STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to recover implementation costs, for approval of stranded cost true-up methodology, and for other relief.	)))))	Case No.: U-11955
In the matter of the application of THE DETROIT EDISON COMPANY for authority to recover retail access program implementation costs and for approval of a true-up mechanism in connection with the recovery of stranded costs.	))))))	Case No.: U-11956

TESTIMONY

OF

THEODORE F. KUHN

ON BEHALF OF

ENERGY MICHIGAN

October 1999

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Theodore F. Kuhn. My business address is 500 East 96th Street, Suite 400, Indianapolis, Indiana, 46240.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am self-employed as the President of Economic Modeling & Computer Consulting, Inc. I am also employed by Butler University, Indianapolis, Indiana, as an Adjunct Instructor in the College of Business Administration.

Q. BY WHOM WERE YOU EMPLOYED PRIOR TO YOUR CURRENT POSITION?

A. I was employed by the engineering consulting firm of R. W. Beck, Inc. from 1980-1997. My last position with R. W. Beck, Inc., was that of Executive Economist. Prior to working for R. W. Beck, Inc., I was employed by the Public Utility Commission of Texas.

Q. PLEASE DESCRIBE YOUR CONSULTING WORK EXPERIENCE.

A. I have conducted a wide variety of studies for clients across the nation. Primarily, my work has involved the application of economic principles and statistical techniques to address the issues faced by my clients. Specific tasks have included market price forecasting, the estimation of stranded costs and methods for stranded cost recovery, load forecasting, price elasticity, weather normalization, financial feasibility, cost of service and rate design, cost of capital, and other economic studies. Many of these assignments included the provision of testimony before a regulatory authority.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE PRIOR TO JOINING R. W. BECK, INC.

A. While a graduate student, I was employed by the Public Utility Commission of Texas as an intern, developing an econometric model for residential energy sales. Later that year, I accepted a full-time staff Economist position with the Commission's Economic

Research Division. I testified in electric rate hearings in the areas of price elasticity and weather adjustments, cost allocation methods, forecasting, and rate of return. I also coordinated all the Division's research projects and was responsible for internal education programs for the other divisions. Finally, I also offered testimony before the Public Service Commission of New Mexico at their request.

Q. PLEASE STATE BRIEFLY YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Arts degree, with high distinction, with a double major in economics and mathematics from Indiana University, Bloomington, Indiana. After graduation, I studied economics at the University of Pennsylvania under a one-year graduate Fellowship. Upon completion of the Fellowship, I transferred to the University of Texas at Austin, Graduate Department of Economics, as a teaching assistant in the doctoral program. For the next 18 months, I taught undergraduate economics courses and continued work towards a doctorate in economics, with concentration in the fields of regulation, econometrics, and finance. I earned a Master's Degree in Economics in December 1978.

I am a member of Phi Beta Kappa (Indiana University, 1975), Phi Kappa Phi (University of Texas, 1977), and other honorary societies. I am also a member of the National Association for Business Economics.

Q. WOULD YOU LIST THE PROCEEDINGS IN WHICH YOU HAVE OFFERED TESTIMONY?

A. Please see Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses certain issues related to the determination of stranded costs and their recovery.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The first section discusses the treatment of open access implementation and employee retraining costs. The second section discusses the true-up process in the near term (through 2001). The third and final section discusses the true-up process in the longer term (2002-2007).

SECTION 1: OPEN ACCESS IMPLEMENTATION AND EMPLOYEE RETRAINING COSTS

Q. COULD YOU PLEASE SUMMARIZE YOUR POSITION REGARDING OPEN ACCESS IMPLEMENTATION AND EMPLOYEE RETRAINING COSTS?

A. All excess utility earnings since January 1, 1998, found in the current U-11560 (Consumers Energy) and U-11495 (Detroit Edison) rate cases should be used to offset claims for specific open access implementation and employee retraining costs. Costs incurred by Consumers Energy and Detroit Edison that are of general benefit to all customers, *e.g.* new computer billing systems, should not be included in the calculation of stranded costs. If, after applying such excess earnings in this manner, a surplus still remains, that surplus should be used as a mitigation measure to reduce other stranded cost categories.

Q. COULD YOU BRIEFLY DESCRIBE THE HISTORY OF OPEN ACCESS IMPLEMENTATION COSTS AND EMPLOYEE RETRAINING COSTS?

A. The MPSC Orders treat open access implementation costs as stranded costs and allow recovery from all customers. The MPSC gave approval for deferred accounting of these costs since 1998.

Q. HOW MUCH OF THESE IMPLEMENTATION COSTS HAVE THE COMPANIES REQUESTED, AND HOW DO THEY WANT TO RECOVER THESE COSTS?

A. Consumers Energy is asking for $19.9 million for 1998 and $43.2 million for 1999. Over the period 2000-2002, Consumers Energy requests recovery of additional amounts exceeding $130 million. Detroit Edison is requesting $11.6 million for the year 1999 in the year 2000. Detroit Edison's requested recovery also more than doubles during the 2001-2004 time period. Both companies suggest recovering these costs through a per kWh surcharge.

Q. DO YOU AGREE WITH THE COMPANIES' POSITIONS REGARDING COST RECOVERY?

A. No.

Q. WHY NOT?

A. According to Financial Statistical Reports compiled by the Financial Analysis Section of the MPSC Staff, Consumers Energy has earned over 16% return on its equity since January, 1998. Similarly, Detroit Edison is reported to have earned over 12% return on its equity since January 1998. Both of these values are in excess of the rates of return authorized in the most recent Orders from this Commission, which are 12.25% for Consumers Energy and 11% for Detroit Edison.

Q. HOW DO THESE EXCESS EARNINGS RELATE TO THE IMPLEMENTATION COSTS REQUESTED BY THE COMPANIES?

A. On the one hand, these two utilities have filed requests with this Commission for millions of dollars for costs that they claim are related to open access implementation. At the same time, these companies may be recovering from ratepayers revenues that are substantially in excess of the levels granted by this Commission.

Q. WHAT IS YOUR PROPOSAL IN THIS REGARD?

A. Any excess utility earnings should be used to offset the claims for the costs specific to open access implementation and employee retraining. To the extent that such earnings are in excess of these cost categories, the remaining excess should be used to offset claims for other stranded costs.

SECTION TWO: TRUE-UP PROCESS, NEAR TERM (THROUGH 2001)

Q. DOES THE RETURN ON EQUITY ISSUE IMPACT ON THE TRUE-UP PROCESS?

A. Yes.

Q. PLEASE EXPLAIN.

A. If Consumers Energy and Detroit Edison were earning returns in excess of the levels granted by this Commission and in excess of the incurred and deferred implementation and employee retraining costs, this would indicate that the companies are currently recovering their stranded costs.

Q. HOW SHOULD THE RETURN ON EQUITY ISSUE BE HANDLED IN THE TRUE-UP PROCESS?

A. If the returns on equity continue to be at levels which are in excess of those granted by this Commission, the true-up process should require that some percentage of the excess be used to mitigate stranded costs. If the returns should fall below the levels granted by this Commission, the true-up process should direct the companies to accrue such shortfalls through 2001 for later recovery. To the extent that the returns on equity fall within an acceptable range, as determined by this Commission, no adjustments would be required. In making this recommendation, I am assuming that the revenues obtained through the bid process will be treated as revenues that will positively impact the rate of return.

Q. DOES OPEN ACCESS CREATE ANY ADDITIONAL STRANDED COSTS IN THE NEAR TERM?

A. No.

Q. PLEASE EXPLAIN.

A. Due to projected load growth in conjunction with current and projected statewide capacity shortages, open access does not create any additional stranded costs.

Q. WHAT IS THE AMOUNT OF OPEN ACCESS ALLOWED BY THIS COMMISSION BY DECEMBER 31, 2001?

A. Excluding pilot programs, Consumers Energy will have at most 750 MW, and Detroit Edison will have at most 1125 MW, for a total of at most 1875 MW.

Q. WHY DO YOU USE THE PHRASE “AT MOST” WHEN DESCRIBING OPEN ACCESS AMOUNTS?

A. While the maximum amounts available to open access are restricted, there is no certainty that these totals will, in fact, be subscribed. Depending upon the transition charges and other competitive facts, current and prospective customers may or may not subscribe to open access.

Q. WHAT IS THE RECENT HISTORY OF LOAD GROWTH FOR CONSUMERS ENERGY AND DETROIT EDISON?

A. Over the period 1995-1998, Consumers Energy’s load has grown at a compound annual rate of 3.8%. Over this same time period, Detroit Edison’s load has grown at a compound annual rate of 3.9%.

Q. HOW DOES LOAD GROWTH AFFECT THE ISSUE OF STRANDED COSTS?

A. Load growth in the Consumers Energy and Detroit Edison service territories, projected at the relatively conservative rate of 2 ½ % per year, would accumulate to nearly the same amount as the open access limitations by the end of 2001. As previously discussed, if the companies are currently enjoying excess earnings, the conclusion would be that no stranded costs will be incurred through 2001.

Q. ARE THERE ANY ISSUES THAT MIGHT IMPACT UPON THIS RESULT?

A. This result assumes that the returns earned by both companies from now through 2001 continue to be at least within the bounds of reasonableness described by this

Commission. If returns were to fall below these bounds, accruals of these deficiencies for future recovery would be required.

Q. YOU ALSO MENTIONED THAT THE CURRENT AND PROJECTED STATEWIDE CAPACITY SHORTAGES HAVE A ROLE IN THIS ISSUE. PLEASE EXPLAIN.

A. Claims of stranded cost are fundamentally based on an inability to recover previously invested resources at market prices. If current and projected consumer demand is greater than the companies' current capability to provide power, then the companies should be able to sell power at market prices within the state. Consumers Energy and Detroit Edison, being the nearest power suppliers, will necessarily have an advantage over other suppliers who must transmit their power over greater distances to reach Michigan's consumers.

Q. CAN YOU PROVIDE A QUANTITATIVE EXAMPLE OF THIS PRICING ADVANTAGE?

A. Yes. Perhaps the clearest example of record would be found in the rebuttal testimony of Mr. James H. Byron for Detroit Edison in Case No. U–11726. Mr. Byron explains an example in clear detail whereby a Michigan seller (*e.g.* Fermi) selling in Michigan would realize $48.12 per MWh after transmission charges, whereas that same seller selling to the CINergy hub would realize only $24.12 per MWh after transmission charges.

Q. HOW DID YOU CALCULATE THE CAPACITY SHORTAGES YOU DESCRIBE?

A. From Consumers Energy's filing in U-11889, I obtained its native generation, including qualifying facilities (QFs) of 8699 MW, or 8149 MW prior to additional summer capacity plans for 1999. Similarly, from this same docket, I obtained Detroit Edison's native generation of 11,212 MW, or 10,311 MW prior to planned generation additions during 1999. Based on the peak demands projected by each company and allowing for typical required reserves of 12%, the shortfall on the Consumers Energy system would be about

220 MW for 1999. This value can be expected to grow by about 185 MW each year from 1999 through 2001 due to load growth, resulting in a total shortfall for Consumers Energy of about 590 MW by 2001. Using this same approach and values provided by Detroit Edison, the shortfall on the Detroit Edison system would be about 2525 MW for 1999. This value can be expected to grow by about 275 MW each year from 1999-2001. The result is a total shortfall for Detroit Edison of about 3075 MW by 2001. For the two utilities, there would be a combined shortfall of about 3650 MW.

Q. HOW DOES THIS SHORTFALL COMPARE TO THE OPEN ACCESS AMOUNTS?

A. As described previously, the combined open access total is 1875 MW, which is only about one-half of the projected shortfall in capacity.

Q. IS THE SHORTAGE YOU DESCRIBE A YEAR-ROUND PHENOMENON OR OF SHORTER DURATION?

A. These calculations are based on peak conditions.

Q. DOES THIS AFFECT YOUR CONCLUSIONS?

A. Perhaps. However, the utilities cannot precisely predict when such peaks will occur. In fact, to cover the probable nature of customer demands, power must be available (or purchased) for large blocks of time to ensure that it will be available should peak conditions occur. In addition, the magnitude of the shortfall means that more than just the peak time periods will be affected. I believe that the size of the capacity shortage is of such an extent that a prudent utility would need to have (or purchase) substantial blocks of power to maintain acceptable coverage of expected demand.

Q. DO YOU HAVE ANY EVIDENCE TO SUPPORT THIS BELIEF?

A. Yes. Consumers Energy and Detroit Edison have each requested to purchase large blocks of power to enable them to serve existing customer loads during peak times.

Q. WHY DID YOU EXCLUDE FROM YOUR CALCULATIONS PLANNED GENERATION ADDITIONS FOR 1999?

A. These calculations are made in an effort to determine the extent and recovery of stranded costs. Generation additions made during 1999 should not qualify as stranded costs, nor should generation additions made from this point forward. Both companies are, of course, free to add generation or make purchases to serve their customers. But such additions should meet the market test; they must be able to obtain sufficient revenues from the market to survive. We can, therefore, exclude the costs of such generation or purchases from calculations of stranded costs. We should also exclude the capacity represented by these additions in our capacity shortage calculations because, without them, existing capacity claimed as stranded could have served all or part of these loads. For example, it would be clearly unfair to ratepayers to force them to pay for the construction of a new plant to serve their loads and then to claim all the costs of a previously built plant as stranded.

Q. COULD YOU SUMMARIZE YOUR TESTIMONY WITH REGARD TO THE TRUE-UP PROCESS IN THE NEAR TERM?

A. Subject to this Commission's findings in the pending rate cases, both companies may be enjoying excess returns on equity, which are greater than the requested implementation costs. This would indicate that both companies are covering whatever current stranded cost recovery is necessary. Over the period from now through 2001, a capacity shortage will continue to exist in Michigan that is nearly twice as great as the open access limitations. Unless these companies' returns fall below the range of reasonableness set by this Commission, it is clear that stranded costs will be adequately recovered throughout this period even if the entire open access amount obtains power elsewhere.

SECTION THREE: TRUE-UP PROCESS, LONG TERM (2002-2007)

Q. WHAT IS THE NATURE OF THE MPSC'S PROCESS FOR DETERMINING TRANSITION CHARGES TO OPEN ACCESS CUSTOMERS?

A. As described in case U-11290, a predefined market price "base" is first subtracted from the actual market price. This differential is then applied to a transition "base" charge of 1.20¢ (Consumers Energy) or 1.25¢ (Detroit Edison) to yield a net transition charge. The total cost of market power to a consumer taking power from an alternative supplier would therefore be the actual market price plus the net transition charge.

Q. COULD YOU PROVIDE A NUMERICAL EXAMPLE?

A. Assume that the actual price of market power was 3.5¢ in a given year, and that the market price "base" for that year was 2.9¢, resulting in a differential of 0.6¢. This differential would be subtracted from the 1.2¢ (Consumers Energy) transition base charge to yield a net transition charge of 0.6¢. Open access customers would pay a total of 4.1¢ for their power (3.5¢ to the market and 0.6¢ in transition charge).

Q. WHAT DO YOU BELIEVE WAS THE UNDERLYING RATIONALE FOR THIS METHOD?

A. I believe that the Commission was trying to come up with a relatively simple, easy to apply procedure that would effectively recover stranded costs, while accounting for the impact of changing market prices.

Q. WHAT ROLE DOES THE ACTUAL MARKET PRICE PLAY IN THIS METHOD?

A. Surprisingly, none whatsoever.

Q. PLEASE EXPLAIN.

A. Under the Commission's approach, as market prices rise, the net transition charge is reduced, reflecting the fact that with higher market revenues, stranded costs will be reduced. In addressing this dimension of the impact of market prices, the Commission's approach succeeds admirably. But when we consider what open access customers will pay *over time* under the Commission's method, we discover that the total cost of power to open access customers has been predetermined by the Commission, regardless of how market prices change.

Q. COULD YOU PROVIDE AN EXAMPLE OF THIS PROBLEM?

A. Let's continue with the previous example for an open access customer from Consumers Energy. Fast forward to 2002, and assume that the actual market price for power has increased to 3.8¢. Over this same time period, the market price "base" has increased at the predetermined rate of about 3% annually, which would make the base value in 2002 about 3.3¢. Using the same calculations as before, we would determine a total cost of power to open access customers of about 4.5¢ (3.8¢ market price plus 0.7¢ transition charge). Now let's consider an entirely different future, in which market prices remain at 3.5¢ in 2002. In this case, the net transition charge would be about 1.0¢. Yet, even with this substantial difference in market prices in comparison to our first case, what does the open access customer pay for power including all charges? The very same 4.5¢ as in the first set of assumptions (3.5¢ market price plus 1.0¢ transition charge)!

Q. DO YOU HAVE AN EXHIBIT THAT ILLUSTRATES THIS PROBLEM?

A. Yes. Please see Exhibit__(TFK-1).

Q. WHY IS THIS PROCEDURE A PROBLEM FOR THE OPEN ACCESS MARKET?

A. If the transition charge that is ultimately determined by this Commission is set too high, Consumers Energy and Detroit Edison will be unfairly able to undercut any reasonable market offer of power.

Q. WHAT DO YOU BELIEVE TO BE THE ROOT OF THE PROBLEM WITH THE CURRENT APPROACH TO TRANSITION CHARGE DETERMINATION?

A. The procedure fails to recognize that the fixed cost to produce power from existing Consumers Energy and Detroit Edison facilities will decline, not increase, in the future. Variable cost changes, like the price of fuel, will impact both utility costs and other power suppliers. But continuing depreciation and further cost reductions on the part of Consumers Energy and Detroit Edison will lower their non-fuel cost of power in the future.

Q. WHAT SUPPORTING EVIDENCE DO YOU HAVE FOR THIS ASSERTION?

A. I examined the FERC Form1 Reports filed by both Consumers Energy and Detroit Edison over the period 1995-1998. From the detailed information contained in these reports, I was able to calculate both a total cost of power and a cost of power excluding fuel and purchased power expenses. The result of my analysis shows that Detroit Edison was able to reduce its non-fuel/purchased power cost per kWh by about 5% per year over that period. Consumers Energy was able to reduce its non-fuel/purchased power cost per kWh by about 6% per year over that period.

Q. COULD YOU SUMMARIZE THE PROBLEM THAT YOU HAVE FOUND WITH THE MPSC TRUE-UP PROCESS?

A. The current mechanism increases the cost of open access power at a time when utility costs are declining.

Q. WHAT IS YOUR PROPOSAL REGARDING THE CALCULATION OF TRANSITION CHARGES?

A. The market price "base" should be redefined to take into account (1) the reductions in non-fuel power costs that have occurred since the original 2.9¢ figure was derived, and (2) the reductions in non-fuel power costs that will occur as we move forward. Specifically, the base value of 2.9¢ should be reduced to reflect the cost reductions achieved by each utility during 1998. In addition, the base value should thereafter decline by at least 1% per year in recognition of the obtainable reductions in cost from both Consumers Energy and Detroit Edison. With these two changes, the Commission's method would both incorporate these companies' cost mitigation efforts in a sharing fashion, as well as recover whatever level of stranded cost exists during the 2002-2007 period.

Q. WHY ARE YOU SUGGESTING THAT THE 2.9¢ MARKET PRICE BASE BE REDUCED FOR THE REDUCTION IN POWER COSTS DURING 1998?

A. This Commission's Order on this matter came out in early 1998 and could not, therefore, have incorporated this data.

Q. HOW WOULD THE ACTUAL MARKET PRICE BE DETERMINED?

A. The Commission would need to require market-clearing price information from marketers and others, through an annual report format. The primary data required would be straightforward elements such as total energy sales (kWh), total revenue obtained from sales. Basic rate information, such as the demand and energy rates, could be collected. Finally, certain related items, such as demand served, could also be required. The mechanics of calculating an annual average market price could be worked out by the Commission's Staff.

Q. IS IT POSSIBLE TO DIRECTLY COMPARE MARKET-BASED PRICES WITH UTILITY COSTS?

A. Yes.

Q. ARE THERE ANY DIFFERENCES UNDERLYING THIS COMPARISON?

A. Yes. The market-based prices may not be related to serving the same type of customer loads as those served by the traditional utility. Experience with market transactions indicates that large industrial customers with relatively high load factors are disproportionately represented in market transactions at present.

Q. WHAT DOES THIS DIFFERENCE IN LOAD FACTORS MEAN IN RELATION TO THE COMPARISON OF MARKET-BASED PRICES WITH UTILITY COSTS?

A. Under current technology, it is less expensive on a per kWh basis to serve a higher load factor load. In very basic terms, this has to do with, for example, the fact that the generating unit(s) serving the load can run for longer periods of time, thereby reducing the fixed cost per kWh. In economic terms, it is a reflection of economies of scale. For the purposes of our comparison of market-based prices with utility costs, however, this disparity in load factor makes a direct comparison of these two figures misleading. Even if the structural costs underlying the competitors were identical, the average price of power calculated from the open access data would be lower, reflecting the higher load factor served. Therefore, the market-based prices should be adjusted to the utility's average load factor to obtain a comparable set of figures.

Q. HOW WOULD YOU ADJUST THE MARKET PRICE DATA TO OBTAIN A FIGURE THAT IS COMPARABLE TO THE MARKET PRICE BASE SET BY THIS COMMISSION?

A. The adjustment process could use the information provided by the marketers. Specifically, the market price data would need to be re-expressed at the same load factor as the average load factor of either Consumers Energy or Detroit Edison, depending on service location.

Q. IN ADDITION TO REDEFINING THE MARKET PRICE BASE TO RECOGNIZE RECENT COST REDUCTIONS, YOU ALSO PROPOSE REDUCING THIS FIGURE EACH YEAR BY 1%. WHAT SUPPORT TO DO YOU HAVE THAT THIS LEVEL OF COST REDUCTION IS ACHIEVABLE?

A. Detroit Edison stated in a recent filing that it could achieve approximately $750 million in mitigation reductions. If this amount were evenly spread over the time period 2002-

2007, it would result in $125 million in mitigation savings each year. Expressed on a per kWh basis, this would amount to over 2 mills per kWh or about 5% annually. More important than such statements made by the utilities regarding mitigation, the historical record of lower costs shown in Exhibit___(TFK-2) demonstrates that reductions of 1% annually are feasible.

Q. YOU STATE THAT FORMULATING THE MARKET PRICE BASE IN THIS MANNER RESULTS IN A "SHARING" OF COST MITIGATION EFFORTS. PLEASE EXPLAIN.

A. By formally incorporating a 1% reduction, the Commission passes along to customers a definite amount of cost reduction. But to the extent that either Consumers Energy or Detroit Edison is able to achieve reductions in excess of this amount, the company achieving such savings would retain the additional cost reductions. Such a win-win philosophy of rate regulation would provide an excellent start to Michigan's efforts in open access restructuring.

Q. WHAT WILL HAPPEN UNDER THE CURRENT PROCEDURE OF DETERMINING TRANSITION CHARGES IF UTILITY PRODUCTION COSTS WERE TO BE REDUCED TO, FOR EXAMPLE, 4.2 CENTS PER KWH BY 2002?

A. Market power would be unable to compete effectively, due to the transition charge.

Q. PLEASE EXPLAIN.

A. Under the current plan, the total cost of power to open access customers would be about 4.5 cents per kWh in 2002 regardless of the actual market price for power, as shown in Exhibit___(TFK-1). Assume for the purposes of this explanation that current utility costs for Consumers Energy, for example, averaged roughly 4.5 cents per kWh in 1998. We should assume that Consumers Energy would continue to strive to reduce its costs. Assume only a modest reduction to 4.2 cents per kWh by 2002. Market power at a total cost of 4.5 cents cannot compete with utility-supplied power at a cost of 4.2 cents, and the load factor issue previously discussed would only exacerbate this differential.

Q. HOW WOULD YOUR PROPOSAL HELP ELIMINATE THIS PROBLEM?

A. Under the modified MPSC plan, the market price "base" would start from a lower figure, reflecting the cost savings actually achieved during 1998. In addition, the market price "base" would decline by about another 0.1 cents by 2002. Both of these changes would reduce the transition charges and allow for some degree of competition.

Q. COULD YOU SUMMARIZE YOUR TESTIMONY REGARDING THE TRANSITION PLAN?

A. In the near term (through 2001), the amount of open access under consideration should cause no additional stranded costs to be incurred. If the rates of return continue to be at acceptable levels during this period, then no additional stranded costs will have been incurred. In the longer term (2002-2007), the MPSC should consider a modification in its current procedure for calculating the market price "base" figure to incorporate realized mitigation and a portion of future mitigation efforts.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

RECORD OF TESTIMONY SUBMITTED BY THEODORE F. KUHN

Utility Involved	Proceeding	Subject	Before	Client	Date
Nebraska Public Power District and MidAmerican Energy Company	Case No. 8:97CV346	Market Price Projection	US District Court	NPPD	1999
AEP	Docket No. EL99-66-000	Cost of Capital	FERC	Wabash Valley Power Association	1999
Public Service Electric & Gas Company	Docket No. E097070462 OAL PUC 7347-97-N	Stranded Costs	New Jersey BPU	Enron	1998
Atlantic City Electric Company	Docket No. E097070456 OAL PUC 7311-97-N	Stranded Costs	New Jersey BPU	Enron	1998
GPU Energy	Docket No. EO97070459 OAL PUC 7308-97-N	Stranded Costs	New Jersey BPU	Enron	1997
Consumers Energy Company	Case No. U-l 1451	Stranded Costs	Michigan PSC	Energy Michigan	1997
Detroit Edison Company	Case No. U-l 1452	Stranded Costs	Michigan PSC	Energy Michigan	1997
NIPSCO	Docket No. ER96-399	Cost of Capital	FERC	Wabash Valley Power Association	1996
CINERGY	Docket No. ER95-625, Docket No. ER95-626, Docket No. EL95-039	Cost of Capital	FERC	Indiana Municipal Power Agency, Wabash Valley Power Association, Logansport Municipal Utility, Jackson County REMC, Indiana Municipal Electric Association	1995
Central & Southwest / El Paso Electric	Docket No. 12700	Price Elasticity Load Forecast Industrial Customer risk	Texas PUC	City of El Paso	1994
Illinois Power Company	Docket ER92-809	Cost of Capital Capital structure	FERC	Illinois Municipal Electric Agency	1993
OK Sand & Gravel	Civil Action IP-901051-c	Pricing and Market Structure	US District Court Southern Div.	OK Sand & Gravel	1993
Potomac Electric Power Company	Formal Case No.912	Marginal Cost Allocation & Rate Design	PSC DC	Washington Metropolitan Area Transit Authority	1992
New England Power Pool	Docket No.EFSC 91-100	Load Forecasting	Massachusetts EFSC	PGE / Bechtel	1992
Potomac Electric Power Company	Formal Case No.905	Marginal Cost Allocation & Rate Design	PSC DC	Washington Metropolitan Area Transit Authority	1991
New England Power Pool	Docket No.EFSC 90-100	Load Forecasting	Massachusetts EFSC	Eastern Energy Corporation	1990
Indiana Municipal Power Agency	Docket No.38850	Load Forecasting	Indiana URC	Indiana Municipal Power Agency	1990
Colorado-Ute Electric Association	Docket No.89I-627E	Price Elasticity	Colorado PUC	Colorado-Ute	1990
Public Service Company of Indiana	Cause No.38655	Comparable Land	Indiana URC	Morgan County REMC	1989
Ohio Edison Company	Docket No.ER88-544	Load Scheduling	FERC	American Municipal Power - Ohio	1989

Continued

RECORD OF TESTIMONY SUBMITTED BY THEODORE F. KUHN					
Utility Involved	Proceeding	Subject	Before	Client	Date
Public Service Company of Indiana	Cause No.38219-S1	Comparable Land	Indiana URC	Tipmont REMC	1988
Indiana Michigan Power Company	Docket No.ER88-30	Cost of Capital Cost of Service	FERC	Wabash Valley Power Association	1988
Public Service Company of Indiana	Docket No.ER87-61	Cost of Capital Demand Allocators	FERC	Wabash Valley Power Association	1988
Wabash Valley Power Association	IP85-2238RA S	Load Forecasting	US Bankruptcy Court Southern District, IN	Wabash Valley Power Association	1987
Ohio Edison Company	Docket No.ER82-79	Cost of Service	FERC	Wholesale Customers of Ohio Edison	1982
Indiana Municipal Power Agency	Cause No.36835	Economic Feasibility Load Forecasting	Indiana URC	Indiana Municipal Power Agency	1982
Ohio Edison Company	Docket No.ER80-454	Cost of Service Rate Design	FERC	Wholesale Customers of Ohio Edison	1981
Houston Power & Light	Docket No. 2676	Cost of Service Weather & Price Normalization	PUC Texas	Commission Staff	1979
El Paso Electric	Docket No.2641	Cost of Capital	PUC Texas	Commission Staff	1979
Texas Electric Service	Docket No.2606	Cost of Service Weather & Price Normalization	PUC Texas	Commission Staff	1979
Dallas Power & Light	Docket No.2572	Weather & Price Normalization	PUC Texas	Commission Staff	1979
El Paso Electric	Docket No. 1454	Load Forecasting	PSC New Mexico	PSC New Mexico	1979
Texas Electric Service	Docket No.1 903	Cost of Service Load Forecasting Weather & Price Normalization	PUC Texas	Commission Staff	1978
El Paso Electric	Docket No.1891	Load Forecasting	PUC Texas	Commission Staff	1978
El Paso Electric	Docket No. 1642	Load Forecasting	PUC Texas	Commission Staff	1978
Texas Power & Light	Docket No.1 517	Weather & Price Normalization	PUC Texas	Commission Staff	1978

CURRENT MPSC PROCEDURE FOR THE CALCULATION OF TRANSITION CHARGES

Year	(A)	(B)	(C)	(D)	(E)	(F)
	Market Price		Transition Charge			Total Paid by Open Access (Market) Customers
	Actual (1)	Base (2)	Base (3)	Market Price Adjustment (4)	Net (5)	(6)
1998	3.5	2.9	1.2	0.6	0.6	4.1
2002 ①	3.8	3.3	1.2	0.5	0.7	4.5
2002 ②	3.5	3.3	1.2	0.2	1.0	4.5

Notes:
All values expressed as cents per kWh.
(1) Assumed here for illustrative purposes.
(2) Approximate; based on 2.9¢ per kWh escalated at 3% per year.
(3) Consumers Energy value used for illustration.
(4) Column (A) – Column (B)
(5) Column (C) – Column (D)
(6) Column (A) + Column (E)

Consumers Power Company FERC Form 1 data	1995	1996	1997	1998
		Value ($000)		
Total Production Plant (Gross)	$ 2,409,562	$ 2,490,062	$ 2,484,318	$ 2,460,519
Less Accumulated Depreciation	(1,380,922)	(1522,646)	(1,649,585)	(1,753,372)
Plus Nuclear Decomm. Rsrv	226,732	226,732	226,732	226,732
Gen/Com/Intngbl Plant	75,119	75,902	118,905	96,195
Plant held for future use	118	118	118	118
Net Production Plant	$ 1,330,609	$ 1,270,168	$ 1,180,487	$ 1,030,192
Less Deferred Tax Adjustment	(270,043)	(259,369)	(246,973)	(236,875)
Plus Materials & Supplies	79,267	74,763	71,920	77,121
Rate Base (I)	$ 1,139,833	$ 1,085,561	$ 1,005,434	$ 870,438
DOE SpentNuc (Acct.224)	45,218	53,300	64,191	69,877
Rate Base (PI)	$ 1,185,051	$ 1,138,861	$ 1,069,625	$ 940,315
Rate of Return on Rate Base	10.6%	10.6%	10.6%	10.6%
Pre-Tax Return	125,615	120,719	113,380	99,673
Income & Other Taxes	103,745	109,064	116,015	114,599
Depreciation Expense	106,503	108,597	108,055	106,615
Prod. Operations & Maintenance	1,179,426	1,304,658	1,324,101	1,356,902
A&G Alloc. Share	126,470	128,939	116,360	116,969
TOTAL Production Costs	1,641,758	1,771,978	1,777,910	1,794,759
Fuel & Purchased Power Costs	978,103	1,095,949	1,146,574	1,178,577
Non-Fuel/PP Costs	663,655	676,029	631,336	616,182
Energy Provided (excl. losses)	35,521	37,066	37,896	39.782
Cost per MWh (mills/kWh)	**46.2**	**47.8**	**46.9**	45.41
Cost per MWh (mills/kWh) EXCL Fuel/PP	**18.7**	**18.2**	**16.7**	**15.5**

Detroit Edison Company FERC Form 1 data	1995	1996	1997	1998
		Value ($000)		
Total Production Plant (Gross)	$ 8,644,659	$ 8,697,949	$ 8,768,930	$ 6,865,728
Less Accumulated Depreciation	(3, 176,007)	(3,454,631)	(3,755,140)	(2324,353)
Plus Nuclear Decomm. Rsrv				
Gen/Com/Intngbl Plant	432,301	481,580	527,730	557,563
Plant held for future use	9,623	9,623	9,623	9,623
Net Production Plant	$ 5910,576	$ 5,734,521	$ 5,551,142	$ 5,108,560
Less Deferred Tax Adjustment	(1,378,761)	(1,361,817)	(1,319,253)	(1,122,379)
Plus Materials & Supplies	231,773	210,745	205,835	238,837
Rate Base (I)	$ 4,763,587	$ 4,583,448	$ 4437,724	$ 4,225,017
DOE SpentNuc (Acct.224)				
Rate Base (II)	$ 4,763,587	$ 4,583,448	$ 4,437,724	$ 4,225,017
Rate of Return on Rate Base	10.0%	10.0%	10.0%	10.0%
Pre-Tax Return	476,359	458,345	443,772	422,502
Income & Other Taxes	333,606	330,238	372,885	314,184
Depreciation Expense	320,948	322,798	324,068	290,049
Prod. Operations & Maintenance	1,111,180	1,111,614	1,076,917	1,311,166
A&G Alloc. Snare	257,285	256,303	274,067	256,313
TOTAL Production Costs	2,499,378	2479,299	2,491,709	2,594,214
Fuel & Purchased Power Costs	828,957	810,792	813,193	988,157
Non-Fuel/W Costs	1,670,421	1,668,507	1,678,516	1,606,057
Energy Provided (excl. losses)	49,207	48,723	50,898	55,204
Cost per MWh (mills/kWh)	**50.8**	**50.9**	**49.0**	**47.0**
Cost per MWh (mills/kWh) EXCL Fuel/PP	**33.9**	**34.2**	**33.0**	**29.1**