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BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

CHAPTER II – Customer Conservation and Energy Management Programs

DIRECT TESTIMONY

OF JEFF D. MAKHOLM, PH.D

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ■ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ☐ OTHER

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1 **I. INTRODUCTION**

2 **Q. Please state your name, business address and current position.**

3 A. My name is Jeff D. Makholm. I am a Senior Vice President at National Economic
4 Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with its
5 principal offices in a number of major U.S. and European cities. My business address is
6 200 Clarendon Street, Boston, Massachusetts, 02116.

7 **Q. Please describe your academic background.**

8 A. I have M.A. and Ph.D degrees in economics from the University of Wisconsin, Madison,
9 with a major field of Industrial Organization and a minor field of Econometrics/Public
10 Economics. I also have B.A. and M.A. degrees in economics from the University of
11 Wisconsin, Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct
12 Professor in the Graduate School of Business at Northeastern University in Boston,
13 Massachusetts, teaching courses in microeconomic theory and managerial economics.

14 **Q. Please describe your work experience.**

15 A. My work centers on economic issues involving pricing, regulation and market issues for the
16 natural gas and electricity industries, among others. My consulting work includes the
17 specific issues of competition, rate design, fair rate of return, regulatory rulemaking,
18 incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract
19 obligations and bankruptcy. I have prepared expert testimony and statements, and I have
20 appeared as an expert witness in many state, federal and United States District Court
21 proceedings, as well as in regulatory and judicial hearings abroad.

22 I have also directed studies on behalf of utility companies, governments and the World
23 Bank in many countries. In these countries, I have drafted regulations, established tariffs,
24 recommended financing options for major capital projects and advised on industry
25 restructurings. I have also assisted in the privatization of state-owned gas utilities. As part
26 of my international work pertaining to the gas industry, I have conducted formal training

sessions for government, industry and regulatory personnel on the subjects of privatization, pricing, finance and regulation of the gas industry.

Regarding rate of return and utility financing questions specifically, I have testified for electric, natural gas, water and telecommunications utility clients before state commissions in Pennsylvania, Oregon, Ohio, North Carolina, Kansas, New Jersey, New York, Maryland, California, Virginia, Rhode Island, New Hampshire, Texas, Illinois, Indiana, Maine, and Connecticut, as well as before the Federal Energy Regulatory Commission ("FERC"). My current curriculum vitae, which more fully details my educational and consulting experience, is provided as **Exhibit JDM-1**.

Q. Does your testimony in this proceeding determine the cost of common equity, and therefore the fair rate of return on common equity, on behalf of The Dayton Power and Light Company ("DP&L" or the "Company")?

A. Yes. This cost of common equity will be used by the Company to calculate its revenue requirements for retail ratemaking purposes. **Exhibits JDM-2, JDM-3,** and **JDM-4** explain my use of the Discounted Cash Flow ("DCF") analysis, **Exhibits JDM-5** and **JDM-6** summarize my comparable group selection process, and the balance of my exhibits presents my DCF and Capital Asset Pricing Model ("CAPM") analyses as well as a survey of allowed returns in other jurisdictions and an explanation of the risks that electricity distributors face in the current environment. I use the projected actual capital structure ratios, cost of long-term debt, and cost of preferred equity that would be applicable for DP&L at the time that new rates would go into effect, as shown on **Exhibits JDM-7, JDM-18,** and **JDM-19**, respectively.

Q. Please summarize your conclusion as to the fair rate of return on common equity for DP&L.

A. The fair rate of return on common equity I recommend and conclude is reasonable for DP&L is **11.30 percent**, as summarized on **Exhibit JDM-7**. My recommendation is based on DCF and CAPM analyses of fifteen comparable electric utilities.

Q. What is the required overall rate of return for a firm?

A. The required rate of return for a firm is the firm's weighted average overall cost of capital ("WACC"). The WACC is the sum of the costs of the component parts of the capital structure, *i.e.*, debt and common equity, weighted by their relative proportions in the capital structure.

On **Exhibit JDM-7**, I present the capital structure and the cost of capital components that are appropriate for the companies. The overall cost of capital for DP&L is **9.36 percent** for distribution and **9.24 percent** for generation.[1]

Q. How do you characterize the nature of your rate of return testimony?

A. One of the most important goals of my rate of return testimony is to minimize the amount of subjectivity in the determination of the fair rate of return. I view subjectivity as the principal source of contention in the calculation of the rate of return in utilities' rate cases. This subjectivity has four sources: (1) lack of attention to detail in employing the methods provided by decades of work in the field of theoretical finance; (2) a proliferation of quantitative approaches to determining the cost of capital, under the dubious premise that the use of *more methods*—no matter how shaky the foundation for each—provides better rate of return evidence; (3) insufficient candor on the part of analysts regarding their application of objective, reproducible standards or personal judgment; and finally, (4) subjective adjustments to the results of empirical analyses.

Subjectivity creates a regulatory atmosphere in which it is very difficult, if not impossible, to resolve the contentious issues surrounding the determination of a utility's cost of equity and therefore setting of the fair rate of return. Most, if not all, other rate case issues have objective standards (*e.g.*, legal, policy, empirical) upon which to measure the value of evidence presented in rate cases. Only the process of finding the cost of equity and fair rate of return seems immune to measurement by such standards. I have attached, as **Exhibit**

[1] The cost of debt for generation includes certain debt instruments that are specifically related to generation, such as pollution control revenue bonds.

1 **JDM-2**, an article that discusses some of the problems associated with rate of return
2 investigations.[2]

3 To avoid contention, I make every attempt to avoid injecting subjectivity into the
4 calculation of the fair rate of return. I am very careful in my choice of models and data. I
5 also resist performing a multitude of ROE calculations, because I conclude that this
6 approach obscures rather than clarifies. When the use of judgment is unavoidable, I explain
7 the basis for my judgment. Finally, I avoid making subjective "risk" adjustments that do
8 not have a solid and empirically verifiable financial basis. Rate of return analysis suffers
9 widely from a fog of *ad hoc* adjustments that are impossible to verify empirically or
10 theoretically.

11 As a result, the standards to which I hold my evidence, as well as that of others, are: (1)
12 clarity; (2) theoretical support; (3) empirical objectivity; (4) stability (*i.e.*, not producing
13 widely disparate results); and (5) the ability to reproduce (*i.e.*, allowing others to readily re-
14 compute my results). My analysis for DP&L reflects my desire to hold to these five
15 standards of evidence.

16 **Q. Do you engage in detailed discussions of general economic trends?**

17 A. No. I do not include much discussion of general economic trends (Federal Reserve policy,
18 etc.) that some other witnesses provide. Such discussions do not inform us regarding what
19 *investors* believe is going to happen in the future. In order to gauge investor expectations,
20 we must resort to the financial models that have become familiar in rate of return
21 proceedings. These models all employ the markets for utility securities as the source of
22 investors' verdicts regarding the cost of capital.

23 The markets for utility securities provide the only evidence of what investors require as a
24 return on the money they invest in utilities, and the financial models that currently exist put
25 evidence from those markets in its proper context. The utilities security markets use
26 general economic information in the most efficient way. It is neither efficient nor

[2] *See* Jeff D. Makholm, "In Defense of the 'Gold Standard,'" *Public Utilities Fortnightly*, May 15, 2003, pp. 12-18.

appropriate for me to render a verdict on the future of markets when the law and economic theory require me to try to reflect what *investors* think. My task should be to combine *investors'* verdicts on the value of utility securities and sound financial models to determine the fair rate of return in the most direct and objective way possible.

Q. How does your testimony in this case reflect your desire to pursue objective, reliable and reproducible results?

A. I pursue these goals in two main ways: (1) I use those financial models and methods that permit the greatest objectivity; and (2) I make use of comparable company groups (also known as "proxy groups") to draw more reliable conclusions about investors' expectations.

Q. Please discuss how the selection of financial models and methods facilitates the greatest objectivity in finding the cost of equity and fair rate of return.

A. Although much time is devoted to discussions of various techniques for finding the cost of equity and fair rate of return, little discussion is usually devoted to determining whether these techniques are practical in the rate case setting and whether they are capable of limiting the scope for contention in rate cases. There are two main attributes of financial models that help on both counts: (1) the models should be strictly forward-looking; and (2) the models should offer an objective way of dealing with the uncertainty that is inherent in gauging investors' future expectations.

Q. Why is a forward-looking perspective important?

A. Investors look toward the future when they demand compensation for the use of their money. Therefore, the cost of capital is a forward-looking concept. However, there are few ways to look into the future, particularly from the perspective of what *investors* expect to occur. Those strategies are generally indirect—we look at stock prices or interest rates to gauge these expectations. This indirection is precisely why the field of finance has developed models like the DCF and CAPM models. Those models use the limited types of information that we *can observe* to draw conclusions about *unobservable* investor expectations of the future.

A forward focus and the use of valid financial models reduce the types of information that can help determine the cost of capital. Only a limited amount of information, either observed (such as stock prices and interest rates) or produced by disinterested sources (forecasts from widely distributed financial advisory services), fits our needs in the context of the available financial models. The use of this information limits the sources of contention in rate cases, minimizing the role of subjective judgment and restricting the ability to bias the results.

If we abandon a strict forward focus we open the floodgates to a sea of information that: (1) cannot help to determine today's investors' expectations; and (2) can be used selectively to bias rate of return results. With *any* backward-looking method of determining the rate of return, we can greatly alter the results simply by changing the historical time period used in our analysis (*e.g.*, two years, five years, 50 years). Furthermore, we abandon financial theory and therefore have no guide to the proper time. Any period seems as good as any other, and we cannot resolve this matter in the context of a rate case.

Q. Why is it important to use financial theories that allow an objective way of dealing with the uncertainty involved with gauging investors' expectations?

A. Gauging investors' future expectations involves an unavoidable element of uncertainty. There is no direct and reliable way to learn today's cost of capital for the utility in question. Our indirect methods use models with simplifying assumptions and require data that may not always be accurate or timely. That is, given a model's simplifying assumptions, the data used may cause us to think that investors are overly ambitious for one company and the reverse for another. The models we use should resolve this uncertainty objectively, because we have little use for a financial model that leaves us with a 250 basis point range containing the cost of capital and no way to choose within it.

Q. What specific issues do you address in your testimony?

A. First, I summarize my findings and discuss the meaning of the term "fair rate of return" on equity. Second, I describe the DCF method. Third, I present my cost of common equity recommendation for DP&L's regulated electricity operations, based on my DCF and CAPM analyses. I base my recommendation on a group of companies whose levels of risk

are comparable to DP&L's: a fifteen-company electric and combination electric and gas group. Fourth, I check the reasonableness of my recommendation using a comparison of allowed returns in other jurisdictions. Fifth, I discuss the business risk that electric utilities face in the current environment. Finally, I discuss the appropriate capital structure, embedded costs of preferred stock and debt, and the recommended overall cost of capital for DP&L.

II. SUMMARY AND BACKGROUND TO THE DETERMINATION OF A FAIR RATE OF RETURN ON EQUITY

Q. Please summarize your conclusions regarding the fair rate of return on common equity for DP&L's electricity operations.

A. I recommend a fair rate of return on common equity of **11.30 percent** as summarized on **Exhibit JDM-7.** I base my recommendation on the results of DCF and CAPM analyses performed on a proxy group of U.S. utilities that are comparable to DP&L's electric operations.

I recommend an overall cost of capital of **9.36 percent and 9.24** for distribution and generation, respectively, as presented on **Exhibit JDM-7.**

A. Background to the Determination of the Fair Rate of Return on Common Equity

Q. What do you mean by "fair rate of return on common equity?"

A. The essence of traditional public utility ratemaking—the "regulatory compact"—has been that utilities like DP&L have been protected by franchise against certain specific and limited types of competition. In return, the utility has accepted the obligation to provide service on just and reasonable terms. The utility has also accepted the duty to reasonably anticipate the future needs of its customers and to make whatever investments it judges necessary in order to meet those needs as efficiently as possible. Finally, the utility has accepted that prices would be set so as to recoup operating costs plus a reasonable profit. For a public utility, reasonable profit, under the law and in the financial world, has been defined as a rate of return sufficient to attract capital.

The capital attraction—or "opportunity cost"—standard has been key in determining the fair rate of return for public utilities. When investors make their funds available to a utility, they forego the option to use those funds for another purpose (either current consumption or another investment). They also put their funds at some risk. In return for foregoing current consumption and incurring risk, utility investors require a return on their funds. This return to investors is a cost to the utility—the "*cost of capital.*" In order for the utility to compensate its investors adequately for the current consumption foregone and the risk incurred, the utility must be allowed, as a component of its rates for service, a *fair rate of return* that covers its cost of capital.

Q. Does the way you have just defined the concept of fair rate of return on equity comport with its traditional definition?

A. Yes. The United States Supreme Court established the traditional standard for a fair and reasonable return in its *Hope* decision (*Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944)):

> ...the return to the equity owner should be *commensurate with returns on investments in other enterprises having corresponding risks.* That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to *maintain its credit and attract capital.* (Emphasis added.)

This often-quoted passage from the *Hope* decision, besides providing a legal standard for determining the fair rate of return, comports precisely with the opportunity cost standard for determining the fair rate of return that covers the utility's cost of capital.

In an earlier case, *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679, 693 (1923), the Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.

Furthermore, the Supreme Court stated in *Bluefield* that establishing an insufficient return on invested capital denies shareholders the Constitutional right of due process under the Fifteenth Amendment.

> Rates, which are not sufficient to yield a reasonable return on the value of the property used at the time it is being so used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fifteenth Amendment.

These principles from Bluefield are consistent with the economic principles that I apply in this testimony.

Q. Has the traditional regulatory compact changed over time?

A. The return that investors are due on their invested capital has not changed. The extent to which utility operations are regulated has changed.

Q. Please explain.

A. Deregulation has been implemented in many industries throughout many countries in the past twenty years. The electric and gas industries have not been immune to these changes. Technological changes and increased competitive pressures have made restructuring possible in the industry, and successful deregulation in other industries has created demand for it.

Most states have begun to consider how to restructure their electric and gas industries; a number of states have already introduced retail choice and many states are well on their way. Pursuant to Ohio law, the Public Utilities Commission of Ohio (the Commission) has opened electricity generation to competition and has provided for retail competition in the electricity commodity, while continuing to regulate electric transmission and distribution and provide for a standard offer product. More recently, the Ohio legislature has passed a law that, among other points, would allow electric distribution utilities such as DP&L to upgrade and modernize their distribution infrastructure, and to encourage energy efficiency and demand-side management efforts.

Q. Does the traditional concept of fair rate of return apply to all of the capital raised by the utility from investors, or just the common equity component?

A. It applies to all of the capital. This includes a company's common stock equity, preferred stock equity and debt.

Q. How are the individual fair returns or costs of capital pertaining to debt and preferred stock determined in a rate case?

A. Fixed payment obligations accompany both debt and preferred stock: interest on the former, preferred dividends on the latter. Calculating the dollars needed to cover interest or preferred stock dividend payments currently or over the period of time in which the rates in question for a utility will be in effect is not difficult. The *embedded* cost of debt and preferred stock proceeds directly from these calculations.

I highlight the word "embedded" because, for debt and preferred equity, all that we need in a base rate case is the embedded cost of these financial instruments (the payments to investors proceeding from existing agreements accompanying the existing bonds and preferred shares). Thus, parties in rate cases seldom significantly disagree over the embedded cost of debt and preferred equity capital. One can compare the promised interest and preferred dividend payments with the company's proceeds from the sale of those securities. The current market is irrelevant for such embedded cost calculations.

Q. Can a current (as opposed to embedded) cost of debt and preferred equity capital be observed in the market?

A. Yes. Since we know the schedule of interest and preferred stock dividends, and since we know the current market price for these financial instruments (a bond or share of preferred stock), we can observe the current (as opposed to embedded) cost of capital for both types of financing. The current cost of debt and preferred stock capital, reflecting investors' required return, is the discount rate that equates the present value of the known stream of interest (and principal) payments, or preferred dividend payments, with the observed price of those securities.

In other words, a relatively straightforward way to determine the current cost of debt and preferred equity securities is to observe the known market price and the known stream of interest and preferred dividend payments and to calculate the discount rate that equates the

1 two. The derived discount rate is equivalent to the current cost of debt and preferred equity
2 capital.

3 **Q. Can we calculate the current cost of common equity capital in the same way?**

4 A. No. An essential component to that calculation is knowledge of the (fixed) interest and
5 preferred stock dividend payments. Dividend payments on common stock equity are not
6 fixed, nor is their growth rate known. They are generally expected to grow as the company
7 in question grows. This growth rate is not observable—the growth rate is embodied in
8 unobservable equity investor expectations regarding the future performance of the company
9 in question. Because this growth rate is not observable, the future stream of dividend
10 payments is not known. There is therefore no known stream of payments that may be used
11 directly to find the discount rate equating the present value of the future stream of dividend
12 payments with the observed common stock price.

13 **Q. How can we estimate the cost of the common equity in DP&L's capital structure?**

14 A. One way to estimate the cost of equity capital (and generally the most popular method
15 among regulatory commissions) is to determine the stream of common dividends that
16 investors expect. This determination entails observing the current dividend and engaging in
17 the difficult task of estimating what investors expect regarding the growth in that dividend.
18 After the growth expected by investors is estimated, the cost of common equity can be
19 calculated by equating the present value of the estimated stream of dividend payments with
20 the observed common stock price. The calculated cost of capital resulting from this method
21 is entirely dependent on the quality and dependability of the estimates of investor
22 expectations regarding dividend growth. Another way to estimate the cost of equity capital
23 is to implement the CAPM model by taking the sum of the "risk free" rate, and an estimated
24 company-specific risk premium. I use both of these methods in my derivation of DP&L's
25 cost of equity capital, as explained further in my testimony.

1 **B. Estimating the Cost of Equity Capital**

2 **Q. How do you determine the fair rate of return on common equity for DP&L that is**
3 **consistent with the standards you described and that addresses the difficulties**
4 **inherent in estimating the cost of equity capital?**

5 A. Estimating the cost of capital involves theoretical and empirical components. I focus on
6 both of these aspects in my cost of capital calculation.

7 The theoretical component relies on the standard financial literature to develop cost of capital
8 methods that are consistent with what we know and observe about the way that financial
9 markets work. All of the cost of capital models that appear in the financial literature result
10 from theoretical investigations. The most important theoretical consideration when
11 determining the cost of capital for DP&L is to employ a method that provides an accurate
12 reflection of the market for the DPL Inc. common stock.

13 The empirical component includes the collection of the data to be used with the theoretical
14 cost of capital methods. The most important empirical consideration is to gather data that are:
15 (1) consistent with the theoretical models employed; (2) timely; and (3) unbiased. It is also
16 important that the calculations made with the empirical data be reliable and stable. In other
17 words, the resulting cost of capital measure should not be highly sensitive to minor or
18 judgmental changes in the type or source of the data used.

19 **Q. What theoretical method do you use in your evaluation of DP&L's cost of capital?**

20 A. As I mentioned in the previous section, I employ the DCF and CAPM methods. The DCF
21 method makes use of the relationship between the current stock price and the expected
22 future stream of dividends in order to calculate investors' estimated discount rate, or cost of
23 equity. The DCF method has a long history of being used to derive the cost of equity for
24 both regulatory and market investment purposes. It is a sound, reliable, easy-to-understand
25 and easy-to-reproduce method for determining the fair rate of return. Furthermore, it is
26 unique among rate of return determination methods in that the model's results become
27 stable and reliable when it is applied to a group of similar utilities. I also use the CAPM
28 methodology. The CAPM is the sum of two components: (1) a risk-free rate applicable to

all companies; and (2) a company specific risk premium (the product of a company-specific beta and a market risk premium). Given that CAPM is one of the methods used to determine the cost of common equity in Ohio, I use CAPM as a method to set the cost of common equity for DP&L.

III. THE DCF METHOD

A. A Description of the DCF Method

Q. Please describe the DCF method.

A. The DCF method is used to estimate the cost of common stock equity by determining the present value of all future income expected to be received from a share of common stock. As such, the DCF method is the common stock equity analogue to the way in which debt and preferred stock equity cost rates are calculated. With the DCF method, the cost of common stock equity is computed as the discount rate that equates a stock's current observed market value with the present value of all future expected returns from holding the common stock (*i.e.*, dividends and capital gains). The prevailing common stock price is assumed to reflect investors' expectations of the value of common stock, including future dividends and price appreciation.

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[3] The research performed by subsequent writers (including Gordon himself) resulted in the equation known as the "Periodic" DCF model. The "Periodic" DCF model generally expresses k_e, the cost of the common stock equity portion of total capital, as a relationship between the prevailing price of common stock equity, P_0, current dividends, D_0, and the dividend growth rate, g.

[3] *See*: Myron J. Gordon, *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

1 Following is a formal statement of the "Periodic" DCF model. The derivation of this model
2 appears in **Exhibit JDM-3** of my testimony.

$$k_e = \frac{D_0 * (1+g)}{P_0} + g \qquad k_e = \frac{D_1}{P_0} + g$$

Where: **(1)**

P_0	=	price of stock
D_0	=	previous dividend paid
k_e	=	cost of equity
g	=	dividend growth rate

3
4 This "periodic" or annual version of the DCF model has been very popular in regulatory rate
5 of return proceedings. In order to use the model properly, however, it is important to reflect
6 accurately how dividends are paid and how they grow. This model has two significant
7 abstractions from the reality of dividend payments. First, it assumes that dividends are paid
8 annually; and second, it assumes that dividends grow continuously from period to period. In
9 fact, most utilities pay dividends quarterly and increase their dividends only once a year, if at
10 all.

11 A different version of the DCF model avoids these abstractions. Specifically, the "Quarterly"
12 DCF model recognizes quarterly dividend payments and allows these payments to grow at a
13 constant rate from one quarter to the corresponding quarter in the following year. It is the
14 proper model for the purpose of calculating the cost of the common stock equity portion of
15 total capital, in terms of investors' required return, for firms that pay dividends quarterly and
16 normally increase dividends only once a year, if at all.

Q. Is the "Quarterly" DCF model the proper model for calculating the cost of the common stock equity portion of total capital in this rate case?

A. No. It is the proper way to calculate the total return required by *investors*, but that is not the appropriate rate of return to apply to rate base in proceedings such as these. For ratemaking purposes, the rate of return reflects the utility's cost of equity. As such, the rate of return should be developed from the perspective of the utility, not from the perspective of the investor.

Q. Please explain the difference.

A. The difference is the reinvestment of quarterly dividends paid by the utility. Because dividends are paid quarterly instead of annually, investors can choose how they wish to reinvest the dividends to obtain their total return for the year. They can, for example, reinvest in the equity of the utility. Alternatively, they can invest in the securities of another company. For this reason, then, the reinvestment of quarterly dividends (implicit in the quarterly DCF model) is the appropriate model when considering total return from the perspective of investors. The utility, however, does not control the reinvestment decisions of investors and therefore is responsible only for providing the fair rate of return as calculated in the "periodic" DCF model above. If the utility provides the fair rate of return, investors can reinvest the utility's dividends in a manner that will allow them to reach their total required return.

In other words, the cost of the common stock equity portion of total capital developed in the "Quarterly" DCF model accurately mirrors *investors'* current return requirements on common stock equity. It does not, however, reflect the *utility's* fair rate of return that must be applied to the rate base to yield the revenue requirement necessary to give investors what they require.

When the appropriate adjustments are made to reflect the perspective of the utility, the quarterly model reduces mathematically to the "Periodic" DCF model I presented above. In **Exhibit JDM-3**, I present the calculations that confirm this. Thus, the "Periodic" or "Annual" DCF model is the one to use in this proceeding.

1 **B. Selection of Comparable Company Group**

2 **Q. Do you use a comparable group of combination electric and gas utilities to determine**
3 **the fair return on equity for DP&L?**

4 A. Yes. I employ a group of fifteen electric and combination electric and gas utilities that are
5 comparable in risk to DP&L.

6 **Q. Please explain why comparable groups of companies are useful in this context?**

7 A. My reasons for using data from multiple firms to determine the fair rate of return on equity,
8 even if company-specific data are available, are: (1) a group of companies produces a more
9 *reliable* and *objective* estimate of the current cost of capital required by capital markets; (2)
10 the computation of comparable group's fair rates of return gives substance to the *Hope*
11 decision's finding that a reference should be made to return on *investments with*
12 *corresponding risks*; and (3) a specific jurisdiction's regulatory process affects investor
13 expectations regarding the company whose fair rate of return is being set. This effect leads
14 to the problem of "*circularity*." Circularity is particularly problematic in states where
15 primary weight is given to the "sustainable dividend growth rate" in determining a
16 company's fair rate of return on equity. This growth rate is a function of the proceeding
17 that supposedly estimates this growth rate. The use of a proxy group will assuage the
18 circularity problem.

19 **Q. Why should circularity be a concern to the regulator?**

20 A. Circular reasoning has long been considered a serious problem in the determination of a fair
21 rate of return for investors. For example, the principle of "fair value" rate regulation
22 (which dominated public utility regulation at both the state and federal level before the
23 1940s) gave way to "cost-based" rate regulation in large part because of a problem of
24 circularity. As Professor Bonbright stated: "[a]ny attempt to test the fairness of the rates by
25 reference to a valuation of the properties is an attempt to reason in a circle, or, if you like, to
26 put the cart before the horse."[4] After all, a valuation of the properties will be based on the

[4] J.C. Bonbright, *Principles of Public Utility Rates*. (New York: Columbia University Press, 1961), p. 164.

present value of the cash flows that the property will provide in the future, which, of course, will depend on the rates that can be charged to customers.

Whenever a commission uses a formula for determining a fair return that depends on investors' expectations of future growth, circularity arises because we know that investors' expectations depend on the return that the regulator is expected to allow. The path of supposed causation proceeds in both directions simultaneously, which, of course, is the source of circular reasoning. Another example of the circularity problem in the determination of the fair rate of return is the practice of using other public utilities' returns in a "comparable earnings" analysis. If the past earnings of the comparable group are low, it will likely result in a lower awarded rate of return on equity for the company under consideration. This company will, in turn, become part of another comparable group and will contribute to lower rates of return for other companies, creating a cycle from which it is difficult to escape.

By the same token, there is a circularity problem inherent in using a sustainable dividend growth formula for calculating the dividend growth in a DCF analysis when the principal components of that growth (i.e., the expected return and the retention ratio) are a function of the rates to be awarded. This practice is an impediment to the objective and impartial determination of a fair rate of return for a regulated utility.

Proxy group DCF calculations are far less likely to depend on the anticipated return granted in this case and, therefore, are far less likely to be susceptible to problems of circularity.

Q. What comparable companies do you employ in your DCF analysis of DP&L's electric operations?

A. The fifteen-company electric and combination electric and gas company group is listed in **Exhibit JDM-5 and JDM-6.**

Q. What criteria do you use to determine that the companies you choose are comparable to DP&L's electric operations?

A. I have identified what I conclude are the minimum number of criteria that satisfy two basic objectives. The first basic objective is to assemble a group of companies with publicly-

traded stock that are representative, on average, of the business risk faced by DP&L's electric delivery service operations. The second basic objective is to assemble a group of companies with stock price and dividend payment data that could be readily applied to the annual DCF model. I have consistently used this same approach to select comparable companies for a number of years.

Q. What criteria satisfy your first basic objective—that of mirroring the business risk faced by DP&L's investors?

A. The current rate case involves DP&L's electric utility operations. While DPL Inc. is the parent holding company of DP&L, the focus should be on determining the cost of common equity for DP&L's regulated electric utility operations in Ohio. The following two characteristics help to define the business risks faced by those who invest in either an electric or a combination electric utility company and are recognized by investment analysts as pertinent factors in evaluating the risk of an equity investment: (1) type of business, in this case a regulated electric utility; and (2) size.

Given these characteristics, I use two criteria to exclude companies from the proxy group for my combination electric and gas group. *First*, I select those electric and combination electric and gas utility companies that derive at least 85 percent of operating revenues from regulated electricity and gas operations. The average proportion of total operating revenue from electricity and gas activity in 2007 for the proxy group was 97 percent. DP&L derived 87.4 percent of its operating revenues from regulated electric activities and has total capital of $2.44 billion, as shown on **Exhibit JDM-6**. *Second*, I restrict the group of companies to those with a total capital of less than $10.0 billion. Some of the utilities in the proxy group have a higher total capital than DP&L and some have a lower total capital, but my goal (as stated above) is to create a proxy group that, *on average*, is representative of the business risk faced by DP&L. The average total capital for the group is about $2.61 billion.

Q. What criteria satisfy your second basic objective—to assemble a group of companies with stock price and dividend payment data that can be readily applied to the annual DCF model?

A. I establish two additional criteria to ensure that the data collected from the assembled proxy group companies can be used reliably in a DCF analysis. *First*, I restrict the group to utilities for which no explicit concern was raised in my financial data sources regarding the ability of the company to maintain its existing dividend. Because the DCF model I employ assumes a constant long-term dividend growth rate, it is inappropriate to apply the model to companies where a dividend decrease is expected.

Second, I exclude from the analysis any companies that are the publicly known targets of possible takeovers or are involved in mergers. Tender offers associated with takeovers generally affect stock prices in a temporary way unrelated to the overall cost of capital and make the use of those stock prices in a DCF analysis suspect. At this particular time, some electric and gas utilities are involved in merger activities and are therefore not potential candidates for my proxy group.

Q. What is the result of applying your criteria?

A. The result of applying the four criteria is that I develop a group of fifteen electric and combination electric and gas utilities, listed in **Exhibit JDM-5** and **JDM-6**. I conclude that this group has a degree of business risk that is comparable to DP&L's utility operations. **Exhibit JDM-5** explains the selection of the proxy groups. The resulting proxy group analysis produces an accurate estimate of the cost of equity for DP&L.

Q. Would it be preferable to use different selection criteria (such as bond ratings) or to use a larger proxy group?

A. No. Bond ratings measure the default risk associated with a firm's debt securities, such as its first mortgage bonds.[5] Bond ratings do not necessarily accurately measure the firm's equity risk.

While it might be possible to begin to select a proxy group by using a group of all utilities with a certain bond rating (say, all utilities with A rated bonds), it would still be necessary

[5] Indeed, a utility's various debt securities (*e.g.*, senior mortgage bonds, subordinated debt, etc.) are likely to have slightly different bond ratings. Further, different bond rating agencies (*e.g.*, Fitch, Moody's, and S&P) will sometimes have different bond ratings for a particular utility's first mortgage (or other) bonds.

to use a screening process to eliminate: (1) very large firms; (2) firms that are highly diversified; (3) firms that are involved in mergers; and (4) firms that cannot be used in the standard DCF model (*e.g.*, firms that have recently cut their dividend). Thus, in the end, the sort of analysis that I have used in my testimony would be necessary even if you started with a group of firms that had the same A bond rating. Further, given that bond ratings measure default risk rather than equity risk, it is not at all clear that you would end up with a group that is more comparable (or even as comparable) to the risk of DP&L than the group that I have used in my testimony.

I fear that the end result after screening a group of utilities with the same bond rating would be a very small comparable group. It is generally desirable to have a fairly large comparable group, although it is also very important that the comparable group accurately reflect the subject utility's risks and meet the requirements of the DCF model. It would certainly not be appropriate to simply add back companies—perhaps by relaxing the selection criteria—in order to obtain a large group. My fifteen-company electric and combination gas and electric utility group was selected using a methodology that I have consistently used for many years, which provides the best available basis for estimating the return on equity required by investors in DP&L's common equity.

C. Inputs into the DCF Calculations

Q. Please turn now to your description of the data you use to determine the fair rate of return for DP&L's electric service operations.

A. As I stated previously, it is important to use data that are: (1) consistent with the theoretical DCF method, (2) timely, and (3) unbiased. It is also important that the calculations made with the empirical data be reliable and stable.

The DCF analysis requires three data inputs: (1) current stock prices, P_0, (2) the current annual dividends, D_0, and (3) estimated dividend growth rates, g. I will deal with each of these DCF inputs in turn.

1. Calculation of the Stock Price, P_0

Q. What data do you use for the stock price input, P_0, in your DCF calculations?

1 A. I use stock prices obtained from *Yahoo! Finance*. It is my normal practice to use stock
2 prices on the latest day consistent with the filing, because only the latest stock prices are
3 consistent with up-to-date investor expectations.[6] This is because the informative value
4 (with regard to investor expectations) of yesterday's stock prices will be completely
5 superseded by today's stock prices. This is a widely held tenet of efficient markets. If
6 today's stock prices embody all of the expectations regarding the value of those stocks, then
7 yesterday's prices represent "old news." Yesterday's prices, therefore, are useless as a gauge
8 to investors' current expectations.

9 I use a closing stock price from on August 4, 2008, which was the latest day possible given
10 DP&L's filing date in this case.

11 **Q. Do you adjust the observed stock prices?**

12 A. Yes. I perform an "ex-dividend date" adjustment on all of the stock prices to remove the
13 known effect that the next quarterly dividend payment has on the stock price. Failing to
14 remove this effect would make the stock price used inconsistent with the DCF formula.

15 This adjustment is necessary because of the assumption in all standard DCF models that the
16 next quarterly dividend will be received one full period from the date the stock price is
17 measured. The problem with this assumption is that the next quarterly dividend is usually
18 closer than one full quarter from the day the stock price is observed. This affects the stock
19 price in a known way and must be corrected in order to avoid a downward bias in the
20 calculated result.

21 **Q. What is the ex-dividend date and how can ignoring it bias the DCF calculations**
22 **downward?**

23 A. The ex-dividend date is the date on which the right to the next dividend no longer
24 accompanies a stock. In other words, if you purchase a share of stock the day before the
25 ex-dividend date, you will receive the next quarterly dividend paid by the Company. If you

[6] I am very concerned about applying the cost of capital estimation methods that I use in a consistent manner. With regard to the stock price, for example, analysts could use selective stock price averaging to surreptitiously raise or lower a calculated result.

purchase that share one day later, you will not receive that dividend. Because dividends are an important part of the return to utility shareholders and in view of the relatively high payout ratios involved, the ex-dividend date is an important determinant of the stock price. Utility stock prices, like other stock prices, are observed to drop by an amount approximately equal to the quarterly dividend on the ex-dividend date.[7]

All of the DCF models that I outline in my testimony apply *only on the ex-dividend date*. In other words, all of these models assume that future dividends begin a full period hence. Failure to adjust the stock price observed at an arbitrary date to account for the ex-dividend date will bias the applicable stock price upward (by approximately the amount of the "accrued" portion of the quarterly dividend), and the resulting DCF calculation downward.

Q. How do you make the adjustment in the stock price?

A. I make the adjustment by removing from the stock price the portion of the dividend that has already accrued. I make this adjustment to the P_0 term before performing the DCF calculations for a proxy group. In cases where I employ a single day's stock price, the adjustment is straightforward. That is, I subtract from the stock price a proportion of the last dividend payment. That proportion is the number of days since the last ex-dividend date, divided by 90 (*i.e.*, a full quarter). I make this adjustment to the P_0 term in **Exhibit JDM-8** before performing the DCF calculations shown in **Exhibit JDM-14.**

2. Calculation of the Dividend, D_1

Q. How do you measure the dividend, D_1?

A. The DCF model requires that $D_1 = D_0 * (1+g)$, where D_0 is equal to the sum of the four most recent dividend payments. Thus, my starting point is to obtain the data for D_0. I

[7] A discussion of the importance of the ex-dividend date appears in most financial texts. See for example: E.F. Brigham, *Financial Management Theory and Practice*, 3rd Edition, (New York: The Dryden Press, 1982), 687. Empirical evidence on this phenomenon can be found in articles written by J.A. Campbell and W. Beranek, "Stock Price Behavior On Ex-Dividend Dates," *Journal of Finance*, 10, 4, (December 1955), 425-429; D. Durand and A.M. May, "The Ex-Dividend Behavior of American Telephone and Telegraph Stock," *Journal of Finance*, 15, 1 (March 1960), 19-31; and E.J. Elton and M.J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," *Review of Economics and Statistics*, (February 1970), 68-74.

1 obtain the sum of the past four quarterly dividends per share payments from *Value Line*
2 *Investment Survey*.[8] I use the sum of the four most recent dividend per share payments for
3 each company in the proxy group, which is the D_0 term shown on **Exhibit JDM-9.**

4 **3. Calculation of Growth, *g***

5 **Q. How do you estimate the dividend per share growth term, *g*?**

6 A. I use three different prospective growth measures to estimate dividend growth from which I
7 then take the simple average. The first is a measure of sustainable growth that examines
8 projections of the separate components of dividend growth—that is, retained earnings and
9 expected returns to book equity, as well as the possibility of issuing new shares at prices in
10 excess of book values. The second measure is calculated using the forecasts of earnings per
11 share published by *Value Line* in the issues listed above. The third measure uses analysts'
12 estimates of earnings, as summarized by Zacks.

13 **Q. Please describe the first method you use to calculate growth for the companies in your**
14 **comparable group.**

15 A. The first method is known as either the "retention growth" or "sustainable growth" method.
16 This method produces a forward-looking, sustainable growth rate by multiplying the
17 fraction of earnings that analysts expect a company to retain by the expected return on book
18 equity. The sustainable growth method also allows for growth stemming from new
19 issuances of stock at premiums over book value. This is a valid way of estimating future
20 dividend growth, because future growth in the dividend can occur only if: (1) a portion of
21 the expected equity return is reinvested instead of being paid out in the form of dividends;
22 or (2) if new common stock is issued at prices above current book values (causing existing
23 shares to appreciate in value).

24 I estimate a sustainable growth rate for each company using the following formula:

[8] Data for the electric utilities were taken from *Value Line Investment Survey*, May 30, 2008 (Edition 1), June 27, 2008 (Edition 5), August 8, 2008 (Edition 11). Each edition, updated regularly, provides data for a number of years for electric utilities from a particular region of the country.

$$g = B * R + S * V$$

Where:

B	=	expected retention ratio
R	=	expected return on equity
S	=	percent new equity expected
V	=	$1 - \frac{B}{M}$

This formula for estimating sustainable growth is explained in more detail in **Exhibit JDM-4.** This theoretical growth measure shows that investors can expect growth through both retained earnings and the sale of new stock at a premium of book. In this formula, current end-of-year book value data is used as a *factor* to transform projected book values from *Value Line* to mid-year book values.

For all the publicly traded stocks in the comparable company group, investors can currently expect both forms of growth, as the market-to-book ratio for all is above one. As the Department has recognized in past decisions, if the $S*V$ term is ignored in the sustainable growth calculation, the resulting formula will not accurately represent investor perceptions of growth. The results of implementing the sustainable growth formula are presented in **Exhibits JDM-10** and **JDM-11.**

Q. Is the use of forecasts in your second and third methods, which use information provided by *Value Line* and Zacks, appropriate?

A. Yes. The practice of using forecast growth rates provides a sound basis for estimating the long-term growth of the utility. Financial analysts exert considerable influence over the many investors who do not possess the resources to make their own forecasts. The accuracy of these forecasts, in the sense of whether they turn out to be correct, is not the issue as long as they reflect widely held expectations. **Exhibit JDM-12** summarizes the

1 *Value Line* and Zack's growth rates and provides the details of the calculation of the *Value*
2 *Line* EPS growth rates.

3 Analysts' forecasts are sometimes criticized on the ground that it is very difficult to forecast
4 growth rates accurately in the short term, let alone in the long term. However, this general
5 objection is irrelevant to a DCF analysis because this method is based upon present investor
6 expectations. Widely distributed forecasts influence both the current stock price and DCF
7 cost of equity, not what the future will actually turn out to be.

8 **Q. Are the five-year annual projected growth rates in earnings published by *Value Line***
9 **and Zacks reasonable indicators of long-term growth?**

10 A. Yes. They are reasonable in the context of proceedings in which rate of return is being
11 examined. It would be naïve to assume that the growth rates forecasted by *Value Line* and
12 those summarized by Zacks are applicable far into the future. However, there are two
13 strong reasons for employing such forecasts in the present proceeding. First, to the extent
14 that investors employ forecasts like those published by *Value Line* and Zacks as long-term
15 growth rates, these forecasts accurately reflect the current expectations of long-term growth
16 included in the cost of capital. Second, *Value Line* and Zacks forecast growth rates might
17 not be substantially different, on average, from what investors believe long-term growth
18 prospects to be, given that the forecast is widely distributed in the financial community. In
19 addition, a study by Brown and Rozeff shows that *Value Line* analysts make better forecasts
20 than could be obtained by employing historical data only.[9]

21 **4. Selling and Issuance Cost Adjustment**

22 **Q. Do you make any adjustments to your DCF results?**

23 A. Yes. I make an adjustment for selling and issuance costs when calculating the DCF costs in
24 **Exhibit JDM-14.**

25 **Q. Why do you make such an adjustment?**

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[9] L.D. Brown and M.S. Rozeff, "The Superiority of Analyst Forecasts As Measures of Expectations: Evidence From Earnings," *Journal of Finance*, 33, 1 (March 1978), 1-16.

1 A. The issuance of common equity, as well as long-term debt and preferred stock, involves
2 costs. These costs are often measured as a percentage of the total debt, preferred equity or
3 common equity issuance. Because of issuance costs, the net proceeds of a debt, preferred
4 equity or common equity issuance will always be less than the total purchase price of the
5 securities issued. Unless an adjustment is made to reflect this phenomenon in the fair rate
6 of return—an adjustment consistent with the issuance cost adjustment already made for
7 debt and preferred stock—the resulting fair rate of return calculations will be too low. The
8 same problem with a return that is too low will result if selling and issuance costs are
9 ignored in calculating embedded debt costs.

10 **Q. Is such an adjustment generally made by regulators?**

11 A. Yes. An adjustment to factor out selling costs is made as a traditional part of computing the
12 embedded cost of debt and preferred stock—even though it is often contested where equity
13 is concerned.

14 **Q. Please explain.**

15 A. Basing required returns on net, rather than gross, proceeds is standard regulatory practice
16 when the capital is in the form of debt or preferred stock. It is inconsistent—and the source
17 of improper DCF calculations—to exclude the same type of issuance cost allowance from
18 outstanding common stock balances if those costs were incurred in the issuance of that
19 common stock and were not reflected as a current expense in rates at the time the issuance
20 was made. For long-term debt and preferred stock issuances, these costs are capitalized by
21 calculating a required rate of return on the net proceeds to DP&L. It would be inconsistent
22 to allow the capitalization and collection of these costs on long-term debt and preferred
23 stock issuances and not to allow the collection of the same kind of costs on common stock
24 issuances.

25 **Q. What is the most common way for regulatory commissions to compensate for issuance**
26 **costs?**

27 A. The most common way to compensate utilities for necessary issuance costs related to
28 common stock, as well as for preferred stock and long-term debt, is to allow a return *on*

these costs for any one year and a return *of* these costs over the life of the issue. For common stock, because the life of the issue is, in essence, perpetual, the return component to recover the return on these costs is permanently a part of the return on equity. The only way these costs will "go away" is if they are paid off as a current expense. Failing to compensate a utility for its issuance costs will assure the under-recovery of its prudently incurred costs of raising capital.

Q. Is there more than one way that a commission can deal with selling and issuance costs?

A. Yes. A commission appropriately can handle these costs in one of three ways. *First*, a commission can allow the company to recover these costs automatically in the year they are incurred as an expense component of the revenue requirement (or the expense could be amortized over a number of years—with a return on the outstanding balance).

Second, a commission can allow the issuance costs to be included in the rate base (like the treatment of interest charges on construction work in progress). This will allow the company to earn a return *on* the costs, as opposed to a return *of* the costs.

Third, a commission can adjust the cost of capital upward over the life of the issue. This adjustment in effect allows the company to earn a return *on* the issuance costs, even though the costs are not in the rate base. The financial result and the revenue requirement are the same as for the second method.

All of these methods would compensate the utility for the actual issuance costs incurred.

Q. How do you make your issuance and selling expense adjustment?

A. It is proper to include an issuance expense return adjustment for the entire equity component of the capital structure.[10] Therefore, I use the conventional form of the issuance expense adjustment:[11]

[10] Support for using total common equity appears in: Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), pp. 28-36.

$$r = \frac{D_1}{P_0 * (1 - f)} + g$$

Where:

r = required return adjusted for issuance expenses

f = flotation cost percentage

1 For the purpose of choosing an appropriate value for f, the flotation cost percentage, I refer
2 to a publication by Victor Borun and Susan Malley as well as information specific to
3 DP&L's most recent public equity issuances.[12] Borun and Malley conclude that total
4 flotation costs for electric utilities are about 5.5 percent. As shown in **Exhibit JDM-13**, the
5 average of DP&L's last ten equity offerings is 4.27 percent. The average of the two is 4.88
6 percent, which I use as the issuance cost percentage for the DCF calculations in this case,
7 according to the formula above.

8 **Q. Please explain why the issuance expense adjustment should be made to total common**
9 **equity.**

10 A. Investors are entitled to earn the expected cost of capital on their investment. The DCF
11 model illustrates that this expected cost is equal to dividend payments plus capital gains on
12 the value of their shares. The cash paid in by investors is greater than the net proceeds that
13 the company takes in. Therefore, the company must earn a greater return on the smaller net
14 proceeds balance to compensate investors adequately for their expected cost of capital. But
15 the money paid to the investors in any year, the dividend, reflects only a portion of the
16 returns on equity. Retained earnings represent the other portion, or the funds used to
17 finance future growth and future dividends. If retained earnings do not receive a selling and

(...continued)

[11] This formula appears in Roger A. Morin, *Utilities' Cost of Capital*, (Arlington Virginia: Public Utilities Reports, Inc., 1984), 106; and Eugene F. Brigham, *et al.*, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, (May 2, 1985), pp. 28-36.

[12] Victor M. Borun and Susan L. Malley "Total Flotation Costs for Electric Company Equity Issues," *Public Utilities Fortnightly*, (February 20, 1986), 33-39.

1 issuance return adjustment, they will not grow at a rate sufficient to allow for the payments
2 of dividends at investors' expected growth rate in the future and the company would not
3 earn its true cost of capital.

4 **D. Empirical DCF Calculations for Proxy Group**

5 **Q. How do you calculate a DCF cost of common equity for the proxy group of electric**
6 **and combination electric and gas utilities?**

7 A. Using the ex-dividend date adjusted stock prices for August 4, 2008, the most recent four
8 actual dividend per share payments, the average of the sustainable growth and forecast
9 earnings growth estimates, and the issuance cost method shown above, I estimate a cost of
10 common equity for the electric and combination electric and gas proxy group of **11.00**
11 **percent,** as shown in **Exhibit JDM-14.**

12 **IV. CAPM ANALYSIS**

13 **Q. Please provide your overall evaluation of the CAPM.**

14 A. The CAPM is the sum of two components: (1) a risk-free rate applicable to all companies;
15 and (2) a company-specific risk premium (the product of a company-specific beta and a
16 market risk premium). There are a wide variety of risk-free rates from which to choose
17 (*e.g.*, long-term/short-term/average of both). Furthermore, because the same risk-free rate
18 applies as an additive term to all companies' cost of equity estimates, there is no measure of
19 central tendency in the result. In short, we cannot resolve the question of uncertainty
20 surrounding short-term versus long-term rates by repeated sampling.

21 The CAPM is one of the methods used to determine the cost of common equity in Ohio
22 and, therefore, I use CAPM as one method to set the cost of common equity for DP&L.

23 **Q. Is there more than one way to calculate the CAPM model?**

24 A. Yes. The CAPM formula itself is rather straightforward. Its components are: (1) the risk
25 free rate of return; (2) the market rate of return; and (3) the beta. Yet despite this algebraic
26 simplicity, experts have applied different methods to obtain each of these components and

1 to compute the required rate of return. The effects of choosing one method over another
2 can be to substantially change the required cost of capital.

3 **Q. Have you calculated a CAPM ROE?**

4 A. Yes. I have derived CAPM return on equity estimates. My CAPM results for my
5 comparable group and for DP&L are shown on **Exhibit JDM-15.**

6 I use a risk-free rate of 4.65 percent, which is the yield on 30-year U.S. Treasury bonds, as
7 reported in the *Value Line Selection and Outlook* (August 8, 2008). I use the most up-to-
8 date *Value Line* betas for the companies in my comparable group. *Value Line* data are
9 unique in that *Value Line* is not affiliated with any bank, broker, or insurance company."[13]

10 Two approaches are used to calculate the appropriate risk premium: (1) I calculate a "top-
11 down" return on the market (the S&P 500) using analysts' estimates; and (2) I use historical
12 Ibbottson and Sinquefield data.

13 Forward-looking measures of the market risk premium are available. A forward-looking
14 market risk premium can be calculated by subtracting the risk-free rate from the estimated
15 14.14 percent "top-down" cost of equity capital of the S&P 500. First Call[14] provides a
16 11.48 percent estimate of the "top-down" estimated five-year earnings growth rate of the
17 S&P 500, and S&P[15] provides a 2.27 percent estimate of the current dividend yield of the
18 S&P 500. Combining these inputs using the standard DCF model provides a forward-
19 looking, top-down DCF cost of common equity for the S&P 500 of 14.14 percent, as shown
20 on **Exhibit JDM-16**. As shown in **Exhibit JDM-15**, p. 1 of 2, this method of estimating
21 the risk premium produces a 12.94 percent result for the proxy group using CAPM.

22 While Ibbottson and Sinquefield's market risk premium data is a useful source of
23 information on the historical risk premium of large company stocks relative to long-term

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[13] Jennifer Francis, Qui Chen, Donna R. Philbrick, and Richard H. Willis, *Security Analyst Independence* (Charlottesville, VA: Research Foundation of CFA Insitute, 2004), p. 22.

[14] First Call Long term Estimated Annual Growth Rate (S&P 500) https://personal.vanguard.com/us/StocksEarningsSec?Ticker=DPL (8/6/2008)

[15] Standard & Poor's.

1 government bonds, it is backward looking. As shown on **Exhibit JDM-15**, p. 2 of 2, this
2 method of estimating the risk premium produces a 10.26 percent result for the proxy group.

3 **Q. What conclusion do you draw on CAPM cost of common equity for the proxy group?**

4 A. As demonstrated on **Exhibit JDM-15**, I use two approaches to estimate a CAPM cost of
5 common equity for the combined gas and electric proxy group. My CAPM cost of equity
6 recommendation of 11.60 percent, which is the average of my CAPM results using two
7 methods of estimating the risk premium, is summarized on **Exhibit JDM-7**.

8 **V. RECENT ALLOWED RETURNS ON EQUITY**

9 **Q. What checks of reasonableness do you perform?**

10 A. I review the most recent rate of return decisions for electric utilities listed by Regulatory
11 Research Associates from January 2007 through June 2008.

12 **Q. Please explain how you develop the allowed return on common equity comparison.**

13 A. **Exhibit JDM-17** presents the individual state commissions' allowed returns that have been
14 authorized by regulatory commissions throughout the country between January 2007 and
15 June 2008. My data base covers 67 decisions. The figure also shows the number of
16 decisions associated with each allowed return on common equity figure.

17 **Q. What conclusions do you draw from the information presented in Exhibit JDM-17?**

18 A. My recommended return is within the range of returns (9.10 percent to 12.12 percent)
19 authorized by commissions throughout the country over the period January 2007 through
20 June 2008, which suggests that my recommendation is reasonable.

21 **VI. THE GENERAL SOURCES OF ELECTRIC UTILITY COMPANY RISK**

22 **Q. What is the purpose of this section of your testimony?**

23 A. In this section, I examine the basis of the business risks for electric utilities, both to show
24 that they are substantial and to point out that they differ very little—in principle or in
25 practice, from one another.

26 **Q. What are the basic types of business risks applicable to electricity utilities?**

A. Electricity utilities face practical risks in ratemaking, risks in planning and upgrading their systems to maintain reliability, and dealing with problems of accidents and outages that interrupt service.

- Tariff structure risks. Electric utilities have largely fixed costs devoted to their respective networks—but collect their revenues largely through volumetric rates. This exposes revenues—and earnings—to risks of unseasonable weather and economic downturns. This is a basic risk for utilities that follows from a rate structure that does not (for various reasons) match the structure of costs.

- Electric utilities connect to the multitude of a state's end-use consumers. Therefore, electric utilities are the ones charged with the planning of upgrades to networks that in many cases are decades old. The needs for major expenditures to provide safe local service do not always follow rate case schedules—and hence are often not recouped, as such.

- Risks of service interruptions. Major or minor service interruptions are generally the responsibility of the electric utility—as are the costs of remedying outages. Storm damage to electricity wires and sub-stations is the responsibility of the utility, which can try to plan for—but cannot guarantee—the collection of all costs that are incurred.

- Adequacy of depreciation. The depreciation allowance included in utility company rates is an estimate based on historical experience. Depreciation allowances do not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions. As such, there is a risk that utility plant will be under-depreciated, and changes in technology or regulation will cause shareholders to bear the result of inadequate depreciation.

- Risk of technological bypass. Electric utilities are at risk for customers bypassing the network by switching fuels or adopting alternate technologies. If bypass is significant, there is no guarantee that the remaining rates will be adjusted to recover the cost of abandoned or excess capacity.

- Risk of the competitiveness of rates. Electric utilities are at risk for the continued variables of the overall business. Competitive pressures from distributed generation or alternate fuels could create a situation in which allowed revenues are not competitively viable. In this instance, the controlling limit on rates would be competition from other sources, not regulatory limits or charges—and utilities would be unable to recover their actual costs.

- Risk of timeliness and adequacy of allowed revenue levels. Electric utilities face the need to increase distribution rates as costs increase. It is expensive and difficult to file for a small rate increase. The utilities will absorb such costs until they become large enough to cover the cost of a rate filing.

- Provider of last resort risks. Electric utilities must stand ready (have the capacity capability) to supply customers who default to the utility's standard service offer, upon the failure of a supplier to provide retail electric generation service to customers.

VII. THE CAPITAL STRUCTURE, EMBEDDED COST OF LONG-TERM DEBT, AND OVERALL COST OF CAPITAL

Q. What is the required overall rate of return for a firm?

A. The required rate of return for a firm is the firm's weighted average overall cost of capital ("WACC"). The WACC is the sum of the costs of the component parts of the capital structure, *i.e.*, debt, preferred stock, and common equity, weighted by their relative proportions in the capital structure.

On **Exhibit JDM-7**, I present the capital structure and the cost of capital components that are appropriate for DP&L. I use the projected actual capital structure ratios that would be applicable for DP&L at the time that new rates would go into effect. **Exhibits JDM-18** and **JDM-19** present the embedded cost of long-term debt and preferred stock, respectively. The overall cost of capital is **9.36 percent** for distribution and **9.24 percent** for generation.

Q. What is the appropriate capital structure to employ in determining DP&L's overall cost of capital?

A. There are two considerations that are noteworthy in determining the appropriate capital structure. First, since this rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components upon the best available estimates for the period of time in which the rates will be in effect. The appropriate capital structure should reflect all known changes, including new security issuances and retirements.

Second, modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[16]

[16] See Roger Morin, *Utilities' Cost of Capital* (Arlington, VA: PUR, 1984), p. 268.

1 Third, a utility's management must be granted a measure of discretion as to the type of
2 capital raised. Having a solid level of financial integrity can provide rate stability and other
3 benefits to customers.

4 **Q. Do you recommend that the Commission use the projected actual capital structure for**
5 **the Company as of the date that new rates are expected to go into effect?**

6 A. Yes, I do. The capital structure, as shown on **Exhibit JDM-7**, reflects the capitalization
7 that is expected at the time when new rates would go into effect.

8 **Q. What issues do you address pertaining to the cost of debt for DP&L?**

9 A. Regulated utilities generally use a mixture of debt and equity (and sometimes preferred
10 stock) to raise capital for their operations. The mixture of debt and equity represents
11 generally a desire on the part of a company's management to minimize the overall cost of
12 capital. The cost of debt, as such, is not generally a contentious aspect of regulated rate
13 cases, as it is customary to use a company's embedded—and hence observable—interest
14 costs on its outstanding long-term debt. I would also note that *Value Line* projects
15 generally that electric utilities will increase their equity ratios over the next few years.

16 **VIII. CONCLUSION**

17 **Q. What is your final recommendation for DP&L's rate of return on equity?**

18 A. My final recommended rate of return on common equity for DP&L is **11.30 percent**, which
19 is based on the average of my DCF and CAPM results for a proxy group of electric and
20 combination electric and gas utilities, as shown on **Exhibit JDM-7**.

21 **Q. Please summarize your conclusions as to the overall weighted average cost of capital**
22 **for the Company.**

23 A. I conclude that the overall cost of capital for the Company is **9.36 percent** and **9.24 percent**
24 for generation and distribution respectively, as shown on **Exhibit JDM-7**.

25 **Q. Does this conclude your direct testimony?**

26 A. Yes.

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Dr. Makholm concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries—those that operate networks (such as oil and gas pipelines, electricity transmission and gas distribution systems, telecommunications and water utility systems) and those operating infrastructure business at specific sites, such as airports, electricity generation plants, oil refineries, gas treatment plants and sewage treatment plants. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers, including the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies and Parliamentary panels abroad.

Dr. Makholm's clients in the United States include privately held utility corporations, public corporations and government agencies. Focusing mainly in the areas of gas and electric utilities, he has represented dozens of gas distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas producers. Dr. Makholm has also worked with many leading law firms engaged in natural gas and electricity issues.

Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
PROVIDENCE, RHODE ISLAND
Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY (SINCE 2000)

Before the Illinois Commerce Commission, Testimony on behalf of Northern Illinois Gas Company, Case No. 08-____. April 29, 2008. Subject: Cost of equity.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. April 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, Case No. 07-M-0906. January 31, 2008. Subject: Regulatory philosophy/ merger issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. January 14, 2008. Subject: Stand-alone costs and cost allocation issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No. 07-09016. January 11, 2008. Subject: Allocation of pipeline transport costs.

Before the Illinois Commerce Commission, Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. January 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Consolidated Edison Company of New York, Docket No. OA08-13-000. January 7, 2008. Subject: Planning and allocation of electric transmission costs.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. December 14, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the New Hampshire Public Service Commission, Docket No.. DE 07-064, invited appearance on an expert panel to present perspectives and answer questions on policies and practices regarding retail gas and electric distribution rate "decoupling." November 7, 2007.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-05019. May 15, 2007. Subject: Prudence of gas purchase costs.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., *et al.*, Debtors, Case No. 03-17949 (PCB) (Jointly Administered), April 20, 2007. Subject: Discount rate for contract rejection damages.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. April 19, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., et al., Debtors, Case No. 03-17949 (PCB) (Jointly Administered), March 23, 2007. Subject: Discount rate for contract rejection damages.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the United States District Court, District of Kansas, Expert Report on behalf of J.P.Morgan Trust Company, *et al.* in the matter of J.P. Morgan Trust Company, *et al.* V. Mid-America Pipeline Company, *et.al.*, Docket No. 05-CV-2231-CM/JPO. March 21, 2007. Title: "Harm to Farmland's Coffeyville Refinery Expert Report", by Jeff. D. Makholm.

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Before the Public Utilities Commission of the State of Hawaii, Supplemental Testimony on behalf of Hawaii Electric Light Company, Inc., Docket No. 05-0135. December 29, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of the State of Hawaii, Testimony on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386. December 22, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. December 1, 2006. Subject: Stand-alone costs and cost allocation issues.

Before the State of New Jersey Board of Public Utilities, Prepared Reply Testimony on behalf of Public Service Electric & Gas, OAL Docket No. PUC1191-06 and BPU Docket No. EO05111005. November 3, 2006. Subject: Unregulated contract prices for telecommunication conduit rental contracts.

Before the State of New Jersey Board of Public Utilities, Rebuttal Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, October 10, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of the State of Alaska, Docket No. OR05-2-001, August 11, 2006. Subject: Relative risk and capital structure for the Trans Alaska Pipeline System (TAPS).

Before the Maine Public Utilities Commission, Response to the Bench Analysis on behalf of Central Maine Power Company, Docket 2005-729. May 19, 2006. Subject: Specification of productivity offset for price cap formula.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 05-12001. May 17, 2006. Subject: Prudence of the company's gas hedging strategy.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company (Gas Division, WestPac Gas), Docket No. 06-0516. May 15, 2006. Subject: Prudence of the company's gas hedging strategy.

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, March 29, 2006. Subject: Cost of Capital.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Nevada Power Company, Docket No.06-01016. January 17, 2006. Subject: Prudence of the company's gas hedging costs.

Before the New Brunswick Board of Commissioners of Public Utilities, Rebuttal Testimony on behalf of the Public Intervenor, Board Reference 2005-002. December 30, 2005 (original filing), January 23, 2006 (updated filing). Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No.05-12001. December 1, 2005. Subject: Prudence of the company's gas hedging costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No.05-9016. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Nevada Power Company, Docket No.05-9017. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Ohio, Supplemental Testimony on behalf of The Dayton Power and Light Company. Case No. 05-276-EL-AIR. September 26, 2005. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. May 12, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Reply Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). April 12, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No 05-1028. April 12, 2005. Subject: Prudence of gas purchase costs.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. April 5, 2005. Subject: Cost of capital.

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Before the Public Utilities Commission of Nevada, Testimony on behalf of Nevada Power Company. Docket No. 04-11028. November 10, 2004. Subject: Examination of the prudence of gas purchase and hedging decision in the Company's 2004 deferral case.

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Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 03-10001 and 03-10002. February 5, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

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Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. September 2, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

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Before Federal Energy Regulatory Commission, Testimony on behalf of PPL Wallingford Energy LLC. Case No: ERO3-421-000. January 9, 2003. Subject: Cost of equity.

Before the State of New Hampshire Public Utilities Commission, Rebuttal Testimony on behalf of Kearsarge Telephone Company. Case No. DT 01-221. December 20, 2002. Subject: Rebuttal on cost of equity.

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Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, October 24, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, September 18, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the State of New York Public Service Commission, Prepared Rebuttal Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. September 12, 2001. Subject: Electric price protection plan

Before the State of Maine Public Utilities Commission, Joint Rebuttal Testimony on behalf of Community Service Telephone Company. September 6, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the Public Service Commission of the State of Missouri, Rebuttal Testimony on behalf of Gateway Pipeline Company. Case GM-2001-595. August 20, 2001. Subject: Acquisition of Capital Stock of Utilicorp Pipeline Systems, and connection.

Before the State of New York Public Service Commission, Prepared Direct Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. August 3, 2001. Subject: Electric price protection plan.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of the Association of Oil Pipe Lines. Case No: OR96-2-000. June 21. 2001. Subject: Light-handed regulation of oil pipeline tariffs.

Before the Illinois Commerce Commission, Direct Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, June 1, 2001. Subject: Economic pricing for unbundled retail distribution services.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Florida Power & Light Co. May 31, 2001. Subject: Pricing of transmission services.

Before the Public Utility Commission of the State of Oregon, Rebuttal Testimony on behalf of Portland General Electric Company. May 21, 2001. Subject: Cost of capital.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of Community Service Telephone Company. April 4, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the State of New Jersey Board of Public Utilities, Cross-Answering Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564 , March 26, 2001. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

Before the Indiana Utility Regulatory Commission, Testimony on behalf of Tipton Telephone Company, Inc, February 23, 2001 (with C. Zarkadas). Subject: Cost of capital.

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PARTIAL LIST OF CLIENTS SERVED WORLDWIDE

ELECTRIC UTILITY

AEP Energy Services, Inc
Alberta Power Limited
American Electric Power Company
Atlantic Electric Company
Boston Edison Company
Central Hudson Gas and Electric
Central Maine Power Company
Central Power & Light Company
Commonwealth Edison Company (Unicom/Exelon)
Commonwealth Energy System
Consolidated Edison Company of New York, Inc
Conowingo Power Company
Duquesne Light Company
Edison Electric Institute
Entergy Gulf States, Inc
Florida Power and Light Company
Green Mountain Power Company
Long Island Lighting Company
Massachusetts Municipal Wholesale Electric Company
Massachusetts Electric Company
Nantahala Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power
Ohio Power Company
Orange & Rockland Utilities
Pennsylvania Power and Light Company
Pennsylvania Power Company
Philadelphia Electric Company
PJM electricity transmission owners
Public Service Company of New Hampshire
Public Service Company of New Mexico
Public Service Electric and Gas Company
Portland General Electric Company
Reliant Energy HL&P
Rochester Gas and Electric Corp.
Sierra Pacific Power Corporation
Southwest Electric Power Company
Southwestern Public Service Company
Tampa Electric Company
Texas-New Mexico Power Company
TXU Electric Company
United Illuminating Company
UtiliCorp Networks Canada
Virginia Electric and Power Company
West Penn Power Company
West Texas Utilities Company
Western Massachusetts Electric Co.

GAS UTILITY

ARKLA, Inc.
Atlanta Gas Light Company
Bay State Gas Company
Berkshire Gas Company
Blackstone Gas Company
Boston Gas Company
Bristol & Warren Gas Company
British Gas plc
Brooklyn Union Gas Company
Canadian Western Natural Gas
Chattanooga Gas Company
Colonial Gas Company
Commonwealth Gas Company
Connecticut Natural Gas Corp.
Consolidated Gas Supply Corp.
Elizabethtown Gas Company
Empire State Pipeline Company
ENAGAS (Spain)
EnergyNorth, Inc.
Essex County Gas Company
Fall River Gas Company
Fitchburg Gas & Electric Light Company
Gas and Fuel Corporation of Victoria
Gateway Pipeline Company
Granite State Gas Transmission, Inc.
Great Falls Gas Company
Holyoke, Mass. Gas & Electric Dept.
ICG Utilities (Ontario) Ltd.
KN Energy, Inc.
Middleborough Municipal Gas & Electric
National Fuel Gas Distribution Corp.
Natural Gas Corporation of New Zealand
Natural Gas Pipeline of America
Norwich Department of Public Utilities
Pacific Gas Transmission
Pemex Gas y Petroquímica Básica
Pennsylvania Gas and Water Company
Peoples Gas Light and Coke Company
Providence Gas Company
Southern Connecticut Gas Company
Southwest Gas Corporation
Transwestern Pipeline Company
Valley Gas Company
Washington Gas Light Company
Westfield Gas & Electric Light Dept.
Wisconsin Gas Company
Yankee Gas Services Company

PARTIAL LIST OF CLIENTS SERVED WORLDWIDE (CONT.)

TELEPHONE UTILITY

Centel Corporation
Chichester Telephone Company
Community Service Telephone Company
Continental Telephone Company of Illinois
General Telephone of Pennsylvania
General Telephone Company of Ohio
Kearsarge Telephone Company
Meriden Telephone Company
Pacific Bell Telephone Company
Tipton Telephone Company

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REGULATORY AND GOVERNMENT

Delaware Public Service Commission
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District of Columbia Public Service Commission
re: Potomac Electric Power Company
Washington Gas Light Company

Massachusetts Municipal Wholesale Electric Company

The Government of Chile
Gas industry regulations

The Government of Argentina
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The Government of Tanzania
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OTHER

Air New Zealand
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Jamaica Water Supply Company
Nucor Steel Corporation
Parsons Brinckerhoff Development Group

MEMBERSHIP IN PROFESSIONAL ORGANIZATIONS

The American Economic Association

Perspective

In Defense of the 'Gold Standard'

It is hard to foresee abandoning the discounted cash flow method relied upon so heavily for the past couple of decades.

By Jeff D. Makholm, Ph.D.

In the Feb. 15, 2003, edition of *Public Utilities Fortnightly*, Jonathan Lesser says that regulators need to rethink the traditional discounted cash flow (DCF) method for finding the cost of capital, or "at the very least, regulators should no longer rely solely on the DCF to set allowed returns."

This is an old issue. Lesser may (or may not) be aware that commissions in the United States have been searching for a way to streamline utilities' rate of return investigations for decades, and yet they still generally rely on the DCF method. For practical purposes, this is unlikely to change in the United States, despite the recommendations of those like Dr. Lesser and those before him who have recommended a different path.

The topic of the fair rate of return continues to be a vexing part of utility regulation. No one, anywhere, has yet devised a way to make the process agreeable. Why has the process been so difficult?

It is not possible to assess the adequacy of particular rate of return techniques without looking more broadly at how those techniques fit into the larger regulatory process.

The Current State of the Ratemaking Process

The current ratemaking process is tortuous and often unpleasant, for commissions, utilities and ratepayers. A Mississippi Supreme Court Judge captured a quintessential aspect of the process when he said:

"Utility rate litigation has become sport, a vent for passions. Each contest satiates for the moment, then fuels the appetite for further fight. We shrink from the thought of the season ending."[1]

That was true when this quote was written(1989), and it's true today. It is not, however, the direct consequence of the actions of attorneys, consultants, intervenors, commissioners, or staff that creates this problem. It is the regulatory process that makes it almost inevitable that rate case issues are subject to repeated, increasingly detailed, and costly inquiry. This regulatory framework not only provides a questionable incentive for efficient operation for utilities, it also is expensive. Both of these features create an environment for contentiousness over the issue of rate of return.

Incentives for Efficiency

The current regulatory framework sets efficient utility behavior as its goal but always seems to fail to reach it. Why?

First, the definition of efficiency is elusive. It is difficult for regulators, consultants, accountants, and sometimes the company itself, to distinguish efficient behavior from inefficient. While measures of utility efficiency have been developed (e.g., labor productivity, total factor productivity, number of complaints, etc.), there always will be a large component of utility performance that falls outside of what can be objectively analyzed and measured.

This inability to effectively monitor performance means that hands-on regulators are doomed to steer a course between dangerous rocks and a powerful whirlpool. By steering away from the pure cost-plus contract, where ratepayers face runaway costs, regulators risk being drawn into periodic and sometimes large disallowances that threaten utility financial integrity and ratepayer security.

Second, this failure to have objective standards for efficiency is compounded by "information" and/or "agency" problems. It is difficult for outsiders or those without years of experience to evaluate the decisions of utility managers (or to even know what those managers do). Utility managers are likely always to be more informed than regulators or their staffs regarding the company they manage. It is terribly difficult to monitor utility decisions when the information flow is so incomplete or when regulators must rely on utility managers to volunteer information on poor decisions.

Third, and most pertinent to rate of return, objective confirmable standards may never exist to confirm estimates of costs. In the case of rate of return, there is no way of knowing what the true fair rate of return is (or was), even in hindsight. All we ever have is forward-looking rate of return estimates and historical earned returns. This is not so for any other cost category. »

For example, estimates of depreciable lives can always be updated by experience with actual capital assets. The same is true with estimates of marginal cost—experience will tend to confirm better estimates in the future. But the "true" rate of return is always unverifiable.

Cost of the Process

The second major problem with the current ratemaking process is its cost. Not only does the process serve us poorly, it is very expensive. There have been attempts by the Federal Energy Regulatory Commission (FERC) and the New York Public Service Commission to regularize the rate of return component of rate cases. Both have failed to do so. The Generic Financing Proceeding in New York, conducted in the early 1990s, despite its staggering price tag in professional fees and the loss of productive time for utility and commission employees, failed, as FERC's did before it, to streamline the process.

The Evolution of Rate of Return Analysis

The fair rate of return became a hotly contested issue in the early 1970s, when the electric utility business was undergoing the "triple threat" of unprecedented inflation, rapid fuel price increases, and the end of decades of impressive technical advances in lower-cost generating technology. The DCF and capital asset pricing model (CAPM) methods got their start at this time and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions.

Improvements in the theoretical accuracy, objectivity, and reliability of these methods have come at a snail's pace and generally address only minor issues. For example, more than 20 years ago, arguments raged in rate of return proceedings over whether to use forward-looking, rather than historical, information in the financial models used to calculate the rate of return.[2]

A dozen years ago, the argument had progressed to smaller issues (in terms of the potential effect on rate of return) such as the ex-dividend date adjustments and the inclusion into the sustainable growth model of an allowance for the selling of stock at prices above book value.

Most rate case issues, with the exception of major cost items, are capable of being settled in relatively short order.

Meanwhile, every seeming advance in rate of return analysis is followed by a retreat. Historically based "comparable earnings" analyses, presumed dead after the advent of the well-grounded financial theories like DCF and CAPM, have risen from the ashes of past regulation to be considered a genuine rate of return technique. Furthermore, sound theoretical models are often sacrificed on the altar of *ad hoc* adjustments, when staff or company analysts scramble to move a model's results down or up for a never-ending variety of reasons that are impossible to verify empirically or theoretically.

It remains true today that most rate case issues, with the exception of major cost items, are capable of being settled in relatively short order except for rate of return, where the old issues are continually battled out. So, what are the options to reduce the scope of the interminable fighting over rate of return?

Previous Attempts to Standardize Rate of Return Analysis

Rate of return techniques abound, but very little time and attention is paid to determining which have practical usefulness. The theories that underlie the empirical determination of the cost of capital have become increasingly arcane and irrelevant to the practical ratemaking world, where common sense, believability, and simplicity determine which techniques an administrative law judge or commissioner will use to set the allowed return. At times it seems that the goals of theoretical accuracy and usefulness are mutually exclusive attributes in rate of return models used in utility rate cases.

Although much time is spent discussing the technical aspects of rate-of-return techniques, we never get around to establishing criteria for determining whether they are any good in real rate cases.

Both FERC and the New York Public Service Commission tried to regularize rate of return investigations by concentrating on the method (or methods) involved. FERC's generic rate-of-return process, begun in 1986, ended in a fog of adjustments for a seemingly endless procession of "special cases." The 1991-1993 Generic Financing Proceeding in New York, which was designed to produce an objective standard for setting the fair rate of return, has not streamlined the process. On the contrary, the outcome of that generic proceeding (which was never adopted by the commission in New York) continues to haunt New York rate cases like a dusty book of alchemy from ancient times—understandable only to those who witnessed its creation.

The methods adopted in New York, for example, were overly complex, »

ad hoc, and led inevitably to further expensive fights and litigation when the financial winds shifted. Both proceedings consumed a great amount of time, effort, and expense in an attempt to establish generic rules in the first place. In a larger sense, there was so much ground to make up that the proceedings could not be said to have been worthwhile—even if durable rules had come out of them.

Why the Appeal of the DCF?

The DCF method has endured for most of the past two decades for three basic reasons:

- It rests on a solid, straightforward theoretical base;
- It capitalizes on the depth of U.S. capital markets—meaning analysis can use "proxy groups" of publicly traded companies in the same industry to manage the variability of individual company DCF calculations; and
- It makes use of company growth projections from disinterested *industry analysts—a key attribute* for a method to gauge the opportunity cost of capital in the mind of investors.[3]

It is difficult to overstate the practical importance of these three attributes of the DCF method. The CAPM, by comparison, is abstruse as a piece of theory. Further, because most of the components of the calculation are common to all companies (i.e., the risk-free rate and the market risk premium), the CAPM cannot make use of the law of large numbers. That is to say, the problems associated with which risk-free rate to pick, or which market risk premium to adopt, hinder the result, no matter how many companies the calculations are performed upon. Finally, the CAPM has no tie to disinterested company analysts that not only reflect, but also shape, the opinions of investors. It is thus no surprise that the CAPM is vastly less popular among U.S. regulatory commissions as a rate of return method.

The other methods mentioned by Lesser have more debilitating attributes still. The comparable earnings method is generally irrelevant to investor expectations, to the extent that is uses historical earnings data. Risk premium analyses take the cost of debt as given (easy to do, as debt costs are observable), but struggle perpetually with how to calculate the equity risk premium. To the extent that the equity risk premium uses historical data, it is again generally irrelevant to investor expectations. If it derives the premium by reference to a prospective cost of capital method (like the DCF or CAPM), then it is simply not an independent method at all.

In the context of U.S. rate cases, the DCF method's attributes are magnified, as are the drawbacks of the other methods. The nature of the methods to resolve disputes in U.S. utility rate cases is at least as important as the theoretical attributes of the particular methods employed. "Informationally demanding" methods, like the CAPM, do not stand a chance as a method for resolving conflict between contending parties compared to the "informationally simple" methods, with tangible parameters, like the DCF.

As a result, Lesser's "more methods" recommendation is a dead end. He is correct to point out the greater variability in estimates now than in years past. Mergers, the advent of holding companies, and deregulation all have served to shrink the number of companies to which the DCF analysis can be applied. Nevertheless, the marginal reduction in proxy group size or stability in the past decade does not countervail the three underlying reasons why the DCF is so popular.

Perhaps the best way to deal with the perpetual contention surrounding the rate of return is not to repudiate the overwhelmingly preferred DCF method or pretend that more methods and more investigation might work, but rather to shrink the scope for contention surrounding the issue.

Reducing Rate of Return Conflicts

One tried and tested method to reduce rate of return contention is to turn to alternative regulatory frameworks that either eliminate the need to set the fair rate of return or that lengthen the time between rate cases. There are at least three potential ways to reduce rate of return contention.

Unbundling and deregulation. The airline industry, trucking industry, gas production and transport, and electricity generation capacity once fell under comprehensive rate of return regulation but were subsequently deregulated either partially or fully.

Unbundling and deregulation reduces rate of return battles because they reduce the size of the asset base subject to rate regulation. In other words, with a smaller pie, there should be less incentive to fight. For example, in what I called the "contractualization" of the U.S. interstate gas transport industry, the determination of the fair rate of return has become increasingly less important as contractual obligations between gas transporters and distributors replace traditionally regulated rates. And if rate regulation ends completely, then the reason for the fight over rate of return vanishes.

Reduce the number of contested issues. Permitting cost pass-throughs like fuel adjustment clauses, weather adjustments, revenue decoupling mechanisms, and other techniques that remove attrition,[4] reduces the need for filing frequent rate »

cases because it eliminates factors outside of management's control.

Institutionalized price cap regulation. Price cap regulation, or performance-based regulation (PBR), allows prices to be indexed to both the general price level and durable industry-wide productivity trends. As such, it has reduced the frequency of contested price-setting cases where rate of return is an issue. However, PBR regulation does not prevent rate of return from arising as an issue when it does appear.

In conclusion, contention over the fair rate of return is an unavoidable component of utility regulatory oversight, even under alternative frameworks. Efforts to make the process objective and mechanical are futile as an administrative and practical matter. The only realistic way to reduce rate of return contention over the long term is to unbundle and deregulate utility functions (like gas transmission), and lengthen the time between rate cases by instituting PBR or other progressive regulatory programs.

For the rate of return contention that does exist, it is hard to foresee abandoning the DCF as the gold standard relied upon so heavily by U.S. commissions and utilities for the past couple of decades. From the perspective of dispute-resolution techniques and simple efficiency, the DCF—despite its difficulties—retains attributes that other rate of return methods just cannot match. ■

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Endnotes

1. Justice Robertson, *Mississippi Supreme Court, State of Mississippi et al, v. Mississippi Public Service Commission and Mississippi Power Company*, Jan. 4, 1989.
2. In reality, this issue has, alas, never gone away entirely.
3. Regulatory commissions outside the United States do not have the luxury of either such deep capital markets (with many publicly traded companies in the same industry) or the associated vast array of stock analysts. As a result, they use other methods, but with less robust results and often more extensive contention.
4. Attrition occurs when earnings are depressed over time because the marginal cost of new plant and equipment exceeds average costs and average prices.

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THE DERIVATION OF THE DCF MODEL

The DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962 (*The Investment, Financing and Valuation of the Corporation*, published by Irwin). In his original version, the "Gordon" model was:

$$P_0 = \frac{D_0}{k_e - g} \tag{3.1}$$

where:

P_0 = price of stock

D_0 = last dividend

k_e = cost of equity

g = growth rate of dividends

Professor Gordon derived his model assuming *continuous* compounding of dividends, using integral calculus. The "continuous" version of the DCF model is thus:

"Continuous" DCF Model

$$k_e = \frac{D_0}{P_0} + g \tag{3.2}$$

Since dividends are not normally received continuously and, therefore, cannot be continuously reinvested by the investor, subsequent writers (including Gordon himself) modified this initial approach to reflect annual dividend payments. The resulting modification is known as the "periodic" DCF model.

Since all DCF models relate the current price of a stock to an expected stream of future dividend payments, the basic "periodic" DCF model starts with the equation:

$$P_0 = \frac{D_1}{(1+k_e)} + \frac{D_2}{(1+k_e)^2} + \ldots + \frac{D_n}{(1+k_e)^n} + \ldots$$

where:

$P_0 =$ current stock price **(3.3)**

$D_1, \ldots, D_n =$ last dividend

If dividends are assumed to grow at a constant growth rate, g, we can rewrite equation (2.3) as:

$$P_0 = \frac{D_0(1+g)}{(1+k_e)} + \frac{D_0(1+g)^2}{(1+k_e)^2} + \ldots + \frac{D_0(1+g)^n}{(1+k_e)^n} + \ldots$$

where:

$D_0(1+g) = D_1$ **(3.4)**

$D_0 =$ last dividend payment

Equation (2.4) can be solved for k_e to obtain:

$$k_e = \frac{D_0(1+g)}{P_0} + g. \qquad \textbf{(3.5)}$$

This is the familiar equation for the DCF cost of equity, which is the model most commonly used in regulatory proceedings. The model assumes annual dividend payments and a constant annual growth rate. However, if dividends are paid quarterly, rather than annually, equation (2.5) can understate the return that equity investors require. Because of the time value of money, annual and quarterly dividend payments are not perfect substitutes. Therefore:

$$P_0 = D_{04}\frac{(1+g)^{.25}}{(1+k_e)^{.25}} + D_{04}\frac{(1+g)^{.50}}{(1+k_e)^{.50}} + D_{04}\frac{(1+g)^{.75}}{(1+k_e)^{.75}} + \ldots$$

where:

D_{04} = last quarterly dividend payment (3.6)

This DCF model would be an acceptable quarterly model except for the assumption that dividend payments grow each quarter. A variant of equation (2.6) which allows the quarterly dividends to increase, if at all, only once a year is shown in equation (2.7).

$$P_0 = \frac{D_{01}(1+g)}{(1+k_e)^{.25}} + \frac{D_{02}(1+g)}{(1+k_e)^{.5}} + \frac{D_{03}(1+g)}{(1+k_e)^{.75}} + \frac{D_{04}(1+g)}{(1+k_e)^{1.00}} + \frac{D_{01}(1+g)^2}{(1+k_e)^{1.25}} + \frac{D_{02}(1+g)^2}{(1+k_e)^{1.5}} + \frac{D_{03}(1+g)^2}{(1+k_e)^{1.75}} + \frac{D_{04}(1+g)^2}{(1+k_e)^{2.00}} + \frac{D_{01}(1+g)^3}{(1+k_e)^{2.25}} + \frac{D_{02}(1+g)^3}{(1+k_e)^{2.5}} + \ldots \quad (3.7)$$

where:

$D_{01}, \ldots, D_{04}$ = last four previous quarterly dividend payments.

This model is a more accurate extension of equation (2.6). The DCF formula presented as equation (2.7) can be reduced to:

$$k_e = \frac{D_{01}(1+k_e)^{.75} + D_{02}(1+k_e)^{.5} + D_{03}(1+k_e)^{.25} + D_{04}}{P_0}(1+g) + g \qquad (3.8)$$

In this model, the last four dividend payments may be specified explicitly. It is also assumed that each of the dividend payments is reinvested to years' end at the cost of equity. The model is, therefore, attractive for the purpose of calculating the cost of equity capital for firms which pay dividends quarterly.

The quarterly model, however, is not necessarily the correct model to apply to a utility's rate base. Because equity investors, with an opportunity cost equal to the effective annual cost of capital, may be presumed to be able to reinvest quarterly dividends at that same rate, the dividend reinvestment portion of the effective annual cost of equity shown in (2.8) is:

$$\frac{D_{01}[(1+k_e)^{.75} - 1] + D_{02}[(1+k_e)^{.5} - 1] + D_{03}[(1+k_e)^{.25} - 1]}{P_0}(1+g) \qquad (3.9)$$

Subtracting the return due to reinvestment from (2.8) leaves:

$$k_{e(nominal)} = k_{e(quarterly)} - \frac{D_{01}[(1+k_e)^{.75} - 1] - D_{02}[(1+k_e)^{.50} - 1] + D_{03}(1+k_e)^{.25} - 1]}{P_0}(1+g)$$

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

where:

$$D_1 = D_0(1+g) \qquad (3.10)$$

$$= [D_{01} + D_{02} + D_{03} + D_{04}](1+g)$$

Therefore, the return to apply to rate base with quarterly dividend payments is equal to the annual form of the DCF model.

DAYTON POWER AND LIGHT COMPANY

DERIVATION OF SUSTAINABLE GROWTH WITH EXTERNAL STOCK FINANCING

The sustainable growth formula is:

$$g = B * R$$

where:

B = the expected retention rate **(4.1)**

R = the rate of return expected to be earned on common equity.

An assumption of the standard DCF model is that only one source of equity financing occurs, specifically the retention of earnings. That is, current dividends, D, are set at a constant percentage of normalized earnings, where normalized earnings are the expected rate of return on equity, R, applied to the current book value, V. Therefore, the sustainable growth formula is:

$$B = 1 - \frac{D}{(R_{av} * V)} \qquad \textbf{(4.1)}$$

and the long-run sustainable growth rate is:

$$g = B * R_{av}$$

$$= \left(1 - \frac{D}{(R_{av} * V)}\right) * R_{av} \qquad \textbf{(4.2)}$$

$$= R_{av} - \frac{D}{V}$$

where:

D = dividends declared per share, estimate

V = year-end book value per share, estimate

R_{av} = return on average equity

However, the issuance and sale of new common equity can also increase earnings and dividends. Thus, the growth rate must be expanded to allow for continuous new equity financing. In the expanded formula, two activities are recognized: (1) investment decisions that earn the rate of R_{av}, and (2) stock financing operations which earn the rate $S*V$.

The sustainable growth would then be:

$$g = B * R_{av} + S * V \tag{4.3}$$

where:

B = the fraction of earnings to be expected to be retained

R_{av}= the expected return on average equity

S = funds raised from the sale of stock as a fraction of existing common equity

V = the fraction of funds raised from the sale of stock that accrues to shareholders at the start of the period.

The $S*V$ term is a measure of the impact on growth of the sale of stock at prices above or below book value. If stocks are sold at a price that exceeds book value, a portion of the funds goes to shareholders, whereas, if stocks are sold at a price less than book value, stockholders' equity will be diluted. For instance, given a market-to-book ratio of 1.3, abstracting from market pressure and selling costs, 23 percent of the funds raised in the issuance (1 – 1 / 1.3) go to increasing the value of stockholders' pre-existing shares (V = 0.23). If the new issuance is equal to 10 percent of the existing equity (S = 0.1), then $S*V$ = 0.023, meaning that ignoring the $S*V$ term in such a circumstance would understate k_e (cost of equity) by 2.3 percent.

Note: The expanded growth rate (and hence, the expanded DCF formula) will reduce to the standard version either when: (1) the company does not regularly sell new stock, S = 0, or (2) the new stock is sold at a price that equals book value, V = 0.

In calculating the sustainable growth rate, g, in this testimony, the S and V terms were calculated for the comparable group of companies as follows:

$$V = 1 - \left(\frac{BVPS}{P_{stock}}\right) \tag{4.4}$$

where:

P_{stock} = closing stock price

$BVPS$ = year-end book value per share

and,

$$S = \frac{Issuance_t}{CEQ_{t-1}} \tag{4.5}$$

where:

$Issuance_t$ = net proceeds the issuance of common stock in time period, t

CEQ_{t-1} = total common equity in previous time period, t-1

An average S was multiplied by V. This product was then added to $B * R$ to yield g, the sustainable growth rate.

Note: See Roger A. Morin, *Utilities' Cost of Capital*, (Arlington, Virginia: Public Utilities Reports, Inc., 1984), 99-102, for a full discussion of the DCF model considering external financing.

SELECTION OF THE COMBINATION GAS AND ELECTRIC COMPANIES

The initial pool of combination gas and electric utilities used to select a proxy group consisted of 58 electric utilities as reported in the *Value Line Investment Survey*:

Allegheny Energy Corp.
ALLETE
Alliant Energy Corp.
Ameren Corp.
American Electric Power
Aquila, Inc.
Avista Corp.
Black Hills Corp.
CenterPoint Energy
Central Vermont Public Service
CH Energy Group
Cleco Corp.
CMS Energy Corp.
Consolidated Edison
Constellation Energy Group, Inc.
Dominion Resources, Inc.
DPL, Inc.
DTE Energy Co.
Duke Energy Corp.
Edison International
El Paso Electric
Empire District Electric
Energy East Corp.
Entergy Corp.
Exelon Corp.
FirstEnergy Corp.
FPL Group, Inc.
Great Plains Energy Inc.
Hawaiian Electric
IDACORP, Inc.
Integrys Energy Group, Inc.
MDU Resources Group, Inc.
MGE Energy, Inc.
NiSource Inc.
Northeast Utilities
NSTAR
OGE Energy Corp.
Otter Tail Corp.
Pepco Holdings, Inc.
PG&E Corp.
Pinnacle West Capital
PNM Resources
Portland General Electric
PPL Corp.
Progress Energy
Public Service Enterprise Group
Puget Energy, Inc.
SCANA Corp.
Sempra Energy
Sierra Pacific Res.
Southern Co.
TECO Energy, Inc.
UIL Holdings Corp.
UniSource Energy
Vectren Corp.
Westar Energy
Wisconsin Energy
Xcel Energy, Inc.

From this collection, those utilities that met the following criteria were included in the proxy group: 1) total capitalization less than $10 billion; 2) at least 85 percent of total operating revenue from utility operations; 3) not involved in a merger; and 4) dividend stability.

First, if a company's total capitalization was greater than $10 billion, it was eliminated from the proxy group. This criterion is targeted at selecting a proxy group of an average size similar to DP&L. Those eliminated include:

Ameren Corp.
American Electric Power
CenterPoint Energy
Consolidated Edison
Constellation Energy Group, Inc.
Dominion Resources, Inc.
DTE Energy Co.
Edison International
Entergy Corp.
Exelon Corp.
FirstEnergy Corp.
FPL Group, Inc.
NiSource, Inc.
PG&E Corp.
PPL Corp.
Progress Energy
Public Service Enterprise Group
Sempra Energy
Southern Co.
Xcel Energy, Inc.

Second, if a company's operating revenues from regulated electricity and gas were less than 85 percent of its total revenues, the company was eliminated. Those companies eliminated under this criterion are:

Black Hills Corp.
CH Energy Group
Great Plains Energy, Inc.
Hawaiian Electric
Integrys Energy Group, Inc.
MDU Resources Group, Inc.
OGE Energy Corp.
Otter Tail Corp.
Pepco Holdings, Inc.
Pinnacle West Capital
PNM Resources
SCANA Corp.
TECO Energy, Inc.
Vectren Corp.

Third, those companies that were currently or had recently been involved in merger activity were eliminated from the proxy group.

Energy East Corp.
Puget Energy, Inc.

Fourth, stability in dividend payments is required for inclusion in the proxy group. I define stable dividend payments as those that either remain constant or increase over 10 quarters. To determine this, I examined the *Value Line* company summaries as well as *Value Line*'s dividend estimates over 10 quarters for the remaining companies. The following companies were excluded from the proxy group:

Allegheny Energy Corp.
Aquila, Inc.
CMS Energy Corp.
Duke Energy Corp.
El Paso Electric
Portland General Electric
Sierra Pacific Res.

The fifteen combination gas and electric companies that are included in my proxy group are:

ALLETE
Alliant Energy Corp.
Avista Corp.
Central Vermont Public Service
Cleco Corp.
DPL, Inc.
Empire District Electric
IDACORP, Inc.
MGE Energy, Inc.
Northeast Utilities
NSTAR
UIL Holdings Corp.
UniSource Energy
Westar Energy
Wisconsin Energy

Dayton Power and Light
Comparable Group

	Company	Ticker Symbol	Revenue from Regulated Operations[1] (Percent)	Total Capitalization[2] ($ millions)	Equity Ratio (Percent)
	(a)		(b)	(c)	(d)
1	ALLETE	ALE	85.99%	1,153.5	64.40%
2	Alliant Energy	LNT	90.57%	4,329.5	61.9%
3	Avista Corp.	AVA	90.87%	1,548.9	59.0%
4	Cen. Vermont Pub. Serv.	CV	100.00%	311.8	60.6%
5	Cleco Corp.	CNL	95.88%	1,780.5	56.7%
6	DPL Inc.	DPL	87.39%	2,437.1	35.8%
7	Empire Dist. Elec.	EDE	99.34%	1,081.1	49.9%
8	IdaCorp	IDA	99.55%	2,364.2	51.1%
9	MGE Energy	MGEE	99.04%	660.1	64.8%
10	Northeast Utilities	NU	98.65%	5,974.6	48.8%
11	NSTAR	NST	95.75%	4,248.2	40.1%
12	UIL Holdings	UIL	99.90%	943.6	49.2%
13	UniSource Energy	UNS	95.67%	2,214.9	31.2%
14	Westar Energy	WR	100.00%	3,738.3	48.9%
15	Wisconsin Energy	WEC	99.69%	6,302.1	49.2%
	Average		95.9%	$2,605.9	51.4%

[1] From SEC Filings 10-K and Annual Reports. Data for 2007.
[2] Source: *The Value Line Investment Survey*: May 30, 2008 (*Edition 1*), June 27, 2008 (*Edition 5*), August 8, 2008 (*Edition 11*)

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Dayton Power and Light
Weighted Average Cost of Capital

Dayton Power and Light - Distribution

	Capital Structure (Amount)	Capital Structure (Percent)	Average Cost (Percent)	Weighted Cost (Percent)
Debt[1]	$759,404,859	34.35%	5.86%	2.01 %
Preferred Stock[2]	$20,755,037	0.94%	4.18%	0.04 %
Equity	$1,430,469,308	64.71%	11.30%	7.31 %
WACC	**$2,210,629,204**	100.00 %		**9.36 %**

Dayton Power and Light - Generation

	Capital Structure (Amount)	Capital Structur (Percent)	Average Cost (Percent)	Weighte Cost (Percent)
Debt[1]	$759,404,859	34.35%	5.49%	1.89 %
Preferred Stock[2]	$20,755,037	0.94%	4.18%	0.04 %
Equity	$1,430,469,308	64.71%	11.30%	7.31 %
WACC	**$2,210,629,204**	100.00 %		**9.24 %**

Cost of Equity Summary

DCF Cost of Capital[3]	11.00 %
CAPM[4]	
Method 1	10.26 %
Method 2	12.94 %
Average CAPM	11.60 %
Average of DCF and CAPM	11.30 %

[1] See: Exhibit JDM-18.
[2] See: Exhibit JDM-19.
[3] See: Exhibit JDM-14.
[4] See: Exhibit JDM-16.

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Dayton Power and Light
Comparable Group
Spot - Date Adjusted Stock Prices

	Company	Ticker Symbol	Ex-Dividend Date [1] Last [a]	Ex-Dividend Date [1] Next [b]	Stock Price Date [c]	Days to Ex-Div Date [d]	Percent Days Expired [e]	Last Dividend [f] ($/Share)	Adjusted Dividend [g]=[e]*[f] ($/Share)	Closing Stock Price [h] ($)	Adjusted Stock Price [i]=[h]-[g] ($)
1	ALLETE	ALE	13-May-08	13-Aug-08	04-Aug-08	9	90.00	0.430	0.39	39.07	38.68
2	Alliant Energy	LNT	29-Jul-08	27-Oct-08	04-Aug-08	84	6.67	0.350	0.02	31.39	31.37
3	Avista Corp.	AVA	20-May-08	18-Aug-08	04-Aug-08	14	84.44	0.165	0.14	22.21	22.07
4	Cen. Vermont Pub. Serv.	CV	29-Jul-08	27-Oct-08	04-Aug-08	84	6.67	0.230	0.02	21.83	21.81
5	Cleco Corp.	CNL	31-Jul-08	29-Oct-08	04-Aug-08	86	4.44	0.225	0.01	24.73	24.72
6	DPL Inc.	DPL	13-May-08	13-Aug-08	04-Aug-08	9	90.00	0.275	0.25	24.92	24.67
7	Empire Dist. Elec.	EDE	28-May-08	27-Aug-08	04-Aug-08	23	74.44	0.320	0.24	20.17	19.93
8	IdaCorp	IDA	1-Aug-08	30-Oct-08	04-Aug-08	87	3.33	0.300	0.01	29.46	29.45
9	MGE Energy	MGEE	28-May-08	26-Aug-08	04-Aug-08	22	75.56	0.355	0.27	34.27	34.00
10	Northeast Utilities	NU	28-May-08	27-Aug-08	04-Aug-08	23	74.44	0.213	0.16	26.13	25.97
11	NSTAR	NST	8-Jul-08	6-Oct-08	04-Aug-08	63	30.00	0.350	0.11	31.66	31.56
12	UIL Holdings	UIL	10-Jun-08	10-Sep-08	04-Aug-08	37	58.89	0.432	0.25	30.85	30.60
13	UniSource Energy	UNS	9-May-08	7-Aug-08	04-Aug-08	3	96.67	0.240	0.23	29.6	29.37
14	Westar Energy	WR	5-Jun-08	3-Sep-08	04-Aug-08	30	66.67	0.290	0.19	22.04	21.85
15	Wisconsin Energy	WEC	12-May-08	12-Aug-08	04-Aug-08	8	91.11	0.270	0.25	44.24	43.99

Notes:
[1] ((90-Days to Ex-Div Date)/90))*100
[2] Yahoo! Finance Research, *http://finance.yahoo.com*. Closing prices on August 4, 2008.

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Dayton Power and Light
Comparable Group
Dividends

	Company	Recent Quarterly Dividends Paid Per Share (D_0)				Annual Dividend Sum	Growth [1] Rate	Expected Dividend
		Q_1 ($/Share)	Q_2 ($/Share)	Q_3 ($/Share)	Q_4 ($/Share)	D_0 ($/Share)	g (Percent)	D_1 ($/Share)
1	ALLETE	0.410	0.410	0.430	0.430	1.680	3.45	1.738
2	Alliant Energy	0.318	0.318	0.350	0.350	1.336	5.46	1.409
3	Avista Corp.	0.150	0.150	0.165	0.165	0.630	9.30	0.689
4	Cen. Vermont Pub. Serv.	0.230	0.230	0.230	0.230	0.920	2.59	0.944
5	Cleco Corp.	0.225	0.225	0.225	0.225	0.900	11.30	1.002
6	DPL Inc.	0.260	0.260	0.275	0.275	1.070	8.28	1.159
7	Empire Dist. Elec.	0.320	0.320	0.320	0.320	1.280	8.78	1.392
8	IdaCorp	0.300	0.300	0.300	0.300	1.200	4.56	1.255
9	MGE Energy	0.355	0.355	0.355	0.355	1.420	5.63	1.500
10	Northeast Utilities	0.200	0.200	0.200	0.213	0.813	8.48	0.882
11	NSTAR	0.325	0.325	0.350	0.350	1.350	6.76	1.441
12	UIL Holdings	0.432	0.432	0.432	0.432	1.728	4.00	1.797
13	UniSource Energy	0.225	0.225	0.240	0.240	0.930	2.60	0.954
14	Westar Energy	0.270	0.270	0.270	0.290	1.100	3.26	1.136
15	Wisconsin Energy	0.250	0.250	0.270	0.270	1.040	8.68	1.130

Notes:
[1] Simple Average of *Value Line* EPS, *Value Line* BR+SV, and Zacks earnings growth rates.

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Dayton Power and Light
Comparable Group
Sustainable Growth Method

	Company	R Estimated Return on Common Equity [1] (Percent)	D_e Estimated Dividend Per Share [1] ($)	V_e Estimated Book Value Per Share [1] ($)	V Book Value/Share 2007 ($)	V Book Value/Share 2006 ($)	R_{av} Return on Average Equity [2] (Percent)	B [3] (Percent)	B*R [4] (Percent)	S*V Average[5] (Percent)	B*R+S*V (Percent)
1	ALLETE	9.5	2.00	32.50	24.11	21.90	9.96	38.19	3.80	0.46	4.26
2	Alliant Energy	10.0	1.92	31.95	24.30	22.83	10.31	41.72	4.30	0.90	5.20
3	Avista Corp.	8.5	1.15	21.25	17.27	17.46	8.45	35.98	3.04	0.43	3.48
4	Cen. Vermont Pub. Serv.	7.5	0.92	22.10	18.43	17.70	7.65	45.59	3.49	(0.37)	3.12
5	Cleco Corp.	11.0	1.50	21.75	16.85	15.22	11.56	40.34	4.66	1.62	6.29
6	DPL Inc.	19.0	1.34	12.50	7.69	6.30	20.89	48.68	10.17	(1.38)	8.78
7	Empire Dist. Elec.	10.5	1.40	18.25	16.04	15.49	10.68	28.19	3.01	1.65	4.66
8	IdaCorp	7.5	1.20	28.90	26.79	25.77	7.65	45.69	3.49	0.32	3.81
9	MGE Energy	12.0	1.50	21.05	19.49	17.89	12.51	43.06	5.39	1.97	7.36
10	Northeast Utilities	9.5	1.03	25.80	18.65	18.14	9.63	58.55	5.64	1.22	6.86
11	NSTAR	14.5	1.85	20.75	15.95	14.82	15.03	40.69	6.12	0.07	6.19
12	UIL Holdings	10.5	1.73	21.05	18.55	18.53	10.51	21.77	2.29	0.40	2.69
13	UniSource Energy	7.5	1.20	22.75	19.54	18.59	7.69	31.38	2.41	0.34	2.75
14	Westar Energy	8.5	1.32	22.75	19.14	17.62	8.85	34.45	3.05	0.76	3.81
15	Wisconsin Energy	12.0	1.60	36.00	26.50	24.70	12.42	64.22	7.98	0.06	8.04
	Average:										**5.15 %**

Source: *The Value Line Investment Survey*: May 30, 2008 (*Edition 1*), June 27, 2008 (*Edition 5*), August 8, 2008 (*Edition 11*)

Notes:
[1] 2011-2013 estimated return on common equity, dividends per share, and book value per share as reported in *Value Line*.
[2] Rav=R*[(2*V01)/(V01+V00)]. In this formula, current data (on the end-of-year book values for 2006, and 2007) is used as a factor to transform the end-of-year 2011-2013 projected *Value Line* book values to a mid-year book value.
[3] B=1-(De/(Rav*Ve)).
[4] B*R=B*Rav=(Rav-De/Ve).
[5] S*V equals the four year average of S, multiplied by current V, where S = annual growth rate of common shares outstanding and V = fraction of new funds provided that accrues to original shareholders.

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Dayton Power and Light
Comparable Group
S and V Estimation

Company	Growth Rate of Common Shares Outstanding (S) 2003 (a)	2004 (b)	2005 (c)	2006 (d)	2007 (e)	Average S [1] (f)	V [2] (g)	S*V (h)=[(f)*(g)]
1 ALLETE	N/A [3]	N/A	0.0135	0.0100	0.0132	0.0122	0.3767	0.0046
2 Alliant Energy	0.2022	0.0431	0.0112	(0.0078)	(0.0497)	0.0398	0.2253	0.0090
3 Avista Corp.	0.0062	0.0027	0.0025	0.0807	0.0076	0.0199	0.2175	0.0043
4 Cen. Vermont Pub. Serv.	0.0060	0.0322	0.0074	(0.1751)	0.0109	(0.0237)	0.1552	(0.0037)
5 Cleco Corp.	0.0030	0.0517	0.0075	0.1516	0.0412	0.0510	0.3184	0.0162
6 DPL Inc.	0.0000	0.0000	0.0081	(0.1138)	0.0051	(0.0201)	0.6883	(0.0138)
7 Empire Dist. Elec.	0.1068	0.0288	0.0148	0.1599	0.1111	0.0843	0.1953	0.0165
8 IdaCorp	0.0084	0.1012	0.0104	0.0227	0.0328	0.0351	0.0903	0.0032
9 MGE Energy	0.0438	0.1118	0.0029	0.0259	0.0462	0.0461	0.4268	0.0197
10 Northeast Utilities	0.0011	0.0104	0.0198	0.1720	0.0129	0.0433	0.2819	0.0122
11 NSTAR	0.0000	0.0045	0.0024	0.0000	0.0000	0.0014	0.4945	0.0007
12 UIL Holdings	0.0029	0.0063	0.0129	0.0222	0.0068	0.0102	0.3937	0.0040
13 UniSource Energy	0.0063	0.0139	0.0178	0.0092	0.0037	0.0102	0.3346	0.0034
14 Westar Energy	0.0186	0.1811	0.0094	0.0063	0.0923	0.0616	0.1239	0.0076
15 Wisconsin Energy	0.0207	(0.0122)	(0.0001)	(0.0001)	(0.0003)	0.0016	0.3976	0.0006

Source: *The Value Line Investment Survey* : May 30, 2008 (*Edition 1*), June 27, 2008 (*Edition 5*), August 8, 2008 (*Edition 11*)

Notes:
[1] Average common shares outstanding growth rate for 2003-2007.
[2] V = (1-(2007 Book Value per Share/Average Stock Price)). See also Exhibit JDM-10, footnote 6.
[3] N/A=Not Available

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Dayton Power and Light

Comparable Group

Growth Rate Estimates

	Company	Value Line EPS [1] 2007	Value Line EPS [1] 2011-13	Estimated VL Growth [2]	Zacks Growth [3]	B*R+S*V Growth	Average Growth [4]
		($)	($)	(Percent)	(Percent)	(Percent)	(Percent)
1	ALLETE	3.08	3.25	1.08	5.00	4.26	3.45
2	Alliant Energy	2.69	3.30	4.17	7.00	5.20	5.46
3	Avista Corp.	0.72	1.75	19.44	5.00	3.48	9.30
4	Cen. Vermont Pub. Serv.	1.49	1.65	2.06	N/A[5]	3.12	2.59
5	Cleco Corp.	1.32	2.50	13.62	14.00	6.29	11.30
6	DPL Inc.	1.81	2.35	5.36	10.70	8.78	8.28
7	Empire Dist. Elec.	1.09	2.00	12.91	N/A	4.66	8.78
8	IdaCorp	1.86	2.25	3.88	6.00	3.81	4.56
9	MGE Energy	2.27	2.75	3.91	N/A	7.36	5.63
10	Northeast Utilities	1.59	2.40	8.58	10.00	6.86	8.48
11	NSTAR	2.07	3.00	7.70	6.40	6.19	6.76
12	UIL Holdings	1.87	2.20	3.30	6.00	2.69	4.00
13	UniSource Energy	1.55	1.75	2.46	N/A	2.75	2.60
14	Westar Energy	1.84	1.95	1.17	4.80	3.81	3.26
15	Wisconsin Energy	2.84	4.25	8.40	9.60	8.04	8.68
	Average:			**6.93 %**	**7.95 %**	**5.22 %**	**6.41 %**

Notes:

[1] Source: *The Value Line Investment Survey*: May 30, 2008 (*Edition 1*), June 27, 2008 (*Edition 5*), August 8, 2008 (*Edition 11*)

[2] ([2011-2013 EPS Estimate]/[2007 EPS]^0.20-1)*100.

[3] Estimated Long Term EPS Growth Rate of next 5 yrs as reported by Zacks Growth Rate in its Full Company Reports.

[4] Simple average of Estimated Value Line growth, Zacks growth, and B*R+S*V growth.

[5] N/A-Not Available

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Dayton Power and Light
Equity Issuance Expense [4]

SEC Filing Date	Number of Shares Issued (No.)	Price/Share ($)	Proceeds ($)	Per Share Underwriting Discounts & Commissions ($)	Total Underwriting Discounts & Commissions ($)	Net Proceeds [1] ($)	Estimated Company's Expenses ($)	Selling & Issuance Costs [2] (Percent)
12/15/1970	1,000,000	23.750	23,750,000	0.70	700,000	23,050,000	85,500	3.31 %
9/7/1972	1,300,000	22.875	29,737,500	0.70	910,000	28,827,500	102,515	3.40
8/29/1974	1,700,000	12.125	20,612,500	0.94	1,598,000	19,014,500	128,000	8.37
6/19/1975	1,500,000	16.000	24,000,000	0.77	1,155,000	22,845,000	122,263	5.32
8/25/1977	2,500,000	20.250	50,625,000	0.59	1,475,000	49,150,000	176,000	3.26
9/28/1978	2,500,000	17.000	42,500,000	0.53	1,325,000	41,175,000	146,000	3.46
7/16/1980	3,000,000	14.750	44,250,000	0.54	1,605,000	42,645,000	105,000	3.86
5/12/1981	3,100,000	12.875	39,912,500	0.57	1,767,000	38,145,500	134,000	4.76
3/11/1982	4,000,000	15.700	62,800,000	0.54	2,160,000	60,640,000	130,000	3.65
4/5/1994	3,200,000	20.375	65,200,000	0.60	1,920,000	63,280,000	200,000	3.25
Average					**1,461,500**	**38,877,250**	**132,928**	**4.27 %**
Borun and Malley [3]								**5.50**
Average Expense								**4.88**
Issuance Expense Adjustment								**95.12 %**

Notes:
[1] Net Proceeds = Proceeds - Total Underwriting Discounts & Commissions.
[2] Selling & Issuance Costs = (Total Underwriting Discounts & Commissions + Estimated Company's Expenses)/Proceeds.
[3] Victor M. Borun and Susan L. Malley, "Total Flotation Costs for Electric Company Equity Issues."
[4] Issuance data is derived from Company.

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Dayton Power and Light
Comparable Group
DCF Cost of Equity

	Company	Dividend [1] Yield (Percent)	Growth [2] Rate, g (Percent)	Adjusted [3] Stock Price, P_0 ($)	Stock Price [4] S&I Adjusted ($)	Unadjusted [5] ROE, k_e Before S&I (Percent)	Change (Percent)	S&I [6] Adjusted ROE (Percent)
1	ALLETE	4.49	3.45	38.68	36.79	7.94	0.23	8.17
2	Alliant Energy	4.49	5.46	31.37	29.84	9.95	0.23	10.18
3	Avista Corp.	3.12	9.30	22.07	20.99	12.42	0.16	12.58
4	Cen. Vermont Pub. Serv.	4.33	2.59	21.81	20.75	6.92	0.22	7.14
5	Cleco Corp.	4.05	11.30	24.72	23.51	15.36	0.21	15.56
6	DPL Inc.	4.70	8.28	24.67	23.47	12.98	0.24	13.22
7	Empire Dist. Elec.	6.99	8.78	19.93	18.96	15.77	0.36	16.13
8	IdaCorp	4.26	4.56	29.45	28.01	8.82	0.22	9.04
9	MGE Energy	4.41	5.63	34.00	32.34	10.05	0.23	10.27
10	Northeast Utilities	3.40	8.48	25.97	24.70	11.88	0.17	12.05
11	NSTAR	4.57	6.76	31.56	30.01	11.33	0.23	11.57
12	UIL Holdings	5.87	4.00	30.60	29.10	9.87	0.30	10.17
13	UniSource Energy	3.25	2.60	29.37	27.93	5.85	0.17	6.02
14	Westar Energy	5.20	3.26	21.85	20.78	8.46	0.27	8.73
15	Wisconsin Energy	2.57	8.68	43.99	41.85	11.25	0.13	11.38
	Average					**10.78 %**	**0.22 %**	**11.00 %**

Notes:
[1] Forward Annual Dividend per Share (Df) = $\{[D_0*(1+g)]/P_0\}$
[2] Simple Average of Value Line, Zacks earnings and BR+SV growth rates.
[3] Spot-Date Adjusted Stock Price.
[4] Adjusted Price=0.9512*Ex-Div Price. Adjustment based on flotation cost of 4.88 percent.
[5] Not adjusted for selling and issuance expenses.
[6] ROE adjusted by selling and issuance expenses.

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Dayton Power and Light
Comparable Group
Capital Asset Pricing Model (CAPM)

No.	Company	30-Year T-Bond Return (Rf)[1]	Beta Value Line[2]	Market Risk Premium: Top-Down DCF - 30 Yr T-Bond Return[3,4]	CAPM Cost of Equity[5]: Top-Down DCF - 30 Yr T-Bond Return
		%		%	%
1	ALLETE	4.65	0.90	9.49	13.19
2	Alliant Energy	4.65	0.80	9.49	12.24
3	Avista Corp.	4.65	0.90	9.49	13.19
4	Cen. Vermont Pub. Serv.	4.65	1.10	9.49	15.09
5	Cleco Corp.	4.65	1.00	9.49	14.14
6	DPL Inc.	4.65	0.80	9.49	12.24
7	Empire Dist. Elec.	4.65	0.85	9.49	12.72
8	IdaCorp	4.65	0.90	9.49	13.19
9	MGE Energy	4.65	0.95	9.49	13.67
10	Northeast Utilities	4.65	0.75	9.49	11.77
11	NSTAR	4.65	0.80	9.49	12.24
12	UIL Holdings	4.65	0.90	9.49	13.19
13	UniSource Energy	4.65	0.75	9.49	11.77
14	Westar Energy	4.65	0.90	9.49	13.19
15	Wisconsin Energy	4.65	0.80	9.49	12.24
	Average		**0.87**		**12.94**

Notes:
[1] From *The Value Line Selection and Opinion*, August 8, 2008.
[2] Source: *The Value Line Investment Survey: May 30, 2008 (Edition 1)*, June 27, 2008 *(Edition 5)*, August 8, 2008 *(Edition 11)*
[3] *The formula used is Risk Premium = [[Do*(1+g)]+g] - Rf*
[4] Vanguard Long term Estimated Annual Growth Rate (S&P 500) https://personal.vanguard.com/us/StocksEarningsSec?Ticker=GAS (8/4/2008)
[5] Cost of Equity = Rf + Beta (RM - Rf), where Rf is the return on the 30-year Treasury Bond, and (RM - Rf) is the market premium computed as described in footnotes [3] and [4].

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Dayton Power and Light
Comparable Group
Capital Asset Pricing Model (CAPM)

No.	Company	30-Year T-Bond Return (Rf)[1]	Beta Value Line[2]	Market Risk Premium (I/S)[3] 1926-2006	CAPM Cost of Equity[4] Value Line, (I/S) 1926-2006
		%		%	%
1	ALLETE	4.65	0.90	6.42	10.43
2	Alliant Energy	4.65	0.80	6.42	9.79
3	Avista Corp.	4.65	0.90	6.42	10.43
4	Cen. Vermont Pub. Serv.	4.65	1.10	6.42	11.71
5	Cleco Corp.	4.65	1.00	6.42	11.07
6	DPL Inc.	4.65	0.80	6.42	9.79
7	Empire Dist. Elec.	4.65	0.85	6.42	10.11
8	IdaCorp	4.65	0.90	6.42	10.43
9	MGE Energy	4.65	0.95	6.42	10.75
10	Northeast Utilities	4.65	0.75	6.42	9.47
11	NSTAR	4.65	0.80	6.42	9.79
12	UIL Holdings	4.65	0.90	6.42	10.43
13	UniSource Energy	4.65	0.75	6.42	9.47
14	Westar Energy	4.65	0.90	6.42	10.43
15	Wisconsin Energy	4.65	0.80	6.42	9.79
	Average		**0.87**		**10.26**

Notes:
[1] From *The Value Line Selection and Opinion*, August 8, 2008.
[2] Source: *The Value Line Investment Survey: May 30, 2008 (Edition 1)*, June 27, 2008 *(Edition 5)*, August 8, 2008 *(Edition 11)*
[3] Computed as the difference between the arithmetic averages of annual returns over the period 1926-2006 from [a] large company stocks, and [b] long-term government bonds, from Ibbotson Associates, 2007 Yearbook.
[4] Cost of Equity = Rf + Beta (RM - Rf), where Rf is the return on the 30-year Treasury Bond, and (RM - Rf) is the market premium computed as described in footnote [3].

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Dayton Power and Light
DCF of the S&P 500

Dividend Yield S&P 500 [1]	2.27	%
Growth Rate S&P 500 [2]	11.48	%
DCF S&P 500 [3]	14.01	%
Issuance Expense[4]	0.13	%
Total DCF S&P 500[5]	14.14	%

Notes:

[1] From Standard & Poors S&P 500 statistics overview (Accessed 8/4/08), available at: http://www2.standardandpoors.com/portal/site/sp/en/us/page.topic/indices_500/2,3,2,2,0,0,0,0,0,5,11,0,0,0,0,0.html

[2] First Call Long term Estimated Annual Growth Rate (S&P 500) https://personal.vanguard.com/us/StocksEarningsSec?Ticker=DPL (Accessed August 6 2008)

[3] DCF=(Div Yield*(1+Growth))+Growth

[4] Average Issuance Expense: Calculated in Exhibit 10.12

[5] Total DCF = ((Div Yield S&P 500)*(1+Growth Rate S&P 500)/(1-Average Issuance Expense)) + Growth Rate S&P 500

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Dayton Power & Light Company

Gas & Electric Rate Cases in Other Jurisdictions January 2007-June 2008

Company	Date	Return on Equity (%)
Oklahoma Gas and Electric Co.	1/5/2007	10.00
Puget Sound Energy Inc.	1/5/2007	10.40
Metropolitan Edison Co.	1/11/2007	10.10
Pennsylvania Electric Co.	1/11/2007	10.10
Wisconsin Public Service Corp	1/11/2007	10.90
Portland General Electric Co.	1/12/2007	10.10
Wisconsin Power and Light Co	1/19/2007	10.80
Pacific Gas and Electric Co.	3/21/2007	NA
Rockland Electric Company	3/22/2007	9.75
Appalachian Power Co.	5/15/2007	10.00
Aquila Inc.	5/17/2007	10.25
Aquila Inc.	5/17/2007	10.25
Union Electric Co.	5/22/2007	10.20
Monongahela Power Co.	5/22/2007	10.50
Nevada Power Co.	5/23/2007	10.70
AEP Texas North Co.	5/24/2007	NA
Public Service Co. of NH	5/25/2007	9.67
Entergy Arkansas Inc.	6/15/2007	9.90
PacifiCorp	6/21/2007	10.20
Appalachian Power Co.	6/22/2007	10.50
Arizona Public Service Co.	6/28/2007	10.75
El Paso Electric Co.	7/3/2007	NA
Granite State Electric Company	7/12/2007	9.67
Delmarva Power & Light Co.	7/19/2007	10.00
Potomac Electric Power Co.	7/19/2007	10.00
Southwestern Public Service Co	7/27/2007	NA
Southern Indiana Gas & Elec Co	8/15/2007	10.40
Public Service Co. of OK	10/9/2007	10.00
Orange & Rockland Utlts Inc.	10/17/2007	9.10
Electric Transmission Texas	10/31/2007	9.96
Kansas City Power & Light	11/20/2007	NA
Cheyenne Light Fuel Power Co.	11/29/2007	10.90
Wisconsin Power and Light Co	11/29/2007	NA
Kansas City Power & Light	12/6/2007	10.75
PPL Electric Utilities Corp.	12/6/2007	NA
AEP Texas Central Co.	12/13/2007	9.96
South Carolina Electric & Gas	12/14/2007	10.70
Madison Gas and Electric Co.	12/14/2007	10.80
Avista Corp.	12/19/2007	10.20
Bangor Hydro-Electric Co.	12/20/2007	10.20
Duke Energy Carolinas LLC	12/20/2007	11.00
Pacific Gas and Electric	12/21/2007	11.35
San Diego Gas & Electric	12/21/2007	11.10
Southern California Edison	12/21/2007	11.50
PacifiCorp	12/28/2007	10.25
Georgia Power Co.	12/31/2007	11.25
Northern States Power Co-WI	1/8/2008	10.75
Wisconsin Electric Power Co.	1/17/2008	10.75
Connecticut Light & Power Co.	1/28/2008	9.40
Potomac Electric Power Co.	1/30/2008	10.00
Central Vermont Public Service	1/31/2008	10.71
Interstate Power & Light	2/6/2008	11.70
Idaho Power Co.	2/28/2008	NA
Fitchburg Gas & Electric Light	2/29/2008	10.25
PacifiCorp	3/12/2008	10.25
Consolidated Edison Co. of NY	3/25/2008	9.10
Virginia Electric Power	3/31/2008	12.12
MDU Resources Group Inc.	4/23/2008	10.25
Public Service Co. of NM	4/24/2008	10.10
Hawaiian Electric Co.	5/1/2008	10.70
UNS Electric Inc.	5/27/2008	10.00
Idaho Power Co.	5/30/2008	NA
Consumers Energy Co.	6/10/2008	10.70
Central Maine Power	6/12/2008	NA
MidAmerican Energy	6/16/2008	11.70
Appalachian Power Co.	6/26/2008	10.50
Sierra Pacific Power Co.	6/27/2008	10.60
Average		10.42

Source: Regulatory Research Associates

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Dayton Power and Light Company
Embedded Cost of Long-Term Debt

Date of Long-Term Debt: June 30, 2008
Type of Filing: Original
Work Paper Reference No(s).: WPD-2.1, WPD-2.2, WPD-2.3

Line No.	Debt Issue Type, Coupon, Rate	Date Issued (Mo/Day/Yr)	Maturity Date (Mo/Day/Yr)	Principle Amount	Face Amount Outstanding	Unamort (Discount) or Premium	Unamort Debt Expense	Unamort Gain or (Loss) On Reacquired Debt	Carrying Value	Annual Interest Cost**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I = E + F - G + H)	(J)
				$	$	$	$	$	$	$
1	First Mortgage Bonds:									
2										
3	FMB 10.70% SERIES	8-01-75	8-01-05	45,000,000	-	-	-	-	-	-
4	FMB 5.125% SERIES	9-30-03	09-30-13	470,000,000	470,000,000	(954,923)	2,320,824	-	466,724,253	24,711,452
5	FMB 6.35% SERIES *	4-15-77	4-15-07	25,000,000	-	-	-	-	-	-
6	FMB 12-1/8% SERIES	12-01-79	12-01-09	65,000,000	-	-	-	(379,590)	(379,590)	267,951
7	PCB 4.70 KY	8-17-05	1-01-28	35,275,000	35,275,000	-	624,697	-	34,650,303	1,689,961
8	PCB 4.80 OH AIR	8-17-05	1-01-34	137,800,000	137,800,000	-	2,191,158	-	135,608,842	6,700,328
9	PCB 4.80 OH H2O	8-17-05	1-01-34	41,300,000	41,300,000	-	791,948	-	40,508,052	2,013,457
10	FMB 16-3/4% SERIES	3-01-82	3-01-12	60,000,000	-	-	-	(1,285,980)	(1,285,980)	346,781
11	FMB 8.40% SERIES	12-01-92	12-01-22	225,000,000	-	-	-	-	-	-
12	FMB 6.40% SERIES A & B	9-29-92	8-15-27	60,100,000	-	-	-	-	-	-
13	FMB 6.50% SERIES	11-24-92	11-15-22	48,000,000	-	-	-	-	-	-
14	FMB 8.15% SERIES	1-14-93	1-15-26	226,000,000	-	-	-	(8,557,974)	(8,557,974)	487,866
15	FMB 7-7/8% SERIES	2-11-93	2-15-24	220,000,000	-	-	-	(7,800,211)	(7,800,211)	499,214
16	PCB 4.80 OH FGD	9-13-06	9-01-36	100,000,000	100,000,000	-	1,687,121	-	98,312,879	4,859,898
17	PCB Var OH AIR (held in trust 6/3	11-15-07	11-01-40	-	-	-	49,035	-	(49,035)	49,864
18										
19	Other Long-Term Debt:									
20										
21	OAQDA 6.10% SERIES	9-01-95	9-01-30	110,000,000	-	-	-	-	-	-
22	Logicalis Capital Lease	12-31-04	12-31-07	612,061	-	-	-	-	-	-
23	VISTA Capital Lease	12-31-02	9-01-10	4,276,385	1,673,320	-	-	-	1,673,320	66,833
24										
25	TOTALS				786,048,320				759,404,859	41,693,695
26										
27	***EMBEDDED COST OF LONG-TERM DEBT FOR GENERATION***									5.490%
28										
29	**EMBEDDED COST OF LONG-TERM DEBT FOR DISTRIBUTION*** **									5.864%
30										
31	^1 Line 22 Column J / Column I									
32	^2 Excludes Pollution Control Bonds and Vista Capital Lease from calculation									
33	* Sinking Fund issue.									
34	** Annualized interest expense plus (or minus) amortization of discount or									
35	premium plus amortization of issue costs minus (or plus) amortization									
36	of gain (or loss) on reacquired debt.									
37	*** Embedded cost of long-term debt for distribution excludes the cost of pollution bonds.									

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

Dayton Power and Light Company
Embedded Cost of Preferred Stock

Case No. 08-1094-ES-SSO
Exhibit JDM-19

Date of Preferred Stock: June 30, 2008
Type of Filing: Original
Work Paper Reference No(s).:

Line No.	Dividend Rate Type, Par Value	Date Issued (Mo/Day/Yr)	Dollar Amounts Outstanding at Par Value	Premium or (Discount)	Issue Expense	Gain or (Loss) on Reacquired Stock*	Net Proceeds	Annual Dividends
	(A)	(B)	(C)	(D)	(E)	(F)	(G = C + D - E + F)	(H)
1	3.750% Series A $100 Par Value	6/01/47	9,328,000	-	-	-	9,328,000	349,800
2	3.750% Series B $100 Par Value	6/01/47	6,939,800	-	-	-	6,939,800	260,243
3	3.900% Series C $100 Par Value	6/01/50	6,583,000	-	-	-	6,583,000	256,737
4	7.480% Series D $100 Par Value	4/8/69	-	-	-	54,000	54,000	-
5	7.700% Series E $100 Par Value	3/23/71	-	-	-	(320,513)	(320,513)	-
6	7.375% Series F $100 Par Value	5/17/73	-	-	-	(365,970)	(365,970)	-
7	12.50% Series G $100 Par Value	10/30/74-4/30/75	-	-	-	-	-	-
8	8.625% Series H $100 Par Value	4/06/78-6/01/78	-	-	-	(247,775)	(247,775)	-
9	9.375% Series I $100 Par Value	5/16/79-8/08/79	-	-	-	(274,455)	(274,455)	-
10	11.60% Series J $100 Par Value	7/16/80	-	-	-	(941,050)	(941,050)	-
11								
12	TOTAL		22,850,800				20,755,037	866,780
13								
14	**DP&L EMBEDDED COST OF PREFERRED STOCK**							4.176%
15								

16 ^1 Line 12 Column H/Column G
*Source - General ledger balances at June 30, 2008.

Prepared by:
Jeff D. Makholm, Senior Vice President
National Economic Research Associates, Inc.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

CHAPTER II – Customer Conservation and Energy Management Programs

DIRECT TESTIMONY

OF TERESA F. MARRINAN

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

TERESA F. MARRINAN

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION 1

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III. CONCLUSION 4

1 I. **INTRODUCTION**

2 Q. **Please state your name and business address.**

3 A. My name is Teresa F. Marrinan. My business address is 1065 Woodman Drive, Dayton,
4 Ohio 45432.

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

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as a
7 Vice President, Commercial Operations.

8 Q. **How long have you been in your present position?**

9 A. I assumed my present position in August, 2007.

10 Q. **What are your responsibilities in your current position and to whom do you report?**

11 A. In my current position, I am responsible for the dispatch of DPL's generation fleet, its
12 fuel procurement and delivery, fuel and wholesale power contract administration, energy
13 and fuel trading activities, the market analytics function, DP&L's relationship with PJM
14 and the operation of two (2) unregulated subsidiary companies. I report to the Senior
15 Vice President of Generation and Marketing.

16 Q. **Will you describe briefly your educational and business background?**

17 A. I received a Bachelor of Science degree in Business Administration from the University
18 of Dayton in 1983 and an MBA from Xavier University in 1993. I joined DP&L in 1984
19 in the Company's Regulatory Area. I held various positions in the Regulatory area until
20 1993 when I transferred to System Operating. Since 1993, I have held various roles

1 including Energy Marketer, Risk Manager, Head Trader, Director, Managing Director
2 and my current position.

3 **Q. What is the purpose of this testimony?**

4 A. The purpose of this testimony is to support and explain the demand and energy savings
5 valuations utilized for the Total Resource Cost ("TRC") tests conducted by DP&L related
6 to the energy efficiency and demand response programs in this filing, and the demand
7 and energy savings valuations utilized for the Societal Benefits determinations conducted
8 by DP&L in this filing.

9 **Q. What Workpaper are you supporting?**

10 A. I am jointly supporting with Witness Bubp workpaper WPF-1. I sponsor the relevant
11 parts of WPF-1 dealing with the demand and energy savings valuations and Witness
12 Bubp is responsible for the estimated energy savings and demand reductions.

13 II. METHODOLOGY

14 **Q. Can you explain the methodology you used in determining the values for the**
15 **demand and energy savings included in Workpaper WPF-1?**

16 A. Yes. For each individual program, Witness Michaelson provided me with the estimated
17 energy savings divided into two blocks per month extended over 15 years. The blocks
18 were on-peak energy and off-peak energy to coincide with the commonly-traded market
19 products of the same definition. I determined the value of the savings by taking the
20 megawatt hours for each month and for each block, times the market price of power for
21 that month and for that block. The source I used for the market price of power was
22 DP&L's forward curve which was developed from broker quotes. These broker quotes

represent the bids and offers of market participants to buy and sell energy for future periods. Broker quotes were used in the analysis I am sponsoring for each year through 2012. Beyond 2012, I escalated the energy prices by 3.25%, consistent with the inflation rate used throughout this filing.

Witness Bubp provided peak energy demand reductions for each program. I multiplied those reductions against projected capacity prices at the time of the request. Because there are no forward capacity markets in PJM, DP&L acquired projected capacity prices from a third party consultant. The consultant, Charles River Associates, used its market knowledge and models to project the rate at which capacity prices will increase until they reach the fundamental price level of the cost of new generation. The PJM Base Residual Auctions ("BRA") have already been held through the 2011/2012 planning year. For years where the BRA has already occurred and DP&L's load responsibility had been set, I estimated the capacity value of these programs to be $0. The exception to the BRA rule is the capacity made available through the Direct Load Control programs, where a mechanism exists for DP&L to enlist this capacity into PJM's Demand Response program, which effectively reduces the Company's capacity obligation for the subsequent summer period.

Q. Is this approach reasonable?

A. Yes.

Q. Why?

A. For estimating the value of energy, using market values for the calculation of the benefits is, in my experience, common in the industry. Market prices provide an unbiased and

1 objective estimate of future benefits. For capacity valuation, where market prices do not
2 exist, I believe our consultant's fundamental supply/demand model is an accurate and fair
3 estimate of the value.

4 III. CONCLUSION

5 **Q. Please summarize your testimony.**

6 A. In summary, I estimated the value of demand and energy savings of each individual
7 demand side management program against market prices to arrive at the value of the
8 energy and demand for each program.

9 **Q. Does this conclude your direct testimony?**

10 A. Yes, it does.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

CHAPTER II – Customer Conservation and Energy Management Programs

DIRECT TESTIMONY

OF SCOTT R. MICHAELSON

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

SCOTT R. MICHAELSON

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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II. TRC TEST METHODOLOGY 2

III. TRC TEST PROGRAM COSTS 4

IV. TRC TEST PROGRAM BENEFITS 6

V. CONCLUSION 7

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott R. Michaelson. My business address is 1900 Dryden Rd, Dayton, Ohio 45439.

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

A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as a Business Representative.

Q. How long have you been in your present position?

A. I assumed my present position in April 2006. I worked most of the last nine years prior to that as a Rate Analyst in the Regulatory Operations department.

Q. What are your responsibilities in your current position and to whom do you report?

A. In my current position, I am responsible for developing energy efficiency and demand response programs to meet the targets set forth in Senate Bill 221, and for implementing those programs. I report to the Director responsible for DP&L's energy efficiency and demand response programs.

Q. Will you describe briefly your educational and business background?

A. I received a Bachelor of Science degree with majors in Mathematics and Business Administration from the College of Mount St Joseph in 1997. I also received a Master in Business Administration with a Finance concentration from the University of Dayton in 2000. I have been employed by DP&L since 1997.

Q. Have you previously provided testimony before the Public Utilities Commission of Ohio ("PUCO" or the "Commission"?

A. Yes. I have sponsored testimony before the PUCO in Case No. 05-717-EL-UNC.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to support and explain the Total Resource Cost ("TRC") tests conducted by DP&L related to the energy efficiency and demand response initiatives proposed in this filing. The TRC test is utilized as the methodology to determine the cost effectiveness of an energy efficiency measure. Measures that create more benefits than costs over the measure life are considered to be cost-effective.

Q. What Workpapers are you supporting?

A. I am supporting the workpapers related to the TRC test, WPG-1.18 through WPG-1.22.

II. TRC TEST METHODOLOGY

Q. Can you please describe DP&L's methodology used in conducting the TRC tests?

A. Yes. DP&L conducted TRC tests based on the California Standard Practice Manual. The TRC section of this manual is a widely-recognized and used description of the TRC test; indeed, it is used by the Commission's Staff. The methodology defined in that manual identifies the participant and the utility costs and benefits. Energy efficiency and demand response programs that create more benefits than costs over the measure life are considered to be cost effective. Relevant costs related to the programs are equipment costs including installation, operation and maintenance, and administration costs. Relevant benefits related to the programs are avoided supply costs, the reduction in

generation, transmission, distribution and capacity when load is reduced. The test results are calculated in Workpaper WPG-1.18 and summarized in SRM-Table 1.

Q. Did you consider all of the relevant components defined in the California Standard Practice Manual?

A. Yes. DP&L considered all of the components included in the model. However, several of the items were found to be not applicable for the purposes of the analysis and were not included. Items not included are costs resulting in the cost of additional supply when supply is increased or benefits for tax credits or for fuel substitution programs. These components were unnecessary or inapplicable to the programs considered.

Q. Can you explain how DP&L performed the final evaluation to determine the cost effectiveness of the programs and measures included in WPG-1.18?

A. Yes. DP&L took the net present value of the benefits divided by the net present value of the costs, which produced a ratio. Programs and measures with a ratio of greater than 1.0 are considered to be cost-effective and have been incorporated into DP&L's suite of energy efficiency and demand response programs.

Q. Are there any programs for which TRC test results have not been calculated?

A. Yes. DP&L did not calculate a TRC for the low-income, education or any of the pricing programs. The TRC test for the low-income program was omitted due to the charitable nature of this efficiency program. The test for the education program was omitted due to the difficulty in measuring the energy savings resulting from these efforts; however, DP&L believes that these efforts are an important part of its overall energy efficiency

strategy. Finally, the test for the pricing programs was omitted because the TRC test is not applicable to these types of programs.

III. TRC TEST PROGRAM COSTS

Q. What are the first-year participation levels for the programs and measures included in WPG-1.19?

A. The first-year participation level used for each of the programs is supported in Workpapers WPG-1.1 through WPG-1.5, WPG-1.7 and WPG-1.10 through WPG-1.12. When the first year of the program was not scheduled until after 2009, the first year for which the program is scheduled was used for the TRC test.

Q. Can you explain the methodology that DP&L used to determine the incremental cost of a program or measure?

A. Yes. The incremental cost of a measure is defined in two ways. For programs in which it is likely that an expense would have occurred regardless of DP&L's program, the incremental cost is the difference between the cost of the standard-efficiency equipment and the more energy-efficient equipment. An example would be a failed industrial motor. For programs where the expense would not have taken place but for the program, then the entire cost of the measure would be included in the incremental cost. An example would be the removal of an inefficient refrigerator. The sources used for incremental costs of a program or measure are identified in WPG-1.19.

Q. Did DP&L consider any ongoing expenses for any of the programs included in Workpaper WPG-1.19?

A. Yes. The residential and non-residential direct load control programs require DP&L to incur some O&M expense for replacement of failed thermostats.

Q. Can you explain what the Net to Gross ratios are and how they were applied in the calculations in the TRC tests?

A. Yes. The Net to Gross ("NTG") ratios provide a means of identifying both the level of participation that would have occurred absent the program, as well as the actions taken as a result of the program by customers who do not knowingly seek to participate in the program. These concepts are typically referred to as "free riders" and the "spillover effect." DP&L applied the NTG ratios to the incremental measure costs as well as to the program benefits. The resulting calculation approximates the results of DP&L's programs.

Q. How did DP&L determine the NTG ratios identified in Workpaper WPG-1.19?

A. DP&L used the NTG ratios published in the California Database of Energy Efficiency Resources ("DEER").

Q. Can you explain how the Marketing and Administration costs were derived?

A. Yes. The first-year Marketing and Administration cost was used for each of the programs supported in Workpaper WPG-1.21. When the first year of the program was not scheduled until after 2009, the first year for which the program is scheduled was used for the TRC test. One exception to this methodology is in the case of the Direct Load Control programs, which instead utilizes the 7-year average cost of customer acquisition for the purpose of this test.

Q. Can you explain how the Evaluation, Monitoring and Verification costs were derived?

A. Yes. The Evaluation, Monitoring and Verification ("EM&V") costs used for each of the programs are supported in Workpaper WPG-1.22. This workpaper utilizes the same methodology used in calculating the EM&V costs for the entire suite of programs in Workpaper WPG-1 on a program-specific basis in order to allocate those costs to the various programs. EM&V costs are allocated to the various programs by multiplying the expected budget of each program by 5%.

IV. TRC TEST PROGRAM BENEFITS

Q. What is the origin of the demand and energy savings related to the programs and measures included in Workpaper WPG-1.20?

A. The program-level demand and energy figures are supported in Workpapers WPG-1.1 through WPG-1.5, WPG-1.7 and WPG-1.10 through WPG-1.12. The measure-specific demand and energy savings figures came from the public filings of Duke Energy, Commonwealth Edison Company and Ameren. All per-measure demand and energy savings were then multiplied by the estimated level of participation for that measure.

Q. Can you explain how DP&L valued the demand and energy savings included as a benefit in Workpaper WPG-1.20?

A. Yes. DP&L reviewed each program or measure in order to estimate a load shape related to the demand and energy savings, as shown on SRM-Table 2. For example the residential lighting program would save energy on a year-round basis; however, an HVAC measure would provide energy savings primarily during the summer months.

Information on Table 2 summarizes the load shape used for the various measures. By identifying how a consumer uses energy related to the individual program or measure, DP&L determined the timing of the resulting savings. The time categories were broken into two blocks per month identified as on-peak and off-peak for a total of 24 categories per year as well as peak demand savings.

These estimates of demand and energy savings were extended over 15 years and were provided to DP&L's Commercial Operations group. Commercial Operations valued the estimated savings and provided forecast estimates of energy and capacity savings, included in Workpaper WPF-1. DP&L calculated the present value of the savings by applying the forecasted energy and capacity values to the demand and energy savings over the life of the measure.

Q. Can you describe how DP&L determined the expected life of the measures included in Workpaper WPG-1.20?

A. Yes. DP&L primarily used the California DEER as the source for expected measure lives. When data was not available within DEER, DP&L also relied on information available from the public filings of Duke Energy and of Commonwealth Edison Company.

Q. What discount rate did DP&L utilize in calculating the Net Present Value of program costs and benefits?

A. DP&L utilized the Weighted Average Cost of Capital calculated in Schedule D-1.

V. CONCLUSION

Q. Please summarize your testimony.

A. In summary, DP&L performed Total Resource Cost tests in accordance with the California Standard Practice Manual. The results of those TRC tests show that DP&L's Energy Efficiency and Demand Response programs are cost-effective, as indicated on SRM-Table 1.

Q. *Does this conclude your direct testimony?*

A. Yes, it does.

SRM - Table 1

Program Total Resource Cost Test Results

Residential Programs	Test Results
Lighting	4.9
HVAC Diagnostic and Tune-Up	1.5
HVAC Rebates	1.2
Appliance Recycling	2.0
Appliance Rebates	3.3
Direct Load Control	1.8
Non-Residential Programs	
Prescriptive Incentives	3.9
Custom Incentives	2.7
Direct Load Control	2.4

* Programs with a TRC test result greater than 1.0 are considered to be cost effective.

SRM - Table 2

Program Total Resource Cost Test Results

Residential Programs	Allocation of Savings
Lighting	Year Round
HVAC Diagnostic and Tune-Up	Summer Only
HVAC Rebates	Summer Only
Appliance Recycling	Year Round
Appliance Rebates	Year Round
Direct Load Control	Summer On-Peak
Non-Residential Programs	
Prescriptive Incentives	
Lighting Rebates	Year Round
Motors and Drives Rebates	Year Round
HVAC Rebates	Summer Only
Other Rebates	Average of Lighting/Motors/HVAC
Custom Incentives	Average of Lighting/Motors/HVAC
Direct Load Control	Summer On-Peak

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

BOOK II – Customer Conservation and Energy Management Programs

DIRECT TESTIMONY

OF SCOTT W. NIEMANN

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

SCOTT W. NIEMANN

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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I. INTRODUCTION AND QUALIFICATIONS 1

II. DISCUSSION OF RPM FORECAST 5

III. CONCLUSION 12

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name, title, and business address.

A. My name is Scott W. Niemann. I am a Principal of CRA International ("CRA"), an international economics, finance, and business consulting firm. My business address is 200 Clarendon Street, T-33, Boston, MA 02116.

Q. Please describe your professional and educational background and qualifications.

A. I am a member of the Energy and Environment Practice Group at CRA. The primary focus of my consulting is in the areas of wholesale electricity market analysis, electricity market design and restructuring, regulation, and business strategy in the increasingly competitive U.S. electricity industry. I have advised clients and conducted quantitative studies related to business and regulatory issues affecting wholesale markets for electric power, installed generating capacity, and operating reserves. My work has focused on a broad range of issues including resource adequacy, fuel markets, environmental regulations, market structure, locational marginal pricing, financial transmission rights, seams issues, and market power. I have conducted studies and made numerous presentations to utility and merchant power clients, rating agencies, state agencies and utility commissions, and the U.S. Department of Justice. I have been retained as an independent market expert both in support of asset transactions and in litigation and regulatory proceedings.

I have extensive experience conducting detailed wholesale market modeling and analysis using a broad range of market analysis tools. Over the past ten years, I have conducted or managed more than 50 modeling studies addressing financial performance of generating

assets, benefits of potential transmission upgrades, valuation of financial transmission rights, market power concerns, and economic damages. These studies have involved forecasting of market prices, cash flows for generating assets, and costs to utility customers, as well as cost-benefit analysis and measurement of ratepayer impacts.

Much of my work has focused on the markets administered by Regional Transmission Organizations ("RTOs") in the Midwest and Northeast US, including the PJM Interconnection ("PJM"). I have conducted numerous market modeling studies of the energy and capacity markets, including fundamental market price forecasts. I have developed detailed models of the capacity markets administered by each ISO, including the recently implemented Reliability Pricing Model ("RPM") for PJM and the Forward Capacity Market for ISO-NE. These models forecast market prices in light of both the economic fundamentals and detailed rules behind each market design. Recently, I have been actively involved in advising numerous market participants on the implications of these markets and the outlook for capacity prices.

Prior to joining CRA in 2001, I was a Principal Consultant in the Energy Economics Practice of PA Consulting Group. I hold a BA degree in Mathematics, Economics, and Political Science from the University of Kansas and MS and PhD degrees in Economics from the University of Wisconsin. My resume is attached as Exhibit SWN-1.

Q. What has been your role in the development and implementation of the RPM market?

A. I have been closely involved with the development and implementation of the RPM market over the last 2 years, both in development of the market design and in advising

45 market participants as the market has been implemented. I was one of two CRA
46 economists retained by a generation owner during the RPM settlement proceeding before
47 the Federal Energy Regulatory Commission (FERC). During this process, I followed
48 closely the development of the market design and market rules now included in the PJM
49 Tariff. Following the approval of the RPM Settlement Agreement by FERC, I have
50 advised several market participants, including both generation owners and load serving
51 entities, about the RPM market design and rules. Much of my work in this area has
52 focused on detailed aspects of the market rules and the implications of these rules for
53 generation portfolios and individual generating assets.

54 I have also been retained on numerous occasions as an independent market advisor
55 supporting asset transactions in PJM, including the acquisition or financing of several
56 assets that are expected to generate cash flows predominantly from the RPM market. In
57 this role, I have assisted market participants with their due diligence efforts, including
58 price forecasting and detailed review of the RPM market rules. I have also advised rating
59 agencies, equity investors, and lenders regarding the commercial implications of several
60 aspects of the RPM rules.

61 **Q. What are your responsibilities in preparing CRA's forecasts of RPM prices?**

62 A. I was the primary developer of CRA's RPM pricing model and oversee the preparation of
63 all forecasts, which are regularly provided to several CRA clients, including The Dayton
64 Power and Light Company ("DP&L"). I follow the RPM market and associated
65 regulatory developments closely, making sure that all relevant factors are reflected in the
66 RPM model. I routinely discuss the CRA forecasts with market participants and explain

67 the underlying fundamental drivers of the expected prices along with the risks and
68 uncertainties associated with the market.

69 **Q. What is the purpose of your testimony in this matter?**

70 A. It is my understanding that as part of this filing, DP&L has developed estimates of the
71 value of projected demand and energy savings programs, based in part on resulting
72 reductions in DP&L capacity obligation under the RPM market. In order to estimate the
73 value of the reduced RPM capacity obligation, DP&L relied in part on a forecast of RPM
74 capacity market prices provided by CRA. I have been asked by counsel for DP&L to
75 describe this market forecast, discuss the underlying methodology and assumptions, and
76 explain why it is an appropriate basis for calculating savings stemming from a reduction
77 in DP&L's capacity obligation.

78 **Q. What are your principal conclusions?**

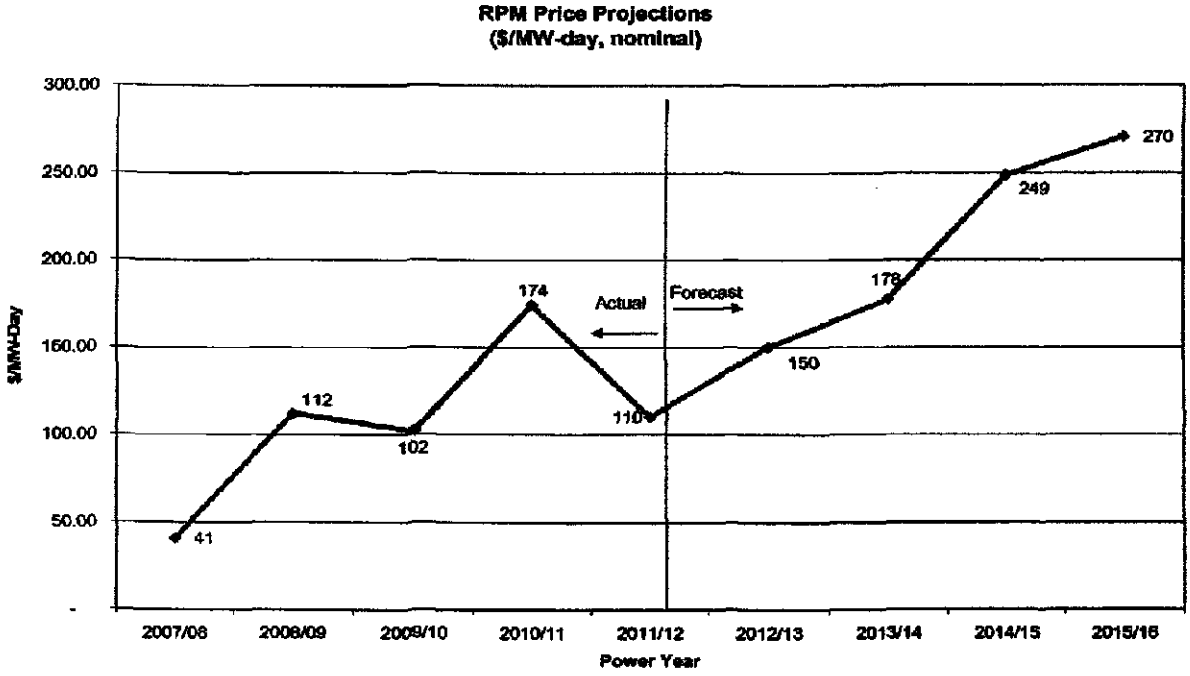
79 A. CRA's RPM price forecast represents a well-founded, independent projection of RPM
80 capacity market prices under the RPM rules and expected future market fundamentals. It
81 is appropriate for DP&L to use the forecast in valuing projected demand savings, as it
82 provides an unbiased view of future market capacity prices. The specific forecast used
83 by DP&L in its analysis was provided to DP&L in early July 2008 and represented
84 CRA's market view at the time. Additional information that has become available since
85 DP&L performed its valuation analysis, in early July 2008, confirms that the assumptions
86 underlying CRA's RPM forecast at that time were reasonable for the purpose of
87 projecting demand program savings.

II. DISCUSSION OF RPM FORECAST

Q. Can you provide a summary of the forecast used by DP&L in its calculations?

A. Yes. Figure 1 shows the RPM capacity price forecast used by DP&L in its valuation analysis. CRA routinely maintains a forecast of RPM prices, based on expected, forward-looking market conditions and RPM market rules. The forecast is derived from publicly-available information and CRA's proprietary model of the RPM market clearing and pricing mechanism. CRA provides this forecast to DP&L and other clients on a regular basis. Market participants have used the CRA forecasts in several commercial contexts, including auction and hedging strategy, bilateral trading of RPM capacity, asset valuation, asset transactions and financing and long-term planning.

Figure 1: Projected RPM Market Clearing Prices



The projections used in DP&L's calculations and shown in Figure 1 were prepared following the RPM auction for the 2011/2012 Delivery Year, conducted in May 2008. At

the time that DP&L prepared its projections in early July 2008, this forecast represented CRA's outlook for the RPM market, based on the most recent available public data at that time.

As shown in Figure 1, the forecast includes a gradual increase in the RPM clearing price for the Dayton zone, trending to a long-run equilibrium price set by the cost of building new generating capacity, net of expected earnings from the sale of energy and ancillary services by new resources. PJM currently has a capacity surplus relative to the required reserve margin, which was reflected in the relatively low clearing price that resulted from the RPM Base Residual Auctions ("BRA") for the 2011/12 Delivery Year.[1] As this surplus is absorbed by growth in the forecasted peak demand, prices are expected to increase. Once new capacity is needed to satisfy the growing regional needs, as determined by PJM's installed reserve margin requirement, the capacity price is expected to be set by the all-in cost of building new generating capacity, net of expected earnings from the sale of energy and ancillary services from new generating facilities, typically referred to as the net cost-of-new-entry ("Net CONE"). CRA's forecast indicates that RPM prices are likely to reach the level of Net CONE by the 2015/2016 delivery year.

Q. What methodology was used to develop this forecast?

A. CRA's model of the RPM market is built around replication and projection of the two key components of the RPM market: the PJM Variable Resource Requirement ("VRR")

[1] Under RPM, PJM conducts a centralized procurement of capacity to meet projected needs for each 12-month Delivery Year, running from June 1 to May 31 of the subsequent year. Three years in advance of each delivery year, PJM conducts a mandatory forward auction, called a Base Residual Auction, in which sufficient capacity to meet expected needs is procured, with the resulting costs allocated to load serving entities, such as DP&L.

121 "demand curve," and an offer curve, which is composed of supply offers from all
122 available capacity resources. The VRR curve is designed to allow the market to clear
123 with slightly more or less capacity than PJM's target reserve margin, with prices
124 increasing for quantities below the target and decreasing for quantities above the target.
125 The VRR curve passes through the target long-run market clearing point, where the
126 quantity is equal to the PJM required reserve margin plus one percent, and the price is
127 equal to PJM's estimate of Net CONE. Prices decrease to the right of that point,
128 reflecting surplus supply conditions, and prices rise to the left of that point, reflecting
129 relative scarcity in supply.

130 The offer curve applied in each BRA is developed from offers submitted by resource
131 owners for all capacity resources, both existing and new, including internal PJM
132 resources and capacity available for import from neighboring markets. In addition to
133 generating capacity, offers may be submitted for demand-side resources and transmission
134 expansion projects. The offers for each resource represent the price level at which the
135 resource owner is willing to supply the capacity to the PJM market, expressed in $/MW-
136 day. Offers are subject to cost-based mitigation by PJM's market monitor.

137 The RPM auctions are conducted as single-price auctions, in which all resources that
138 clear in the auctions are paid a single clearing price. The market price is determined by
139 the point at which the mitigated offer curve and VRR curve intersect. Any resource
140 offers lower than the clearing price are accepted and the resource owner is paid the
141 market clearing price; resources with offers above the clearing price remain unsold.

142 The CRA RPM model is built around estimates of both the VRR curve and mitigated
143 offer curve, and the model calculates the market clearing price and quantity for each
144 relevant location within the PJM market.[2] Both the offer curves and VRR curves are
145 developed based on publicly-available information and CRA's knowledge and view of
146 the market. The parameters of the VRR curve are informed by PJM's forecast for
147 demand growth and interruptible load programs, PJM and CRA estimates of Net CONE,
148 and the parameters of the VRR curves applied in prior auctions. The offer curve is
149 developed from published listings of PJM resources (including PJM's RPM Resource
150 Model[3] and PJM's EIA-411 Report[4]), information about offered capacity and the offer
151 curves published by PJM following each BRA,[5] and CRA's view about likely retirements
152 and new resource additions, informed by several industry sources.

153 Figure 2 shows the offer curve, VRR curve, and projected market clearing point
154 underlying the CRA price forecast for 2012/13 that was used in DP&L's valuation
155 calculations. The VRR curves applied in later years reflects expected load growth and
156 shifts in Net CONE over time. The offer curves for subsequent years reflect expected
157 shifts in the offers for RPM resources due to expected changes in avoidable costs, energy

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[2] The RPM market is designed as a locational market in which there can be price separation among various zones within PJM, referred to as Locational Deliverability Areas ("LDAs"). A local capacity requirement and import limit is established for each LDA allowing separated VRR and offer curves to be developed and applied in the market clearing process. To date, the Dayton zone has not been within a constrained LDA and has therefore received the "rest-of-market" price. Given expected transmission upgrades, the CRA forecast indicates that within the forecast horizon, locational price separation is unlikely for Dayton or any other PJM Zone and the clearing price for DP&L will continue to be set by supply and demand conditions throughout the entire PJM RTO footprint.

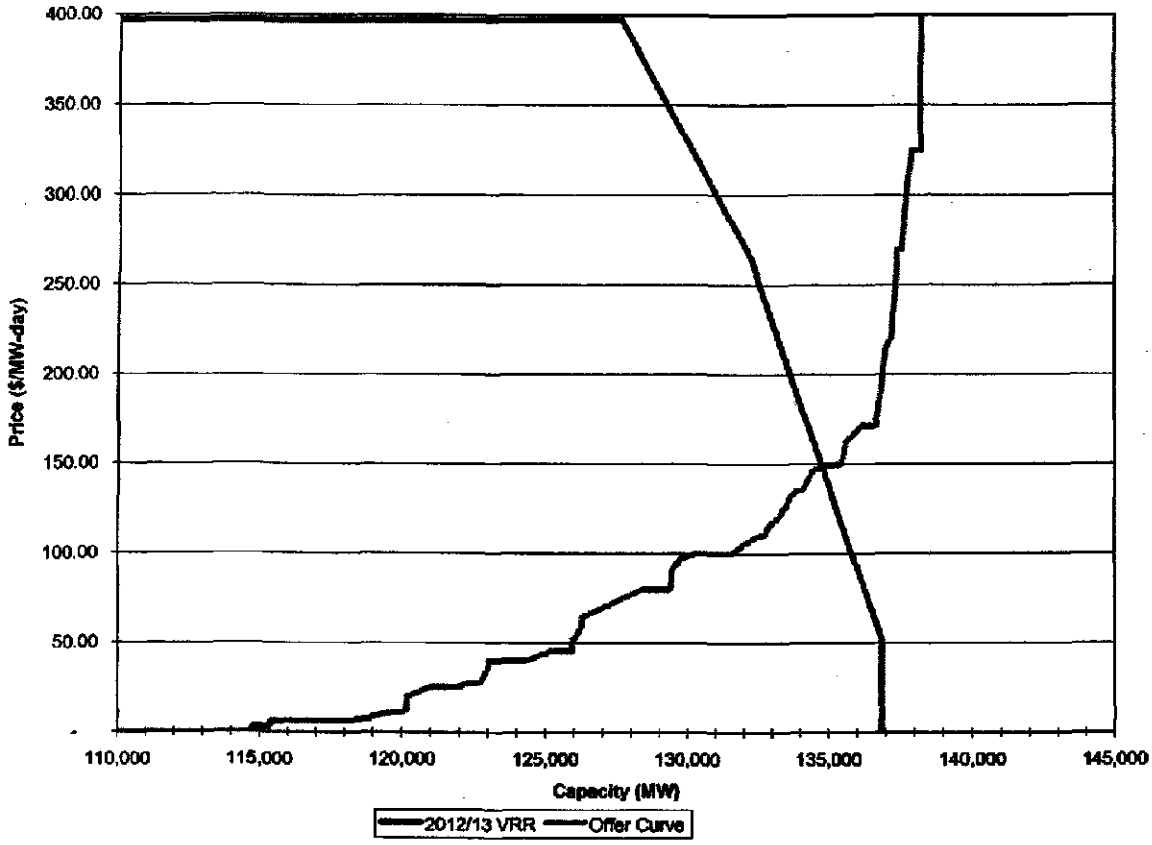
[3] Available at http://www.pjm.com/markets/rpm/downloads/20080425-rpm-resource-model-2011-2012.xls.

[4] Available at http://www.pjm.com/documents/downloads/reports/2007-pjm-411.pdf.

[5] See 2011/2012 Base Residual Auction Report, available at http://www.pjm.com/markets/rpm/downloads/20080515-2011-2012-bra-report.pdf.

158 and ancillary service earnings for various resources, and changes in the parameters
159 applied in review and mitigation of offers by the PJM Market Monitoring Unit. The
160 subsequent-year offer curves also include offers for new resources that are expected to be
161 included in future auctions. These new resources include both capacity that is likely to be
162 added regardless of RPM prices (e.g., new units already under construction based on
163 secured long-term contracts), and therefore offered at relatively low prices, and those
164 offered on a competitive basis, with offer prices reflecting the actual Net CONE for
165 development of new generation resources.

166 **Figure 2: Projected Market Clearing Outcome for 2012/13 RPM Auction**



167
168 **Q. Please describe the key assumptions underlying this forecast.**

169 A. The CRA forecast used by DP&L was based on several assumptions about future RPM
170 market conditions, including demand growth, Net CONE, availability of demand

171 response, entry of new capacity resources, and imports and exports. CRA relied on
172 PJM's forecast of load growth, as published in its most recent Load Forecast Report.[6]
173 For each year of the CRA forecast, the Installed Reserve Margin used to set the VRR
174 curve was determined based on the projected peak load from the PJM forecast. The other
175 major determinant of the VRR curve, PJM's estimate of Net CONE, was based on a level
176 for gross CONE proposed by PJM in late 2007,[7] and CRA estimates of the earnings from
177 energy and ancillary services sales from new capacity resources.

178 Demand response resources have been an important source of capacity in the RPM
179 market, with steady growth in the amount of these resources offered into the market. For
180 future auctions, CRA forecast that available demand response will continue to grow at its
181 historical average rate.

182 Additionally, CRA's forecast incorporates certain assumptions about what new
183 generating resources will enter the market. All new units currently under construction,
184 but not yet cleared in an RPM auction, were assumed to be offered into the market as
185 price takers. Other new resources were assumed to be added as needed to meet demand
186 growth, with offers equal to CRA's estimates of actual Net CONE. CRA assumed that
187 the amount of resources exported from PJM will remain unchanged.

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[6] Available at http://www.pjm.com/planning/res-adequacy/downloads/2008-load-report.pdf.

[7] See http://www.pjm.com/committees/members/downloads/20080124-item-04-rpm-cone-by-region-for-posting.xls. The proposed increase was not approved for procedural reasons, but PJM is in the process of updating its CONE estimate and is expected to propose an increase in advance of the next BRA.

188 **Q. Have any market factors changed since the forecast was prepared that led CRA to**
189 **revise any of these assumptions in its current RPM market forecast?**

190 A. Yes. Two changes have occurred. First, expectations about the future construction and
191 financing costs of new capacity have increased. These changes are reflected in two
192 recent studies provided to PJM stakeholders. PJM recently retained consultants to
193 provide updated estimates of CONE, which it will use to inform future proposals for the
194 Net CONE used develop the VRR curve parameters. The updated studies show a very
195 significant increase relative to both current PJM assumptions and the assumptions used
196 by CRA in development of the forecast shown in Figure 1.[8] The construction cost
197 increase is, however, partially offset by an increase in expected market earnings,
198 tempering the projected change in Net CONE. Second, the level of actual interruptible
199 load in PJM has exceeded the forecast used by PJM in forming the VRR curves for prior
200 auctions, indicating that the amount of capacity remaining to be procured through the
201 RPM auctions is likely to be lower.

202 **Q. How would these two changes have affected CRA's estimate of RPM prices**
203 **compared to those used by DP&L in its analysis?**

204 A. The two changes have directionally different impacts on RPM prices. The higher
205 expected level of Net CONE leads to an upward shift in the VRR curve and a
206 corresponding increase in clearing prices, while the increase in interruptible load results

[8] See *Cost of New Entry Combined Cycle Power Plant Revenue Requirements*, Pasteris Energy, Inc, July 2008 (available at http://www.pjm.com/committees/mic/downloads/20080723-item-2d-2012-2013-cone-update-cc.pdf), and *2008 Update of Cost of New Entry: Combustion Turbine Power Plant Revenue Requirement*, Power Project Management, LLC, July 2008 (available at http://www.pjm.com/committees/mic/downloads/20080723-item-2d-2012-2013-cone-update-ct.pdf).

in a leftward shift of the VRR curve and a reduction in prices. Overall, the impact of higher Net CONE slightly outweighs the availability of additional interruptible load, but CRA forecasts that the net effect of those changes is small.

III. CONCLUSION

Q. Does the CRA forecast underlying DP&L's analysis provide a reasonable set of projection for evaluating future capacity costs for DP&L?

A. Yes. This forecast accurately reflects the RPM market design and market rules. It was developed using the best information available at the time that DP&L conducted its analysis. Changes in the market outlook since that forecast was prepared are relatively small.

Q. Does this conclude your testimony?

A. Yes.

199554.1

SCOTT W. NIEMANN

Principal

Ph.D. Economics,
University of Wisconsin

M.S. Economics,
University of Wisconsin

B.A. Mathematics, Political Science, Economics,
University of Kansas

Scott Niemann is an economist with extensive experience in the design, policy, and analysis of energy markets. As a member of CRA's Energy and Environment Practice, he has advised clients on a broad range of power market issues including market design, LMP pricing, financial transmission rights, resource adequacy markets, seams issues, and market power. Dr. Niemann has conducted numerous market studies addressing financial performance of electric generating assets, benefits of potential electric generation, transmission, and gas infrastructure upgrades, valuation of financial transmission rights, market power concerns, and economic damages. He has been retained as a market expert by a broad range of clients, including utilities, merchant power providers, investors, and trading organizations.

Prior to joining CRA, Dr. Niemann was a Principal Consultant at PA Consulting (and predecessor companies, PHB Hagler Bailly, and Putnam, Hayes, and Bartlett), where he conducted economic analyses in the environmental, energy, and commercial litigation practice areas.

EXPERIENCE

ENERGY

- On behalf of numerous market participants, conducted independent market assessments of northeast ISO resource adequacy markets. Led the development of CRA's price forecasting models for ISO-NE Forward Capacity Market, NYISO UCAP market, and PJM RPM Market. Served as capacity market expert in numerous assignments to support capacity acquisitions, financing, transfer pricing, and strategic decision making.

- Advised market participants during the FERC proceedings related to the design and implementation of the FCM, RPM, and NYISO UCAP markets.

- Provided expert testimony (both written and live oral) on behalf of NRG as part of the Connecticut Department of Public Utility Control (DPUC) proceeding regarding procurement of energy and capacity awarded under the Connecticut Energy Independence Act. Testimony focused on the benefit evaluation approach implemented in the selection of winning projects.

- On behalf of companies involved in power marketing and electricity generation, performed more than 50 analyses of energy prices, power plant performance, and generation asset values in North American wholesale energy markets. This work has involved contributing to the development of a detailed GE MAPS model of the North American wholesale energy market and numerous simulations of the Eastern and Western U.S. and Canadian electricity markets.

- On behalf of US Power Generating, LLC., conducted an analysis of the New York City capacity and energy markets to support the evaluation and successful acquisition of the Astoria generating portfolio. Prepared independent market assessment and forecast of financial performance to support the financing process.

- Served as Project Manager for a CRA team engaged by ESB National Grid, the Irish system operator, to assist in the design of a competitive wholesale market for Ireland and develop the rules for the market. As Project Manager, coordinated team staffing and deliverables schedule, working on-site in Dublin. Led or participated in meetings with CRA team and client staff to develop straw man proposals for market design aspects. Drafted and presented discussion papers outlining aspects of the proposed design.

- On behalf of the Vice President of Energy Management at Con Edison, conducted several studies related to the NYISO market, including:

  - Analysis of the impact of changes in a wheeling arrangement between Con Edison and PSE&G using a GE-MAPS model of the Northeast U.S. The analysis included comparison of location prices, transmission congestion, and generation patterns within the PJM and NYISO systems under a range of PJM-NYISO transfer scenarios. Evaluated various strategies for implementation of the wheeling arrangement in light of market rules, commitment and dispatch methodologies, and transmission constraints within PJM and the NYISO.

  - Evaluation of the impacts on locational prices, generation costs, and costs to retail consumers within both PJM and the NYISO of moving Rockland Electric load from the NYSIO to PJM.

  - Evaluation of benefits of potential transmission upgrades both within New York City and other parts of the NYISO system.

  - Analysis of the impacts on locational prices and costs to retail customers of generation and transmission outages within New York, generating capacity additions in various locations, and proposed retirement of existing units.

- On behalf of participants in auctions for financial transmission rights (FTRs) and Transmission Congestion Contract (TCCs), analyzed bidding strategies, historical and forecasted congestion patterns, impacts of changes in market rules on FTR values, and historical FTR and TCC auction outcomes.

- Provided expert testimony regarding expected electricity prices, generator unit operations, and the corresponding value of transmission credits held by the owners of a merchant power plant in the Southeast U.S.

- Led analytical efforts to estimate the gas demands related to steam and electric generation for a New York utility, examining a range of scenarios based on the relative prices of natural gas and other fuels, electricity demand, and the future mix of generating technology and fuel options.

- On behalf of a large power generating and trading organization, acted as independent market expert supporting agency approval of a natural gas asset acquisition. Led an evaluation of potential market power concerns stemming from the acquisition of natural gas transportation and storage assets and presented analysis to the Department of Justice in support of the company's application for agency approval under the HSR Act.

- On behalf of a large U.S. utility, assessed the impacts on the value and operation of its assets of integrating its service area into a competitive, LMP-based market. The analysis examined a broad range of issues including the effects of constraints outside the utilities service area on LMPs within the area, mitigation of seams issues, impacts of the precise definition and implementation of constraints within market software on the congestion patterns affecting nodal prices in the utilities territory, and the ability to hedge congestion risks through an FTR portfolio.

- On behalf of various U.S. clients, contributed to studies of the costs and benefits of forming Regional Transmission Organizations and implementing economic congestion management and LMP in place of physical congestion management. Specifically, the studies address the elimination or alleviation of seams issues between markets, FTR allocations, formation of regional load prices in markets with nodal prices for generators, and impacts of market changes on retail electric rates.

- On behalf of clients in the wholesale electric power industry involved in mergers or assets sales, assessed market power concerns under the FERC's Appendix A Merger Guidelines for transactions in several U.S. regions, including NYISO, ISO-NE, PJM, SERC, ECAR, SPP, ERCOT, and WECC.

- On behalf of the New York Research and Development Authority, worked as part of a team to develop an integrated natural gas and electric modeling system to evaluate the adequacy of the gas delivery system for meeting the future demands of electric generators. Led electricity modeling efforts related to the estimation of fuel demands among electric generators in New York and neighboring regions, accounting for transmission constraints, gas delivery constraints, and fuel switching by generations.

- Led analytical efforts supporting CRA expert testimony before the Federal Energy Regulatory Commission regarding the manipulation of electric power prices in the Pacific Northwest during the California Energy Crisis. Analysis addressed the reasonableness of a wholesale power contract in light of spot and forward market prices and the ability of power markets and traders to influence those prices.

- Led the development of CRA's GE-MAPS model database, including compilation and auditing of generation, load, fuel price, and transmission data, and incorporation of these data into an MS-ACCESS database and interface with the GE-MAPS model.

- Evaluated benefits of potential transmission upgrades in the northeastern U.S. and Canada. The analysis used the GE MAPS model of the Eastern interconnection to measure the change in energy prices, and consumer and producer surplus in the Great Lakes Region.

- Studied generator bidding behavior in northeastern electricity markets and the impacts of market power mitigation measures.

- Evaluated the economic and environmental impact on a North American regional energy market of retiring coal-fired generation. The analysis involved estimation of the resulting changes in energy prices, power plant emissions, costs to consumers, and financial performance of generation assets.

- Conducted analyses supporting CRA expert testimony in litigation and FERC proceedings, including:

  - Wholesale power contract disputes.

  - Disputes over transmission rights.

  - Market design and market power mitigation issues.

  - Allegations of market power abuses.

  - Damages analysis related to generating unit outages.

- On behalf of a generation owner selling in the ISO-NE market, conducted an audit of payments for out-of-merit generation and associated uplift payments and production costs to identify recoverable costs and potential underpayments by the ISO.

- As part of a team working for an electric transmission and distribution utility, designed and conducted the econometric analysis for a study of customer value of service reliability. The study involved design and implementation of a survey and econometric analysis of the resulting data to measure residential and commercial customers' outage costs and willingness-to-pay to avoid various outage scenarios.

ENVIRONMENTAL LITIGATION

- On behalf of a municipal utility involved in litigation involving alleged natural resource damage, assisted in estimating the economic value of damaged resources. Project work included review of documents, collection of data, formulation of an economic framework for measuring damages, and support of an academic expert witness.

Exhibit SWN-1

- On behalf of a Middle-Eastern country making a claim for environmental damages arising out of the 1990 Gulf War, assisted in the assessment and valuation of potentially recoverable economic damages. Conducted substantial in-country research and developed techniques to value changes in health and environmental conditions. The confidential assessment was submitted to the United Nations Compensation Commission.

- For a property value dispute in the western United States, evaluated alternative valuations of environmentally impaired commercial real estate. The project involved review and critique of a survey used to elicit willingness-to-pay and evaluation of alternative measures based on market transactions.

- For a residential property value dispute, conducted an econometric analysis of survey-based willingness-to-pay measures for changes in groundwater quality and associated health risks. The effort involved analysis of data from several surveys, each with a different design and format, to assess potential biases in the survey responses and determine the effects of various demographic characteristics.

- For companies engaged in settlement discussions and litigation regarding environmental insurance coverage claims, estimated the cleanup costs and potential natural resources and property damage liability at hazardous waste sites. The work involved development of detailed, site-specific estimates using probabilistic assessment methods to determine the expected present value and distribution of future costs, which reflect technical and regulatory uncertainty.

OTHER COMMERCIAL LITIGATION

- For a major corporation involved in an intellectual property and antitrust dispute, performed analyses of market share, production capacity, output prices, and production costs. Assisted in the estimation of alternative measures of economic damages using market share, lost profits, and stock market valuation methods. Provided support in the preparation of expert reports.

- For a privately held company involved in a tax dispute, evaluated cash retention strategies of publicly and privately held firms. The analysis involved reviewing academic literature and evaluating implications of finance theory for the decisions of different types of firms in various industries.

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

Book II – Customer Conservation and Energy Management Programs

DIRECT TESTIMONY

OF DONA R. SEGER-LAWSON

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ■ OPERATING INCOME
- ■ RATE BASE
- ■ ALLOCATIONS
- ☐ RATE OF RETURN
- ■ RATES AND TARIFFS
- ☐ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

DONA R. SEGER-LAWSON

ON BEHALF OF
THE DAYTON POWER & LIGHT COMPANY

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1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Dona R. Seger-Lawson. My business address is 1065 Woodman Drive,
4 Dayton, Ohio 45432.

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

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or "Dayton" or the
7 "Company") as Director, Regulatory Operations.

8 **Q. Will you describe briefly your educational and business background?**

9 A. I received a Bachelor of Science degree in Business Administration with majors in
10 Finance and Management from Wright State University in Dayton, Ohio in 1992. I
11 achieved a Master in Business Administration with a Finance Administration
12 concentration also from Wright State University in August of 1997. I have been
13 employed by DP&L in the Regulatory Operations division since 1992.

14 **Q. How long have you been Director of Regulatory Operations?**

15 A. I assumed my present position on August 25, 2002. Prior to that time, I held various
16 positions in the Rates/Pricing Services/Regulatory Operations division, my most recent
17 prior position being that of Manager, Regulatory Operations, beginning in February 2001.

18 **Q. What are your responsibilities in your current position?**

19 A. I have overall responsibility for all base rate development, for both retail and wholesale
20 electric rates. I am responsible for evaluating regulatory and legislative initiatives, and

21 regulatory commission orders that impact the Company's retail and wholesale rates and
22 overall regulatory operations.

23 **Q. Have you previously provided testimony before the Public Utilities Commission of**
24 **Ohio ("PUCO" or the "Commission")?**
25 A. Yes. I have sponsored testimony in Case No. 99-220-GA-GCR; Case No. 00-220-GA-
26 GCR; DP&L's Electric Transition Plan, Case No. 99-1687-EL-ETP; DP&L's Extension
27 of the Market Development Period Case No. 02-2779-EL-ATA; in Opposition to the
28 Complaints in Cases Nos. 03-2405-EL-CSS, and 04-85-EL-CSS; and in the Company's
29 Rate Stabilization Period Case No. 05-276-EL-AIR.

30 **II. PURPOSE OF TESTIMONY**

31 **Q. What are the purposes of your testimony in this proceeding?**
32 A. One purpose of my testimony is to support the revenue requirement calculation as well as
33 the schedules and workpapers used in the development of the CCEM related riders,
34 specifically, the Infrastructure Investment Rider (IIR) and the Energy Efficiency Rider
35 (EER). Further, I support schedules and workpapers relating to 1) the overall calculation
36 of revenue requirements for the IIR and EER riders; 2) the rate design for IIR; 3) the
37 proposed tariffs; and 4) case expenses.

38 **Q. What specific Chapter and Schedules are you supporting?**
39 A. I am supporting parts 6 and 7 of Chapter 1 Executive Summary of the CCEM portion of
40 this case and Schedule A-1, Schedule A-2, Schedule A-3, Schedule B-1, Schedule C-1,
41 Schedule E-1, and Schedule E-2. Further I am supporting DP&L's calculation of deferred

costs, stranded investment, case expenses, and shared savings. Finally I am supporting the tariffs included in Schedule E-3.

III. CUSTOMER CONSERVATION AND ENERGY MANAGEMENT (CCEM) RATE OVERVIEW

Q. Can you give a brief overview of the cost recovery structure the Company is seeking?

A. The Company proposes to recover costs associated with this plan via two separate rate riders; an energy efficiency rider (EER) and an infrastructure improvement rider (IIR). Because ORC § 4928.66 (A)(2)(c) allows a mercantile customer that implements its own energy efficiency programs to avoid the energy efficiency rider, the EER will be bypassable for any mercantile customer that meets the criteria set forth in the PUCO rules related to this provision. The IIR will contain two components, a $ / customer per month charge to recover metering and billing investment, and the remainder of the IIR costs will be collected via a cents per kWh charge. The IIR rider is non-bypassable because it funds energy delivery infrastructure improvements to all customers regardless of their generation supplier status.

IV. DP&L'S INFRASTRUCTURE INVESTMENT RIDER (IIR)

Q. What is the IIR designed to recover?

A. The IIR is designed to recover the costs associated with the new automated metering infrastructure (AMI) systems, telecom systems, substation automation systems, and IT systems including a new billing system. All of these functions are necessary to build a delivery system of the future, or Smart Grid system, which is the necessary platform by

which all of the energy efficiency programs can be provided to our customers. Therefore, the IIR should be non-bypassable for all customers.

Q. How was the IIR rate calculated?

A. The IIR rate was developed by calculating a revenue requirement based on the costs to be incurred for the infrastructure improvement portion of the CCEM plan. A rate of return based on June 30, 2008 regulated business capital structure was applied to capital investments over the initial seven-year period. Operational and maintenance expenses, as well as depreciation expenses, and taxes other than income taxes were added to form the base revenue requirement. The Company incurred project development costs beginning in 2007 and is incurring additional expenses in 2008. A carrying cost, equal to the rate of return, was applied to those costs until they are expected to be fully recovered via the CCEM riders. These costs were either directly assigned or allocated to the EER and IIR and built into rate recovery over a three-year period.

As part of the CCEM comprehensive plan, the Company will be implementing AMI meters system-wide over a six-year period. All meters currently in service will be replaced by more advanced, or smart meters. The cost of meters that are taken out of service before the end of their useful lives will be a stranded cost. Thus, the stranded cost of meter investment, less salvage value, is added to the IIR revenue requirement on a net plant basis, consistent with the timing at which the meters are taken out of service. The gross plant value of the retired meters is subtracted from the gross plant additions each year during the CCEM plan, so that the value is not double counted in the rate recovery

85 calculation. In addition, the cost of preparing and litigating the CCEM case before the
86 Commission is calculated on Schedule C-8, added to the revenue requirement, and is to
87 be recovered over a three-year period, consistent with Commission practice. Two
88 separate gross revenue conversion factors were calculated on Schedule A-8, and applied
89 to debt and equity return components to reflect the relevant tax impacts.

90 **Q. Why are there two separate gross revenue conversion factors and how are they**
91 **applied?**

92 A. There are two separate gross revenue conversion factors because the gross revenue
93 conversion factor converts a cost-based amount to a revenue requirement amount; the
94 difference is the tax effect and the impact of uncollectible expense. All expense items
95 should be collected on a one-for-one basis so that revenues will equal expenses; there is
96 no income tax effect on the new revenue. There is, however, an uncollectible impact on
97 expenses. In other words, one dollar of expenses should equate to one dollar of revenues,
98 but for the fact that DP&L has an uncollectible rate of 1.7609% and certain taxes apply to
99 new revenues. Therefore, in order to recover one dollar of expenses, DP&L must bill
100 $1.021.

101 The equity portion of the return on rate base is subject to municipal income tax, federal
102 income tax, and uncollectible expense, and therefore the gross revenue conversion factor
103 that applies to this amount should be calculated to take into account these facts.
104 Therefore, the equity portion of the return on rate base is grossed up by 1.579 to consider

105 the income tax effect on the revenue as well as the uncollectible factor. Company
106 Witness Hergenrather supports the Gross Revenue Conversion factor calculations.

107 **Q. Why is it appropriate to use two separate gross revenue conversion factors for the**
108 **IIR rate calculation?**

109 A. In a typical rate case, the revenue requirement calculation takes into consideration total
110 expenses, total taxes, and return on total rate base. The gross revenue conversion factor
111 is usually applied to the difference between the total revenue requirement and the total
112 amount of revenues the Company is collecting prior to the change in rates. Given that
113 this case addresses only certain costs, the revenue requirement is not reflective of total
114 costs and is not compared to total revenues currently being collected. Therefore, it is
115 appropriate to apply two separate gross revenue conversion factors based on the nature of
116 the cost and the tax effect of those costs.

117 **Q. Did you subtract savings the Company will experience by implementing these new**
118 **metering systems?**

119 A. Yes. To account appropriately for the O&M expenses that will be saved from
120 implementing the infrastructure improvements as well as line loss reductions, and
121 depreciation savings, fifty percent of these amounts was credited to the revenue
122 requirement. This approach is consistent with ORC §4928.143(B)(2)(h) which permits
123 shared savings to be included in a utility's energy delivery modernization plan. The fifty
124 percent factor allocates the savings to the customers and utility equally.

125 **Q. Why did you split the IIR into a $ per customer per month basis and a $ per**
126 **kilowatt-hour basis?**
127 A. ORC §4928.143(B)(2)(h) also provides for incentives and revenue decoupling
128 mechanisms with respect to a utility's energy delivery modernization plan. DP&L is
129 proposing a flat per month per bill recovery mechanism for a portion of the infrastructure
130 investment costs. The Company recognizes that the majority of these infrastructure
131 improvement costs are customer-driven costs, i.e., costs that vary based on the number of
132 customers served by DP&L, or the number of bills rendered on a monthly basis.

133 **Q. How was the $ per customer per month fee established?**
134 A. The per customer per month fee was calculated by taking the average annual revenue
135 requirement over the initial seven-year period and determining how much of this amount
136 was customer-related. The average annual customer-related IIR revenue requirement was
137 then assigned to the various tariff classes based on a weighted average number of
138 customers. The weighting factor that was used is the same weighting factor that was used
139 in the Company's last cost of service, in Case No. 99-1687-EL-ETP. The allocated
140 revenue requirement was then divided by the average number of customers for 2007, and
141 the result is a price per customer per month for Infrastructure Improvements. Because
142 this rate design levelizes the IIR investment, in the early years recovery is occurring
143 faster than the investment is being made. For that reason, the time value of money was
144 calculated for the years in which an over-recovery was expected.

145 **Q. How did you factor in the time value of money?**

146 A. I calculated the difference between the annual revenue requirement for a given year and
147 the levelized revenue requirement. I accumulated the overage or underage amounts each
148 year, and applied a carrying charge equal to the cost of capital to each annual balance.
149 The total amount of carrying charges was then subtracted from the revenue requirement,
150 which reduced the total amount of revenue recovered from customers.

151 **Q. How much was the revenue requirement reduced for the time value of money? And**
152 **how was this reduction implemented?**
153 A. The total carrying costs amounted to approximately $23 million over the seven-year
154 period. The $23 million was subtracted from the total seven-year revenue requirement
155 and then the rate design process described above was repeated, resulting in the $ per
156 customer per month charge by tariff class.

157 **Q. How was the remainder of the IIR rate established?**
158 A. The remainder of the IIR revenue requirement was divided by adjusted sales to get an
159 average rate per kWh of approximately 0.14 cents. In the normal course of business the
160 Company prepares a corporate sales forecast. The expected energy efficiency savings
161 that result from implementing the energy efficiency programs contained in this plan were
162 subtracted from the corporate sales forecast by year. The resulting adjusted sales were
163 used as the denominator to develop the IIR per kWh charge.

164 **Q. Have any previous expenditures associated with CCEM been deferred for future**
165 **recovery in rates?**

A. Yes. The costs incurred in the formulation and analyses of various programs have been deferred in Account 182.3, Other Regulatory Assets. Also deferred in Account 182.3 are the costs incurred in the preparation of this rate case. Schedule C-8 calculates the amount of these costs and DP&L requests to recover those costs over a three-year amortization period.

Q. Why is the IIR non-bypassable by mercantile customers and customers that take service from a Competitive Retail Electric Service (CRES) Provider?

A. The IIR recovers costs associated with delivery system infrastructure improvements, advanced metering infrastructure, and new IT billing systems. Costs associated with these system investments do not vary based on whether a customer takes service from the utility or a CRES Provider; they are necessary for building and improving service quality to all customers. Allowing certain customers to bypass these charges would place an inappropriate burden on the remaining customers.

Q. Where can the IIR rate by tariff class be found in this filing?

A. The IIR rider is contained on Tariff Sheet No. D42 that can be found in Schedule E-3 of this filing, as well as lines 46 and 50 of Schedule E-1.

V. ENERGY EFFICIENCY RIDER (EER)

Q. What is the EER designed to recover?

A. In compliance with ORC §4928.66 DP&L is required to implement energy efficiency and demand response programs to meet the annual targets set forth in this section of the legislation. The EER is designed to recover the costs associated with energy efficiency

and demand response programs which DP&L anticipates that it will be offering to customers beginning in 2009, upon approval of the Application in this case. For a more detailed explanation of the programs DP&L will be offering, see the Testimony of Company Witness Bubp.

Q. How was the EER rate developed?

A. The EER was developed from cost estimates for developing and implementing the energy efficiency programs, which were then used to calculate a revenue requirement for the EER. Although there is very little capital investment associated with EE programs, a rate of return was applied to the small capital investment expected to be made. Operational and maintenance expenses, as well as depreciation expenses, and taxes other than income taxes were added to form the base revenue requirement. The Company incurred project development costs beginning in 2007, and is incurring additional expenses in 2008. A carrying cost, equal to the rate of return, was applied to those costs until they are fully recovered via the CCEM riders. This cost was either directly assigned or allocated to the EER and IIR and built into rate recovery over a three-year period. As stated previously, two separate gross revenue conversion factors were calculated (Schedule A-4), and applied to debt and equity return components to reflect the relevant tax impacts.

Q. Did you subtract savings the Company will experience by implementing these new programs?

A. As a placeholder, we have a line in the revenue requirement calculation on Schedule A-3 that would subtract shared savings from the revenue requirement for the EER. However,

because the Company does not have any energy efficiency programs in place today, there are no savings that result from implementing these new programs, only additional costs. Thus, the shared savings amount is zero.

Q. How was the rest of the rate developed?

A. The resulting total revenue requirement was then divided by sales to determine an energy efficiency rate per kWh by year. The energy efficiency rate is approximately $0.0015 / kWh starting in 2009, and grows to approximately $0.0068 / kWh by 2015. This rate increases each year as additional spending on energy efficiency programs is incurred each year to meet the increasing EE annual target contained in S.B. 221.

Q. Why aren't stranded costs associated with EER?

A. Unlike the IIR, no plant or equipment that is being removed from service prior to being fully depreciated is associated with the energy efficiency or demand response programs of the Company. Therefore there is no stranded investment included in the EER revenue requirement calculation.

Q. Is the EER bypassable? If so, by whom?

A. Consistent with 4928.66(A)(2)(c) this charge is bypassable by a mercantile customer that implements its own energy efficiency measures and meets the Commission's rules contained in proposed OAC 4901:1-39-06. It is not bypassable by customers that take generation service from a CRES provider, unless those customers meet the mercantile definition and the PUCO rule requirements for bypassibility of this charge.

Q. Where can the EER rate by tariff class be found in this filing?

229 A. The EER rider is contained on Tariff Sheet No. D43 that can be found in Schedule E-2 of
230 this filing, as well as line 7 of Schedule E-2.

231 VI. SCHEDULES AND WORKPAPERS

232 **Q. What is the purpose of Schedule A-1?**

233 A. Schedule A-1 summarizes the revenue recovery amounts for the Infrastructure
234 Investment Rider (IRR) as well as the revenue requirement for the Energy Efficiency
235 Rider (EER) by year.

236 **Q. Why is line 1 on Schedule A-1 "Revenue Recovery" as opposed to Revenue**
237 **Requirements?**

238 A. Since a levelized rate design was developed for the IIR, the carrying charge to reflect the
239 time value of money was subtracted from the revenue requirement. Thus, the revenue the
240 Company proposes to recover is less than the revenue requirement that result from the
241 IIR-related portion of the Customer Conservation and Energy Management plan.

242 **Q. What is the purpose of Schedule A-2?**

243 A. This schedule calculates the revenue requirement for the IIR. It starts with the rate base,
244 applies the cost of debt and cost of equity components of the cost of capital. Then O&M,
245 depreciation expense, taxes other than income taxes, deferred costs, stranded investment,
246 and case expenses are added to develop the revenue requirement exclusive of income
247 taxes. Next the gross revenue conversion factor is applied to derive the annual revenue
248 requirement. Shared savings are then subtracted to get the net infrastructure investment

revenue requirements. Last the adjusted revenue requirement is pulled from the rate design schedule E-1.

Q. What is the purpose of Schedule A-3?

A. This schedule calculates the revenue requirement for the EER. It starts with the rate base, applies the cost of debt and cost of equity components of the cost of capital. Then O&M, depreciation expense, taxes other than income taxes, and deferred costs are added to develop the revenue requirement exclusive of income taxes. Next the gross revenue conversion factor is applied to derive the annual revenue requirement. Lost revenues are then added and shared savings are subtracted to get the net energy efficiency revenue requirements.

Q. What is the purpose of Schedule B-1?

A. Schedule B-1 calculates rate base components by type of CCEM rate. Gross Plant in Service is pulled from Schedule B-2, and accumulated depreciation is subtracted from gross plant amount to derive the net plant balance by year. The stranded cost value is subtracted during the year the equipment is removed from service. Rate base is then adjusted for deferred taxes associated with the new plant in service as well as deferred taxes on the stranded investment. Next construction work in progress is added to rate base, assuming that it is seventy-five percent completed as of the measurement date.

Q. Why are there few adjustments to rate base for the energy efficiency rider?

A. The only plant investment associated with energy efficiency programs are some customer in-home energy displays, and there is no stranded investment, deferred taxes, nor construction work in progress associated with this type of property.

Q. What is the purpose of Schedule B-8?

A. Schedule B-8 shows the stranded cost calculation. The Company took the net book value of the assets at the time they were being retired and subtracted the salvage value of the equipment to get the stranded cost value.

Q. Why is it appropriate to seek recovery of the full value of the stranded cost?

A. It is appropriate to allow recovery of net book value of stranded meter investment less salvage value since absent deployment of the AMI technology, the metering equipment that is currently in service would continue to be used and useful throughout its remaining life. To retire the assets before they have reached the end of their useful lives is a cost of implementing the new technology and thus it should be recovered through this rider.

Q. What is the purpose of Schedule C-1?

A. Schedule C-1 summarizes the expense items associated with both the EER and IIR portions of the CCEM project. Operation and maintenance expense is gathered from Schedule C-2, then depreciation expense from Schedule C-3, and finally taxes other than income taxes from Schedule C-4 are summed to derive the total expenses associated with each rider. This information is then pulled to Schedule A-2 and A-3 and used in developing the revenue requirement by year for each rider.

Q. What is the purpose of Schedule C-6?

A. Schedule C-6 calculates the deferred cost aspect of the Customer Conservation and Energy Management project. Approximately $1.2 million was incurred in 2007, with another $6 million incurred in 2008 associated with the background development of the project. These costs are related to both energy efficiency and infrastructure investment and thus some of the deferred costs were directly assigned, while other common costs were allocated to the two riders. Finally, a carrying cost equal to the cost of capital was applied to the end-of-the-year balances and assumed to be recovered over a three-year period.

Q. What is the purpose of Schedule C-7?

A. An uncollectible percentage factor was calculated on Schedule C-7 based on 2007 costs from the Company's FERC Form No 1. This factor is used in the gross revenue conversion factor, Schedule A-4.

VII. RATES AND TARIFFS

Q. What is contained in Schedule E-1?

A. Schedule E-1 shows the IIR rate design to and the methodology to derive the $ / month per customer rate by tariff class as well as the $ / kWh rate. It contains the time value of money calculation and demonstrates the amount that was credited to the revenue requirement for the time value of money that is a result of the levelized rate design.

Q. What is contained in Schedule E-2?

A. Schedule E-2 shows the EER rate calculation by year.

Q. What is contained in Schedule E-3?

310 A. Schedule E-3 contains proposed new tariffs. The Company is proposing to implement
311 two new distribution rate riders associated with the CCEM plan. Tariff sheet No D43
312 contains the EER and Tariff Sheet No. D42 contains the IIR.

313 VIII. CASE EXPENSES

314 **Q. Is DP&L seeking recovery of its case expenses in the CCEM filing?**
315 A. Yes. As shown on Schedule C-8, DP&L is seeking recovery of case expenses for
316 attorneys' fees, consulting fees, and other associated costs.

317 **Q. Why did DP&L decide to engage outside counsel?**
318 A. DP&L made the decision to engage outside counsel for two reasons. First, as a part of
319 DP&L's overall goal to keep costs to a minimum, DP&L's legal department is leanly
320 staffed. As a practical matter, currently DP&L's legal department could not take on the
321 substantial additional work of litigating a case such as this one. Second, DP&L has long
322 used Mr. Faruki's law group, now called the law firm of Faruki Ireland & Cox P.L.L.
323 ("FI&C"), to handle rate cases (e.g., Case Nos. 91-414-EL-AIR, 82-517-EL-AIR, 81-
324 1256-EL-AIR) and many other cases at the PUCO since 1990, including DP&L's ETP
325 case (Case No. 99-1687-EL-ETP), MDP case (Case No. 02-2779-EL-ATA), and RSP
326 case (Case No. 05-276-EL-AIR). FI&C thus has developed expertise in handling cases
327 before this Commission, and DP&L's in-house attorneys do not have similar experience.
328 It is thus more efficient to use outside counsel.

329 **Q. What efforts is DP&L making to keep its case expenses to a minimum?**

A. Company personnel meet about once a week with outside counsel and communicate with them on the telephone more often than that. I monitor the work done by outside counsel to ensure that their work is necessary, and that it cannot be done in-house at a lower cost. DP&L monitors bills from outside counsel to ensure that the number of hours expended is reasonable for the nature of the tasks assigned.

Q. What is the accounting treatment for Case Expenses?

A. Case expenses are being tracked in a separate deferred account for accounting purposes. These expenses will be deferred until the Commission's final order in this case is issued. Once the final order is issued, depending on how the Commission rules with respect to case expenses, the items in the deferred account will either be expensed immediately, or amortized over the period of time specified in the Commission order. DP&L has proposed a three-year amortization period for these expenses, which is reasonable and appropriate.

IX. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, at this time.

198922.1

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

THE DAYTON POWER AND LIGHT COMPANY
CASE NO. 08-1094-EL-SSO

BOOK II – Customer Conservation and Energy Management Programs

DIRECT TESTIMONY

OF JEFFERY E. TEUSCHER

- ☐ MANAGEMENT POLICIES, PRACTICES, AND ORGANIZATION
- ☐ OPERATING INCOME
- ☐ RATE BASE
- ☐ ALLOCATIONS
- ☐ RATE OF RETURN
- ☐ RATES AND TARIFFS
- ■ OTHER

BEFORE THE

PUBLIC UTILITIES COMMISSION OF OHIO

DIRECT TESTIMONY OF

JEFFERY E. TEUSCHER

ON BEHALF OF
THE DAYTON POWER AND LIGHT COMPANY

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1 I. **INTRODUCTION**

2 Q. **Please state your name and business address.**

3 A. My name is Jeffery E Teuscher. My business address is 1900 Dryden Road, Dayton,
4 Ohio 45439.

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

6 A. I am employed by The Dayton Power and Light Company ("DP&L" or "Company") as
7 an Operations Manager.

8 Q. **How long have you been in your present position?**

9 A. I assumed my present position in July of 2007. Prior to that time, I have had several
10 different responsibilities at DP&L. I started with DP&L in December 1986 as a
11 Distribution System Planning Engineer. From there, I became an Assistant Service
12 Center Manager, working at the North Dayton Office and moving to the Dayton West
13 Office. I was promoted to the Manager of Technical Service in 1995 and helped the
14 Company to implement the one-way AMR system that DP&L is currently using. I
15 assumed the position of Manager of Technology in June, 1996 and from there moved to
16 the Energy Resource Center in January, 1997 to help develop energy efficient products
17 and services for commercial and industrial customers. After the Energy Resource Center
18 closed, I have held various positions as a Manager of technical areas within the
19 Transmission and Distribution businesses, until my current position.

20 Q. **What are your responsibilities in your current position and to whom do you report?**

1 A. In my current position, Manager of Operations, I am responsible for Transmission and
2 Substation Engineering, the capital project engineering group, drafting department and
3 the Electric Meter Department. I report to the Director of Engineering.

4 **Q. Will you describe briefly your educational and business background?**

5 A. I received a Bachelor of Science degree in Electrical Engineering from Ohio Northern
6 University in May 1982. After graduation I went to work for Appalachian Power Co. in
7 Charleston, WV as a planning engineer and was promoted to an Energy Services
8 Engineer two years later. In late 1986, I left APCO to begin my career with DP&L in
9 Greenville, Ohio. I have been in the utility industry for 26 ½ years.

10 **Q. What is the purpose of this testimony?**

11 A. The purpose of this testimony is to support and explain DP&L's plan for implementing
12 an Advanced Metering Infrastructure (AMI) and our plan for a Smart Grid Development
13 phase. These are the field components and communication infrastructure required for
14 DP&L's Customer Conservation and Energy Management ("CCEM") Programs.

15 **Q. What chapters and workpapers are you supporting?**

16 A. I am supporting Chapters 2 and 3 of the CCEM filing entitled, "The Dayton Power &
17 Light Company's Advanced Metering Infrastructure Plan" and "The Dayton Power and
18 Light Company's Smart Grid Development Plan." I also support work papers WPH – 1.1,
19 1.2, 1.3, 1.5, 1.6, 1.7, 1.8 relating to AMI. Ms. Garrison, will support WPH – 1.4 as that
20 work paper pertains to the Information Technology ("IT") systems that support AMI. I
21 will also support all work papers relating to Smart Grid Development which are WPI –
22 1.1 through WPI – 1.6.

II. ADVANCED METERING INFRASTRUCTURE (AMI)

Q. Can you describe the new functionality provided by AMI?

A. Yes. Via the use of "smart meters," AMI transforms the meter from a simple measuring and counting device, to one element of an integrated system of hardware, software, and people that can be used to better manage the electric distribution system. AMI is not only a tool to capture customer consumption of energy, but is also a hardware and software architecture capable of capturing real-time consumption, demand, voltage, current and other information. Data can be provided at the customer level and for other enterprise-level systems either on a scheduled basis or on demand. A typical AMI network will communicate this data to a central location, sorting and analyzing it for a variety of purposes such as customer billing, outage response, system loading conditions and demand-side management. The AMI network will also send this information to other systems, customers and third parties.

AMI introduces new functionality that will permit DP&L to improve operations and provide greater value to our customers. The availability of near-real and/or real-time energy data supports time-differentiated rates for customers. DP&L will have access to more complete and current customer data when addressing customer concerns. Further, the interval data and accurate load shapes can be made available to customers to help them to manage energy costs.

Q. Please describe what you mean by a smart meter.

A. The smart meter will allow DP&L to collect the interval data for the customer's electric service and will be equipped with remote disconnect/reconnect technology for ease and

convenience of reconnecting customers. These meters will also allow us to provide a wide variety of time-of-use pricing schedules for all customer types. The new meters are all electronic which will provide for improved accuracy and quicker outage detection. They include tools to detect potential energy theft. The meters will be equipped to support the Home Area Network infrastructures which include programmable thermostats, home energy displays, load control relays and smart appliances.

Q. Is AMI necessary to support demand response programs and time-varied pricing which help customers control peak energy usage?

A. Yes. The proposed AMI system will help to minimize the cost of energy and permit customers to access various demand response programs that improve system load factor and help to defer the construction of new facilities. AMI is a necessary enabling technology for the success of demand response for three primary reasons. First, AMI provides the reliable interval data necessary to measure and verify load reductions achieved by customers, individually and as groups. This capability allows the market to accurately value customer demand response, and third parties can develop demand response programs at a reasonable incremental cost.

Second, AMI provides information necessary for customers to determine the effects on their own actual loads of specific demand responses that they might take. This ability allows customers to make intelligent decisions concerning their level of participation in particular demand response programs available today and in the future.

Third, AMI provides a platform to engage customers in demand response actions. Time-based pricing programs can be tailored carefully and precisely with AMI. Customers can be notified in their homes or businesses when a demand response action would save them

the most money. Prices and financial incentives can target specific outcomes. Optional load control can help customers to optimize their participation in demand response programs without reducing the benefits and value of those appliances to the customers.

Q. Does your testimony cover DP&L's proposal for the introduction of demand response programs?

A. No. The full benefits of demand response cannot be achieved unless the Company is able to implement new programs that encourage load shifting and curtailment. Such programs are part of DP&L's integrated CCEM filing. Details of proposed programs will be provided by DP&L witness Bubp.

Q. Is AMI necessary to support grid automation upgrades considered part of a Smart Grid?

A. Yes. Most utilities consider the implementation of an AMI system to be the fundamental enabling component of the Smart Grid. Much of the benefit of a Smart Grid infrastructure relies on the capture of detailed data and timely communications of the status of the utility distribution system to process-intelligent controls for the network equipment. AMI can capture meter-level activities and data for Smart Grid applications; for example:

- Supervisory Control and Data Acquisition (SCADA) system voltage information at feeder breakers in the substations can indicate the quality of the power supply to the distribution network, but voltage information at service transformers and customer delivery points is necessary to discern circuit or transformer level problems for more effective Voltage and Reactive Loading control.

- Substation breaker and reclosure operations can be used to evaluate the large-scale extent of an outage, but meter-level outage and restoration notification events are necessary to optimize outage restoration efforts.
- Emergency load response activities such as load shedding can alleviate potentially catastrophic system concerns, but at a significant cost to customer satisfaction. Demand response distributed to the individual premise allows utilities to achieve expected load reductions without sacrificing customer satisfaction.

Q. DP&L's AMI proposal includes significant investments in IT upgrades. How do these IT systems relate to DP&L's AMI proposal?

A. Effective implementation of advanced AMI technology requires installation of a meter data management system (MDMS) and the modification or purchase of supporting IT systems that will make it possible for DP&L to manage the enhanced operational environment and to take advantage of the new data that is captured by the AMI system. DP&L has several key legacy and home-grown IT systems in place to maintain daily operations. Our current customer information system, outage management system and service order processing system were designed and developed independently of each other and, over time, have been integrated with each other as needed. Although they are currently meeting our operational requirements, AMI will require a more flexible set of IT systems that will more readily meet the needs of our new AMI customer base and will enable customer participation in evolving energy efficiency and demand response programs. As explained in the testimony of DP&L witness Garrison, it will be difficult and costly to further customize our existing legacy and home grown systems in order to take advantage of the new opportunities and benefits afforded by AMI to respond quickly

to market and/or regulatory changes, and to create and manage a suite of energy efficiency programs tailor-made for our customers.

DP&L witness Garrison will provide more detail on the specific IT investments required.

Q. Can you explain more about the home energy display device and how you see it in DP&L's vision for AMI?

A. Yes. The energy display will allow DP&L to give all customers access to their energy information. We expect that approximately 70% of the customers will have access to the internet and will be able to obtain this information from the internet. The home energy display is a device we will provide to the customers who do not have access to the internet that will allow them to get their energy information directly from the smart meter. This device will provide a way for all customers to gain greater energy awareness and to be able to take actions to reduce energy usage and costs. The home energy displays and the AMI system will allow DP&L to provide customers with important messages about energy prices and energy awareness to educate customers about their energy usage patterns.

Q. Please describe how an investment in a Geographical Information System fits in with the CCEM proposal.

A. The Geographical Information System (GIS) is an underlying system that provides the location of each and every component of the AMI and Smart Grid system. This provides the distribution system connectivity and line parameters for analysis. The GIS provides a model of the distribution system; the data for that model comes from a field audit conducted by the company. The GIS provides a connectivity model and a field collection

1 process that will connect the customer's meter to the transformer serving the customer;
2 the transformer to the primary branchline serving the transformer; and the branchline to
3 the substation breaker. While DP&L has a GIS, we require a field audit in order to
4 collect and verify the attributes and GPS coordinates of the distribution system that will
5 be used for analysis and proper positioning of the AMI and Smart Grid devices.

6 III. SMART GRID DEVELOPMENT

7 **Q. What does DP&L mean by a Smart Grid Development?**
8 A. The Company's Smart Grid plan includes a fully network-connected system that
9 identifies and communicates the status of the grid and automates the transmission and
10 distribution decision-making systems on that network.

11 The Company is proposing to implement and evaluate a set of technologies commonly
12 considered part of a Smart Grid. We plan to implement individual technologies to
13 evaluate the Smart Grid concepts, primarily pertaining to distribution and substation
14 automation, in combination with AMI systems and demand response programs to validate
15 assumptions regarding operational, reliability, and efficiency benefits. Following this 7-
16 year "development" phase we expect to submit to the Commission an expanded proposal
17 for full deployment of an integrated Smart Grid deployment plan.

18 **Q. What are the benefits of a Smart Grid?**
19 A. A Smart Grid uses the multitude of vertical system solutions currently available and
20 deploys a horizontal integration of these systems into a real-time, secure, and automated
21 network that will manage all of the variables involved in delivering energy to the
22 consumer. This advanced decision-making system will allow DP&L to deliver energy
23 more efficiently and reliably. The results will be a greatly improved delivery system that

reduces line loses, maximizes customer and system reliability, allows for operational savings for the utility and generates substantial benefits for society at large.

The Company's long-term plan for its Smart Grid is a digital energy system that will:

- Detect and address emerging problems on the system before they affect service;
- Respond to local and system-wide inputs and generate much more information about broader system problems;
- Incorporate extensive measurements, rapid communications, centralized advanced diagnostics, and feedback control that quickly return the system to a stable state after interruptions or disturbances;
- Automatically adapt protective systems to accommodate changing system conditions,
- Re-route power flows, change load patterns, improve voltage profiles, and take other corrective steps within seconds of detecting a problem;
- Enable distributed energy resources and demand response controlled loads to participate in operations;
- Operate reliably and securely; and
- Provide system operators with advanced visualization tools to enhance their ability to oversee, manage, and troubleshoot the system.

Q. Can you describe DP&L's proposal to implement and evaluate the Smart Grid technology as part of its 7-Year CCEM filing?

A. Yes. The Company proposes the simultaneous deployment of substation automation and distribution automation in the development phase. The Smart Grid development plan focuses on using the new communications infrastructure to pass data through a series of controls, switches and monitors to increase area reliability.

In addition, the Company proposes to automate substations by upgrading relay protection and communication systems in substations to enable fault isolation and load redistribution in conjunction with the distribution automation technology being deployed. DP&L will study the reliability improvements enabled by this real-time distribution of substation loads under fault conditions.

Q. Please describe in more detail the plan for Distribution Automation.

A. Effective implementation of Distribution Automation ("DA") technology requires installation of a series of controls, switches and monitors as well as supporting communication infrastructure. DP&L plans to automate 4 circuits per year in years 2009 through 2014 and starting in 2014 will begin more aggressive rollout with the automation of between 30 and 50 circuits. Subsequent to this seven-year development, we expect to continue at the rate of 30 to 50 per year through 2023.

The process of automating a circuit will entail the installation of one or more of the following devices and equipment:

Automatic Reclosers

Install three-phase reclosers with full communications and control to minimize the number of customers affected by circuit operations. These devices operate automatically to isolate faulted line sections.

Capacitor Banks

Analyze each distribution circuit for reactive power, and then develop a master plan for both fixed and switched capacitor banks. Existing banks may be utilized, re-deployed, or rebuilt with new controls and communications.

Air Break Switch Controls

An aggressive replacement program is in the final stage of completion. The unitized switch reduces the need for maintenance and adjustment of the operating mechanism. These switches are utilized to isolate circuit sections and to pick up load from other sources. Communications and motor operators are needed to integrate these into the Smart Grid program.

Single-Phase Sensors

These devices are utilized to monitor loads at various points on the distribution system, to reduce outage times, particularly during cold load pickup.

Voltage Regulator Controls

By monitoring and controlling Load Tap Changers (LTC's), voltage regulators, and capacitor banks, the distribution system can be optimized to reduce line losses while maintaining first and last customer voltage levels within standards.

Pad-Mounted Switch Gear

These devices operate similarly to air break switches; they are three-phase gang-operated switches for switching operations in the underground distribution system. The addition of relaying and motor operators will allow for fault isolation and service restoration in a timely manner.

New Poles

To facilitate the installation of the new devices (capacitor banks, reclosers, and voltage regulators), pole replacement and new pole installation will be required.

In addition to the DA devices and equipment, the following measures are necessary to realize the potential of an automated circuit:

Distribution SCADA Support

The installation of multiple devices in the field will require a distribution SCADA tool. The number of data points will increase dramatically over the existing SCADA system. We currently monitor fewer than 10,000 data points on the transmission system including distribution breaker information. We anticipate a full-fledged distribution automation system to include 30,000 data points.

Implementation of 2-Way Voice/Data Communication to DA Devices

At the heart of the Distribution SCADA system is a robust communication system to allow for real-time data collection and control from the various sensors and devices on the system. This communication network also will position us for automated data dispatch.

DP&L Engineering & Project Management

Significant engineering time will be required to coordinate the devices proposed for the system. Relay and feeder switching schemes must be properly designed and tested prior to implementation to ensure proper operation of each component. The installation of components will require coordination with various work groups to ensure all components are installed in the appropriate timeframe and to DP&L standards. New Standard Operating Procedures will need to be developed to ensure that safety standards continue to be met while accommodating the automatic and operator control of the equipment in the distribution system.

Outsourced Engineering

External engineering resources are needed to support the extra work of creating the new processes, programs, installation of additional equipment and support the expansion of equipment deployment after year six when the volume of circuits increases dramatically. Power factor analysis, capacitor installation, and fuse/device coordination are all functions which will require circuit analysis, design and optimization during and after the initial deployment.

Q. Please describe in more detail the plan for Substation Automation.

A. Effective implementation of Substation Automation ("SA") technology requires upgraded relay protection and communication systems in substations to enable fault isolation and load redistribution. In years 2009 through 2014, DP&L plans to automate 6-7 substations per year and in the final year of the development phase, 2015, DP&L will automate an estimated 12 substations. The Company expects to continue to automate substations at the rate of 12 per year through 2023.

Specific technology and infrastructure required to fully automate a substation will include the following:

New Relays

To fully implement Smart Grid technology electro-mechanical relays need to be replaced with digital, programmable relay schemes. The digital relays store event data which can be accessed to aid in the diagnosis of circuit problems. The digital relays do not require on-going calibration; via secure communications they can be remotely adjusted for changing field conditions.

Upgraded Pilot Wire

The Pilot Wire Upgrade to a fiber network is necessary to allow protection switching between the various relays around the Crown Substation area. The current copper wire system is inadequate for our system needs and creates a situation where additional transmission lines trip due to a lack of communication between the substations. The fiber will also be used for SCADA communication to the substation equipment in this region and will provide backhaul for AMI infrastructure co-located in these substations.

Communication Gateways

The communications gateway will be installed at all distribution substation locations. These gateways will provide communications between devices in the Distribution SCADA control system and the Distribution Management System, which is critical to the success of the CCEM Programs. The real-time collection of data from the various sensors at the substation and the control of the Smart Grid enabled substation equipment will be utilized for contingency switching plans and optimizing the voltage of the substation during normal conditions. This will be done in conjunction with capacitor banks and monitoring the voltage at the smart meters and will allow us to lower the line loss along the distribution network. In addition, the communication gateway at the substation will be used to adjust the voltage at the substation during normal operations and during peak energy conditions to reduce peak energy demand.

SCADA Communication Upgrade

DP&L will provide real-time communications to all substations through IP-enablement of existing fiber, upgrading the Microwave sites to support IP, or through broadband IP radios. The communication gateway requires a Distribution SCADA tool and real-time

communication system to bring substation data and control back to the system operator. The Distribution SCADA system and communication upgrade will permit the operator to monitor the state of the substations and distribution system and respond to changing field conditions to minimize customer outages and power system losses.

2-Way Voice Radios

Communications between system operators and field maintenance crews will be required for advanced switching and maintenance activities. Release of specific equipment and clearance points associated with each device are required. In addition, the 2-Way Voice and data network will supply an Internet Protocol ("IP") communication pipe between the Distribution SCADA system and the communication gateway in the substations.

Similar to the resources required for DA, DP&L engineering, project management, and outsourced engineering resources will be required to move from non-monitored substations to a fully automated system. Communication paths between substation Remote Terminal Units ("RTUs") and system operating must be designed for the approximately 40 substations not currently monitored via the SCADA system. In addition, relays at these substations will need to be upgraded to digital recording relays.

IV. TELECOMMUNICATIONS INFRASTRUCTURE

Q. Please describe the telecommunications infrastructure required to support both AMI and Smart Grid Development.

A. Required telecommunications are broken into three key areas: AMI Infrastructure, a licensed 800 MHz IP fixed-data solution (2-Way Voice/Data Network), and Microwave IP backbone. These three networks make up the critical communications that provide the

end-to-end communications to connect the AMI Meters for commercial and industrial ("C&I") and residential customers, new substation control, and the distribution automation devices on the feeders to the DP&L IT systems that control, monitor, and collect data from these more than 500,000 devices in the field.

AMI Communications Infrastructure

The AMI Infrastructure consists of the communications hardware and software and associated system and data management software that creates a two-way communications network between AMI meters and the new Microwave IP backbone which connects to the utility business systems that allow collection and distribution of the AMI information to customers and the utility. This infrastructure must provide the connectivity to all the meters in DP&L's service territory which has a wide variety of coverage requirements from urban to rural and from outdoor meters to those in a basement or metering closet. As with any AMI and Smart Grid deployment, the communications network is indispensable to the ability to share this new valuable information across the distribution system. DP&L has invested significant time into deciding what will be the best solution for today and into the foreseeable future. Some utilities look to have multiple communications solutions for the AMI system to cover the urban and rural areas, but after much time working with the various AMI communications vendors, DP&L has determined that one communication system can fulfill the needs of our proposed system. This one system will be at a lower price than two systems and the ongoing operational costs will be lower by maintaining one system for the smart metering. The key requirements of the system are:

- Expandable for growth of future applications.

- Low enough latency to be able to get an on-demand reading from a customer's meter while the customer is on the telephone with the DP&L call center to resolve quickly billing issues and service issues.

- Enough bandwidth to support short-interval data from C&I customers and residential customers.

- Home Area Network support to extend the communication to Energy Displays, Load Control Relays, and Programmable Thermostats.

- Fast Communication for Pricing signals, Load Management Events, and message information, such as severe storm warnings or messages about power outage events, directly to the Home Energy Display or programmable thermostats.

Licensed 800 MHz IP Fixed-Data Solution (2-Way Voice/Data Network)

This wide-area data network will be necessary to provide connectivity to over 500 of DP&L's largest Commercial and Industrial customers for AMI power quality services, to provide connectivity to distribution automation devices, and to ensure standard AMI service to 100% of DP&L's meters anywhere in its service territory.

This new network was selected to enable the communications to DP&L's top 500 C&I customers while meeting the DP&L's requirements for reliability, flexibility, throughput, and very low latency (less than one second response time). The licensed 800 MHz IP fixed-data network supports IP communications at 96kbps over the air data rate, enabling DP&L not only to collect 5 minute interval AMI information, but also to remotely open the user interface of the C&I meter to analyze key power quality measurements associated with the energy being delivered to DP&L's largest customers. This ability to

view real-time power quality information from DP&L's largest customers in an on-demand fashion will enable DP&L to remotely troubleshoot and to monitor any power-related issues for this customer segment. Today's standard AMI solutions have high latency characteristics and cannot provide the real-time power quality feeds from the C&I power quality meters. And, while public carrier based IP solutions can provide real-time power feeds from C&I smart meters, these IP solutions do not have ubiquitous coverage throughout our service territory. In addition, public carrier-based solutions do not have the operational reliability required by DP&L during mission critical emergency situations.

The licensed 800 MHz IP fixed-data network is also critical to support DP&L's Smart Grid strategy by providing communications to distribution automation devices that make up the new control and monitoring points in the electrical distribution network. This network provides continuous coverage in the urban and rural areas as well as the reliability and security necessary to support these new critical components in DP&L's electric distribution network. The Company believes that for both safety reasons and for optimal control, the control of these active devices must be through a licensed, secure, and extremely low latency communication link that also has coverage throughout DP&L's service territory. It is important that the communication link be IP-based with significant capacity to be able to deliver remote, real-time SCADA information but also be able to remotely configure and troubleshoot control devices.

The third reason to deploy the licensed 800 MHz IP fixed-data network is to deliver AMI capabilities to those otherwise excluded from the standard AMI solution due to lack of AI radio coverage for those meters. The number of meters that otherwise would be expected not to have AMI coverage is between 0.5% and 1.0%.

Microwave IP Backbone

Due to the additional bandwidth needed to support the new data systems for AMI, distribution automation, substation automation, the licensed 800 MHz IP fixed-data network, as well as the fact that the current SONET Microwave network is near 80% of its capacity, a new IP-based Microwave system will be installed. This network provides the connectivity to the licensed 800 MHz IP fixed-data network base stations and AMI access points, and distribution substation communication gateways, located in substations dispersed throughout DP&L's 6,000 square mile service territory. The upgraded Microwave IP network will allow for IP traffic flexibility and bandwidth for all devices in the field along with bandwidth shaping capability and redundancy in case of any one individual link failure. This network will provide the necessary capacity, reliability, and security to support the extensive communications required for all of DP&L's needs related to AMI, energy efficiency, demand response, and Smart Grid.

Q. Please provide the rationale for replacing DP&L's existing analog 800 MHz system used for voice dispatch of DP&L's mobile workforce and the current SONET Microwave network?

A. DP&L looked at several potential solutions to meet the needs of power quality meters, distribution automation, and 100% AMI meter coverage. DP&L concluded that a licensed 800 MHz two-way IP fixed-data solution would best meet the Company's needs. Due to spectrum constraints in this band, the most cost effective method is to replace the existing analog 800 MHz dispatch solution with a multi-functional 2-way voice/data IP solution that can reuse the 800 MHz frequencies that DP&L already owns. Since the new system is spectrally more efficient, it will meet the requirements of the licensed 800 MHz IP fixed-data network as well as support the voice dispatch requirements that were previously supported by the existing analog 800 MHz system. Effectively, this new

licensed 800 MHz IP fixed-data solution will replace DP&L's existing analog 800 MHz system used for voice dispatch of the mobile workforce.

The Company also evaluated several options to provide the necessary bandwidth to support the integrated CCEM Programs. DP&L determined that the most cost-effective solution is to replace the existing SONET Microwave system. The existing SONET Microwave system does not have the additional capacity to support the communication from the substations, distribution automation components, or the AMI meters. DP&L explored an overlay design that would add an additional Microwave channel on the current ring architecture to carry the IP traffic. DP&L concluded, however, that the most cost effective solution is to replace the existing SONET Microwave network with a new IP-based Microwave system. The primary benefits of this replacement strategy include:

- Reduction of maintenance from two microwave networks to a single network
- Reduction of power, battery back-up, and floor space requirements at the microwave sites
- More expedient switchover to back-up control center during a disaster.

V. COSTS AND BENEFITS

Q. What capital investments are required to implement AMI?

A. DP&L will need to invest $ 296.6 million in modernization infrastructure to support its CCEM plan. The approximate costs for AMI for the smart meters, communications infrastructure, home energy displays and the development of the Smart Grid deployments are listed below:

- Smart meter and installation costs $ 90,500,000

• Communications systems infrastructure	$ 55,300,000
• Home energy displays	$ 13,400,000
• Smart grid development	$ 41,600,000
Subtotal	$200,800,000*

**(Excludes IT investment which is covered in testimony of DP&L witness Garrison)*

The exact figures are shown in workpapers WPH-1.1; 1.2; 1.3 and WPI – 1.1; 1.2.

Q. What O&M expenditures are required to implement AMI?

A. DP&L will need $67.4 million in O&M costs over the first seven years to support the modernization infrastructure for the CCEM plan. The approximate O&M costs for the AMI for the smart meters, communications infrastructure, home energy displays and the Smart Grid deployments are listed below:

• Smart meter and installation costs	$12,600,000
• Communications systems infrastructure	$10,100,000
• Home energy displays	$ 2,500,000
• Smart grid development	$ 4,400,000
Subtotal	$29,500,000*

**(Excludes IT investment which is covered in testimony of DP&L witness Garrison)*

The exact figures are shown in workpapers WPH-1.2; 1.5; 1.6 and WPI-1.3; 1.4.

Q. Is that investment reasonable and prudent?

A. Yes. The above costs were derived from Requests for Proposals (RFPs), vendor-solicited quotes and our internal capital work-order estimating process. In February of 2008, DP&L and Bridge Strategy consultants began to develop the requirements for three distinct RFPs:

1. AMI – This RFP included the smart meters with remote disconnect technology, communication system to the meters, home energy display and demand response equipment costs.

2. Two-way mobile/fixed-data and voice system – This RFP included all costs for a new mobile data and voice system with the capabilities to communicate to 500 high-end polyphase meters, to communicate with the Smart Grid components and transport this data back to the main office or to additional smart devices located in the substations.

3. Microwave Communication IP Backbone system – This system will be the primary communication system for transporting the entire field collected data back to the main office. The system will provide information flow among the main office and the DP&L substations.

The remaining costs were solicited from the vendors working in the Smart Grid field. DP&L estimated the head count figures and O&M costs.

Q. Does your proposal place sufficient emphasis on and dedicate sufficient resources to meeting customers' expectations about the reliability of your distribution system?

A. Yes. One of the primary customer benefits of AMI is improved network reliability and system responsiveness. AMI meters can help to reduce both the number of outages and the duration of outages by providing:

- Real-time monitoring of the distribution network, which allows for earlier outage detection;

- Enhanced ability to locate where an outage has occurred, allowing a utility to dispatch repair crews directly to the location;
- Improved verification of customer service restoration; and
- Better control of activity over the distribution systems

The Smart Grid technology that we plan to deploy relies directly upon the new capabilities of the meters to enhance the reliability of the distribution network even further. For example, distribution automation technologies will allow us to isolate faults and restore non-damaged portions of the circuit based on real-time parameters of voltage, current, breaker status and supervisory-controlled switch positions. To optimize the benefits to customers' reliability, we will prioritize equipment rollout based on each circuit's current Customer Average Interruption Duration Index ("CAIDI") ratings. There is a strong precedent for relying upon DA to improve reliability. Examples include utilities such as Long Island Lighting Co, CenterPoint Energy, and PPL (Allentown, PA.)

Q. Can you describe the reliability of DP&L's existing distribution system?

A. DP&L tracks and reports reliability indices to the Public Utilities Commission of Ohio. These are: 1. Customer Average Interruption Duration Index ("CAIDI"), 2. System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). DP&L has performed well in meeting and exceeding their reliability targets. DP&L and the PUCO established the reliability targets pursuant to O.A.C. 4901:1-10-10(B)(2) and the 2007 target and actual scores are shown in table 1 below. The Smart Grid investments discussed in this testimony will further improve the reliability of DP&L's existing distribution system.

Table 1			
Reliability Targets:	**Performance Target**	**Performance With Storm & Transmission Exclusions**	**Performance Without Storm & Transmission Exclusions**
Customer Average Interruption Duration Index ("CAIDI")	98.38	88.53	112.72
System Average Interruption Duration Index ("SAIDI")	94.61	83.98	143.88
System Average Interruption Frequency Index ("SAIFI")	0.99	0.95	1.28

Q. Will DP&L be able to maintain its current level of reliability without additional reliability investment?

A. No, it will not. DP&L's existing distribution system is aging, and needs significant investment to maintain and improve reliability. DP&L intends to implement the Smart Grid investments discussed in this testimony in part to improve reliability of its distribution system.

Q. Do you believe that DP&L's expectations as to the reliability of its distribution system are aligned with the expectations of DP&L's customers?

A. Yes. The best measure of customer expectations as to reliability is the standards set by the Commission, which DP&L consistently meets. It is important to note that as customers become more reliant on electricity (to operate home computers, cell phones, cordless telephones, etc.) and their expectations as to reliability continue to increase, DP&L's Smart Grid investments will improve the reliability of DP&L's distribution systems so that DP&L can continue to meet those expectations. DP&L performs an annual "Customer Value Survey" that the company started in 2006. As part of this survey DP&L seeks to find out how customers feel about their electric reliability. The

customer responses indicate DP&L as doing a good or excellent job with reliability (2007 and 2006 at 87.1%).

Q. Are there Energy Efficiency benefits from Smart Grid Development?

A. Yes. DP&L's Smart Grid development and future deployment will significantly improve efficiency, first by reducing line losses. Line loss reduction will be accomplished through modeling the distribution circuits and effective placement of the capacitor banks, which will allow DP&L to reduce energy losses on the distribution system.

Elements of distribution and substation automation can also be used to assist in managing power demands on peak load days. One of the operational characteristics of the distribution system that can be managed through distribution automation is the voltage profile along the feeder. Since loads are dynamic and the amount of current affects the voltage drop along the feeder by using voltage monitoring and dynamic switching of capacitors and regulators, it is possible to control the voltage profile.

With the Smart Grid in place, DP&L will have a real-time monitoring system and be able to better predict areas of the distribution system that create high line losses and will be able to mitigate these areas for greater energy efficiencies.

Q. What are the energy and demand savings from Smart Grid Deployment?

A. DP&L expects to begin to realize a reduction in line losses of 54,110 MWh through 2015. And, based on successes at other utilities, DP&L expects to be able to trigger voltage changes at peak times, also known as dynamic voltage control (DVC), thus reducing peak demand by 5.4 MW in year 2015.

1 Q. **Can you identify the operational benefits that DP&L believes can be achieved**
2 **through the AMI and Smart Grid Development?**

3 A. Yes. Total operational benefits from AMI over the seven years of our proposal are
4 approximately $52M, as follows:

5 **Reduction in Meter Reading Expense - $11,149,321**
6 AMI would eliminate on-cycle manual and mobile meter reading and associated costs.
7 The benefit value includes all direct meter-reading labor expense, supervisory labor
8 expense, vehicles, equipment, associated building leases, and other miscellaneous
9 materials. Also included are maintenance/upgrade expenses for current meter-reading
10 devices and yearly salary increases for meter readers and supervisors.
11 **Reduction in Energy Theft - $8,833,691**
12 AMI reduces energy theft in three ways. First, during deployment, DP&L's vendor will
13 be removing every existing meter and replacing it with a new solid-state meter, and the
14 installers will be trained to notice irregularities that can be investigated as potential theft.
15 Second, a tamper-detection capability of the new meters will virtually eliminate meter
16 tampering as a source of energy theft. The new meters will provide a tamper notification
17 that will be analyzed and potentially investigated for theft. Third, the more sophisticated
18 MDMS should allow DP&L to better detect bypass and partial-bypass theft through data
19 mining. The total of these three reductions in energy theft is anticipated to save an
20 average of 0.5% of the revenue associated with each residential AMI meter.

21 **Reduction in Uncollected Accounts - $970,120**
22 Most collection efforts center on a regimented process that is affected by missed meter
23 readings. With remote disconnect capability on the meters, AMI's effect on collections is

a positive one based on the elimination of estimated reads and reduction in multi-month bills caused by failure to gain access to indoor meters.

Reduction in No Outage Calls - $502,509

This figure results from a reduction of service calls to investigate a customer's meter that the customer believes is not performing properly. Since the AMI solution provides the DP&L customer operations team with the ability to look at the real-time view of the meter status, there will be a reduction in customer-generated service calls when the system is operating properly.

Reduction of Compensation/Claims for Meter Reading - $1,896,000

Utility costs for workers' compensation associated with injuries incurred by employees during meter reading can be reduced upon adoption of an AMI system, as meter readers would no longer be exposed to high-crime areas, dogs, fences, adverse weather, etc. Costs associated with vehicular accidents occurring during travel between meter-reading locations in the field and utility premises would also be eliminated with AMI systems.

Increased Revenue Due to Improvement in Meter Accuracy - $7,069,353

Evidence shows that electro-mechanical electric meters begin to under record usage with age due to the wearing of the moving parts. Solid-state electric meters do not generally have this problem, and, therefore, average meter accuracy will improve as electro-mechanical meters are replaced. Moreover, solid-state meters fail more conspicuously than electro-mechanical meters and are, therefore, more readily identified. Sample testing of DP&L's electro-mechanical meters from the field have shown an average under usage recording of 0.4%.

Reduction of Bill Processing Costs due to Fewer Exceptions - $268,600

1 An important AMI benefit is a reduction in billing department resources needed to
2 investigate billing problems and process adjustments. Daily reads from AMI eliminate
3 the need for calculation of estimated bills caused by service contract disputes, backdated
4 cancellations and turn-ons. Keypunch errors and unusual usage patterns are eliminated or
5 quickly detected by AMI, reducing the need for many of the more difficult billing
6 problems that can occur, and which often take significant clerical time to resolve.

7 **Reduction of Field Service** - $3,476,000

8 Since the AMI system will be capable of obtaining daily reads from all customers, a
9 reduction in the number of field services personnel can be achieved. A high percentage
10 of field work in this category involves obtaining missed meter readings, and turning on
11 and off customer services for cancelled and new accounts. In some cases, a physical
12 shutoff is required, which takes even more time. AMI network services that produce
13 daily readings can accomplish this function without the need for field visits, thereby
14 bringing about a significant reduction in the number of personnel used for this purpose.

15 The implementation of the AMI system will make the process of turn-ons, and shut-offs
16 and off-cycle reads much easier on customers and will resolve many meter access
17 problems. The on-demand reading capability will enable the Company to read meters to
18 issue final bills or initiate service remotely. The increased process efficiency and reduced
19 time to execute the requests will make the company much easier to do business with and
20 enhance the overall customer experience.

21 Again, the reduction in field personnel will produce a corresponding reduction in the need
22 for indoor readings and the number of vehicles used for these functions.

23 **Deferral of Metering Capital Costs** - $79,000

1 Deployment of AMI would defer the capital costs associated with replacement of meters
2 and other manual meter-reading equipment (e.g., vehicles) that would otherwise have
3 been required due to the aging meter assets. This capital deferral is offset by the annual
4 failure rate of newly installed AMI equipment (e.g., meters, telecommunications).

5 **Reduction of Call Center Contacts for Bill-Related Calls - $650,960**
6 Estimated meter readings often generate customer calls associated with billing issues.
7 With monthly, daily, or more frequent readings from AMI, these missed readings and
8 associated estimated bills can be reduced, thereby decreasing customer call volume and
9 call center agent time spent handling these billing inquiries.

10 **Reduction of Load Research Costs - $316,000**
11 AMI can provide data for load research studies, thereby decreasing the need for more
12 costly load research metering equipment and services, such as telephone lines and costly
13 field maintenance.

14 **Reduction of Revenue Losses from Unoccupied Premises - $110,600**
15 With the ability to perform daily or more frequent readings, consumption from premises
16 that are supposed to be unoccupied can be more quickly identified and addressed. DP&L
17 will be deploying remote disconnect relays on all residential AMI meters, enabling the
18 "inactive" meters to be shut off. This capability is expected to limit utility exposure to
19 write-offs of charges for consumption registered on "inactive" advancing meters on
20 accounts closed after customers inform DP&L that they are moving out.

21 **Reduction of Meter Testing Costs for New Meter Shipments - $63,200**
22 During the deployment period of the AMI network, there will not be a need to test a
23 sample of the new meters shipped to DP&L. The cost of providing factory test

information and system validation of all AMI meter deployments is included in the capital costs of the AMI solution.

Total Field Crew Savings from Telecom Upgrades - $884,986

This savings is from lower vehicle and overtime expenses through more efficient dispatch capabilities provided with the new 2-Way Voice & Data network.

Reduction in Existing Two-Way Radio Maintenance - $632,765

This savings comes from the reduction in maintenance expenses for the existing two-way voice and data system during the deployment period of the new network.

Reduction in IT System Capital and Maintenance - $6,588,670

This savings comes from capital improvements and maintenance cost reductions to the existing IT systems that are not going to be spent given the deployment of the new AMI-compatible IT systems that will be deployed during this time period.

Depreciation Savings from Early Retirement of Capital - $8,217,855

Due to AMI deployment, the Company will retire select equipment earlier than expected reducing our total depreciation expense. In addition to meters, select IT will be retired early such as post-2008 software editions.

Total operational benefits from Smart Grid Development over seven years are approximately $1.1M. Operational Benefits from Smart Grid include:

Reduction of Planned Substation Capital Costs - $523,276

The substation upgrades eliminate planned upgrades for the substation equipment.

Reduction of Capacitor Bank Manual Inspection - $135,782

Distribution automation will enable the automatic monitoring of capacitor banks; this reduces the need to perform manual inspection of capacitor banks.

Better Utilization of Substation Capital - $104,655

Monitoring of the substation equipment helps to ensure that the equipment is not operating outside recommended parameters, thereby increasing the life of the equipment.

Reduced RTU Maintenance Cost - $113,634

The upgrade of the communication gateways eliminates the cost of maintaining some of many older RTUs currently deployed in DP&L substations.

Savings from Increased Crew Productivity - $88,913

Distribution automation allows fault isolation, which enables crews to spend less time identifying the point of failure. The deployment of the 2-Way voice/data system that provides the communications to the new distribution and substation automation equipment also supports more automated dispatch of the DP&L field crews. This capability reduces the time needed for the crew to arrive at the failure location.

Reduction in Transformer Replacement Capital - $75,849

The improved monitoring of voltage, current, and power in the distribution network helps to eliminate overloaded distribution transformers and extend their operational lives.

Deferral of Capital Costs (Switches, Cap Banks, etc.) – $53,127

The distribution automation upgrades eliminate planned upgrades for the distribution equipment.

Increase in DP&L Revenue due to SA Related Reduced Outage Time - $16,905

Shorter and less frequent outages due to substation equipment failure will enable the Company to deliver additional electricity to customers.

Savings from Reduction in Outage-Related Calls - $7,873

Shorter and less frequent outages will reduce customer service call volume, resulting in call center cost savings.

Increase in DP&L Revenue due to DA-Related Reduced Outage Time - $7,852

Shorter and less frequent outages due to distribution equipment failures will enable the Company to deliver reliably additional electricity to customers.

VI. IMPLEMENTATION PLAN

Q. Please explain DP&L's plan for implementing AMI and Smart Grid Development as well as the supporting telecommunications infrastructure.

A. DP&L expects to begin deployment in January of 2009 or upon approval from the Commission. One hundred percent of meters should be replaced over six years and the core enabling telecommunications infrastructure will be fully installed by the end of year four. While IT systems necessary to support the AMI functionality are expected to be in place by the end of year three, DP&L will phase in the functionally of the system as the infrastructure goes in to service. The plan is to start infrastructure deployment in the south part of the Metro Dayton area. We currently have sufficient capacity to connect circuits for automated switching. The Company will deploy the entire planned field infrastructure in this area. This will allow DP&L to have a fully-functional-Smart Grid field test area. With this system in place, the evaluation to verify the benefits of the Smart Grid and AMI system can proceed. The infrastructure deployment will continue from this area outwardly across our service territory starting within the most populated

areas. The deployment will start in the urban areas, and by year three, moves into the rural areas and will be complete by year seven of the project.

Q. Please describe what staffing changes will be required to support the implementation.

A. To complete the installation the field automation equipment, DP&L will need to hire additional engineers with skills in the communications, substation and distribution system planning areas. DP&L will also require technicians with field skills in the same areas of expertise. As with any new project installation, DP&L will hire people to fulfill the roles of project managers. As the project progresses the metering functions will be downsized, as will some of the field functions, such as disconnect/reconnect and capacitor bank monitoring as these will be done through the communications systems. Throughout the seven-year project, the staffing will change and adjust and the Company will end up with an additional eight employees to support the ongoing field infrastructure.

VII. WORKPAPERS

Q. For what workpapers are you responsible?

A. I am responsible for AMI Workpapers WPH – 1.1, 1.2, 1.3, 1.5, 1.6, 1.7, 1.8 and Smart Grid workpapers WPI – 1.1, 1.2, 1.3, 1.4, 1.5, 1.6. The numbers in the workpapers came from a process that DP&L started in February of 2008 or from DP&L estimates where DP&L obtained budgetary estimates from the vendors for the different tasks of the project, or from previous costs from the current capital budgeting process. The workpaper identifies which method was used in obtaining the numbers.

Q. What is shown on Workpaper WPH-1.1?

A. Workpaper WPH-1.1 "AMI Meters" shows the annualized capital costs for the smart meters, the installation of the meters, the engineering and project management for the installation and programming the new equipment, and the cost to enhance the GIS system with the connectivity of the new meters.

Q. What is shown on Workpaper WPH-1.2?

A. Workpaper WPH-1.2 "Energy Displays Capital and O&M" shows the annualized capital costs for the home energy displays to be provided for the customers that do not have access to the internet. The customers will utilize these displays to view their energy usage patterns and to get price signals from DP&L.

Q. What is shown on Workpaper WPH-1.3?

A. Workpaper WPH-1.3 "AMI Communications Capital" shows the annualized capital costs for the installation of the communication network to support the AMI. These costs include the installation of the communication equipment, the engineering and project management for the installation and programming the new equipment.

Q. What is shown on Workpaper WPH-1.5?

A. Workpaper WPH-1.5 "AMI Meter O&M" shows the annualized operations and maintenance costs for the ongoing support of the AMI system. These numbers came from DP&L estimates where DP&L obtained budgetary estimates from the vendors for the different tasks of the project, or from projected costs to support the new capital infrastructure based on historical percentages.

Q. What is shown on Workpaper WPH-1.6?

A. Workpaper WPH-1.6 "AMI Communications O&M" shows the annualized operations and maintenance costs for the ongoing support of the AMI core telecom systems. These numbers are based on industry averages for O&M costs as a percentage of the total installation costs.

Q. What is shown on Workpaper WPH-1.7?

A. Workpaper WPH-1.7 "AMI Meter Benefits" shows the benefits of the AMI system and the corresponding estimated savings from the installation of the AMI system. Descriptions of each benefit can be referred to in the AMI chapter of the CCEM Application.

Q. What is shown on Workpaper WPH-1.8?

A. Workpaper WPH-1.8 "AMI Communications Benefits" shows the benefits from the replacement of the current systems and the reduction in O&M costs due to replacement.

Q. What is shown on Workpaper WPI-1.1?

A. Workpaper WPI-1.1 "Distribution Automation Capital" shows the annualized capital costs for the equipment, installation, engineering and project management for the distribution automation portion of the Smart Grid development.

Q. What is shown on Workpaper WPI-1.2?

A. Workpaper WPI-1.2 "Substation Automation Capital" shows the annualized capital costs for the equipment, installation, engineering and project management for the substation automation portion of the Smart Grid development. We will be installing smart relays

and communications gateways to allow the sharing of information between the distribution devices and the substation devices.

Q. What is shown on Workpaper WPI-1.3?

A. Workpaper WPI-1.3 "Distribution Automation O&M" shows the annualized operations and maintenance costs for the ongoing support of the distribution automation equipment. These numbers came from DP&L estimates where DP&L obtained budgetary estimates from the vendors for the different tasks of the project, or from projected costs to support the new capital infrastructure based on historical percentages.

Q. What is shown on Workpaper WPI-1.4?

A. Workpaper WPI-1.4 "Substation Automation O&M" shows the annualized operations and maintenance costs for the ongoing support of the new substation automation equipment. These numbers came from DP&L estimates where DP&L obtained budget estimates from the vendors for the different tasks of the project, or from projected costs to support the new capital infrastructure based on historical percentages.

Q. What is shown on Workpaper WPI-1.5?

A. Workpaper WPI-1.5 "Distribution Automation Benefits" shows the benefits from the implementation of the distribution automation and the corresponding estimated savings. Descriptions of each benefit can be found in the Smart Grid Development chapter of the CCEM Application.

Q. What is shown on Workpaper WPI-1.6?

A. Workpaper WPH-1.6 "Substation Automation Benefits" shows the benefits from the implementation of the substation automation equipment and the corresponding estimated savings. Descriptions of each benefit can be found in the Smart Grid Development chapter of the CCEM Application.

VIII. CONCLUSION

Q. Please summarize your testimony.

A. In summary, DP&L expects to spend $296.6M in capital and $67.4M in O&M between 2009 and 2015 to implement its AMI and Smart Grid Development plans. Deployment will begin in January 2009 or upon PUCO approval. The modernization of the distribution infrastructure will allow DP&L to fulfill the CCEM plan. With this automated system, the customers will have the tools to understand and affect their electric energy usage. The CCEM plan will also allow the Company to have the systems in place to provide the customers with more pricing options and even greater control of their energy usage as the deployment continues. The modernization also allows DP&L to increase the reliability of the distribution system by decreasing customer outage interruption time. With the implementation of these systems, DP&L will be in a position to continue the modernization process in the future and to create more value for the Company's customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.