in the full amount of the WACC carrying cost and credit, as a contra regulatory asset, the equity portion of the WACC carrying cost to be recovered and recognized in the future. As a result, the equity component of the carrying cost not yet recovered will be tracked by this contra regulatory asset account for accounting purposes until it can be recognized when recovered in rates and the resulting net regulatory asset will only equal the debt component of the WACC-based carrying cost. This procedure will result in only the debt component of the post in-service carrying charge being reflected as a net credit monthly to income in compliance with GAAP.

Q. If the proposed rate treatment is approved, will your proposed over/under regulatory deferral accounting, discussed above, be consistent with GAAP?

A. Yes. As discussed earlier in my testimony, (related to gridSMART[SM], EDRT and GIT) FERC ASC 980 requires deferral accounting when a regulator requires future rates to be reduced to refund an over recovery and when a regulator provides for the future recovery of incurred expenses or it is probable that a regulator will provide for such future recovery of an incurred expense. Therefore, in order to record regulatory liabilities or regulatory assets and perform traditional regulatory deferral over/under recovery true-up accounting, it must be probable that the liability will be refunded or that the regulatory asset will be recovered in the future.

Q. What is needed to establish probability and thus meet the accounting criteria for recording a regulatory liability or asset?

A. In order to meet the probability standard, the final order in this proceeding should clearly provide for both the future recovery of any incurred major storm damage restoration expenses, plus a carrying cost, that are greater than actual major storm damage restoration revenues in the next I&M Michigan base rate case and it should provide for the return through base rates in the next I&M Michigan base case of any over recovery plus carrying cost thereon.

Q. Does this complete your pre-filed direct testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

TESTIMONY

OF

INDIANA MICHIGAN POWER COMPANY

VOLUME III

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WILLIAM W. HIX
DIANE KEEGAN
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SCOTT M. KRAWEC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
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PREFILED DIRECT TESTIMONY

OF

WILLIAM W. HIX

PREFILED DIRECT TESTIMONY OF WILLIAM W. HIX

ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. Please state your name and business address.

A. My name is William W. Hix and my business address is One Summit Square, P. O. Box 60, Fort Wayne, Indiana 46801.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as the Senior Regulatory Consultant in the Regulatory Services Department.

Q. Please briefly describe your educational and business experience.

A. I received an Associate Degree in Electrical Engineering Technology and a Bachelor Degree in Electrical Technology from Purdue University in 1978 and 1987, respectively. Additionally, I received an Associate Degree in Supervision from Purdue University in 1987. I have completed the EEI Electric Rate Advanced Course.

I began my utility career with The Detroit Edison Company (DECo) at its Monroe Power Plant as a Power Plant Technician in 1978. After leaving DECo, I joined I&M, which is an operating company subsidiary of the American Electric Power (AEP) System, in January 1979 as an Operation Engineering Technologist in the System Operations Department where I performed various duties including advising and training system operators, and overseeing I&M's statistical metering load research. I assumed the position of Operation Engineer in 1984. In August 1987, I was promoted to the Rate Department as

Rate Analyst Senior. Since that time, I have progressed through various positions and was promoted to my current position of Senior Regulatory Consultant in April 2006. I am responsible to the Director of Regulatory Services for a broad range of matters including tariff application and interpretation, rate design, cost-of-service studies, and various other studies, reports, and regulatory filings, as required.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony to the Michigan Public Service Commission (MPSC) in Case Nos. U-13764, U-14193, and U-14409 in support of I&M's complaints regarding violations of Rule 411. Additionally, I have submitted testimony to the Indiana Utility Regulatory Commission in several cases involving I&M's applications to extend the effective dates of its Indiana Economic Development Rider (EDR), in support of Backup Service Agreements and Alternate Feed Service Agreements, territorial boundary proceedings, and to support I&M's request for a limited waiver of a Commission Rule for the purpose of conducting a Smart Metering Pilot Program.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to sponsor the modifications to I&M's Terms and Conditions of Service and Tariffs, including the changes brought about by merging the St. Joseph (SJRA) and Three Rivers (TRRA) Rate Areas as was proposed and supported by Company witness Krawec. I am also sponsoring the price changes included in the Terms and Conditions of Service. The justification for tariff price changes, rationale for any redesign of existing Company's tariffs, and explaining the rate design of new tariffs and riders will be supported by Company witness Roush.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

Exhibit I&M-62 (WWH-1)	Summary of Significant Terms and Conditions of Service Modifications.
Exhibit I&M-63 (WWH-2)	Summary of Significant Tariff Modifications Other than Price Changes.
Exhibit I&M-64 (WWH-3)	Schedule F5, redline version of Company's proposed Index Section A (Section A).
Exhibit I&M-65 (WWH-4)	Schedule F5, redline version of Company's proposed Terms and Conditions of Standard Service (Section C).
Exhibit I&M-66 (WWH-5)	Schedule F5, redline version of Company's proposed Standard Tariffs – SJRA (Section D).
Exhibit I&M-67 (WWH-6)	Schedule F5, redline version of Company's proposed Standard Tariffs – TRRA (Section E).
Exhibit I&M-68 (WWH-7)	Schedule F5, redline version of Company's proposed Terms and Conditions of Open Access Distribution Service (Section F).
Exhibit I&M-69 (WWH-8)	Schedule F5, redline version of Company's proposed Open Access Distribution Tariffs – SJRA (Section G).
Exhibit I&M-70 (WWH-9)	Schedule F5, redline version of Company's proposed Open Access Distribution Tariffs – TRRA (Section H).

Q. Were the exhibits, or portions of exhibits, which you are sponsoring prepared by you or under your supervision?

A. Yes.

Q. Please summarize the Terms and Conditions of Service modifications proposed by the Company.

A. The significant Terms and Conditions of Service modifications proposed by the Company are outlined in Exhibit I&M-62 (WWH-1). Most proposed modifications were made to better explain and clarify the Company's policies and practices. The Terms and Conditions of Service sections that include customer charges have been updated to reflect current costs. The costs in the current Terms and Conditions of Service for line extensions are based on mid-1970s costs and the nonrecurring charges in the Special Service Charges section are based on early 1980s costs.

Q. Please explain the proposed price changes to the Terms and Conditions of Service that involving line extension provisions, Terms and Conditions of Service numbers 12 and 13.

A. The prices in existing Terms and Conditions of Service number's 12 and 13, applicable to overhead line extensions, underground line and service extensions, and transformer installation costs, are based on costs established in the mid-1970s. The proposed costs were derived from current average actual costs.

Q. Please explain the proposed price changes to Term and Condition of Service Number 16, Special Service Charges.

A. The prices in the existing Term and Condition of Service for Special Service Charges, Term and Condition of Service Number 15, are based on costs established in the early-1980s. The Special Service Charges have been relocated to Term and Condition of Service Number 16. The proposed prices were derived from most recent actual labor and vehicle costs. In addition to updating the costs already included in the Terms and Conditions of Service, some additional reconnect scenarios were added to address those rare instances when those situations might arise such as reconnects on holidays or Sundays and reconnects at poles. A service charge was added to recoup costs associated with trips to the customer's premise to notify the customer that payment is due. These trips are made when attempts to reach the customer by telephone have been unsuccessful.

Q. What changes are being proposed that affect all tariffs?

A. Several changes are being proposed that affect all tariffs. A major proposed change is the merging of the SJRA and TRRA jurisdictions as was supported by Company witness Krawec. Clarification to several availability statements were made to various tariffs, holidays were eliminated as off-peak days which were only recognized in the SJRA, OATT and Retail Transmission rates were removed from tariff rates and have been rolled into the PSCR, rate tables for tariffs were updated to reflect the proposed changes in riders, and column titles for "Generation" and "Distribution" were replaced with "Power Supply" and "Delivery Charge," respectively.

Q. Please explain the changes to residential tariffs.

A. The primary change in Tariff RS is the elimination of the current increasing block rate structure which is part of the current Tariff RS in the (SJRA). The currently SJRA Tariff RS is a two block rate with one price for the first 500 kWh of monthly use and a higher price for all monthly use in excess of 500 kWh. IN Tariff RS-SC the contract requirement has been eliminated.

Q. Please describe the current commercial and industrial tariffs.

A. I&M currently has four commercial and industrial tariffs applicable to customers with demands greater than 10 kW. There are two sets of companion schedules available to customers depending upon the size (demand) of the customer.

St. Joseph Rate Area

Tariff MGS for customer with demands as low as 10 kW and Tariff LGS applicable to customers with demands greater than 100 kW served at secondary voltages. While Tariffs QP and LP are applicable to customers with demands greater than 100 kW and 2,000 kW, respectively, the service voltages offered are primary and subtransmission for Tariff QP and subtransmission and transmission for Tariff LP. Tariffs MGS and QP are generally more beneficial for lower load factor customers whereas Tariffs LGS and LP are generally more beneficial for higher load factor customers. Load factor is simply a measure of the amount of electricity a customer uses over time (energy) relative to the customer's maximum utilization (demand). This structure generally ensures that all customers have the opportunity to choose the rate schedule best suited to their usage characteristics, although the current service voltage limitations sometimes dictates the customer's rate schedule. The schedules provide rate continuity for customers as usage changes whether by size or by load factor.

Three Rivers Rate Area

Tariff MGS for customer with demands as low as 10 kW and Tariff LGS applicable to customers with demands greater than 100 kW served at secondary, primary, and subtransmission voltages. While Tariffs QP and LP are applicable to customers with demands greater than 100 kW and 2,000 kW, respectively, the service voltages offered are primary, subtransmission, and transmission for Tariffs QP and LP. Like the SJRA tariffs, Tariffs MGS and QP are generally more beneficial for lower load factor customers whereas Tariffs LGS and LP are generally more beneficial for higher load factor customers. This structure generally ensures that all customers have the opportunity to choose the rate schedule best suited to their usage characteristics, although the current service voltage limitations sometimes dictates the customer’s rate schedule. The schedules provide rate continuity for customers as usage changes whether by size or by load factor.

Q. Please describe the proposed commercial and industrial tariffs.

A. The proposed commercial and industrial tariffs have made additional service voltage levels available that will allow customers to select the most appropriate tariff and eliminate the service voltage limitations mentioned above. As indicated above, Tariffs QP and LP are compatible tariffs with the primary difference between the two tariffs being the design of the demand and energy charges which makes QP more attractive to lower load factor customers and LP more attractive to higher load factor customers. Customers having load factors that are near the break-even or crossover point between Tariffs QP and LP are faced with the decision of entering into a service contract under one of the tariffs. This decision can be quite difficult, particularly for new or expanding customers that are uncertain of what their ultimate operating characteristics will be. To address and eliminate such concerns as well as simplify tariff and contract administration, the Company proposes to consolidate the two tariffs.

Q. Does I&M propose a new tariff for Alternate Feed Service (AFS)?

A. Yes. Given the special nature of this service for customers that request a second distribution feed in addition to their basic service, I&M proposes a special tariff to address the unique nature and costs of providing that service. For various reasons, AFS customers require a higher level of reliability than other customers. While I&M wishes to meet the needs of its customers, it is important that such customers pay charges that reflect the full cost of providing such service. This prevents I&M's other customers that do not benefit from bearing additional costs for providing this premium service to customers that desire an alternate feed. Most importantly, the proposed Rider AFS provides the proper price signal to customers concerning the cost of alternate feed service. This allows customers to make an economic choice whether an alternate feed or another alternative, such as an emergency generator, is the best way to meet their unique reliability needs.

I&M's proposed Rider AFS includes two main provisions. First, the customer is responsible for all dedicated and/or local facilities required to provide the alternate feed. Second, the customer pays a monthly charge per kW for the capacity reserved on the Company's facilities for the alternate feed.

Q. Does I&M currently provide AFS to any customers?

A. Yes, I&M currently provides Alternate Feed Service to six (6) customers. Historically, I&M provided AFS to customers that requested the service if the alternate feed circuit had available capacity enough to provide the service. The customer was required to pay for the local facilities required to connect their point of basic service delivery to the alternate feed circuit and the transfer switch. More recently, the combination of utilities continuing to look for opportunities to utilize existing capacity to provide basic service to new customers and an increase in requests for AFS has prompted I&M to enter into contracts with customers requesting AFS.

Q. Once approved, will the current customers receiving AFS be subject to the new Rider AFS?

A. I&M has six (6) customers receiving AFS, two (2) of which are by contract. The two customers receiving AFS under contract would be subject to the provisions of the new rider once the rider is approved. The remaining four (4) customers would become subject to the provisions of the rider if and when the capacity of the alternate feed circuit providing their AFS reaches the point that the Company must make investments to maintain the AFS or incrementally when they request an increase in AFS capacity.

Q. Please describe the Company's proposed interruptible and experimental service offerings.

I&M is proposing a new interruptible service offering Contract Service Interruptible Power (CS-IRP). Under Tariff CS-IRP, I&M proposes limiting the total availability of interruptible service to 50 MW, with a minimum of 1,000 kW interruptible capacity per customer. Service under the new tariff is available to all service voltages. Tariff CS-IRP provides for two distinct types of interruptible service: a mandatory or capacity interruptible service and a discretionary or energy interruptible service.

I&M also proposes a three-year experimental Real-Time Pricing tariff whereby customers can manage their electric costs by shifting load from higher cost to lower cost pricing periods or by adding new load during lower price periods. Lastly, I&M proposes to eliminate the current ECS and PCS offerings and replace them with new ECS and EPCS riders which reflect significant modifications from the previous riders to increase their attractiveness to customers. Company witness Roush explains the proposed tariffs and riders in greater detail.

Q. **Please discuss the proposed changes to the Company's streetlighting tariffs.**

A. The proposed changes to Tariffs SLS and ECLS include adding the cost of fiberglass poles into the rates with metallic and concrete poles and provisions to address those instances when municipals desire that streetlight lamps installed as part of an integrated streetlight system be relocated and/or removed from service. Additionally, the Company recognizes that the Commission's Order in Case No. U-16186 directs the Company to establish tariffs governing the provision of unmetered street lighting, area lighting, and traffic signal services based on emerging light-emitting diode technologies. The Company has determined with regard to this Commission directive that the best course of action is to file those tariffs separately from this rate case, therefore Company will be filing such tariffs as directed on or before February 10, 2010.

Q. **Please discuss the proposed changes to the Company's Tariff COGEN/SPP.**

A. Proposed changes to the Tariff COGEN/SPP backup power provision are to address those cogeneration and/or small power production facilities that operate intermittently such that the customer's monthly billing demands under the demand-metered rate schedule will be based upon the customer's maximum monthly demand which will occur at a time when the cogeneration and/or small power production facility is not in operation, such as wind or solar generation facilities.

Q. **Please describe the renewed Economic Development Rider (EDR) the company is proposing as a part of its Economic Development Program.**

A. The proposed EDR will be a tool to increase the effectiveness of the economic development process. The EDR is intended to benefit all stakeholders by attracting new or expanded business to the I&M service territory thereby creating plant and facilities investment and job opportunities. I&M, its customers, the communities I&M serves and the State of Michigan benefit from job creation. The EDR is designed to encourage new development, urban redevelopment, and Brownfield redevelopment by offering a discount on customers' demand charge on a limited term basis when certain criteria are met.

Regional and state economic development efforts would be supplemented by Commission approval of the EDR. New businesses nationwide rely upon publicly available information to determine which states and localities are desirable. These businesses utilize information available on the internet to locate economic development electric rate incentives. After Commission approval of the proposed EDR, the incentives offered by the EDR will be available to the public and accessible by those doing independent research on site location via I&M's website. Further, the EDR will be a valuable tool to those in Michigan who work everyday to attract economic development.

Q. **What will the EDR offer to new development?**

A. For new development customers, I&M proposes that the EDR be offered with the following conditions: (1) the new load applicable to the EDR incentives must be a minimum of 250 kW, (2) the business must not be classified in certain identified Standard Industrial Classifications (SIC) major groups, and (3) the customer must demonstrate to the Company's satisfaction that, absent the availability of this Rider, the qualifying new or increased demand would be located outside of the Company's service territory or would not be placed in service due to poor operating economics. Customers meeting the above conditions will be eligible to receive a reduction in the customers' demand charge.

Q. **What will the EDR offer to business customers locating in existing buildings that are not located in Brownfield sites?**

A. I&M proposes that the EDR be available to new business customers locating in existing buildings that have been unoccupied and/or have remained dormant for at least one year or more, subject to the same requirements indicated above for new development customers. Service must be provided at one delivery point and must not require significant transmission or distribution system investment, other than the connection of service. Customers who meet these EDR requirements will be eligible to receive a limited term reduction in their demand charge.

Q. **What will the EDR offer to new business customers locating in qualifying Brownfield redevelopment areas?**

A. For the reasons indicated above, new businesses typically want greater incentives to invest in Brownfield redevelopment areas. In order to assist Michigan in re-using these sites, I&M's proposed EDR will provide incentives to new business customers who meet the EDR requirements and locate in qualifying Brownfield redevelopment areas, as defined under Michigan or federal law, that are served by existing I&M primary service lines and have been vacant for more than two years. Customers who meet these requirements will be eligible to receive a limited term reduction in the demand charges.

Q. **Please explain the benefits of attracting new customers to Brownfield redevelopments.**

A. Along with the other benefits that economic development provides, attracting new business to Michigan's Brownfield sites helps revitalize blighted areas thereby taking what had been an economic liability and turning it into an economic asset. Generally, a Brownfield site is a property where redevelopment is complicated due to actual or potential environmental contamination. Brownfield sites are typically avoided by new businesses. If new business can be attracted to these sites, Michigan's economy, aesthetics, and its citizen's quality of life are improved.

Q. Please summarize your testimony in this proceeding.

A. I am sponsoring the modifications to the Company's proposed Terms and Conditions of Service and Tariffs. The proposed tariffs represent the consolidation of the two existing I&M Michigan rate jurisdiction's tariffs into one rate jurisdiction. I have introduced several new tariff offerings including Contract Service Interruptible Power (CS-IRP), Experimental Real-Time Pricing (RTP), Alternate Feed Service Rider (AFS), and a renewed Economic Development Rider (EDR).

Q. Does this conclude your prefiled direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. **U-16180**
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

DIANE M. KEEGAN

PRE-FILED DIRECT TESTIMONY OF DIANE M. KEEGAN
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS AND EMPLOYMENT POSITION.

A. My name is Diane M. Keegan. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed as a Principal Regulatory Consultant by American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Indiana Michigan Power Company (I&M or Company).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS EXPERIENCE.

A. I have an associate degree in Business Data Processing from Columbus Technical Institute and also undergraduate degree(s) in Marketing, Business Management and Accounting and a Master of Business Administration from Franklin University. I also completed the EEI Electric Rate Advanced Course.

I have held various progressive positions of responsibility in the Regulated Pricing and Analysis Department starting with Engineering Technician in 1986. I have experience in the operating company as a Rate Analyst in the Columbus Southern Power Company Rate Department. I returned to

AEPSC and worked in the Rate Department until 2000 when I was promoted to Senior Business Analyst, Energy Delivery & Customer Relations where I was responsible for technical support and system specifications for customer billing for all of the AEP System's eleven operating companies. In 2001, I returned to AEPSC Regulatory Services as Regulatory Consultant I, Transmission and Interconnection Services, where I was responsible for transmission cost of service and wholesale contracts. In 2003, I returned to Regulated Pricing and Analysis as a Senior Regulatory Consultant and in 2008 was promoted to my current position.

Q. WHAT ARE YOUR RESPONSIBILITIES AS PRINCIPAL REGULATORY CONSULTANT?

A. My responsibilities include preparation of class cost of service studies, functional cost of service studies, rate design for the AEP System operating companies, and special contracts and pricing for retail and wholesale customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony on behalf of I&M before the Indiana Utility Regulatory Commission. I have also submitted testimony before the Virginia S.C.C. and the Federal Energy Regulatory Commission.

II. PURPOSE OF TESTIMONY AND GENERAL DESCRIPTION OF EXHIBITS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the historical and projected class cost of service studies, which allocate the total Michigan retail jurisdiction rate base, revenues and expenses to each rate schedule.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the class cost of service allocation study portion of Schedule F1:

Exhibit I&M-71 (DMK-1), A-6, Schedule F1 Historical Class Cost of Service Allocation Study

Exhibit I&M-72 (DMK-2), A-6, Schedule F1 Projected Class Cost of Service Allocation Study

Q. FOR WHAT PERIODS DID THE COMPANY PREPARE CLASS COST OF SERVICE ALLOCATION STUDIES?

A. The Company prepared studies for the twelve months ended December 31, 2008, Exhibit I&M-71, (DMK-1), A-6, Schedule F1, pages 19 through 40 and for the projected period twelve months ending December 31, 2010, Exhibit I&M-72, (DMK-2), A-6 Schedule F1, pages 17 through 38. The historic and projected studies are identical in format and methodology.

Q. HAS THE MICHIGAN PUBLIC SERVICE COMMISSION (MPSC) PROVIDED GENERAL INSTRUCTIONS IN APPORTIONMENT OF COST OF SERVICE DATA?

A. The MPSC has provided general instructions for electric utilities that cost of service data shall be based upon the following apportionment methods:

1. Production and transmission demand related costs are allocated based on twelve monthly average peak demand (12 CP) responsibility.
2. Production and transmission plant assigned using a combined demand (75%) and energy (25%) allocation factor.
3. Specific distribution plant such as meters and service drops used exclusively to serve individual customers shall be treated as customer-related. All other distribution plant shall be treated as demand-related.

The Company's class cost of service allocation studies were prepared to comply with the MPSC guidance and methodology utilized by I&M and approved by the MPSC in prior cases.

Q. PLEASE BRIEFLY DESCRIBE THE NATURE AND PURPOSE OF A CLASS COST OF SERVICE ALLOCATION STUDY.

A. Class cost of service studies are utilized to determine the revenue requirement for the services offered by the utility and to determine the costs that different classes of customers impose on the utility system. A class cost of service allocation study is a basic analytical tool used in utility rate design. When all of the jurisdictional costs are allocated to the various customer classes, the result is a class cost responsibility study that is a guide in establishing rates based on costs.

Q. WHAT SOFTWARE DID YOU UTILIZE IN PREPARING THE COST OF SERVICE STUDIES?

I used an Excel based spreadsheet format in preparing the class cost of service studies. The Excel spreadsheet permits the analyst to use two types of allocation factors – those which are generated externally and input to the program, and those which are developed internally as a result of the allocation process. An example of an external allocation factor would be the total number of secondary customers served at distribution (DIST_SERV). An example of an internal factor would be the functionalized, allocated net plant costs assigned to the classes (NP).

Q. WOULD YOU DESCRIBE IN GENERAL TERMS THE METHODOLOGY USED IN ASSIGNING COSTS TO EACH CUSTOMER CLASS?

A. The Michigan retail jurisdictional rate base and expense components are assigned to the different customer classes using the utility standard three-step process to assign costs: functionalization, classification and allocation.

In addition to the MPSC's general instructions in apportionment of cost of service data, the Company considers the following factors in determination of the appropriate allocation methodology:

1) planning and operating characteristics of the utility's system;

2) customer class characteristics such as energy usage, peak demand on the system, diversity characteristics, number of customers, etc;

3) allocation that provides stable results on a year-to-year basis; and

4) customers who benefit from the use of the system should also bear appropriate cost responsibility for the system.

Q. DID THE COMPANY PREPARE SEPARATE STUDIES FOR EACH RATE AREA?

A. No. The Company is proposing to consolidate the rates for the Three Rivers and St. Joseph rate areas into a single set of rates. As such, the Company has prepared class cost of service allocation studies that combine the comparable customer classes (i.e. residential, commercial and industrial) of the two rate areas.

III. COMPONENTS OF RATE BASE

Q. PLEASE DESCRIBE THE ALLOCATION OF ELECTRIC PLANT IN SERVICE.

A. From the jurisdictional cost of service allocation study, as prepared by Company witness Roush, Electric Plant in Service is identified and functionalized into production, transmission, distribution and general and intangible plant. Production plant is classified as demand-related and is allocated using the weighted allocation factor that is based 75% on the production demand allocation factor and 25% on the energy allocation factor

(PROD_DE). The production demand allocation factor assigns costs based on the class contribution to the average of I&M's twelve monthly coincident peaks on the production facilities (12 CP) and each classes' loss adjusted energy allocation.

Q. HOW WAS TRANSMISSION PLANT FUNCTIONALIZED, CLASSIFIED, AND ALLOCATED?

A. Transmission plant was assigned to the functional components of power supply (Bulk) transmission plant and subtransmission plant and classified as demand-related. Bulk transmission plant was allocated using a demand allocation factor that is based 75% on the 12 CP power supply demand allocation factor and 25% on the energy allocation factor (BULK_TE). Subtransmission plant was also allocated using a weighted allocation factor giving a 75% weighting to class 12CP demands at the subtransmission level and a 25% weight to the energy allocator loss adjusted to the subtransmission system (SUB_TE). Generator step-up transformers (GSUs) are included in transmission plant based on the FERC accounts, but are separately identified and allocated using the weighted allocation factor for production plant since GSUs are related to the production function.

Q. HOW WAS DISTRIBUTION PLANT FUNCTIONALIZED, CLASSIFIED, AND ALLOCATED?

A. Distribution plant was functionalized as Primary or Secondary, classified as being either demand- or customer-related, and allocated to the customer classes using factors reflecting relevant demand levels, number of customers or a cost-weighted number of customers. Accounts 360 through 368, were classified solely as demand-related for class allocation purposes. Accounts 360 (Land and Land Rights, 361 (Structures and Improvements) and 362 (Station Equipment) were allocated to the distribution customer classes based on class contributions to the average of I&M's twelve monthly peak demands at the primary distribution system level (DIST_CPD).

Overhead and Underground Lines, Accounts 364 through 367, were split into primary and secondary voltage functions based upon information contained in the Company's records and guidance from the Company's distribution engineers. Primary line components were allocated using the DIST_CPD allocator, while the secondary line components were allocated based on a combination of each class's 12-month maximum non-coincident demand and the summation of individual customers' annual maximum non-coincident demands (DIST_POLES, DIST_OHLINES and DIST_UGLINES). The combination allocators recognize that some secondary facilities serve only one customer, while others serve two or more customers.

Distribution Transformers and Devices, Account 368, was split between the primary and secondary voltage functions based upon information contained in the Company's records and guidance from the Company's distribution engineers as to the determination of the functional use of the equipment. The primary portion of Account 368, cutouts, arresters, capacitors, voltage regulators and network protectors, was allocated using the DIST_CPD allocator, while the secondary portion, primary to secondary transformers, was allocated using the secondary voltage demand allocation factor, which is based on a combination of each class's 12-month maximum non-coincident demand and the summation of individual customers' annual maximum non-coincident demands (DIST_TRANSF).

Services, Account 369, were classified as customer-related and allocated using the number of secondary customers served at distribution (DIST_SERV).

Meter plant, Account 370, was allocated using the average number of customers weighted by a factor which considers the cost differential of various metering installations for the various customer classes (DIST_METERS). Since I&M books its investment in security lighting fixtures in Account 371, Installations on Customer Premises, the cost in that account was directly assigned to the outdoor lighting class (DIST_OL). Likewise, the cost in Account 373, Street Lighting, was directly assigned to the street lighting class (DIST_SL). General and intangible plant investment was allocated to the customer classes on the basis of a payroll labor allocator (LABOR_M), constructed by first allocating the functional components of operation and maintenance (O&M) expense by the applicable class demand, energy and customer allocation factors, and then summing the allocated components by class to create a set of labor expense ratios which is used to allocate the labor, wages and salaries assigned to each function.

Q. HOW WERE PLANT HELD FOR FUTURE USE, COMPLETED CONSTRUCTION NOT CLASSIFIED, AND CONSTRUCTION WORK IN PROGRESS ALLOCATED TO THE CUSTOMER CLASSES?

A. The functional totals of those investment accounts, 105, 106 and 107, were derived from the jurisdictional study and allocated to the classes according to the corresponding allocated functional plant ratios. In the projected study the Completed Construction Not Classified is included with Account 101 Electric Plant in Service costs.

Q. PLEASE DESCRIBE THE ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION.

A. The functionalized components of Accumulated Provision for Depreciation and Amortization were obtained directly from the jurisdictional study and classified and allocated in a fashion similar to Electric Plant in Service.

Q. PLEASE DESCRIBE THE ALLOCATION OF WORKING CAPITAL.

A. The numerous components of working capital allowance were arranged in a balance sheet format recognizing individual items of Other Property and Investments, Current Assets, Regulatory Assets and Deferred Debits, Current and Accrued Liabilities, and Regulatory Liabilities and Deferred Credits. The individual components were allocated using internally and externally derived allocation factors deemed to best reflect the causative nature of the particular asset and liability line items.

Q. HOW WERE THE OTHER RATE BASE ITEMS FUNCTIONALIZED, CLASSIFIED AND ALLOCATED?

A. D.C. Cook Nuclear fuel stock and spent nuclear fuel disposal costs were allocated using the energy allocation factor. The balance of spent nuclear fuel disposal costs in the projected study is zero. The balance of the Deferred gain from the sale of Rockport Unit 2 sale was allocated using the weighted production allocation factor.

IV. REVENUES, O&M and A&G EXPENSES

Q. HOW WERE REVENUES ASSIGNED FOR EACH CLASS?

A. Forecasted and historic retail sales revenues were directly assigned to each class. Demand-related system sales and interruptible sales revenues were allocated based on the weighted production allocation factor. Energy related system sales and interruptible sales revenues were allocated based on the loss adjusted energy allocation factor (PROD_ENERGY).

Forfeited discounts and miscellaneous service revenues were directly assigned based on an analysis of accounting records.

The functional components of rent from electric property and other electric revenue were obtained directly from the jurisdictional study and allocated to classes according to corresponding plant ratios.

Q. PLEASE DESCRIBE THE ALLOCATION OF PRODUCTION O&M EXPENSES.

A. The components of Production-related operation and maintenance (O&M) expenses, Accounts 500 through 557, were separately classified as either demand or energy related, consistent with the jurisdictional study. The demand component was allocated using the weighted demand allocation factor and the energy component was allocated using the loss adjusted energy allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF TRANSMISSION O&M EXPENSES.

A. Transmission O&M, Accounts 560 through 575, were assigned to the functional components of Bulk and sub-transmission consistent with the jurisdictional study, classified as demand-related, and allocated using the weighted demand allocation factors (BULK_TE) and (SUB_TE), respectively. O&M expense associated with generator step-up transformers was separately identified and allocated using the weighted production demand allocation factor.

Q. PLEASE DESCRIBE THE ALLOCATION OF DISTRIBUTION O&M BETWEEN THE VARIOUS CUSTOMER CLASSES.

A. Distribution O&M expenses were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Accounts 581, Load Dispatching and 582, Station Expenses were allocated using the DIST_CPD allocator. Account 583, Overhead Line Expense, was allocated based upon the same allocation used for plant Account 365 Overhead Lines (DIST_OHLINES). Account 584, Underground Line Expense, was allocated based upon the same allocation used for plant Accounts 366 Underground Conduit and 367 Underground Lines (DIST_UGLINES). Account 585, Street Lighting and Signal System Expense, was classified as customer-related and directly assigned to the street lighting class. Meter Expense, Account 586, was classified customer-related and allocated in the same manner as meter plant (DIST_METERS). Account 587, Customer Installation Expense, was classified as customer-related and allocated based on primary customers (DIST_PCUST).

Accounts 588 and 589, Miscellaneous Distribution Expense and Rents, were classified proportionate to distribution electric plant in service and allocated accordingly. Account 580, Operation Supervision and Engineering, was classified demand- and customer-related and allocated using the internally derived allocated subtotal of Accounts 581 through 589, because the cost of labor and expense booked in Account 580 involves general supervision and engineering of both primary and secondary distribution operations.

Account 591, Maintenance of Structures and 592 Maintenance of Station Equipment, were classified as demand-related and allocated on the distribution demand allocation factor DIST_CPD. Accounts 593, Maintenance of Overhead Lines, 594 Maintenance of Underground Lines, and 595, Maintenance of Line Transformers, were functionalized and classified according to the associated distribution plant accounts and allocated accordingly. Maintenance of Street Lighting and Signal Systems, Account 596, was classified customer-related and directly assigned to the street lighting class. Account 597, Maintenance of Meters, was classified as customer-related and allocated in the same manner as meter plant. Account 598, Maintenance of Miscellaneous Distribution Plant, was classified as customer-related and directly assigned to the outdoor lighting class. Account 590, Maintenance Supervision and Engineering, was classified and allocated based on the allocated subtotal of O&M expense Accounts 591 through 598 because the cost of labor and expense booked in Account 590 involves the general supervision and engineering of both primary and secondary distribution maintenance.

Q. CAN YOU EXPLAIN HOW CUSTOMER ACCOUNTING AND CUSTOMER SERVICES AND SALES EXPENSES WERE ALLOCATED?

A. Account 902, Meter Reading Expense, was allocated to those classes with meter installations based upon an average number of customers weighted to reflect differences in meter reading requirements. Customer Records Expense, Account 903, was divided into two categories, costs related to the customer call center and other records and collections expenses. The residential tariff class was directly assigned call center costs based on the

the actual number of calls received by the call center. The remaining call center costs were allocated among the other tariffs (excluding outdoor lighting) based on the number of customers in those classes. The other records and collections expenses were allocated to all classes based on the number of customers. In the historical study, Account 904, Uncollectible Accounts, which is primarily associated with losses related to uncollected rent revenues, was allocated based on an allocated total of rents from non-associated companies and rent from electric property. Accounts 901, Supervision, and 905, Miscellaneous Customer Account Expense, were allocated based on the sum of the allocated Accounts 902, 903 and 904 because the cost of labor and expenses booked in these accounts are of a general nature which includes supervision of the customer accounting and collection activities.

Costs associated with Customer Service and Information Expense, Accounts 907-916, were allocated using the allocated total of Accounts 901-905 because of the general nature of these costs which include supervision, labor and materials, support efforts to provide services to all customer classes. All customer accounting, customer services and sales expense accounts were classified as customer-related.

Q. PLEASE DESCRIBE THE ALLOCATION OF A&G EXPENSE.

A. The expenses associated with the Nuclear Regulatory Commission, including inspection and licensing fees, were assigned to the production demand function and allocated based on the weighted production demand allocation factor. The regulatory expense associated with retail rate case proceedings was allocated based on payroll labor. The functional components of property insurance were taken directly from the jurisdictional study and allocated based on the related plant allocation factor. The majority of A&G expenses are functionalized, classified and allocated based on payroll labor.

V. DEPRECIATION AND TAXES

Q. PLEASE DESCRIBE THE ALLOCATION OF DEPRECIATION AND AMORTIZATION EXPENSE.

A. The functionalized components of depreciation and amortization expense were allocated using the corresponding plant or demand allocation factors.

Q. PLEASE DESCRIBE THE ALLOCATION OF REGULATORY DEBT EXPENSE.

A. In the projected study, the functionalized components of regulatory debt expense are associated with PJM and RTO fees, VEBA trust, Customer Choice, ARO, enhanced security of the production facilities, rate case expense and Nuclear Decommissioning Studies. All are allocated using related functional plant, labor or revenue ratios.

Q. HOW WERE TAXES OTHER THAN INCOME TAXES ALLOCATED TO EACH CLASS?

A. Taxes other than income taxes were allocated according to the basis for each tax. Payroll taxes are labor related and therefore allocated using the allocated labor (LABOR_M) allocation factor. Taxes associated with property and capital leases were allocated on the internally derived allocated class net plant ratios. PSC assessment and gross receipts taxes were allocated using the revenue allocation factor. Miscellaneous taxes such as sales and use, business franchise and registration fees were allocated based on gross plant ratios.

Q. HOW WERE INCOME TAXES ASSIGNED TO THE RETAIL CLASSES?

A. Interest expense was calculated using a formula to synchronize with allocated rate base. State and current Federal income taxes were computed class by class. Individual Schedule M items, Deferred Federal Income Taxes, and Deferred Investment Tax Credits were allocated based on corresponding allocated costs to which the items relate.

VI. NET INCOME, EARNED RETURNS AND SUMMARY

Q. PLEASE SUMMARIZE THE OVERALL AND CLASS EARNED RATE OF RETURN ON RATE BASE FOR EACH CLASS SHOWN IN THE CLASS COST OF SERVICE STUDIES YOU PREPARED.

A. The resulting earned rates of return, prior to any increase in rates, are as follows:

CLASS	HISTORICAL	PROJECTED
Total Retail	4.90%	3.27%
Residential(RS)	2.89%	1.39%
Small General Service (SGS)	9.29%	8.15%
Medium General Service (MGS)	9.51%	7.35%
Large General Service (LGS)	7.04%	5.48%
Quantity Power (QP)	4.95%	3.53%
Large Power (LP)	4.71%	2.55%
Municipal and School Service (MS)	8.65%	6.71%
Water and Sewage Service (WSS)	7.40%	5.20%
Electric Heating Schools (EHS)	-.18%	-1.85%
Electric Heating General (EHG)	11.20%	9.83%
Irrigation Service (IS)	-.11%	-.96%
Outdoor Lighting (OL)	2.04%	2.20%
Street Lighting (SL)	10.09%	9.15%

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. My testimony describes the class cost of service allocation studies for the Historic and Projected Test Years, 2008 and 2010, respectively, and presents the resulting class by class rates of return. The results of these studies help guide the allocation of the proposed sales revenue to each tariff class, as explained by Company witness Roush.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

DAVID M. ROUSH

PRE-FILED DIRECT TESTIMONY OF DAVID M. ROUSH
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David M. Roush. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). AEP is the parent company of Indiana Michigan Power Company (I&M or Company). I am employed as Manager-Regulated Pricing and Analysis.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND BUSINESS EXPERIENCE.

A. I graduated from The Ohio State University (OSU) in 1989 with a Bachelor of Science degree in mathematics and a computer and information science minor. In 1999, I earned a Master of Business Administration degree from The University of Dayton. I have completed both the EEI Electric Rate Fundamentals and Advanced Courses. In 2003, I completed the AEP/OSU Strategic Leadership Program. In 1989, I joined AEPSC as a Rate Assistant. Since that time I have progressed through various positions and was promoted to my current position of Manager-Regulated Pricing and Analysis in July 2003.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER-REGULATED PRICING AND ANALYSIS?

A. My responsibilities include the oversight of the preparation of cost of service and rate design analysis for the AEP System operating companies, and oversight of the preparation of special contracts and pricing for customers.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony before the Michigan Public Service Commission (MPSC or Commission), the Indiana Utility Regulatory Commission, the Public Service Commission of Kentucky, the Public Utilities Commission of Ohio and the Public Service Commission of West Virginia. With respect to the MPSC, I testified in Case No. U-12652 supporting AEP's October 2, 2000 Michigan Restructuring Plan.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe and support the following:

(a) The historical and projected jurisdictional cost of service allocation studies, which allocate the total Company rate base, revenues and expenses to the Michigan retail jurisdiction;

(b) The allocation of I&M's Michigan retail jurisdiction required rate relief to each rate schedule;

(c) The design of the proposed rates contained in I&M's proposed Tariffs, including the Cost-of-Service Phase-In Rider;

(d) The present and proposed revenue by rate schedule;

(e) The typical bill comparisons;

(f) The design of the proposed rider for net lost revenue recovery under the Company's Energy Optimization Plan;

(g) The design of the proposed unified Power Supply Cost Recovery (PSCR) Clause, including the recovery of transmission costs in the PSCR;

(h) The design of the proposed rider for recovery of gridSMART^{SM} Program costs;

(i) The design of the proposed enhanced distribution reliability cost recovery rider; and

(j) The design of the proposed generation investment cost recovery rider.

Q. WHAT EXHIBITS AND SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring or cosponsoring the following exhibits and schedules:

Exhibit I&M-73 (DMR-1)	A-1, Schedule A1, Historical Revenue Deficiency
Exhibit I&M-74 (DMR-2)	A-2, Schedule B1, Historical Rate Base
Exhibit I&M-75 (DMR-3)	A-2, Schedule B2, Historical Utility Plant
Exhibit I&M-76 (DMR-4)	A-2, Schedule B3, Historical Accumulated Provision for Depreciation
Exhibit I&M-77 (DMR-5)	A-3, Schedule C1, Historical Net Operating Income

Exhibit I&M-78 (DMR-6)	A-3, Schedule C3, Historical Sales Revenue
Exhibit I&M-79 (DMR-7)	A-3, Schedule C4, Historical Fuel and Purchased Power Expense
Exhibit I&M-80 (DMR-8)	A-3, Schedule C5, Historical Operation and Maintenance Expense
Exhibit I&M-81 (DMR-9)	A-3, Schedule C6, Historical Depreciation and Amortization Expense
Exhibit I&M-82 (DMR-10)	A-5, Schedule E1, Historical Sales, Load and Customer Data
Exhibit I&M-83 (DMR-11)	A-6, Schedule F1, Historical Cost of Service Allocation Study
Exhibit I&M-84 (DMR-12)	A-2, Schedule B1, Projected Rate Base
Exhibit I&M-85 (DMR-13)	A-2, Schedule B2, Projected Utility Plant
Exhibit I&M-86 (DMR-14)	A-2, Schedule B3, Projected Accumulated Provision for Depreciation
Exhibit I&M-87 (DMR-15)	A-2, Schedule B4, Projected Working Capital
Exhibit I&M-88 (DMR-16)	A-3, Schedule C1, Projected Net Operating Income
Exhibit I&M-89 (DMR-17)	A-3 Schedule C3, Projected Sales Revenue
Exhibit I&M-90 (DMR-18)	A-3, Schedule C4, Projected Fuel and Purchased Power Expense
Exhibit I&M-91 (DMR-19)	A-3, Schedule C5, Projected Operation and Maintenance Expense
Exhibit I&M-92 (DMR-20)	A-3, Schedule C6, Projected Depreciation and Amortization Expense
Exhibit I&M-93 (DMR-21)	A-3, Schedule C11, Projected Allowance For Funds Used During Construction

Exhibit I&M-94 (DMR-22)	A-5, Schedule E1, Projected Sales, Load and Customer Data
Exhibit I&M-95 (DMR-23)	A-6, Schedule F1, Projected Cost of Service Allocation Study
Exhibit I&M-96 (DMR-24)	A-6, Schedule F2, Summary of Present and Proposed Revenues
Exhibit I&M-97 (DMR-25)	A-6, Schedule F3, Detail of Present and Proposed Revenues
Exhibit I&M-98 (DMR-26)	A-6, Schedule F4, Comparison of Present and Proposed Monthly Bills
Exhibit I&M-99 (DMR-27)	I&M’s Proposed Revenue Allocation
Exhibit I&M-100 (DMR-28)	Design of Cost-of-Service Phase-In Rider
Exhibit I&M-101 (DMR-29)	Design of Net Lost Revenue Recovery Rider
Exhibit I&M-102 (DMR-30)	Design of gridSMART℠ Program Cost Recovery Rider
Exhibit I&M-103 (DMR-31)	Design of Enhanced Distribution Reliability Cost Recovery Rider
Exhibit I&M-104 (DMR-32)	Design of Generation Investment Cost Recovery Rider
Exhibit I&M-105 (DMR-33)	Design of Interim Rate Surcharge Rider

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR TESTIMONY.

A. My testimony is divided into the following sections:

I. Development of Projected Revenues

II. Jurisdictional Cost of Service Allocation Studies

III. Proposed Revenue Allocation Among Classes and Cost-of-Service Phase-In Rider

IV. Rate Design

V. Design of Riders

VI. Summary of Proposed Revenues and Typical Bills

<u>I. DEVELOPMENT OF PROJECTED REVENUES</u>

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COMPANY'S PROJECTED MICHIGAN RETAIL SALES REVENUES FOR 2010.

A. Michigan retail sales revenues for 2010 are based upon the Company's forecasted sales (MWh) for 2010. The Company forecasts Michigan retail sales by revenue class. That sales forecast was applied to historical billing units to develop projected billing units by rate schedule. The projected billing units were then multiplied by current rates to determine the projected base revenues (excluding PSCR) by rate schedule.

Q. HOW DID YOU DETERMINE THE POWER SUPPLY COST RECOVERY (PSCR) FACTOR REVENUES FOR THE PROJECTED TEST YEAR?

A. As discussed by Company witness Allen, PSCR Factors were computed for each rate area based upon allowable costs as projected each month under the current PSCR methodology. Those rates were applied to projected usage by rate schedule to determine projected PSCR revenues by rate schedule.

II. JURISDICTIONAL COST OF SERVICE ALLOCATION STUDIES

Q. PLEASE EXPLAIN THE PURPOSE OF A JURISDICTIONAL COST OF SERVICE ALLOCATION STUDY AND WHAT IT IS DESIGNED TO ACCOMPLISH.

A. The purpose of a jurisdictional cost-of-service allocation study is to determine the Company's cost of providing service to a particular regulatory jurisdiction. This is accomplished by comparing the Company's revenue requirement associated with the cost of serving the customer in a regulatory jurisdiction to the revenues received from that jurisdiction. In order to accomplish this comparison, the study must functionalize, classify, and allocate the costs associated with providing service to customers in each of the regulatory jurisdictions that the Company serves. There are three basic steps to achieve this process. First, costs are functionalized into production, transmission, and distribution functions. The next step is to classify these costs as demand, energy, or customer related. The third step is to directly assign or allocate the costs on the basis of an appropriate allocation methodology.

Certain portions of I&M's rate base, revenue, and expenses are utilized in common for service to retail and wholesale customers, both in Michigan and in Indiana. Because I&M provides service in three regulatory jurisdictions, it is necessary to determine the rate base, revenues, and expenses that relate to serving I&M's Michigan jurisdictional retail customers. The portions of I&M's rate base, revenues, and expenses attributable to serving Michigan jurisdictional retail customers were determined by a jurisdictional cost of service allocation study using the process of cost allocation and direct assignment.

Q. FOR WHAT PERIODS DID THE COMPANY PREPARE JURISDICTIONAL COST OF SERVICE ALLOCATION STUDIES?

A. The Company prepared studies for the twelve months ended December 31, 2008, Exhibit I&M-83 (DMR-11), A-6, Schedule F1, page 1 through 18 and for the projected twelve months ending December 31, 2010,. Exhibit I&M-95 (DMR-23), A-6, Schedule F1, page 1 through 16. The historic and projected studies are identical in format and methodology.

Q. WHAT IS THE SOURCE OF THE INFORMATION USED IN THE JURISDICTIONAL COST OF SERVICE ALLOCATION STUDIES.

A. The books and records of the Company serve as the source of information for the historic period. The source of information for the projected period is the Company's forecast as provided by Company witness Allen.

Q. PLEASE DESCRIBE THE HISTORIC JURISDICTIONAL COST OF SERVICE ALLOCATION STUDY.

A. Exhibit I&M-83 (DMR-11), A-6, Schedule F1, pages 1 through 18, is the historical jurisdictional cost of service allocation study for 2008. Rate Base reflects year end balances. The study begins with total Company amounts and shows the removal of non-applicable items and the assignment of costs associated with the Rockport 2 Unit Power Sale to arrive at Total Company Per Books After Assignment. The next step is to make three standard adjustments to rate base and operating income to comply with past Commission orders. These adjustments are (1) to restate accumulated depreciation and depreciation expense based upon Michigan approved depreciation rates, (2) to adjust plant in service, accumulated depreciation and depreciation expense for Rockport 1 test energy and (3) to adjust plant in service, accumulated depreciation and depreciation expense for AFUDC on CWIP related to Rockport 1 pollution control facilities AFUDC.

Q. PLEASE DESCRIBE THE PROJECTED JURISDICTIONAL COST OF SERVICE ALLOCATION STUDY.

Exhibit I&M-95 (DMR-23), A-6, Schedule F1, pages 1 through 16, is the projected jurisdictional cost of service allocation study for 2010 that is used in the calculation of the Michigan retail jurisdictional revenue deficiency as shown on Exhibit I&M-106 (SMK-1), A-1, Schedule A1. Rate Base includes projected 13-month average balances as supported by Company witness Allen. The study begins with total Company amounts and shows the removal of non-applicable items. There is no assignment of costs associated with the Rockport 2 Unit Power Sale since that sale ended on December 31, 2009. The next step is to make three standard adjustments to rate base and operating income to comply with past Commission orders. These adjustments are (1) to restate accumulated depreciation and depreciation expense based upon Michigan approved depreciation rates, (2) to adjust plant in service, accumulated depreciation and depreciation expense for Rockport 1 test energy and (3) to adjust plant in service, accumulated depreciation and depreciation expense for AFUDC on CWIP related to Rockport 1 pollution control facilities AFUDC.

Q. PLEASE DESCRIBE IN DETAIL THE DERIVATION OF THE MICHIGAN RETAIL JURISDICTIONAL ADJUSTED NET OPERATING INCOME WHICH IS THE BASIS FOR THE REVENUE DEFICIENCY REQUESTED BY I&M IN THIS PROCEEDING.

A. Exhibit I&M-95 (DMR-23), A-6, Schedule F1, page 1 is a summary of operating revenues, expenses and net operating income for I&M on a total Company and on a Michigan retail jurisdictional basis.

Pages 2 through 6 show the detailed development of rate base. Page 7 shows the detailed breakdown of operating revenues. Pages 8 through 15 show the detailed development of expenses, including operation and maintenance expenses, depreciation and amortization expenses, administrative and general expenses, taxes other than income taxes, and income taxes. The computation of the labor allocation factor for the Michigan retail jurisdiction is also shown on page 15.

The allocation factors used are shown throughout the studies in the column labeled "Allocator" and the actual allocation factors are shown on page 16.

Q. PLEASE DISCUSS THE COST ALLOCATION PROCESS USED BY THE COMPANY.

A. The cost allocation procedure is a multi-step process of functionalization, classification, and then jurisdictional allocation.

The first step in the cost allocation process is functionalization, which is the identification and assignment of I&M's rate base and expenses to the task for which each item is employed. The investment in plant and corresponding operation, maintenance, depreciation, and tax expenses are assigned to the major functions of production, transmission, and distribution in accordance with the Uniform System of Accounts. Certain plant and expense accounts, such as general and intangible plant and administrative and general expenses, are not directly assigned to major functions. All such costs are therefore functionalized according to the functionalization of other related costs so that they can be properly classified and allocated.

The second step is classification, the process by which the functionalized costs are designated as being either demand, energy, or customer-related. Demand and customer related costs are fixed costs that are incurred regardless of the level of energy sales. An example of a demand-related cost is the investment in production facilities. An energy-related cost is a cost such as fuel expense, which varies with the level of sales. Meter plant is an example of a cost whose level is affected by the number of customers served.

The final step in the cost assignment process is jurisdictional allocation. Jurisdictional allocation is the process by which the classified functional costs are assigned to the jurisdictions by the use of allocation factors. When each classified and functionalized cost is multiplied by a jurisdictional allocation factor, the product is the cost assigned to each jurisdiction.

Q. PLEASE DESCRIBE THE MAJOR FUNCTIONS OF PRODUCTION, TRANSMISSION, AND DISTRIBUTION AND RELATED ASSIGNMENTS.

A. Production refers to all production facilities including, for I&M, fossil-fueled generation, nuclear generation, and hydraulic generation, together with step-up substation facilities necessary to integrate that generation into the power supply system. Production facilities are used in serving all customers.

Transmission refers to the transmission substations and lines that integrate I&M's sources of power, both I&M owned and purchased or interchanged, with the regional power supply system and the I&M distribution system. All 765 kV, 345 kV, and 138 kV lines were assigned as power supply transmission. All 69 kV and 34.5 kV lines were assigned as Subtransmission. Substations supplying 345 kV and 138 kV transmission lines were assigned to power supply transmission. Substations supplying 69 kV and 34.5 kV lines were assigned as Subtransmission. Certain substations perform more than one of the functions described above. The investment in each such substation has been divided between the functions served.

Distribution refers to the facilities required to connect the customer to the transmission system. Most distribution substations and lines were directly assigned to the jurisdictions. When a substation or line supplies more than one jurisdiction, related costs were assigned or allocated to the jurisdictions based on noncoincident maximum demands. Metering costs were directly assigned based on actual metering investment.

Further separation of common investment and expenses between the Michigan jurisdiction and other jurisdictions is accomplished through the allocation process.

Q. HAS THE MPSC PROVIDED GENERAL INSTRUCTIONS REGARDING APPORTIONMENT OF COST OF SERVICE DATA?

A. Yes. In Case No. U-4771, the MPSC standard rate application filing forms and instructions provided that cost of service data shall be based upon the following apportionment methods:

1. Average twelve monthly peak demand responsibility.
2. Production and transmission plant assigned as 75% demand-related and 25% energy-related.
3. Specific distribution plant such as meters and service drops used exclusively for a given customer shall be treated as

> customer related. All other distribution plant shall be treated as demand-related.

This guidance was previously used for both jurisdictional cost of service allocation studies and class cost of service allocation studies. More recently, jurisdictional cost of service allocation studies used in Michigan have apportioned production and transmission plant as 100% demand-related to be consistent with jurisdictional studies used by the Federal Energy Regulatory Commission, while the class cost of service allocation studies used in Michigan continue to use the 75% demand-related and 25% energy-related.

The Company's jurisdictional cost of service allocation studies and class cost of service allocation studies were prepared to comply with the historical MPSC guidance discussed above. In recent years, other approaches for class cost of service allocation studies have been used by larger Michigan utilities. In fact, 2008 P.A. 286 provided additional specific requirements for utilities serving one million or more retail customers in Michigan. Those requirements do not apply to I&M since I&M serves less than 130,000 customers in Michigan. For I&M, the historical guidance provided in Case No. U-4771 and utilized by I&M in prior proceedings, updated as discussed above to consistently allocate costs among jurisdictions, is the most appropriate apportionment method for this proceeding.

Q. PLEASE DESCRIBE THE METHOD USED IN CALCULATING THE DEMAND AND ENERGY ALLOCATION FACTORS.

A. To comply with the MPSC apportionment methods, the demand allocation factor is an average of 12 monthly loss adjusted coincident peak demands (12 CP). The energy allocation factor is calculated using annual loss adjusted kWh usage.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE FUNCTIONAL COMPONENTS OF ELECTRIC PLANT IN SERVICE.

A. Production Plant is allocated as described above, using the 12 CP demand allocation factor. Transmission Plant is split between Transmission and Subtransmission and also allocated using the 12 CP demand allocation factor. Distribution substations and lines serving specific Michigan jurisdictional loads were directly assigned. Remaining joint use Michigan substations and lines were allocated individually in accordance with the noncoincident maximum demands of the jurisdictional loads served by them. Intangible Plant and General Plant were allocated based on the labor allocation factor which is the ratio of Michigan jurisdictional Operation and Maintenance (O&M) labor expense to total Company O&M labor expense.

Q. PLEASE DESCRIBE THE ALLOCATION OF THE FUNCTIONAL COMPONENTS OF COMPLETED CONSTRUCTION NOT CLASSIFIED, PLANT HELD FOR FUTURE USE AND CONSTRUCTION WORK IN PROGRESS.

A. The functional components of Completed Construction Not Classified, Plant Held for Future Use and Construction Work in Progress were allocated consistent with the allocation of the corresponding functional components of Electric Plant in Service.

Q. PLEASE DESCRIBE THE METHOD OF ALLOCATION OF ACCUMULATED PROVISIONS FOR DEPRECIATION AND AMORTIZATION.

A. The functional components of Accumulated Provisions for Depreciation and Amortization were allocated in the same manner as the corresponding portions of Electric Plant in Service.

Q. PLEASE DESCRIBE THE ALLOCATION OF WORKING CAPITAL ALLOWANCE.

A. The presentation of Working Capital Allowance reflects a balance sheet format as adopted in Case No. U-7350. The jurisdictional amounts of the various items of Working Capital Allowance were the result of allocations that best reflect the causative nature of the particular item.

Q. PLEASE DESCRIBE THE ALLOCATION OF OTHER RATE BASE COMPONENTS.

A. Nuclear Fuel Stock was allocated using the energy allocation factor and the Spent Nuclear Fuel Disposal costs were directly assigned to the Michigan retail jurisdiction pursuant to the special Michigan reporting requirement. The Electric Plant Acquisition Adjustment was directly assigned to the

Indiana retail jurisdiction. The balance of the Deferred Gain from the Rockport Unit 2 Sale was allocated using the production plant allocation factor.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE MICHIGAN RETAIL JURISDICTIONAL REVENUES?

A. Firm Sales of Electricity requires no allocation as the Michigan specific amount is directly assigned. Interruptible sales revenue and non-firm (system sales) revenues were classified between demand and energy and then allocated using the applicable production demand and energy allocation factors.

The components of Other Operating Revenues were assigned to the Michigan retail jurisdiction based upon the nature of each type of revenue. Miscellaneous service revenues and forfeited discounts were directly assigned. Rentals from certain items of I&M property were functionalized and then allocated to the Michigan retail jurisdiction according to the applicable allocation factor. Other Electric Revenue was similarly functionalized and allocated to the Michigan retail jurisdiction according to the applicable allocation factor.

Q. PLEASE DESCRIBE THE CLASSIFICATION AND ALLOCATION OF O&M EXPENSES.

A. Production Expense was classified as demand-related or energy-related and allocated to the Michigan jurisdiction by the application of the corresponding demand or energy allocation factor.

Purchased power expense, reflects the demand-related and energy-related classification of billings for that power. The demand-related charges were allocated by the demand allocation factor and the energy-related charges were allocated by the energy allocation factor.

Transmission expense is classified as entirely demand-related and allocated using the demand allocation factor, except for the RTO administrative cost deferrals included in Account 561 and Account 575, which were directly assigned to the Michigan retail jurisdiction.

Distribution O&M expenses were allocated using the distribution plant allocation factor, which was derived from the assignment and allocation of Distribution Plant.

Customer Accounts O&M expenses and Customer Service & Information Expenses were classified as customer-related and allocated using the number of customers allocation factor. Sales Expense O&M was classified as demand related and allocated using the demand allocation factor.

Most Administrative and General (A&G) Expenses were allocated using the labor allocation factor. Property Insurance, Account 924, was functionalized into production, transmission, and distribution and allocated accordingly. Regulatory Commission Expense, Account 928, was primarily directly assigned or allocated using the demand allocation factor, depending upon the specific nature of the expense.

Q. PLEASE EXPLAIN HOW DEPRECIATION AND AMORTIZATION EXPENSES WERE ALLOCATED.

A. Depreciation and Amortization Expenses by function were allocated consistent with the functional plant-based allocation of Accumulated Provisions for Depreciation and Amortization.

Q. PLEASE EXPLAIN HOW REGULATORY DEBITS AND CREDITS WERE ALLOCATED.

A. Based upon the nature of each item included in Regulatory Debits and Credits, each item was directly assigned to the appropriate jurisdiction or allocated using the corresponding demand or distribution plant allocation factors.

Q PLEASE DESCRIBE THE ALLOCATION OF TAXES OTHER THAN INCOME TAXES.

A. Taxes Other than Income Taxes were classified as relating to payroll, property (net plant), revenue, demand, or gross plant and allocated accordingly, or directly assigned. Payroll taxes are related to labor and were allocated using the labor allocation factor. Property taxes and taxes on capital leases were allocated using the net plant allocation factor. Taxes relating to the IURC and MPSC assessments and Michigan State Single

Business Tax were directly assigned. Sales and Use Taxes, Business Franchise Taxes, and Registration Fees were allocated based on gross plant. State Gross Receipts Taxes were allocated based on firm sales revenues. Federal Excise Taxes were allocated based using the demand allocation factor.

Q. HOW WERE OTHER EXPENSE ITEMS ALLOCATED?

A. Gains and losses on the disposition of utility plant were allocated using the gross plant allocation factor. Gains on the disposition of allowances were allocated using the energy allocation factor. Factoring Expense was allocated based upon the receivables which the Company sells. The functional components of Accretion Expense were allocated using the corresponding demand, energy or distribution plant allocation factors. Allowance for Funds Used During Construction was allocated based upon Construction Work in Progress.

Q. HOW WERE STATE AND FEDERAL INCOME TAXES ASSIGNED?

A. State and Federal Income taxes were calculated for Michigan and provided by Company witness Kelly.

Q. PLEASE EXPLAIN HOW ADJUSTMENTS WERE TREATED.

A. Adjustments were provided to me by various Company witnesses. For those adjustments derived on a total Company basis, I added the total Company adjustment amount to the applicable account to arrive at Total Company After Adjustment and Assignment. I then allocated the total based on the applicable allocation factor. Some adjustments were calculated on a retail jurisdictional basis; those adjustments were directly assigned to the Michigan retail jurisdiction.

Q. PLEASE SUMMARIZE YOUR TESTIMONY REGARDING THE JURISDICTIONAL COST OF SERVICE ALLOCATION STUDIES.

A. The Company's jurisdictional cost-of-service allocation study properly determines the Company's cost of providing service to the Michigan retail jurisdiction consistent with prior Commission guidance.

III. PROPOSED REVENUE ALLOCATION AMONG CLASSES

Q. HAS MICHIGAN PROVIDED ANY GUIDANCE CONCERNING THE IMPACT OF IMPOSING COST OF SERVICE BASED RATES ON CUSTOMERS?

A. Yes. 2008 P.A. 286, which was enacted on October 6, 2008, provided the following guidance:

> This subsection applies beginning January 1, 2009. The commission shall approve rates equal to the cost of providing service to customers of electric utilities serving less than 1,000,000 retail customers in this state. The rates shall be approved by the commission in each utility's first general rate case filed after passage of the amendatory act that added this section. If, in the judgment of the commission, the impact of imposing cost of service rates on

customers of a utility would have a material impact, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that any impact on rates due to the cost of service requirement in this subsection is not more than 2.5% per year.

Q. PLEASE EXPLAIN THE PRINCIPLES OR GUIDELINES THAT YOU FOLLOWED IN ALLOCATING THE PROPOSED REVENUE INCREASE AMONG THE TARIFF CLASSES.

A. One key objective of ratemaking is to design rates such that they reflect as nearly as possible the actual costs of serving the customer. This standard has been amplified by the recent Michigan statute. To fully meet this objective would require that the rates of return for all tariff classes be equalized. The class cost-of-service study prepared by Company witness Keegan (Schedule F1) provides the information needed to make this evaluation.

Q. PLEASE EXPLAIN THE METHOD OF REVENUE ALLOCATION.

A. As shown in Column (3) of page 1 of Exhibit I&M-99 (DMR-27), the rates of return for the RS, LP, EHS, IS and OSL classes are below the total retail current rate of return of 3.27%. On the other hand, the rates of return for the SGS, MGS, LGS, QP, MS, WSS, EHG and SL classes are above the total retail current rate of return.

I&M proposes to apply the rate increase, excluding the proposed riders, of approximately $57.2 million in a manner which produces the same proposed rate of return for each customer class. This is shown in Column (8) on page 1 of Exhibit I&M-99 (DMR-27). I&M's proposed rates are designed based upon this revenue allocation.

Since this results in increases for the RS, EHS, IS and OSL classes which are more than 2.5% above the average increase of 26.88%, I&M proposes to implement a temporary Cost-of-Service (COS) Phase-In Rider. The COS Phase-In Rider is designed to limit the first year increase for any customer class to no more than the average increase plus 2.5%. Any revenue shortfall that is produced by limiting the increases for certain customer classes must be collected from those classes whose increase is less than the limit. The Company proposes to allocate the shortfall collection to the customer classes based upon rate base. This results in an equitable sharing as all customer classes that are not limited will have the same rate of return. This calculation is shown in Exhibit I&M-100 (DMR-28) on pages 2 and 3.

On an annual basis, the sum of the credits provided and charges collected under the COS Phase-In Rider should be zero (0). However, since actual customer usage by customer class will vary, the net of actual credits and charges could be greater than or less than zero (0). Since the intent of the COS Phase-In Rider is neither to increase nor to decrease the

Company's revenues, the Company proposes to include any over or under-recovery in the annual reconciliation of the proposed unified PSCR clause.

In the second, third and fourth years, both the credits and the charges under the COS Phase-In Rider would be reduced so that in the fifth year the credits/charges are zero (0) for all customer classes. This annual change is based upon reducing the credits and charges by 25% each year. The credits and charges for each year are shown in Exhibit I&M-100 (DMR-28) on page 1. By the fifth year, all credits and charges under the rider would be zero (0) and all customer class rates of return will be equalized based on the cost of providing service as determined in this proceeding.

As designed, the Cost-of-Service Phase-In Rider will be in effect for a limited four-year period. However, if the Company were to file another application to change its base rates during that period, the rider could be superceded or replaced based upon the cost-of-service information in that proceeding.

IV. RATE DESIGN

Q. PLEASE EXPLAIN THE COMPANY'S GENERAL APPROACH TO RATE DESIGN.

A. In general, the Company's approach is to design rates and rate components which reflect the underlying costs of the Company. This includes collecting customer-related costs through customer charges and recognizing the differences in the costs to serve customers at different service delivery voltages. As with the allocation of the revenue increases to the customer classes, the concept of gradualism must be considered in the movement toward full cost-based rate components to avoid undue impacts on customers.

Q. PLEASE EXPLAIN THE MAJOR CHANGES TO THE STANDARD MICHIGAN TARIFFS AND RATES.

A. As discussed by Company witness Krawec, I&M proposes to consolidate the two rate areas of St. Joseph and Three Rivers and implement a unified PSCR clause for all of its Michigan customers. The Company also proposes to eliminate all tariff rates for Open Access Transmission and Retail Transmission. As discussed by Company witness Bethel, the Company's transmission costs should be based upon the charges under PJM's Tariff (the Open Access Transmission Tariff or "OATT" and the Operating Agreement). The Company proposes to include these transmission costs in the unified PSCR clause.

Since Company witness Hix discusses in detail the specific proposed changes to each individual tariff, I will only discuss certain major rate design changes.

Q. PLEASE EXPLAIN THE CHANGES TO TARIFF RS.

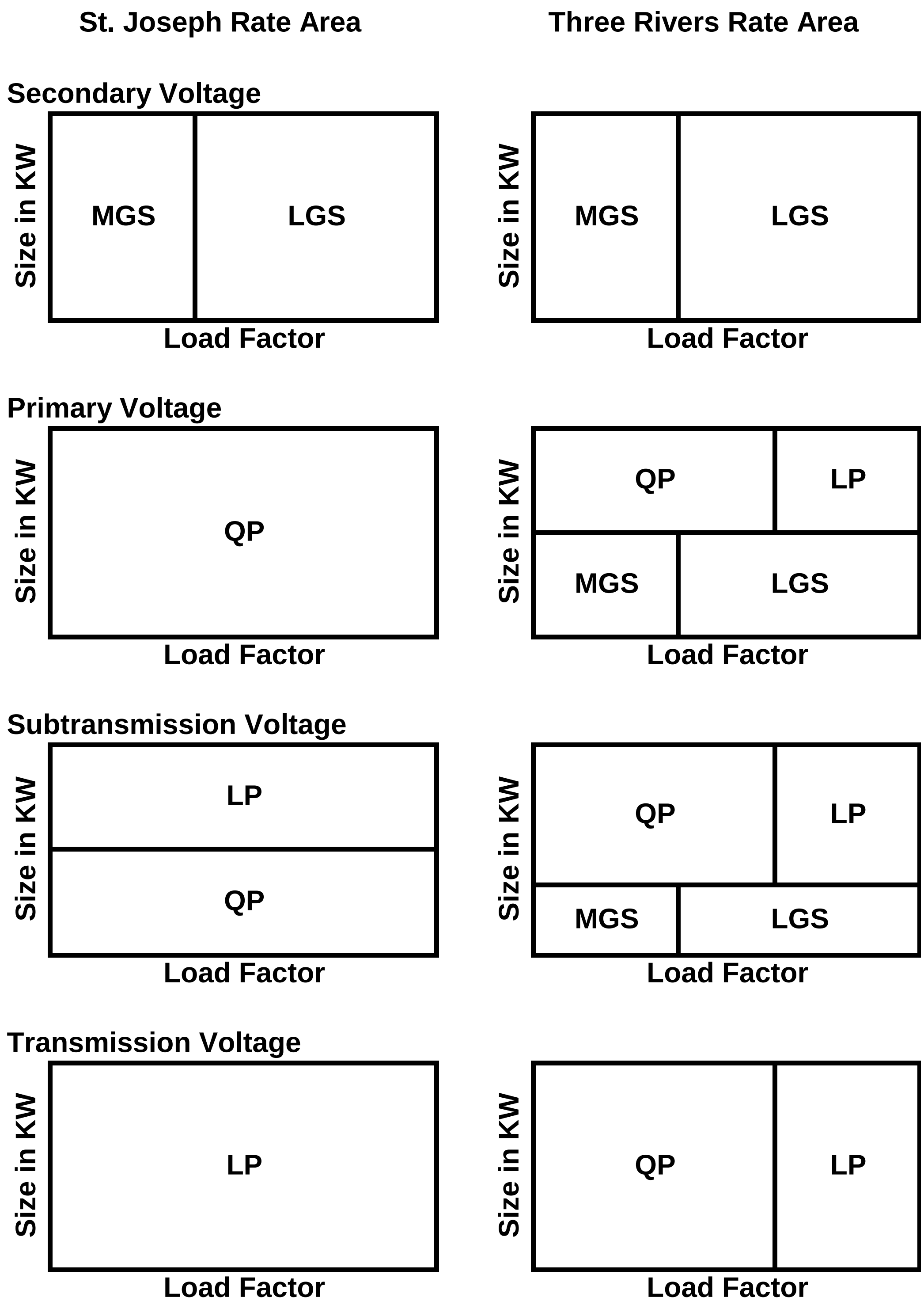
A. The primary change in Tariff RS is the elimination of the current inclining block rate structure in the St. Joseph Rate Area and the establishment of one price for all kWh of monthly use, as is the current structure in the Three Rivers Rate Area. This change helps to limit the impact on individual customers. In addition, I&M is proposing to make the Optional Senior Citizen rate available to Three Rivers Rate Area customers.

Q. PLEASE EXPLAIN THE CHANGES TO TARIFF SGS.

A. The current Three Rivers Rate Area Tariff SGS has a two step energy rate blocked at 2,000 kWh for standard service and at 1,000 kWh for nonmetered service. The current St. Joseph Rate Area Tariff SGS has a two step energy rate blocked at 1,000 kWh for both standard service and nonmetered service. The Company is proposing to continue the two-step energy rate design, using blocked energy charges that change at 2,000 kWh for both standard and nonmetered service.

Q. PLEASE DESCRIBE THE CURRENT COMMERCIAL AND INDUSTRIAL TARIFFS.

A. I&M currently has four commercial and industrial tariffs with differences in availability between the St. Joseph and Three Rivers Rate Areas. The availability of these tariffs is limited based upon the size (demand) of the customer and the delivery voltage of the customer's service. These relationships are illustrated by the following diagrams:


St. Joseph Rate Area
Three Rivers Rate Area
Secondary Voltage
Size in KW
MGS
LGS
Load Factor
Size in KW
MGS
LGS
Load Factor
Primary Voltage
Size in KW
QP
Load Factor
Size in KW
QP
LP
MGS
LGS
Load Factor
Subtransmission Voltage
Size in KW
LP
QP
Load Factor
Size in KW
QP
LP
MGS
LGS
Load Factor
Transmission Voltage
Size in KW
LP
Load Factor
Size in KW
QP
LP
Load Factor

Where a customer has the choice of more than one tariff, that decision is driven by the customer's load factor.

Q. WHAT IS LOAD FACTOR?

A. Load factor is simply a measure of the amount of electricity a customer uses over time (energy) relative to the customer's maximum utilization (demand). An example would be if a customer's average demand is equal to its peak demand, the customer would have a load factor equal to 100%. Said another way, a customer that uses 100 kW for all 744 hours of a 31 day month would have an hours use of 744 and a load factor of 100%. If that customer was a single shift operation and used 100 kW for 200 hours a month and nothing during the remaining hours, the customer's hours use would be 200 and load factor would be 27% (200 / 744).

Q. WHY DO TARIFFS BASED ON LOAD FACTOR MAKE SENSE?

A. A load factor based tariff structure ensures that all customers have the opportunity to choose the tariff best suited to their usage characteristics. Such tariffs provide rate continuity for customers as usage changes whether by size or by load factor.

Q. DOES I&M PROPOSE TO CHANGE THE STRUCTURE OF THE COMMERCIAL TARIFFS?

A. Yes. The proposed tariffs were designed to maintain the load factor relationships (crossovers) that exist in some of the current tariffs and make rates based upon load factor available to most customers. For Tariffs MGS and LGS the crossover is approximately 250 hours use per month (34% load factor). The load factor relationship between Tariffs QP and LP is also being maintained, but Tariff QP is being eliminated. Tariff LP is being modified to a structure that incorporates the existing load factor relationship into the proposed rate structure.

Q. PLEASE EXPLAIN THE CHANGES TO TARIFF LP AND ELIMINATION OF TARIFF QP.

A. Currently, St. Joseph Tariff QP is available to primary and subtransmission customers with maximum demands greater than 100 kW while Three Rivers Tariff QP is available to primary, subtransmission and transmission customers greater than or equal to 2,000 kW. Tariff LP is available to customers with maximum demands of 2,000 kW and greater at subtransmission and transmission voltage levels in both rate areas and additionally at primary voltage level in the Three Rivers Rate Area. The major difference between the two tariffs is the design of the demand and energy charges which makes QP more attractive to lower load factor customers and LP more attractive to higher load factor customers. Such a design makes sense, as the utilities' demand-related costs per kWh decline as the customer better utilizes the Company's facilities by increasing their load factor. Customers having load factors that are near the break-even or crossover point between Tariffs QP and LP are faced with the decision of entering into a service contract under one of the tariffs. This decision can be quite difficult, particularly for new customers and customers that are expanding or contracting operations, and are uncertain of what their ultimate operating characteristics will be. To address and eliminate such concerns as well as simplify tariff and contract administration, the Company proposes to consolidate the tariffs under a new Tariff LP.

The key feature of the consolidated tariff is the continuation of the load factor relationship that existed between Tariffs QP and LP. This is achieved by introducing a load factor blocking of the energy charge. The load factor blocking was set at the existing crossover point of 210 hours of on-peak use per month for Tariffs QP and LP and thus minimizes the impact on all existing customers. The second block energy charge was set at I&M's full energy cost. The demand charge was set at a rate close to the current QP demand charge. Finally, the first block energy charge reflects full energy costs and residual demand costs not collected through the demand charge. The single proposed tariff rate reproduces the pricing and price signals previously provided by the two tariffs.

An additional benefit of the proposed structure is that it provides a smoother transition from Tariffs MGS or LGS when the customer's demand exceeds 1,500 kW.

Q. WHAT OTHER CHANGES ARE PROPOSED FOR THE NEW TARIFF LP?

A. The availability of service has been reduced to accommodate customers using 1,500 kW or more, and primary voltage service is made available to

St. Joseph Rate Area customers. Monthly billing demands are currently determined as the average of the three highest 15-minute integrated peaks. I&M proposes to use the single highest 15-minute integrated peak because the current approach results in higher billing costs for monthly processing and data translation. This change will also result in additional load management incentives for customers. Another change to the determination of monthly billing demand is to include a minimum billing demand based upon 60% of the highest previous billing demand during the last 11-months.

Q. DOES I&M PROPOSE ANY CHANGES TO THE END-USE TARIFF STRUCTURES?

A. Yes. Municipal and School Service (MS), Electric Heating Schools (EHS) and Electric Heating General (EHG) will require customers to move to general service tariffs for which they qualify when new or upgraded facilities are required and eliminate the written contract requirement. Due to the unique load characteristics of Irrigation Service Tariff (IS), which typically operates only a few months of the year, I&M proposes to eliminate the service charge with all costs collected in a single energy charge.

Q. PLEASE EXPLAIN THE COMPANY'S CHANGES IN ITS INTERRUPTIBLE SERVICE OFFERINGS.

A. I&M is proposing a new interruptible service offering Contract Service Interruptible Power (CS-IRP). Tariff CS-IRP provides for two distinct types of interruptible service: a mandatory or capacity interruptible service and a discretionary or energy interruptible service. Customers may select either or both types of service for all or a portion of their load.

The Company continues to have an obligation to ensure that it has adequate capacity to meet the needs of its customers. One method of meeting that need is to construct power plants. Another method is to enter into service arrangements with customers wherein the customer agrees to reduce load at those times when capacity is needed on the Company's system. This type of service is a mandatory (capacity) interruptible service.

Under a discretionary (energy) interruptible service, the Company and customer would agree upon a certain number of hours during which the Company would be able to ask the customer to reduce load. The customer would have the option to either reduce load or pay the hourly price quoted by the Company. Since there is no guarantee that the customer will reduce load upon request, this type of service has no capacity value.

Q. ARE THERE OTHER CHANGES IN THE COMPANY'S INTERRUPTIBLE SERVICE OFFERINGS?

A. Yes. Given the lack of customer interest in the current ECS and PCS rider offerings, I&M proposes to eliminate the current offerings and replace them with new ECS and EPCS riders. These riders reflect significant modifications to the existing offerings with a focus on making them more attractive to customers while maintaining benefits for all of I&M's customers.

One example of such changes is the elimination of the charge for failure to curtail under the new Rider ECS.

Q. PLEASE DESCRIBE I&M'S PROPOSED EXPERIMENTAL REAL-TIME PRICING TARIFF (RTP).

I&M proposes a three-year experimental tariff whereby large customers can manage their electric costs by shifting load from higher cost to lower cost pricing periods or by adding new load during lower price periods. Customers must sign up for one (1) year and will designate the amount of their load which is billed under the existing firm service tariff and the remainder which will be billed under Tariff RTP. In this manner, customers can choose to manage how much of their load they wish to expose to market pricing. Charges for capacity and energy are based upon applicable prices in the PJM market. Distribution charges are based upon I&M's costs and there is a program charge of $150 per month. Offering Tariff RTP on an experimental basis allows the Company to test the design of the rates, the systems needed to implement the tariff and gauge customer interest and acceptance of such a service offering. Contracts under Tariff RTP will run concurrent with the PJM planning year of June through May.

Q. DOES I&M PROPOSE AN ECONOMIC DEVELOPMENT RIDER (EDR)?

A. I&M proposes to eliminate the existing rider, which has expired, and introduce a new rider which encourages new development as well as redevelopment. Company witness Hix explains the proposed EDR.

V. DESIGN OF RIDERS

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED INCLUSION OF TRANSMISSION COSTS IN THE UNIFIED PSCR CLAUSE?

A. As discussed by Company witness Bethel, the Company's transmission costs should be based upon the charges under PJM's Tariff (the Open Access Transmission Tariff or "OATT" and the Operating Agreement). The Company has calculated those costs as shown in Exhibit I&M-29 (WAA-6) and proposes to include them as the transmission component of the unified PSCR Clause discussed by Company witness Krawec.

As discussed by Company witness Gregory, I&M's books and records provide the information necessary to determine I&M's charges under PJM's Tariff. As shown in Exhibit I&M-29 (WAA-6), lines 1 through 16 itemize the total projected I&M charges for transmission under the PJM Tariff for Network Integration Transmission Service (NITS); associated Revenue Credits; Transmission Owner Scheduling, System Control and Dispatch Service; Transmission Enhancement Charges; PJM Administrative Charges; RTO Formation costs; Expansion Cost Recovery Charges; PJM Administrative Charges – Default Assessments; and Transmission Enhancement Charges. In addition to these on-going costs, costs related to the deferred PJM Administrative Charges must be included to allow for their recovery as shown on lines 30 through 34.

Once the total I&M amount is determined on line 18, that amount is divided by I&M's projected Net Energy Requirement (line 20). This results in a rate (line 22) which reflects the allocation of transmission costs to Michigan based upon an energy allocation factor. Since transmission costs are almost entirely demand-related, this resulting rate (line 22) is multiplied by the ratio of the jurisdictional demand allocation factor to the jurisdictional energy allocation factor (line 24) to yield the on-going transmission component of the unified PSCR Clause. Finally, the deferred Michigan retail costs (line 34) are added to yield the total transmission component of the unified PSCR Clause.

Q. PLEASE DESCRIBE THE OPERATION OF TRANSMISSION COMPONENT OF THE UNIFIED PSCR CLAUSE.

A. Consistent with the current operation of the PSCR Clause, I&M will be recording over/under recoveries based upon actual collections under the Transmission Component of the unified PSCR Clause and actual I&M costs under PJM's Tariff. Any over/under recoveries will be reconciled annually as part of the current PSCR process. Refunds and charges under PJM's Tariff for services rendered during the period would be part of the subsequent annual reconciliation.

Q. HOW WAS THE NET LOST REVENUE RECOVERY RIDER DETERMINED?

A. As shown in Exhibit I&M-101 (DMR-29), the kWh impacts were calculated based upon the increased Michigan statutory requirements for 2011 above the level for 2010. The 2010 level is reflected in the kWh forecast for 2010 used in this proceeding. To determine net lost revenues, I calculated the average fixed cost per kWh based upon I&M's proposed rates in this proceeding. To determine this realization, revenues related to the customer charge, the basing point of the PSCR and all surcharges/riders were deducted from total proposed revenues to determine the net fixed cost revenue. The net fixed cost revenue was divided by class kWh usage to determine the net lost revenue realization. Net lost revenues were then calculated by multiplying the incremental 2011 kWh impact by the net lost revenue realization. Finally, net lost revenues were divided by class kWh usage to determine the Net Lost Revenue Recovery Rider rate per kWh for each customer class. As discussed by Company witnesses Hayes and Krawec, these rates will be reconciled to actual amounts and any over or under recovery will be used to adjust the Rider in future proceedings.

Q. PLEASE DESCRIBE THE gridSMART^{sm} PROGRAM COST RECOVERY RIDER.

A. As discussed by Company witnesses Krawec and Walter, the Company proposes a phased-in implementation of I&M gridSMART^{sm} initiatives in Michigan. The Company proposes to collect the net costs associated with the gridSMART^{sm} initiatives in a corresponding phased-in manner through the gridSMART[sm] Program Cost Recovery Rider. Company witness Walter identifies the net costs (costs less operational savings) for each year of the 4-year phase-in plan. These costs are separately identified as either capital or net expense (expense net of expense savings and revenues). The Rider is designed to collect the net expense and a carrying charge on the capital invested. The carrying charge is based upon the expected useful life of each asset as discussed by Company witnesses Walter and Hayes. Company witness Hawkins provided the carrying charge rates.

As shown in Exhibit I&M-102 (DMR-30), the revenue requirement for each year for the gridSMART[sm] Program Cost Recovery Rider is calculated as the sum of the net expense for the year and a carrying charge on the cumulative invested capital. A revenue requirement is also calculated for years after the fourth year to provide for collection of the ongoing level of net costs. Since the Company proposes to implement the Rider concurrent with the commencement of implementation, the projected carrying charge is calculated using a 13-month average balance for the capital investment. For example, in the first year if the Company plans to invest $1.2 million, the carrying charge is calculated using only $0.6 million, since the investment will be occurring throughout the year.

Once the revenue requirement for each year is determined, the Rider rate is determined as a percentage of projected distribution revenue under the Company's proposed rates. As discussed by Company witnesses

Hayes and Krawec, these rates will be reconciled to actual expenditures and any over or under recovery will be used to adjust the Rider in future proceedings.

Q. PLEASE DESCRIBE THE ENHANCED DISTRIBUTION RELIABILITY COST RECOVERY RIDER.

A. As discussed by Company witness Ehler, the Company proposes an incremental vegetation management program to move to a four-year cycle in the Michigan service territory. This program will be phased-in over four years and requires additional spending beyond base levels. The Company proposes to collect the net costs associated with the incremental vegetation management program in a corresponding phased-in manner through the Enhanced Distribution Reliability Cost Recovery Rider. Company witness Ehler identifies the costs for each year of the 4-year plan. These costs are separately identified as either capital or expense. The Rider is designed to collect the expense and a carrying charge on the capital invested. The carrying charge is based upon the expected useful life of the assets. Company witness Hawkins provided the carrying charge rates.

As shown in Exhibit I&M-103 (DMR-31), the revenue requirement for each year for the Enhanced Distribution Reliability Cost Recovery Rider is calculated as the sum of the expense for the year and a carrying charge on the cumulative invested capital. A revenue requirement is also calculated for years after the fourth year to provide for collection of the ongoing level of carrying costs on the invested capital. Since the Company proposes to implement the Rider concurrent with the commencement of implementation, the projected carrying charge is calculated using a 13-month average balance for the capital investment.

Once the revenue requirement for each year is determined, the Rider rate is determined as a percentage of projected distribution revenue under the Company's proposed rates. As discussed by Company witnesses Hayes and Krawec, these rates will be reconciled to actual expenditures and any over or under recovery will be used to adjust the Rider in future proceedings.

Q. PLEASE DESCRIBE THE GENERATION INVESTMENT COST RECOVERY RIDER.

A. As discussed by Company witnesses Krawec, Hruby, and Peifer, I&M is proposing that the capital investment and O&M associated with projects like the Cook Improvement Project and future environmental retrofits for the Rockport Plant be recovered in future regulatory proceedings through a new Generation Investment Cost Recovery Rider. In this proceeding, the Generation Investment Cost Recovery Rider is simply being established and no amounts will be included in the Rider until project costs are reviewed and approved by the Commission in future proceedings.

Once an annual revenue requirement for an approved project is determined in a future proceeding, the Generation Investment Cost

Recovery Rider rate will be calculated. The Rider rate is determined as a percentage of projected power supply revenue. An illustrative calculation is shown in Exhibit I&M-104 (DMR-32). As discussed by Company witnesses Hayes and Krawec, these rates will be reconciled to actual costs and any over or under recovery will be used to adjust the Rider in future proceedings.

Q. PLEASE DESCRIBE THE INTERIM RATE SURCHARGE RIDER.

A. While I&M hopes that this proceeding can be resolved expeditiously, the possibility exists that I&M will need to place interim rates in effect pending the ultimate outcome of this proceeding. Though the specific level of any such interim rates has not been determined, I&M proposes to use a surcharge rider that would be applied to I&M's existing tariffs and rates. This surcharge rider would apply as a percentage of total monthly charges under I&M's existing rates. The applicable percentage would vary by tariff and maintain the same relationships as the Company's requested increase, excluding the proposed riders. For example, using the Company's overall requested increase, excluding riders, of 26.88% the WSS class increase is 16.17%. If the overall interim rate increase is lower, then the customer class increase would be proportionally reduced. The proposed Interim Rate Surcharge Rider and an example calculation are shown in Exhibit I&M-105 (DMR-33).

VI. SUMMARY OF PROPOSED REVENUES AND TYPICAL BILLS

Q. HAVE YOU PREPARED A SUMMARY OF THE COMPANY'S PROPOSED RATE INCREASE, INCLUDING THE PROPOSED RIDERS?

A. Yes. Exhibit I&M-96 (DMR-24), A-6, Schedule F2 and Exhibit I&M-97 (DMR-25), A-6, Schedule F3, summarize and detail the proposed rates and charges that will produce the proposed revenues based upon projected 2010 billing determinants. Schedule F2 summarizes the information both by current tariff and by proposed tariff. Schedule F3 provides the details supporting the summarized information in Schedule F2.

Q. WILL ANY CUSTOMERS FACE DISPROPORTIONATE INCREASES IN THEIR BILLS DUE TO THOSE PROPOSED RATE DESIGN MODIFICATIONS?

A. No. Exhibit I&M-98 (DMR-26), A-6, Schedule F4 is a typical bill comparison between current and proposed rates for each customer class to insure that I&M's proposed rates and charges would not result in a disproportionate increase to a particular customer based upon usage.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. My testimony describes the Michigan jurisdictional cost of service allocation studies, and the allocation of the revenue requirement to each tariff class. I also sponsor the Company's proposed rate design and the design of the proposed Riders.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
INDIANA MICHIGAN POWER COMPANY	)	
For Authority to Increase its Rates	)	Case No. U-16180
For the Sale of Electric Energy	)	

PRE-FILED DIRECT TESTIMONY

OF

SCOTT M. KRAWEC

**PRE-FILED DIRECT TESTIMONY OF SCOTT M. KRAWEC
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

Q. Please state your name and business address.

A. My name is Scott M. Krawec. My business address is One Summit Square, P.O. Box 60, Fort Wayne, Indiana 46801.

Q. By whom are you employed and in what capacity?

A. I am employed by Indiana Michigan Power Company (I&M or Company) as its Director of Regulatory Services.

Q. Please briefly describe your educational and business experience.

A. I received a Bachelor of Science in Business Administration degree, majoring in Accounting, in June 1976, from The Ohio State University. I received a Master of Business Administration degree in May 1989 from Indiana University. I was employed by Consumers Energy (formerly Consumers Power Company) in 1976 as an Internal Auditor. I joined American Electric Power Service Corporation (AEPSC) in 1979 as an Internal Auditor and later that year transferred to I&M as an accountant. I progressed through several accounting and rate department supervisory and administrative roles. In 1997, I returned to AEPSC as a Project Supervisor, and in 1998, I was named Manager of Utility Ledgers for American Electric Power's (AEP) Indiana, Michigan, and Kentucky subsidiaries. In 2001, I was named Director of Regulated Accounting for all of AEP's eastern utility subsidiaries. In 2004, I was named the Director of Wholesale Commodity Accounting. In 2007, I was named Assistant Controller of Commercial Accounting and in 2008, I was named Assistant

Controller of Utility, General and Regulatory Accounting for all of AEP. In August 2009, I assumed my current position as Director of Regulatory Services for I&M.

I am a Certified Public Accountant licensed in the states of Indiana and Ohio. I am a member of the American Institute of Certified Public Accountants and the Ohio Society of CPAs.

Q. Have you previously testified before any regulatory commission?

A. Yes. I have testified on behalf of I&M before the Michigan Public Service Commission (MPSC), the Indiana Utility Regulatory Commission (IURC), and the Federal Energy Regulatory Commission (FERC) in support of accounting and tax matters. In addition, I have submitted testimony before the State Corporation Commission of Virginia on behalf of Appalachian Power Company, another AEP subsidiary.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my pre-filed direct testimony is to provide a description of I&M's Michigan jurisdiction regulatory history and the merger of I&M and Michigan Power Company (MPCo). I provide a general description of I&M's fleet and generating plants and I&M's power supply arrangements related to the Rockport Plant. In addition, I support I&M's expanded and modified uniform Power Supply Cost Recovery (PSCR) clause and basing point. I support, along with other witnesses in this proceeding, the new tracking mechanisms I&M has proposed in this case including the Generation Investment Tracker, the gridSMART^{SM} Tracker, the Demand Side Management Net Lost Revenue Recovery Tracker and the Enhanced Distribution Reliability

Tracker. I discuss the recovery of I&M's regulatory assets and other costs along with recovery of rate case expenses, enhanced security costs and nuclear decommissioning study expense. I describe I&M's proposal for a Major Storm Damage Restoration Reserve. Also, I explain the termination of the AEP/Central and Southwest Corporation (CSW) Merger Savings Reduction Rider. Last, I provide I&M's revenue deficiency for the 2010 projected test year.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring the following exhibits:

1. Exhibit I&M-106 (SMK-1) Schedule A1 Revenue Deficiency
2. Exhibit I&M-107 (SMK-2) Rate Case Expense and Nuclear Decommissioning Study Expense

Q. Were the exhibits, or portions of exhibits, which you are sponsoring prepared by you or under your supervision?

A. Yes. In some cases certain data shown on these exhibits was provided to me and is sponsored by other witnesses.

Q. Please describe how the Company prepared its case-in-chief.

A. The basic filing format for the instant filing recognizes the importance of presenting a case-in-chief in a logical and complete format. The preparation of the forecasted revenue requirement is based on a projected test year of calendar year 2010. In addition, historical financial information has been provided in this case from the amounts and balances recorded in the Company's books of account for the historical period of the 12 months ended December 31, 2008. The Company can rely on these recorded amounts as the foundation for its historical period for several reasons. The Company maintains its books and records in accordance with Accounting Principles Generally Accepted in the United States of America (GAAP) and the FERC Uniform System of Accounts (USofA). Each year tens of thousands of financial transactions are classified and recorded in the Company's books of account. The overall objective is to properly record the financial transactions of the Company and to prepare financial statements and reports on operations for management, regulatory authorities, and other external users of the information.

In addition, I&M files financial reports with the MPSC in accordance with the Michigan uniform system of accounts and has compiled this case on that basis. Company witness Hayes discusses differences between the MPSC and the FERC system of accounts.

Q. Are the Company's books and records audited by outside parties?

A. Yes. While I&M's management is responsible for the information contained in its books and records, there is also a high degree of scrutiny by outside parties. The books and records are subject to audit by the FERC, the IURC and this Commission. The financial statements also undergo an annual audit by Deloitte & Touche, the independent auditors of the AEP System, who provide an objective review as to management's discharge of its responsibilities insofar as they relate to the fairness of the Company's reported financial condition and results of operations. Moreover, the AEPSC Internal Auditing Department, which reports to the Audit Committee of the AEP Company, Inc. Board of Directors, performs audits of I&M's accounts to provide reasonable assurance of compliance with GAAP, the FERC USofA, the Securities and Exchange Commission, and other applicable rules and regulations.

Q. Have there been any recent developments that have had a material impact on how this rate case is being presented?

A. Yes. On October 6, 2008 Governor Jennifer Granholm signed 2008 PA 286 (Act 286) which modified, among other things, certain aspects of the base rate setting process for Michigan utilities. In particular, Act 286: 1) Established a 12-month deadline for rate cases to be completed or the application is considered approved; 2) allows the utility to self-implement rate increases 180 days after a complete rate case application has been filed, if the Commission has not issued a final order; 3) directed the Commission to establish new rate case filing requirements; and 4) allows utilities to use a projected future period in their requests for rate relief.

Q. On December 23, 2008 in Case No. U-15895, the Commission issued new rate case filing requirements. What key changes are reflected in this filing?

A. The key changes reflected in this filing include: 1) Revised exhibit and schedule formats reflecting projected future period data; 2) Supplemental information required at the time of filing (mainly historical accounting and financial data); 3) A reconciliation of the projected test year to the most recent historical calendar year information if the projected test year is not a calendar year; 4) Providing electronic versions of models in Microsoft Excel format to parties who request them; and 5) Providing Tariff changes in redline format in Microsoft Word.

Q. Has I&M complied with the new rate case filing requirements in developing this case?

A. Yes. Included with this rate case filing are the required exhibits, schedules and supplemental data mandated by the Commission's December 23, 2008 Order.

Q. What approach is the Company using to support its projected test year positions and recommendations in this case?

A. Although Act 286 allows for fully projected periods, I&M has used historical actual data as a point of reference for the reasonable comparison of the 2010 test year data. All historical 2008 calendar year data is supported by Company witness Hayes. All projected total company revenues, expenses and account balances for 2010 are supported by Company witnesses Allen, Peifer, Hruby, and Ehler and the Michigan retail jurisdiction portion thereof is supported by Company witnesses Roush and Kelly.

Q. What historical period is being used by I&M, and what projected test year period is being used by I&M for purposes of calculating its projected revenue deficiency?

A. The historical period being used by I&M is calendar year 2008. The projected test year is the calendar year 2010.

Q. Why did I&M use 2008 for its historical period?

A. In order to comply with the Commission's order in U-15895, I&M used the most recent calendar year audited financial statements at the time of this filing, which is the 2008 calendar year statements. At the time of this filing, I&M's accounting books for the calendar year 2009 have not been finalized and the financial statements were not yet prepared nor audited by the Company's public accounting firm. Moreover, I&M's Form 10-K report and Form P-521 for 2009 are not scheduled to be filed until late February 2010 and late April 2010, respectively. Until the Form 10-K statements are filed in late February 2010 the Company cannot publically release the financial statements for the 2009 calendar year. Therefore, by using year 2008 historical information, I&M selected the most current and complete financial information for a calendar year available for use and inclusion in this rate filing.

Depreciation Rates

Q. Is I&M requesting a revision in its depreciation rates as part of this case?

A. No. I&M's depreciation rates were set as part of the Commission Order Approving Settlement Agreement dated September 25, 2007 in Case Nos. U-15162 and U-15276. I&M is using those approved depreciation rates for both the 2008 historical period and projected 2010 test year. As a result, I&M used its recently approved depreciation rates and practices approved in Case Nos. U-15162 and U-15276 to determine its projected 2010 revenue requirement in the instant general rate case.

Q. Please describe I&M's regulatory history in Michigan since 1989.

A. As a result of the I&M and MPCo merger, in Case No. U-9912, I&M's service area in Michigan currently consists of two rate areas, the St. Joseph Rate Area and the Three Rivers Rate Area. I&M's existing retail electric rates in the St. Joseph Rate Area were established pursuant to the Commission's Order Approving Settlement Agreement dated February 12, 1991, in Case No. U-9656 (St. Joseph rate case), based upon projected test year operating costs for the twelve months ending December 31, 1991. Retail electric rates were established for the Three Rivers Rate Area (at that time known as MPCo) pursuant to the Commission's Order Approving Settlement Agreement dated March 9, 1989, in Case No. U-9205 (Three Rivers rate case), based upon test year operating costs for the projected twelve months ending December 31, 1989. Three Rivers Rate Area retail electric rates were subsequently reduced by the Commission's Opinion and Order dated December 16, 1999, approving a settlement agreement in Case Nos. U-11181-R, U-11531-R, and U-11792 (Cook Plant settlement cases).

As a result of the implementation of retail choice in Michigan, retail electric rates in both rate areas were unbundled, and terms and conditions of customer choice were established by Commission Order Approving Settlement Agreement dated October 11, 2001, in Case No. U-12652 et al.

In addition, I&M's rates include: 1) a Nuclear Decommissioning Surcharge first established in accordance with the Commission's Opinion and Order in Case No. U-8559 and most recently modified by a reduction authorized through the Commission Order Approving Settlement Agreement dated September 25, 2007, in Case Nos. U-15162 (Decommissioning Investigation) and U-15276 (Depreciation Request); 2) an Energy Optimization Surcharge, in accordance with the Commission's Order Approving Settlement Agreement dated May 12, 2009, in Case No. U-15808; and 3) an AEP/CSW Merger Savings Reduction Rider credit pursuant to a December 16, 1999 Commission Order Approving Settlement Agreement in Case No. U-12204.

Merger of I&M and Michigan Power Company

Q. Please explain the merger of I&M and MPCo.

A. On July 5, 1991, I&M and MPCo filed in Case No. U-9912 a joint application with the MPSC for approval of their proposed merger. The merger plan called for MPCo to merge into I&M, with I&M being the sole surviving corporation. MPCo would transfer all of its operating rights, operating facilities, and all other property to I&M.

Prior to the merger of I&M and MPCo, the St. Joseph rate area was I&M's service territory and the Three Rivers rate area was MPCo's service territory. Pursuant to the December 5, 1991 order in Case No. U-9912, the MPSC established two rate areas as of March 1, 1992, specifically, the Three Rivers Rate Area and the St. Joseph Rate Area. The Commission authorized the implementation of the Schedule of Tariffs Governing the Sale of Electricity for the St. Joseph and Three Rivers Rate Areas. The Commission Order in Case No. U-9912 further authorized I&M to continue the current authorized MPCo and I&M rate levels and terms and conditions of service within the respective Three Rivers and St. Joseph Rate Areas until modified by a subsequent order of the Commission. As part of I&M's application, I&M seeks such a subsequent Commission order to combine the two rate areas into one with the same rates and charges and a unified PSCR clause.

Q. Please explain I&M's request for merging and combining the two rate areas into one rate area.

A. I&M is making this proposal since the two rate areas are fully integrated, are managed together, and share many of the same I&M employees. Moreover, their loads are served by the same generation sources. Merging the two rate areas simplifies the rates, tariffs, and provides for efficiency for both customers and I&M. The merger of the tariffs for the two rate areas is addressed by Company witness Hix.

Q. What is I&M's overall proposed rate increase?

A. As shown on Schedule A1 of Exhibit I&M-106 (SMK-1), I&M's 2010 projected test year revenue deficiency based on its rate base, net operating income, rate of return and revenue conversion factor is approximately $62.5 million. I&M's case includes a request to increase rates to recover this revenue deficiency which includes a revised unified PSCR clause and four new trackers, which I will address later in my testimony.

I&M Generation

Q. **Please describe I&M's fleet of generating plants.**

A. I&M owns a diverse generating fleet comprised of one nuclear plant, six hydroelectric plants, and two coal-fired power plants. The Cook Nuclear Plant is located in Bridgman, Michigan and consists of two nuclear generating units. I&M's six hydroelectric facilities are located on the St. Joseph River with four facilities in Michigan and two in Indiana. I&M's coal-fired power plants consist of four units at the Tanners Creek Plant, located in Lawrenceburg, Indiana and two units at the Rockport Plant, located in Rockport, Indiana.

Q. Please describe I&M's power supply arrangements related to the Rockport Plant.

A. The Rockport Plant consists of two 1,300-MW (nominal) generating units which are jointly owned or leased by I&M and AEP Generating Company (AEG), another AEP subsidiary. I&M's 2010 generating capacity resources reflect the following Rockport-related arrangements:

1. I&M's 50% ownership share of Rockport Unit 1 and I&M's 50% leased share of Rockport Unit 2 (i.e., 650 MW of Unit 1 and 650 MW of Unit 2).
2. AEG's 50% share of Rockport Unit 1 and AEG's 50% leased share of Rockport Unit 2 (i.e., 650 MW of Unit 1 and 650 MW of Unit 2).
3. The Unit Power sale agreements among AEG, I&M, and Kentucky Power Company (KPCo), another AEP System operating company, under which I&M committed to purchase 70% of AEG's share of each Rockport unit, and KPCo committed to purchase 30% of AEG's share of each Rockport unit.
4. A Unit Power agreement with Carolina Power & Light, now Progress Energy Carolinas (PEC), under which I&M sold 250 MW of its 650 MW share of Rockport Unit 2 capacity to PEC for the period January 1, 1990 through December 31, 2009. The 2010 projected data reflects that beginning January 1, 2010, this 250 MW returns to I&M.

The agreements by which KPCo purchases shares of the Rockport units are through December 7, 2022. Thus, I&M's net capacity resources for 2010 include 1,105 MW of Rockport Unit 1 capacity (its own 650 MW share plus 455 MW purchased from AEG) and 1,105 MW of Rockport Unit 2 capacity (its own 650 MW share, plus 455 MW purchased from AEG).

Q. Please describe the general terms of I&M's purchase of Rockport Units 1 and 2 capacity from AEG.

A. Under the terms of the Unit Power Agreement between I&M and AEG, dated March 31, 1982, as amended, AEG makes available to I&M up to 70% of the power and associated energy from its share of Rockport Units 1 and 2. I&M, in turn, pays to AEG amounts sufficient to cover, among other things, AEG's operating and other expenses related to the amount of power sold to I&M.

Unified PSCR Clause

Q. Please explain I&M's request for a unified PSCR clause.

A. I&M proposes to unify the Three Rivers Rate Area PSCR clause into the St. Joseph Rate Area PSCR clause as part of the merger of the two rate areas into one rate area. This will provide a single uniform PSCR clause mechanism, basing point and PSCR factor. The current St. Joseph Rate Area PSCR clause reflects those costs traditionally allowable pursuant to Act 304 of the Public Act of 1982. The Commission's Order in Case No. U-9912 (Merger Case) modified the PSCR clause to identify the costs of power supply included in the determination of a PSCR factor for the Three Rivers Rate Area. In addition, allowable power supply costs after the merger of I&M and MPCo were to be determined for the Three Rivers Rate Area in the same manner that allowable power supply costs were determined for MPCo before the merger, i.e. the FERC Net Energy Cost (NEC) method. Likewise, allowable power supply costs were to be determined for the St. Joseph Rate Area in the same manner that allowable power supply costs were determined for I&M before the merger.

The following table provides an overview of how the two PSCR clauses are currently structured and how the proposed clause would be after the unification of the two areas and the expansion of the PSCR for certain other proposed cost elements, which I will address later in my testimony:

	St. Joseph	Three Rivers	Unified PSCR
Fuel	Currently in PSCR	Currently in PSCR	Include in PSCR
Purchased Power	Currently in PSCR	Fuel costs only	Include in PSCR
Allowances	Currently in PSCR	Not in PSCR	Include in PSCR
Consumables	Currently in PSCR	Not in PSCR	Include in PSCR
Capacity Settlement	Currently in PSCR	Not in PSCR	Include in PSCR
Ancillary Services and Other PJM Related Costs	Most costs currently in PSCR	Not in PSCR	Include in PSCR
OSS Margins	Currently in PSCR	Not in PSCR	Include OSS sharing mechanism in PSCR
Transmission	Not in PSCR	Not in PSCR	Include in PSCR and expand for all PJM and OATT-transmission costs

Q. Please explain the appropriateness of including Purchased Power in the unified PSCR clause.

A. Total purchased power costs have traditionally been included in Michigan utilities' PSCR clauses.

Q. Please explain the appropriateness of including allowance consumption expenses in the unified PSCR clause.

A. I&M must comply with the Clean Air Act Amendments of 1990 (CAAA). All emission costs and credits should be reflected in the unified PSCR clause as a component of power supply costs as defined in the current St. Joseph Rate Area PSCR clause because such emissions vary with fossil generation and fuel consumed. The emissions represent a chemical by-product of the coal burning process. Moreover, this conclusion was upheld by this Commission in its April 28, 2005 order approving the Company's 2004 Plan filing (U-13919) and cost recovery factor which included all allowance costs incurred and such costs have been included and approved in subsequent St. Joseph Rate Area PSCR clause filings.

Q. Please describe the consumables I&M seeks to include in the unified PSCR clause.

A. I&M currently includes consumables in the St. Joseph Rate Area PSCR clause. The consumables referred to in the above table include materials such as urea and activated carbon used to reduce emissions. These costs should be reflected as a component of power supply costs as defined in the St. Joseph Rate Area because such costs vary with fossil generation and fuel consumed. I&M seeks to include consumables in the proposed unified PSCR clause.

Q. Please explain the appropriateness of including the Capacity Settlement charges/credits in the proposed unified PSCR clause.

A. The Capacity Settlement amounts included in the St. Joseph Rate Area PSCR clause are determined in accordance with the FERC approved AEP Interconnection Agreement. Under its provisions, each pool member is responsible for providing its Member Load Ratio share of the total primary capacity of the pool. It is appropriate to include capacity settlement charges/credits in the unified PSCR clause because they fluctuate and are related to the adequate supply of power necessary to meet I&M's load obligations. Company witness Allen addresses the capacity settlement charges/credits in more detail.

Q. Please explain I&M's proposal to track Off System Sales (OSS) margins in the unified PSCR clause.

A. As discussed in the testimony of Company witness Busby, I&M proposes that OSS margins be tracked in the unified PSCR clause and be shared 50% to customers and 50% to the Company. Company witness Busby discusses that a sharing mechanism can provide a balance for customers and I&M to share in the risks and rewards of AEP's efforts to maximize OSS margins. To operate as an incentive for the Company to continue to maximize its efforts in the OSS market, the Company's share of the OSS margins would be excluded from net electric operating income for ratemaking purposes.

Company witness Allen has provided the calculation of OSS margins for the initial implementation of the OSS margins sharing.

Q. Please explain the appropriateness of including PJM ancillary services and Other PJM Related charges and credits in the unified PSCR clause.

A. In 2004, I&M, along with AEP, became a member of the PJM Interconnection, LLC (PJM) Regional Transmission Organization (RTO). The PSCR clause for the St. Joseph rate area currently includes the following PJM ancillary services and Other PJM Related charges and credits in its PSCR clause.

Account Number	Description
4470097	Synchronous condensing net revenue
4470116	Meter corrections LSE
4470202	Operating reserve LSE credit
4470203	Operating reserve LSE charge
5550036	Emergency energy purchase
5550037	OATT capacity deficiency/reliability assurance
5550040	Inadvertent meter reserve LSE
5550041	Synchronous condensing net expense
5550074	Reactive charge
5550075	Reactive credit
5550076	Black start charge
5550077	Black start credit
5550078	Regulation charge
5550079	Regulation credit
5550083	Spinning reserve charge
5550084	Spinning reserve credit
5550089	PJM 30 min. Supplemental Reserve credit LSE
5550090	PJM 30 min. Supplemental Reserve charge LSE
5550093	Peak Hour Availability Charge

I&M seeks to include additional charges and credits in its PSCR clause for the merged rate area as addressed by Company witness Allen. These are the types of costs/charges that the MPSC has allowed in the past in other companies PSCR clauses.

Q. **Please explain the appropriateness of including the PJM Open Access Transmission Tariff (OATT) charges and credits in the proposed unified PSCR clause.**

A. As provided in the testimony of Company witness Gregory and further discussed by Company witness Bethel, I&M seeks to include PJM OATT charges and credits in the unified PSCR clause as set forth in Exhibit I&M-40 (DLG-1). As explained by Company witness Bethel, it is appropriate to include these costs because transmission and related services are necessary components of the power supply function. I&M uses PJM transmission and related services to deliver power to its Michigan retail customers. The cost of those transmission and related services is based on FERC-approved rates, and as such is not under the direct control of I&M.

Also, as described in the testimony of Company witness Gregory and supported by the testimony of Company witness Bethel, costs are billed to I&M as a member of PJM for functional operation of the transmission system, management of the PJM markets, and general administration of the regional transmission organization. These costs can be variable in nature, and I&M proposes that the costs be annually reviewed and timely recovered as a separate line item in the unified PSCR. Absent the inclusion in the unified PSCR clause, PJM costs would be subject to less frequent review through general rate cases and could cause variations in I&M's net operating results and cost of service that would be less timely in reflecting customers' basic rates and charges. Company witnesses Roush and Allen have calculated the level of PJM OATT net costs for the initial implementation of the PJM OATT costs.

Q. Please describe the proposed OATT cost recovery process, including true-up to actual OATT costs.

A. The OATT cost recovery process, including a true-up to actual OATT costs, will be administered through the unified PSCR clause. PJM OATT charges will be reflected as a separate line item in the unified PSCR clause. Consistent with the PSCR clause process used today, I&M proposes that the OATT factor be established annually based upon a projected level of I&M OATT charges and credits and include a reconciliation of projected versus actual OATT charges and credits and jurisdictional OATT factor revenues. Company witness Gregory will describe the true up over/under recovery accounting.

If in the Commission's judgment the PJM OATT cost recovery should not be approved for I&M at this time, a further adjustment for rate making purposes would be necessary in this proceeding to reflect an appropriate level of PJM OATT net costs in the cost of service.

PSCR Basing Points

Q. Please describe I&M's St. Joseph Rate Area PSCR basing point.

A. I&M's current St. Joseph Rate Area PSCR basing point represents the level of power supply cost embedded in the base rates charged to I&M's customers. Included in the St. Joseph Rate Area PSCR basing point are costs of fossil fuel consumed (including emission costs), nuclear fuel consumed, spent nuclear fuel disposal costs, the cost of purchased power, the charges for energy received from the AEP System Pool and the credits for energy delivered to the AEP System Pool, offset by I&M's share of revenues received from OSS, including any relevant impacts on the forecast of AEP's affiliation with the PJM. In addition wind purchases are included pursuant to the December 4, 2007 MPSC Order in Case No. U-15361 and the September 15, 2009 MPSC Order in Case No. U-15808.

To derive the basing point, the total projected PSCR costs are divided by the projected net energy requirement, resulting in a per unit cost, which, in turn, is multiplied by a loss factor to produce the basing point.

Q Please describe I&M's Three Rivers Rate Area PSCR basing point.

A. The calculation of the Three Rivers Rate Area PSCR factor has been based on the formal FERC NEC method, as approved by the Commission. This approach is similar to the method used for the St. Joseph Rate Area with the following exceptions: the underlying fossil fuel costs of such purchased power and Pool costs reflect FERC Account 151 costs charged to Account 501 only. Specifically, purchased power costs, the charges for primary energy received from Pool and the credits for energy delivered to Pool and energy to Pool for system sales are recorded on a FERC NEC basis. Further, capacity settlement amounts and OSS revenue and adjustments for affiliated transportation exclusion are not included in the PSCR factor calculations.

In addition, recording costs and credits on a FERC NEC basis means that only fuel costs, including affiliated transportation costs, —again, FERC Account 151 costs charged to Account 501 only—are allowed to be included in the Three Rivers Area PSCR factor calculation. Additional non-fuel costs such as fuel handling, one-half maintenance expense, consumed emission allowance costs, and demand charges are not included.

To derive the basing point, the total projected PSCR costs are divided by the projected net energy requirement, resulting in a per unit cost, which, in turn, is multiplied by a loss factor to produce the basing point.

Q. What are I&M's present PSCR basing points?

A. I&M currently has a PSCR basing point for the St. Joseph Rate Area of 3.33 mills per KWH. The St. Joseph Rate Area basing point was established in I&M's last general rate order in Case No. U-9656. The current Three Rivers

Rate Area basing point is 10.30 mills per KWH as established in Case No. U-9912. One basing point will be necessary for the uniform PSCR clause.

Q. What items does I&M seek to include in the proposed unified PSCR clause and basing point?

A. Company witness Allen provides the items included in the proposed unified PSCR clause basing point on Exhibit I&M-28 (WAA-5).

Q. What is the proposed PSCR basing point?

A. I&M is proposing a revised PSCR basing point of 26.87 mills per KWH. This is based on the projected level of costs and net energy requirement in 2010.

Q. How was the basing point incorporated into base rates?

A. Company witness Roush, uses the PSCR basing point of 26.87 mills per KWH in developing the revenue for each of the rate classes and is reflected in proposed rates.

Q. Once a final order is issued, how will the new PSCR basing point be reflected in I&M's PSCR factor?

A. Assuming a final order implemented in 2010, the basing point for the proposed unified rate area and PSCR clause will be 26.87 mills per KWH and, as a result, reduce the PSCR factor billed to customers to zero. This change will occur simultaneously with the change in base rates.

Other Trackers

Q. Please generally describe the Generation Investment Tracker (GIT).

A. The GIT establishes a mechanism for future recovery of capital costs, including a return, and O&M expenses related to significant Commission-approved generation investment projects. In particular, the costs included in this proposed tracker would be generation-related, major in scope, and involve projects constructed over a significant period of time.

Q. Why is I&M requesting establishment of a GIT tracker as part of its rate case?

A. A tracker request at this time is efficient regulation as I&M will not have to submit a new filing or an additional complete base rate case for cost recovery, and the Commission will not have to process and consider a separate case to include these major new pre-approved facilities in rate base. In addition, a tracker allows the Commission to annually review the project and track the amounts. Further, a tracker allows for sufficient oversight and prudence review but requires less resources than required for a full rate case. Without the GIT, the Company may not be able to avoid multiple base rate cases in the near future.

The GIT will also avoid rate shock. Under the proposed GIT, I&M will not be building up its Construction Work in Progress (CWIP) balance with substantial debt and equity Allowance for Funds Used During Construction amounts and consequently its Electric Plant in Service Balance and its rate base. Phasing-in future rate base additions will alleviate rate shock for our customers. As such, the GIT, as well as the other proposed trackers, should reduce the number and frequency of future base rate filings that I&M would have to make to recover expected future incremental costs for known and approved projects and programs.

Q. Please describe how the GIT will operate.

A. As described in the testimonies of Company witnesses Peifer and Hruby, I&M is proposing to undertake additional capital investment and O&M expenditures through specified generation projects to modernize, upgrade, and generally improve certain of I&M's generation units. The GIT will provide efficient recovery of actual CWIP financing costs and in-service costs.

The Company in this filing has identified certain specific initial projects for the GIT. I&M provides these example projects, which include both capital investment and O&M expenses, to initiate investment programs following the Commission's approval and with project funding through the GIT. For capital projects, funding would consist of the recovery through the tracker of a carrying cost on capital investment that would continue until the project is placed in service and reviewed by the Commission in an annual reconciliation proceeding. After a project is placed in service "recovery on and of" the investment would commence through the tracker. "Recovery on" the investment would be calculated at the overall rate of return authorized in the Company's last approved general rate proceeding, with the equity component of the rate of return grossed-up for tax effects. "Recovery of" would be calculated using the Commission-approved depreciation rates applicable to the particular class of property. The completed capital projects and CWIP would be rolled into I&M's rate base in the next general rate case and the GIT rate would be adjusted at that time to exclude these completed capital projects. For the recovery of O&M expenses associated with those capital projects placed in service, the recovery of expenses would occur on a dollar-for-dollar basis. Based on an annual GIT filing schedule, recovery of costs for projects slated to be in-service during the 12-month period would occur over the course of the 12-month effective period of a tracker factor, subject to reconciliation for updated or final project cost and any acceleration or delay of project completion.

The testimony of Company witness Roush discusses the rate design and terms and conditions of the GIT tariff rider. The testimony of Company witness Hayes discusses the accounting for the proposed GIT, including the true-up over/under recovery deferral accounting for the difference between actual incurred GIT costs and actual GIT revenues.

Q. Do the estimated CWIP levels in rate base provide a sufficient cash return on CWIP expenditures if I&M constructs major new qualifying facilities?

A. No. When I&M constructs major new facilities, the inclusion of a return on CWIP in rate base in base rates will become insufficient as construction continues due to a regulatory lag in setting base rates. This will occur even if I&M were to file annual base rate cases, although the effect would be less adverse to I&M.

Q. Is the proposed GIT similar to trackers approved by other state utility commissions?

A. Yes. The GIT is consistent with other state utility commission decisions on trackers of similar purpose. For example, on November 20, 2007 Cause No. 43114, the IURC issued a Certificate of Public Convenience and Necessity and Clean Coal Technology to Duke Energy Indiana (DEI) for its $1.985 billion, 630 MW Integrated Gasification Combined Cycle (IGCC) baseload project in Edwardsport, Indiana. The IURC allowed the incentive of timely recovery of costs including a return on CWIP, net plant in service plus in-service depreciation, O&M and taxes.

Also, on November 24, 2009 in Docket No. 09-008-U, the Arkansas Public Service Commission approved a Generation Recovery Rider for Southwestern Electric Power Company (SWEPCO). The approved Generation Recovery Rider allows SWEPCO to recover through a tracker financing costs, depreciation, taxes and O&M expenses on its 508 MW J. Lamar Stall Plant concurrent with the plant being placed in service.

Also, on April 26, 2007 the Corporation Commission of the State of Oklahoma (OCC) approved, in Cause No. PUD 200200038 Order No. 538439, a Generation Cost Reconciliation Rider for Public Service Company of Oklahoma (PSO) related to new peaking capacity of 166 MW at its Southwestern Station in Anadarko, Oklahoma and of 170 MW at its Riverside Station in Jenks, Oklahoma. The Generation Cost Reconciliation Rider approved by the OCC includes traditional costs associated with plant in service, including a return on the net plant investment at the actual weighted cost of capital and inclusive of an ROE, depreciation expense, O&M expense, and all related taxes.

Q. Please generally describe the gridSMART^{SM} Tracker.

A. I&M is planning to implement gridSMART^{SM} initiatives throughout its Michigan service territory over a four-year period, if appropriate regulatory treatment is granted by the Commission. As with the GIT, for capital projects, funding would consist of the recovery through the tracker of a carrying cost on capital investment that would continue until the project is placed in service, with reviews by the Commission in an annual reconciliation proceeding. After a project is placed in service "recovery on and of" the investment would commence through the tracker. The gridSMART^{SM} tracker provides for recovery of appropriate charges including the recovery of O&M and capital costs. Similar to the GIT, the gridSMART^{SM} Tracker factors will be established annually based upon a projected level of costs and include a reconciliation to actual cost for the prior year. Per Company witness Hayes, I&M proposes to use true-up over/under recovery deferral accounting for the difference between actual incurred gridSMART^{SM} costs and the actual gridSMART^{SM} revenues, which will be based on projected gridSMART^{SM} costs. Company witness Walter provides the level of gridSMART^{SM} costs for the initial implementation of the gridSMART^{SM} Tracker and Company witness Roush supports the revenue requirement and rate design of the gridSMART^{SM} Tracker tariff.

Q. Please generally describe the Enhanced Distribution Reliability Tracker (EDRT).

A. As explained by Company witness Ehler, the purpose of the EDRT is to recover the costs associated with distribution reliability improvement work. The EDRT will provide timely and full recovery of actual EDRT costs. The EDRT factors will be established annually based upon a projected level of costs and will include an annual reconciliation of projected versus actual cost for the prior year. Company witness Ehler has provided the level of reliability enhancement costs for the initial implementation of the EDRT and Company witness Roush supports the revenue requirement and rate design of the EDRT tariff. Company witness Hayes provides the accounting for the EDRT, including the true up over/under recovery deferral accounting for the difference between actual incurred EDRT costs and actual EDRT revenues.

Q. Does I&M propose a carrying cost on over and under recovered EDRT costs?

A. Yes.

Q. What carrying cost rate does I&M propose to apply to over- or under-recoveries of EDRT costs?

A. Due to the short-term nature of the EDRT costs over/under recovery balances, I&M proposes to apply its monthly weighted-average cost of short-term debt to any over- or under-recovery of EDRT costs.

Q Please describe the Net Lost Revenue Recovery Tracker.

A. The Company is proposing a Net Lost Revenue Recovery Tracker to collect net lost revenues in order to make the Company whole for the throughput impacts of mandated energy efficiency programs. The proposed mechanism removes the disincentive for I&M to promote energy efficiency programs, and it does so by compensating the utility for lost sales, net of variable costs (primarily fuel), that directly result from customer responses to such programs. I&M requests the tracker be put into effect beginning in 2011. Amounts recovered through the Net Loss Revenue Recovery tracker would include net lost revenues as described by Company witness Roush. The Net Lost Revenue Recovery Tracker will be annually reconciled. The reconciliation will true-up recovery for net lost revenues. The tracker factors would be adjusted to reflect over/under collection of revenues during the prior annual period. Company witness Roush calculates the net lost revenues and supports the rate design and terms and conditions for the Net Lost Revenue Recovery Tracker. In addition, Company witness Hayes explains I&M's accounting related to the requested recovery of net lost revenues, including the true-up over/under recovery deferral accounting for the difference between actual incurred net lost revenue and actual Net Lost Revenue Recovery Tracker revenues.

Q. Does I&M propose a carrying cost on over and under recovered Net Lost Revenues?

A. Yes.

Q. What carrying cost rate does I&M propose to apply to over- or under-recoveries of Net Loss Revenue Recovery costs?

A. Due to the short-term nature of the net lost revenue over/under recovery balances, I&M proposes to apply its monthly weighted-average cost of short-term debt to any over- or under-recovery of net lost revenues.

Amortization

Q. Please discuss the appropriateness of the inclusion of amortization of certain existing and proposed Michigan regulatory assets.

A. I&M is seeking recovery of these items, except for post-September 11, 2001(9/11) security and the nuclear decommissioning report costs, over two years. These items are described in greater detail by Company witnesses Hayes and Hruby. A two year amortization of these deferred costs will mitigate the rate impact upon I&M's ratepayers, while not affecting materially I&M's financial position. In addition, a two-year period is not out of line with the amortization periods used in Michigan where utilities have been allowed to recover similar costs and amounts. Further, a two year amortization will minimize carrying charges on these amounts.

Q. Is I&M requesting amortization of the proposed Regulatory Assets related to post-September 11, 2001 (9/11) enhanced security?

A. Yes. Consistent with MCL 460.10d(5) I&M is requesting recovery of enhanced security costs, including a reasonable return on the unamortized balance, over a period not to exceed five years. As such, I&M has incorporated a five year amortization in this filing.

Q. Is I&M requesting to amortize expenses related to the filing of this case?

A. Yes. I&M is requesting to amortize over two years incremental expenses associated with the development, filing, and support of this rate case. The proposal includes incremental costs such as, the cost of outside counsel, expenses, and outside witness/consulting services. The requested rate case expenses are set forth on Exhibit I&M-107 (SMK-2).

Q. Please explain I&M's request to recover the jurisdictional expenses related to the Nuclear Decommissioning Study Expense.

A. In its August 26, 1986 order in Case No. U-6150, the Commission approved a plan to review the adequacy of all nuclear decommissioning provisions every three years. Knight Cost Engineering Services, at the behest of I&M, performed a decommissioning funding adequacy (DFA) study of I&M's annual decommissioning provision for the Cook Nuclear Plant in November 2009. This is a study I&M is required to complete every three years and it is therefore appropriate to amortize the expense over the three years. The requested DFA expenses are set forth on Exhibit I&M-107 (SMK-2).

Michigan Major Storm Damage Restoration Reserve

Q. Please explain I&M's proposed Michigan Major Storm Damage Restoration Reserve.

A. I&M requests Commission approval to create a Michigan Major Storm Damage Restoration Reserve. I&M's O&M expenses associated with repairs as a result of major storm damage are volatile in nature as explained by Company witness Ehler. I&M's forecast, as provided by Company witnesses Allen and Ehler, includes approximately $3 Million total company, and approximately $596,000 Michigan jurisdictional, of major storm damage O&M expense. Accordingly, I&M's proposed rates include the $596,000 of the proposed Michigan Major Storm Damage O&M expense on a Michigan jurisdictional basis in retail rates. Beginning with the first month of final rate relief one twelfth of the annual $596,000 reserve amount for Michigan Major Storm Damage Restoration would be compared with actual Michigan jurisdictional major storm damage O&M incurred. If the incurred O&M is less than the monthly revenue amount, the Company will record a regulatory liability for the difference. If the incurred O&M exceeds the monthly revenue amount included in base rates, the Company will record a regulatory asset for the difference. The cumulative regulatory liability or regulatory asset balance would be adjusted each month based on actual major storm damage O&M incurred versus the embedded revenue received. I&M's proposed accounting is more fully described by Company witness Hayes.

Q. Does I&M propose carrying costs be applied to any over or under recovered balances?

A. Yes. Given the likelihood that the reconciliation/recovery period will span more than one year, I&M proposes to apply a weighed average cost of capital rate monthly to the prior month's cumulative over or under recovered balance. The carrying cost mechanism and related proposed accounting is more fully described by Company witness Hayes and the proposed initial rate is supported by Company witness Hawkins.

Q. Does I&M propose to reconcile and adjust the Michigan Major Storm Damage Restoration Reserve amounts?

A. Yes. I&M proposes to adjust the Michigan Major Storm Damage Restoration Reserve in its next base rate case and include in the proposed base rates the effects of returning to customers any over recovery including carrying charges or collecting from customers any under recovery including carrying charges.

Q. Is the proposed Michigan Major Storm Damage Restoration Reserve methodology used by other AEP electric utility operating companies?

A. Yes. On January 14, 2009 in Cause No. PUD 200800144, the OCC approved a similar proposal for PSO.

AEP/CSW Merger Savings Reduction Rider

Q Please explain the termination of the AEP/CSW Merger Savings Reduction Rider credit.

A. Pursuant to Commission Order Approving Settlement Agreement dated December 16, 1999, in Case No. U-12204, I&M's current rates include an AEP/CSW Merger Savings Reduction Rider credit, which will terminate effective with the implementation of new rates for electric service resulting from the instant proceeding. The Order Approving Settlement Agreement in Case

No. U-12204 authorized AEP/CSW Merger Savings Reduction Rider credits for no less than the eight-year period following the June 15, 2000, merger of AEP and CSW, with the Year 8 credit factors continuing until I&M's base rates in Michigan are changed pursuant to a final order.

Q. Does I&M intend to self-implement interim rates in this general rate proceeding?

A. Yes. In accordance with MCL 460.6a(1), I&M intends to self-implement interim rates for service at the earliest opportunity but no sooner then 180 days after the date of filing.

Q. Please summarize your testimony in this proceeding.

A. My testimony describes the preparation of I&M's case-in-chief and supports I&M's Michigan jurisdictional required rate relief, explains I&M's merger of the two PSCR rate areas, the expansion of the PSCR mechanism and the PSCR basing point. I further identify the new tracker mechanisms I&M is requesting and generally describe the reconciliation process for the trackers. Last, I explain I&M's proposed Major Storm Restoration Reserve and the termination of the AEP/CSW Merger Savings Reduction Rider Credit.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.