Otter Tail Corporation d/b/a

Otter Tail Power Company

Before the

North Dakota Public Service Commission

Application for Authority to Increase Electric Rates in North Dakota

Case No. PU - 08 - ____

November 3, 2008

Volume 2B

Direct Testimony and Supporting Schedules

Otter Tail Power Company

North Dakota General Rate Case Documents

Volume	Section	
1	1	Letter of Transmittal Notice of Proposed Change of Rates and Charges Deficiency and Proposed Revenues Alternative Petition for Interim Rates Interim Tariffs
2A	1	Testimony and Schedules of Witnesses Thomas Brause Policy Peter Beithon Jurisdictional Cost of Service Operating Statement Class Cost of Service Kyle Sem Rate Base Bernadeen Brutlag Depreciation Allocation Depreciation Expense Corporate Allocations Economic Development Kevin Moug Financial Soundness Capital Structure Cost of Capital
2B	1	Robert Hevert Return on Equity Peter Wasberg Employee Compensation David Prazak Rate Design Hethie Parmesano Marginal Cost Study
3	1	Present and Proposed North Dakota Rate Schedules, Rules and Regulations
4A	1	2007 Test Year Work Papers Jurisdictional Cost of Service Study (JCOSS) Class Cost of Service Study (CCOSS) Functionalization Input Summary Test Year Adjustments
	2	2007 Actual Year Work Papers Jurisdictional Cost of Service Study (JCOSS) Functionalization Input Summary Work Papers A-D
4B	1	Lead Lag Study

Volume 2B

Testimony and Schedules of Witnesses:

Robert Hevert

Return on Equity

Before the North Dakota Public Service Commission

State of North Dakota

In the Matter of the Application of Otter Tail Corporation

d/b/a Otter Tail Power Company

For Authority to Increase Rates for Electric Utility

Service in North Dakota

Case No. PU-08-___

Exhibit___

RETURN ON EQUITY

DIRECT TESTIMONY AND SCHDULES OF

ROBERT B. HEVERT

November 3, 2008

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert B. Hevert. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

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

A. I am employed by Concentric Energy Advisors ("Concentric") as its President.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of Otter Tail Power Company ("OTP" or the "Company"), a separate operating division of Otter Tail Corporation ("OTC").

Q. PLEASE BRIEFLY OUTLINE YOUR RESPONSIBILITIES AS PRESIDENT OF CONCENTRIC.

A. In addition to providing consulting services, my responsibilities at Concentric include the day-to-day management of the firm and, along with other senior officers, the development of the firm's resources and capabilities, the development of new business and clients, and assuring the quality of services delivered to our firm's clients.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelors degree in Business and Economics from the University of Delaware, and an MBA with a concentration in Finance from the University of Massachusetts. In addition, I hold the Chartered Financial Analyst designation.

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have served as an executive and manager with other consulting firms (REED Consulting Group and Navigant Consulting, Inc.), and as a financial officer of Bay State Gas Company. I have provided expert testimony regarding strategic and

financial matters, including the cost of capital, before the state utility regulatory agencies of Arkansas, Colorado, Maine, Massachusetts, Minnesota, New Hampshire, New Jersey, New Mexico, New York, Rhode Island, Texas, Utah, Vermont and Virginia, as well as the Federal Energy Regulatory Commission ("FERC"). In addition, I have advised numerous energy and utility clients on a wide range of financial and economic issues including both asset and corporate-based transactions. Many of those assignments have included the determination of the cost of capital for valuation purposes. I have included my resume as Exhibit __(RBH-1), Schedule 1 and a summary of testimony that I have filed in other proceedings as Exhibit __(RBH-1), Schedule 2.

Q. PLEASE DESCRIBE CONCENTRIC'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A. Concentric provides financial and economic advisory services to a large number of energy and utility clients across North America. Our financial advisory activities include merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. Our regulatory economic and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, and litigation support.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Company's return on equity ("ROE"), and to provide an assessment of the capital structure to be used for ratemaking purposes, as proposed in the Direct Testimony of Mr. Kevin C. Moug. My analysis and recommendations are supported by the data presented in Exhibit __ (RBH-1), Schedules 3 through 9.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY AND OVERALL RATE OF RETURN FOR THE COMPANY?

A. Based on the analyses I have performed in this proceeding, I recommend that the North Dakota Public Service Commission (the "Commission") authorize OTP the opportunity to earn an ROE of 11.25 percent. As described in greater detail later in my testimony, that recommendation is based on the use of several well-accepted methodologies. I also have concluded that the Company's projected test year capital structure, which includes 53.30 percent common equity, 3.60 percent preferred stock, 40.30 percent long-term debt and 2.80 percent short-term debt, is reasonable.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSIS THAT LED TO YOUR CONCLUSIONS.

A. My analyses begin with consideration of the relevant regulatory structure and precedents. To determine the appropriate ROE, I have employed several well-accepted approaches including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium approach. My applications of the DCF model are based on a variety of analysts' growth projections, current indicated annual dividends, and actual stock price information. Similarly, my CAPM analysis is specified using historical and projected market data with respect to Treasury yields, Beta estimates from Bloomberg and Value Line, and market risk premia data from Morningstar, Inc. (formerly, Ibbotson Associates). Finally, my Risk Premium analysis is based on historical market data with respect to utility bond yields, and average authorized returns for electric utilities.

In applying and assessing the results of my DCF, CAPM and Risk Premium analysis, I considered several specific risks and trends, including the Company's substantial capital expenditure plan. I also considered the flotation costs associated with equity issuances. While I did not make a specific adjustment for any of these factors, they should be considered when determining where, within a reasonable range of returns, the Company's ROE rightly falls.

Finally, I considered the Company's proposed capital structure within the context of its pending capital expenditures, general industry trends and proxy group norms. Based on that review, I concluded that the Company's proposed capital structure is reasonable.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized in seven sections. In Section III, I discuss the regulatory guidelines and financial considerations pertinent to the development of rate of return. Section IV provides an overview of current market conditions and the influence of these conditions on the recommended ROE. Section V explains my selection of a proxy group of integrated electric utilities. Section VI explains my analysis and recommendation of the appropriate ROE for OTP. Section VII provides a discussion of the business and economic risks to which OTP is exposed. Section VIII provides my assessment of the Company's proposed capital structure, and Section IX summarizes my conclusions.

III. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (i) consistency with other businesses having similar or comparable risks; and (ii) adequacy of the return to support credit quality and access to capital, while maintaining financial soundness. (Please refer to Appendix A.) It also is important to note that in *Hope*, the Court found that under the statutory standard of "just and reasonable" it is the result reached, as opposed to the method employed, which is

controlling. Consequently, it is appropriate to consider a variety of approaches and data sources when arriving at a recommended ROE.

Based on those widely recognized standards, the Commission's order in this case should provide OTP with the opportunity to earn a ROE that is:

- Adequate to attract capital on favorable terms, thereby enabling OTP to provide safe, reliable service;
- Sufficient to ensure the financial soundness of OTP operations; and
- Commensurate with returns on investments in enterprises having comparable risks.

The allowed ROE therefore should enable OTP to finance capital expenditures on reasonable terms and optimize its financial flexibility over the period during which rates are expected to remain in effect.

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. There is a long history of precedent regarding the allowed return on equity, the role of capital structure, and the resulting cost of capital in the establishment of just and reasonable rates for utility services. Among the themes common to many federal and state cases is the principle that a utility's cost of capital (including its capital structure and allowed return on common equity) must be reflective of other enterprises having comparable risks acting independently in the financial markets. As noted elsewhere in my testimony, a return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial integrity. To the extent OTP is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

Q. PLEASE DISCUSS THE IMPORTANCE OF THE ALLOWED RATE OF RETURN FROM THE PERSPECTIVE OF THE CAPITAL MARKETS.

A. The financial community continues to put the utility industry under intense scrutiny. Both equity and credit analysts have placed increasing focus on financial metrics and business risks for all utility companies. In its 2007 utility outlook, for example, FitchRatings noted several operating and regulatory issues that are likely to affect utilities' credit profiles:

- Continuing exposure to high and volatile energy commodity costs.
- Rising unit costs and need for base rate increases and steady recovery of fuel costs, so regulatory risk remains high. Event risk of political backlash against tariff increases.
- Electric utilities' higher capital spending will result in increased external funding needs and add to rising unit costs of service.[1]

Equity analysts also have focused on increasing capital expenditures in terms of their potential to elevate both financial and regulatory risks. In a recent report, for example, Barclays Capital (formerly, Lehman Brothers) noted that:

> With the likelihood that the current capex [i.e. capital expenditure] cycle will result in balance sheet strain, increased regulatory risks, and heightened execution risk, investors will likely demand a higher equity risk premium, in our opinion.
>
> ****
>
> While we would remain somewhat cautious regarding regulated utilities as we move through the capital cycle for all the risk factors mentioned above, and would largely key off valuation metrics for the group as a whole, there are three differentiators within the group that we believe are significant: (1) quality of regulation; (2) rate case processes, and (3) market capitalization.[2]

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[1] FitchRatings, *U.S. Power and Gas 2007 Outlook for Key Credits*, Global Power/North America Special Report (25 January 2007), at 2.

[2] Lehman Brothers, Regulated Utilities, *Industry Overview, Consequences of the CapEx Cycle*, June 4, 2008, at 4. [clarification added]

Thus, the capital markets are very aware of authorized utility ROEs and regulatory policy as it relates to utilities' ability to maintain their financial integrity and fund capital expenditures. As a consequence, significant deviations between authorized ROEs and investors' expectations can influence a company's capital investment strategy by reducing the availability of internally generated funds and diminishing access to reasonably priced sources of external capital. This concern is particularly acute in the current capital market.

IV. CURRENT ECONOMIC CONDITIONS

Q. HOW DO ECONOMIC CONDITIONS INFLUENCE THE COST OF CAPITAL AND RETURN ON COMMON EQUITY?

A. The required cost of capital, including the ROE, is a function of prevailing and expected market conditions. Consistent with the *Hope* and *Bluefield* decisions, the authorized ROE for a public utility should allow the company to attract investor capital at reasonable cost under a variety of economic conditions. The ability to attract capital on favorable terms is especially important during a period in which electric utilities are being asked by customers and regulators to enhance and expand system reliability and capacity.

Q. HOW DOES THE CURRENT STATE OF THE FINANCIAL MARKETS AFFECT YOUR ANALYSES AND RECOMMENDATION?

A. As a result of the general dislocation in the financial markets, there is significant pressure on financial institutions and rating agencies to tighten credit standards and, as has been widely reported, even highly creditworthy companies are finding it difficult to access the capital markets. As a result, interest rates on longer-term, intermediate quality corporate bonds have increased substantially, and the spread between Treasuries and corporate bonds has increased even more. As shown in Table 1 (below), while long-term Treasury bond yields have decreased by 75 basis points since August 2007 (which is generally considered to be the beginning of the ongoing credit

contraction), interest rates on long-term intermediate quality corporate bonds actually increased by 213 basis points. As a result, the actual cost of long-term debt has increased by 288 basis points.

Table 1: Recent Credit Spreads[3]

	Difference: 10/10/2008 – 8/1/07	October 10, 2008	January 2, 2008	August 1, 2007
Moody's Baa	+ 2.13%	8.75%	6.45%	6.62%
30-Yr. Treasury	-0.75%	4.15%	4.79%	4.90%
Credit Spread	+2.88%	4.60%	1.66%	1.72%

Q. HOW HAVE EQUITY PRICES RESPONDED TO THE CONTINUING DISRUPTION IN THE CREDIT MARKETS?

A. Since August 2007, the broad market (as measured by the Dow Jones Industrial Average) has fallen by approximately 29.75 percent. The Dow Jones Utility Average has fallen by approximately 24.29 percent during the same time period (*see* Table 2, below). Importantly, those declines reflect the effect of the historical one-day gain that occurred on October 13, 2008.

Table 2: Equity Market Performance[4]

	Difference: 10/13/2008 – 8/1/07	October 13, 2008	January 2, 2008	August 1, 2007
Dow Jones Industrial Average	- 29.75%	9,387.61	13,043.96	13,362.37
Dow Jones Utility Average	- 24.29%	370.58	525.69	489.46

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THAT DATA?

A. Based on that data, it is apparent that investors' perceptions of risk and, therefore, their return requirements, have increased in both the corporate debt and equity markets. This is an important point to bear in mind in the determination of the Company's

[3] Source: Federal Reserve Statistical Release H.15, Selected Interest Rates, data as of dates shown in Table 1. Federal Reserve data was not reported for October 13, 2008.

[4] Source: Yahoo! Finance.

ROE: the fact that Treasury yields remain at comparatively low levels by historical standards does not indicate that the Company's cost of equity (*i.e.*, its ROE) is at commensurately low levels.

Q. HOW SHOULD CURRENT ECONOMIC CONDITIONS AND CAPITAL SPENDING PLANS INFLUENCE THE COMMISSION'S DECISION IN SETTING THE APPROPRIATE ROE FOR OTP IN THIS PROCEEDING?

A. The Commission should recognize that the authorized ROE in this proceeding will send a strong signal to the financial community concerning the ability of OTP to meet its capital needs during a period in which its capital investments are increasing, and both debt and equity investors are requiring higher rates of return. If investors perceive a supportive regulatory environment, as evidenced by an allowed ROE that compensates the Company at a level commensurate with its risk, OTP should be able to attract equity capital at a favorable cost. Alternatively, the Company will not be able to compete for capital on favorable rates if investors perceive that they are not being adequately compensated for the risks associated with owning equity in OTP relative to other utility stocks. Such a result ultimately would increase costs for consumers.

V. USE OF PROXY GROUP COMPANIES

Q. PLEASE EXPLAIN WHY YOU HAVE USED PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR OTP.

A. The use of proxy groups is a widely employed analytical method to assist in estimating the cost of equity for a particular company. The methods most commonly used by financial analysts to estimate the cost of equity are based on company-specific market data and projections. Proxy groups are developed to ensure that the market-based information from which cost of equity estimates are derived reasonably represent the fundamental risks and prospects of the subject company. The primary

benefit of using a proxy group, therefore, is that it serves to moderate the effects of unusual events that may be associated with any one company.

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. Keeping in mind that my objective is to select a proxy group that is highly representative of the risks and prospects faced by OTP, I selected my proxy group based on the following criteria:

- I selected companies that Value Line classifies as Electric Utilities, which includes a group of 58 domestic U.S. utilities.
- Based on Beta estimates from Value Line and Bloomberg, I selected companies whose Betas fall within a reasonable range (plus or minus one standard deviation) of the group average.
- I excluded companies that do not pay cash dividends, because such companies cannot be analyzed using the DCF model (which is the primary method used in my analysis).
- I selected companies that are covered by at least two generally recognized utility industry equity analysts.
- I selected companies that have senior bond and/or corporate ratings of BBB- to AA.
- I selected proxy companies that are vertically integrated utilities (*i.e.*, utilities that own and operate regulated generating assets).
- I excluded companies whose regulated revenues and net income in 2007 comprised less than 60 percent of the respective totals for the company.
- I excluded companies whose regulated electric revenues represented less than 90 percent of total regulated revenues
- I excluded companies whose coal-fired generation constituted less than 10 percent of the generation resource portfolio.
- Finally, I eliminated any companies that are currently known to be party to a merger, or other significant transaction.

Q. DID YOU INCLUDE OTC IN YOUR ANALYSIS?

A. No. While OTC is categorized as an electric utility, it has significant non-regulated operations that provide a substantial portion of both its earnings and revenues. Therefore, OTC was eliminated by my screening criteria. Further, in order to avoid the circular logic that otherwise would occur, it is my practice to exclude the subject company from the proxy group.

Q WHY IS IT IMPORTANT TO CONSIDER ONLY COMPANIES WHOSE RESOURCE PORTFOLIOS INCLUDE COAL-FIRED GENERATING ASSETS?

A. OTP's operations are heavily dependent on coal-fired generation (over 90 percent of kilowatt-hours generated in 2007 and 2006[5]). In general, capital-intensive baseload generation assets such as coal-fired plants face risks associated with capital recovery in the event of market structure changes or plant failure, or replacement cost recovery in the event of extended or unplanned outages. In addition, coal-fired assets may require significant increases in capital requirements to comply with changes in environmental policies. In my view, therefore, it is important to exclude companies that do not have at least a modest amount of coal-fired generation in their resource portfolio.

Q. BASED ON THE CRITERIA DISCUSSED ABOVE, WHAT IS THE COMPOSITION OF YOUR PROXY GROUP?

A. The criteria discussed produce resulted in a proxy group of the following eleven companies:

- American Electric Power
- Cleco Corp.
- Edison International
- Empire District Electric

[5] Otter Tail Corp, Form 10-K, for the period ending December 31, 2007, at 7.

- Entergy Corp.
- IDACORP, Inc.
- Northeast Utilities
- Pinnacle West Capital
- Portland General
- Progress Energy
- Westar Energy

Q. DO YOU BELIEVE THAT A TOTAL OF ELEVEN COMPANIES CONSTITUES A SUFFICIENTLY LARGE PROXY GROUP?

A. Yes, I do. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's cost of equity to the extent that the chosen proxy companies are fundamentally comparable to the subject utility. Because all analysts use some form of screening process to arrive at a proxy group, the group, by definition, is not randomly drawn from a larger population. Consequently, there is no reason to place more reliance on the quantitative results of a larger proxy group simply by virtue of the resulting larger number of observations.

I realize that, because I am using market-based data, my analytical results will not necessarily be tightly clustered around a central point. Results that may be somewhat dispersed, however, do not suggest that the screening approach is inappropriate or the results less meaningful. Further, including companies whose fundamental comparability is tenuous at best, simply for the purpose of expanding the number of observations, does not add relevant information to the analysis. To that point, the New Hampshire Public Utility Commission recognized that comparability is more important than the size of the proxy group:

> [T]he DCF is an economic theory for which a more comparable sample, rather than a larger sample, produces results that are more

likely to be representative of the subject utility. The size of the sample is irrelevant when, as here, the sample is not random.[6]

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. PLEASE BRIEFLY DISCUSS THE COST OF EQUITY IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A. Regulated utilities rely primarily on common stock, long-term debt, and, to a far lesser extent, preferred stock to finance their permanent property, plant, and equipment. The rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity (and the ROE) is market-based and, therefore, must be inferred from market-based information.

Q. HOW IS THE MARKET-BASED ROE DETERMINED?

A. The ROE is estimated by using one or more analytical techniques that use market-based data to quantify investor expectations regarding required equity returns. The results of those analyses are then considered in the context of incremental risks that are not reflected in the results of proxy group analyses. The resulting cost of equity serves as the ROE for ratemaking purposes.

Q. WHAT METHODS DID YOU USE TO DETERMINE OTP'S COST OF EQUITY?

A. For the purposes of my testimony, I have used the constant growth form of the DCF approach, the CAPM approach, and the Risk Premium approach.

[6] Re: Verizon New Hampshire, 232 P.U.R. 4th 24 (N.H. P.U.C., 2004).

Q. WHY IS IT IMPORTANT TO USE MORE THAN ONE METHODOLOGY WHEN CALCULATING THE COST OF EQUITY?

A. Each of the models available to estimate the cost of equity is subject to its own set of assumptions or constraints. For example, while the single-stage DCF model uses market-derived yield data, it also assumes a constant growth rate in perpetuity. Similarly, the CAPM employs observable market data for bond yields, but requires judgment regarding the selection of the beta estimates. Consequently, many finance texts recommend using multiple approaches when estimating the cost of equity. Copeland, Koller and Murrin,[7] for example, suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[8] recommend the CAPM, the DCF, and the Risk Premium approaches.

While there may not be consensus among practitioners or academics as to the effectiveness of each model, the underlying methodologies of all seek to address the same fundamental question: how do you quantify unobservable investor expectations and return requirements? One means of addressing that question is to understand the methodologies used by the analysts currently active in equity markets and investments. In that regard, a 1999 article in *Financial Analysts Journal* concluded that the DCF and CAPM models were widely used by analysts; 42 percent of the survey respondents viewing the DCF model as very important or moderately important, while 31 percent had the same two opinions of the CAPM.

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[7] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, 3rd ed. (New York: McKinsey & Company, Inc., 2000) 214.

[8] Eugene Brigham, Louis Gapenski, *Financial Management: Theory and Practice*, 7th Ed. (Orlando: Dryden Press, 1994) 341.

A. Cost of Equity under the DCF Approach

Q. ARE DCF MODELS WIDELY USED TO DETERMINE THE ROE FOR REGULATED UTILITIES?

A. Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. In its simplest form, the DCF model expresses the cost of equity as the sum of the expected dividend yield and long-term growth rate.

Q. PLEASE DESCRIBE THE CONSTANT GROWTH DCF APPROACH.

A. The DCF approach is based on the theory that a stock's market price represents the present value of all future expected cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

where P_0 is today's stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation, which can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the "Constant Growth DCF" model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE DCF MODEL?

A. The DCF model requires the following assumptions: (i) a constant average growth rate for earnings and dividends; (ii) a stable dividend payout ratio; (iii) a constant price-to-earnings multiple; and (iv) a discount rate greater than the expected growth rate. To

the extent that any of these assumptions are violated, considered judgment and/or specific adjustments should be applied to the results.

B. Dividend Yield for the DCF Model

Q. PLEASE SUMMARIZE THE ELEMENTS USED TO CALCULATE THE DIVIDEND YIELD COMPONENT IN YOUR DCF MODEL.

A. The dividend yield component is based on the proxy companies' current dividends and average closing stock prices over three separate periods of time, the most recent 30, 90 and 180 trading days ending October 13, 2008.

Q. WHY DID YOU USE THE AVERAGE STOCK PRICES OVER THREE PERIODS TO CALCULATE THE DIVIDEND YIELD?

A. While in theory the current (or spot) stock price can be used to calculate the current dividend yield,[9] the average stock price should be representative of expected market conditions over a longer term, and should not be skewed by recent unusual or anomalous circumstances. Over the past year, the market has reacted sharply to short-term events that have resulted in significant declines in stock prices and corresponding increases in dividend yields. Therefore, by using the 30, 90 and 180-day averages, I am able to ensure that the DCF model results reflect more recent economic events and financial market conditions, without unreasonably biasing the analytical results based on anomalous circumstances.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that such increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply

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[9] *See*, for example, J. Fred Weston and Eugene F. Brigham, *Essentials of Managerial Finance*, 9th ed. (Fort Worth: Dryden Press, 1999) 656.

one-half of the expected annual dividend growth for the purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected dividend yield is representative of the coming 12-month period and does not overstate the aggregate dividends to be paid during that time. Accordingly, the DCF estimates provided in Exhibit __ (RBH-1), Schedule 3, reflect only one-half of the expected growth in the dividend yield component of the model.

C. Growth Rates for the DCF Model

Q. IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH IN APPLYING THE DCF MODEL?

A. Yes. In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share, and book value per share will all grow at the same constant rate. Over the long run, however, dividend growth and capital appreciation are sustained by earnings growth. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in *earnings per share* (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[10]

Therefore, for the purposes of the constant growth form of the DCF model, growth in earnings represents the most reasonable measure of long-term growth.

Q. DID YOU INCLUDE EXPECTED DIVIDEND OR BOOK VALUE GROWTH IN THE GROWTH RATE COMPONENT OF YOUR DCF MODEL?

A. No, I did not. Dividend growth rates are unlikely to provide meaningful insight as to investors' long-term growth expectations for utilities. Capital allocation decisions that

[10] Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, at 317 (Concise Fourth Edition, Thomson South-Western).

companies may make in response to short-term changes in the business environment may directly affect short-term dividend payout rates. Further, short-term dividend payout policies change with changes in management's perception of business risks. In contrast, the DCF model is based on long-term growth rates. To the extent that payout ratios do not remain constant, the DCF assumptions of perpetual constant payout and growth are violated. Moreover, it is growth in earnings that will support future dividends and share prices and as such, earnings growth provides the more meaningful guide to investors' long-term growth expectations. Similarly, I did not include book value growth rates in my DCF analysis because it too is derivative of earnings growth. In addition book value growth is a function of retained earnings, which itself is the reciprocal of dividend payouts. As such, book value growth rates may be susceptible to the same concerns as dividend growth rates.

Q. IS IT CONVENTIONAL PRACTICE TO RELY ON ANALYSTS' FORECASTS AS THE BASIS OF GROWTH RATE PROJECTIONS?

A. Yes. The cost of equity is a forward-looking concept that focuses on investor expectations regarding future returns. The estimation of such returns, therefore, should be based on forward-looking or projected data. Indeed, substantial academic research has demonstrated the relationship between analysts' forecasts and investor expectations.[11] Other academic research has pointed to the use of both consensus earnings forecasts, and Value Line in particular, as widely used sources of analyst

[11] In *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, published in Financial Management, Spring 1985, Brigham, Shome and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts." Similarly, in a review of literature regarding the extent to which analyst forecasts are reflected in stock prices (*Using Analyst's Growth Forecasts to Estimate Shareholder Required Rates of Return*, Financial Management, Spring 1986), Harris noted: "VanderWeide and Carleton recently compare consensus [financial analyst forecasts] of earnings growth to 41 different historical growth measures. They conclude that 'there is overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price…consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions.'"

growth forecasts.[12] In my view, therefore, Value Line, and Zacks (the latter of which is a consensus forecast estimate) provide appropriate sources of earnings growth forecasts.

Q. PLEASE SUMMARIZE YOUR APPLICATION OF THE CONSTANT GROWTH DCF MODEL.

A. I applied the DCF model to my proxy group, using the following inputs:

1. The average daily closing prices for the 30, 90 and 180 trading days ended October 13, 2008, for the term P_0;
2. The annualized dividend per share as of October 13, 2008, for the term D_0; and
3. The average of: (a) the Zacks company-specific earnings growth forecast; and (b) the Value Line company-specific earnings growth forecast for the term *g*.

Q. DID YOU CALCULATE A RANGE OF RESULTS?

A. Yes. I calculated the high mean DCF result using the maximum growth rate (*i.e.*, the higher of the Value Line EPS and the Zacks EPS growth rates) in combination with the expected dividend yield for each of the proxy group companies. Thus, the mean high result reflects the average maximum DCF result for the proxy group. I used a similar approach to calculate the mean low results, using the lower of the Value Line EPS and the Zacks EPS growth rates for each proxy group company

Q. DID YOU UNDERTAKE ANY ADDITIONAL ANALYSES TO SUPPORT YOUR DCF MODEL RESULTS?

A. Yes. As noted earlier, I also used the CAPM and the Risk Premium approach as a means of assessing the reasonableness of my DCF results.

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[12] *See*, for example, Christofi, Lori and Moliver, "Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate," *Journal of Investing* (Spring 1999); and Harris and Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management 21* (Summer 1992).

D. CAPM Analysis

Q. PLEASE DESCRIBE THE CAPM APPROACH YOU EMPLOYED.

A. As previously noted, the CAPM is a risk premium approach that specifies the required ROE for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or systematic risk of security). As shown in Equation [3], the CAPM is defined by four components:

$$k_e = rf + B(r_m - rf) \quad [3]$$

where:

k_e = the required market return on equity
B = Beta of an individual security
rf = the risk free rate of return
r_m = the required return on the market as a whole

Here the term $(r_m - rf)$ represents the Market Risk Premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should be concerned only with systematic, or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return.

Q. WHAT DID YOU USE FOR THE RISK-FREE RATE IN YOUR CAPM MODEL?

A. Since the DCF and CAPM models both assume long-term investment horizons, I used the yield on long-term Treasury securities as my estimate of the risk-free rate. In order to ensure that my CAPM results were not biased by my risk-free rate estimate, I used three different measures of long-term Treasury yields. First, I used the actual yield on 30-year Treasury bonds as the risk-free rate. To ensure that the results were not unduly influenced by market events, I used the average yield over a 30-day time

period, which resulted in a risk-free rate of 4.22 percent, a 90-day period, which resulted in a risk-free rate of 4.45 percent, and a 180-day time period, which resulted in a risk-free rate of 4.47 percent.[13] I also used the projected yield on 30-year Treasury Bonds of 4.65 percent, as provided by the Blue Chip Financial Forecast.[14] According to Morningstar, from 1926 through 2007, the total return on long-term government bonds averaged 5.80 percent (arithmetic mean), and the total return on intermediate-term government bond averaged 5.50 percent (arithmetic mean). In the context of long-term averages, therefore, the risk-free rate estimates used in my CAPM analyses are conservative.[15]

Q. WHY IS IT IMPORTANT TO USE THE LONG-TERM TREASURY RATE AS THE MEASURE OF THE RISK-FREE RATE?

A. For the purpose of the CAPM, it is important to select the term that best matches the life of the underlying investment. As noted by Ibbotson Associates:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued… If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[16]

Because vertically integrated electric companies represent long-duration investments, it is appropriate to use yields on long-term Treasury bonds as the risk-free rate component of the CAPM.

Q. WHY IS IT IMPORTANT TO INCLUDE A CAPM SCENARIO BASED ON PROJECTED TREASURY YIELDS?

A. There is little question that the current credit and liquidity crisis has driven investors to seek the relative safety of Treasury securities. As a consequence, Treasury bond

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13 *See* Exhibit___(RBH-1), Schedule 4.
14 Blue Chip Financial Forecasts, Vol. 27, No. 10 October 1, 2008, at 2.
15 Morningstar Ibbotson SBBI, 2008 Valuation Yearbook, at 28.
16 *See* Ibbotson Associates, Stocks, Bonds, Bills and Inflation Valuation Edition, 2005 Yearbook, at 57.

prices have been bid up, and the yields on those securities have fallen. (As Table 1 indicates, the yield on the 30-year Treasury bond fell by approximately 75 basis points since the beginning of the credit contraction.) If we were to focus entirely on a short-term average of Treasury yields, the CAPM result would be considerably lower than would be expected under more normal market conditions. It is important, therefore, to consider both projected Treasury yields and longer averaging periods when applying the CAPM in the current market.

Q. PLEASE DISCUSS YOUR ESTIMATE OF THE EXPECTED MARKET RISK PREMIUM.

A. The calculation of the risk premium should be based on the longest period possible to avoid giving undue consideration to unusual market conditions. When historical risk premia are used, the arithmetic mean, which recognizes market uncertainty, should be used as the relevant long-term average. Morningstar data (from 1926 through 2007) indicates that the equity risk premium of the total return on large company stocks over the income only portion of long term government bonds is 7.10 percent.[17]

Q. WHY DO YOU USE THE ARITHMETIC MEAN, AS OPPOSED TO THE GEOMETRIC MEAN, AS THE RELEVANT LONG-TERM AVERAGE?

A. The arithmetic mean, as compared to the geometric mean, is the simple average of single period rates of return. The geometric mean is the compound rate that equates a beginning value to its ending value. The important distinction between the two methods is that the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random

[17] Ibid., at 189.

> annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean. … [the] geometric mean underestimates the expected annual rate of return.[18]

For purposes of my CAPM analysis, therefore, I have used the long-term arithmetic mean risk premium as reported by Morningstar, Inc. In his discussion of the use of arithmetic versus geometric means, Dr. Roger Morin provides a summary of this issue:

> Because valuation is forward-looking, the appropriate average is the one that most accurately approximates the expected future rate of return. The best estimate of expected returns over a given holding period is the arithmetic average…[O]nly arithmetic means are correct for forecasting purposes and for estimating the cost of capital.[19]

Consequently, the arithmetic mean is the appropriate measure of the market risk premium for use in the CAPM.

Q. WHAT SOURCE DID YOU USE TO DETERMINE BETAS FOR THE PROXY GROUP COMPANIES?

A. When considering alternative sources of Beta estimates, it is important to recognize that such estimates are based on historical data. Over time, Betas will to tend to regress toward the market mean of 1.0. Consequently, I have used adjusted Beta estimates from Value Line and Bloomberg, both of which adjust their Beta estimates based on an average of the raw, historical Beta and 1.0. This adjustment addresses the tendency of the CAPM to underestimate the cost of capital for companies with "unadjusted" or "raw" Betas significantly less than 1.0. For relatively low-Beta companies such as regulated utilities, failure to take such adjustments into consideration will result in an understatement of required returns.

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[18] Ian Cooper, *Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting,* European Financial Management 2.2, (1996): 158.

[19] Roger A. Morin, PhD, New Regulatory Finance, Public Utility Reports, Inc.; 2006, at 156.

E. Risk Premium Analysis

Q. PLEASE DESCRIBE THE RISK PREMIUM APPROACH YOU EMPLOYED.

A. Risk premium approaches generally estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. Since the equity risk premium is not directly observable, it typically is estimated using one of a variety of approaches that themselves must incorporate an estimate of the cost of equity in the analysis. An alternative approach is to use the actual authorized ROEs for electric utilities as the historical measure of the cost of equity. Since both authorized ROEs and utility bond yields are directly observable, this approach substantially mitigates the estimation error.

Q. ARE THERE OTHER ANALYTICAL CONSIDERATIONS THAT SHOULD BE ADDRESSED IN CONDUCTING THIS ANALYSIS?

A. Yes. In my view, it is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that (1) reflects the inverse relationship between interest rates and the equity risk premium and (2) is based on more recent market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of Treasury yields. If we let authorized electric utility ROEs serve as the measure of required equity returns and define utility bond yields as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[20]

[20] *See* for example, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See* also Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

Q. IS IT APPROPRIATE TO USE UTILITY BOND YIELDS AS THE MEASURE OF INTEREST RATES?

A. Yes. The use of utility bond yields as the relevant measure of interest rates also is important in the current economic environment. As noted earlier, while Treasury yields generally have continued to decrease, credit spreads have significantly increased. As such, the use of Treasury yields as the sole measure of interest rates may understate the current equity risk premium.

Q. WHAT DID YOUR RISK PREMIUM ANALYSIS REVEAL?

A. As shown on Chart 1 (below), from 1990 through September 2008 there was a strong negative relationship between risk premia and interest rates on utility bonds. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(y) \qquad [5]$$

where:

RP = Risk Premium (difference between allowed ROEs and Moody's Baa Utility Bond Yield)

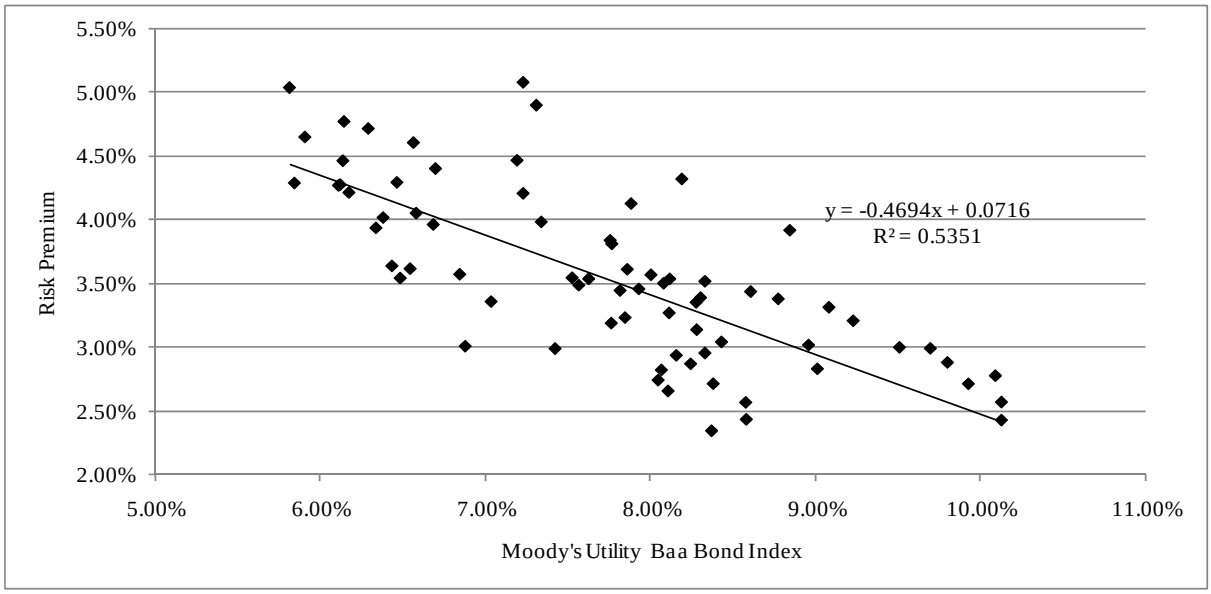
a = Intercept term

b = Slope term

y = Moody's Baa Utility Bond Yield

Data regarding allowed ROEs was derived from 570 rate cases from 1990 through September 2008 (the most recent data available) as reported by Regulatory Research Associates. This equation and its coefficients were statistically significant.

Chart 1: Risk Premium vs. Moody's Baa Utility Bond Yield[21]



As shown on Exhibit ___ (RBH-1), Schedule 5, page 1, from 1990 through September 2008 the average risk premium was approximately 3.51 percent. In a period of relatively low interest rates, however, simply applying that average risk premium to the Treasury yield would understate the required equity return. For example, the average Moody's Baa Utility Bond Index yield for the 30 trading days ended October 10, 2008[22] was approximately 7.34 percent. Simply adding the average risk premium of 3.51 percent would result in an ROE of 10.85 percent. That simple application, however, would understate the ROE; based on the regression coefficients, the risk premium would be 3.71 percent, resulting in an ROE of 11.05 percent. As shown in Exhibit ___ (RBH-1), Schedule 5, page 2, using historical measures of the Moody's Baa Utility Bond Index yield, the ROE would range from 10.82 percent to 11.05 percent, which is within the range of my CAPM analyses, although at the lower end of my DCF analyses.

[21] Sources: Regulatory Research Associates, SNL Database, accessed October 13, 2008 and Bloomberg.

[22] Moody's Baa Utility Bond Index was not reported for October 13, 2008.

It also is important to recognize that in the current financial environment, the ability for utility companies to attract capital, either debt or equity, becomes increasingly constrained on a daily basis. As a consequence, Risk Premium data as of October 10, 2008 (the last day of the data used in the Risk Premium analysis discussed above) does not necessarily reflect the rates that utility companies currently have to pay in order to complete a financing. Compounding the issue, due to a lack of liquidity, there are few instances in which utilities have issued debt and, therefore, few observations from which we can assess whether data as of October 10, 2008 reasonably reflects the current market environment. Nonetheless, I believe that in light of the current situation, it is important to understand the effect of the constrained liquidity on the cost of capital, even if we need to make inferences based on relatively limited data points.

In order to perform such an assessment, I conducted a search for recently issued long-term debt as of October 15, 2008. In doing so, I was able to identify a single issuance of Baa-rated utility debt. On October 15, 2008, Ohio Edison announced the issuance of $275 million in first mortgage bonds due in 2038 at an interest rate of 8.25 percent. These bonds are rated Baa1 by Moody's, and BBB+ by S&P. The interest rate at which these bonds were issued is significantly above the 30 day average of the comparable Moody's Baa Utility Bond Index as of October 10, 2008 of 7.34 percent (91 basis points above). In my view, this differential represents two elements of the current market environment. First, the data demonstrate the accelerating contraction of the credit market over a relatively brief period of time; the 30 day average incorporates the trading days from August 29, 2008 to October 10, 2008. Second, this differential demonstrates the premium that high credit quality utilities currently are paying to access credit markets during this crisis. Importantly, the Moody's Index represents the current yield on currently outstanding utility debt. The 91 basis point spread between the 30 day average of the Moody's Baa Utility Bond Index and Ohio Edison's recent issuance of first mortgage bonds, is arguably the premium companies are paying to issue new debt in a difficult market.

Given the 8.25 percent rate of current long-term debt, as shown in Exhibit __ (RBH-1), Schedule 5, the equation coefficients produce a risk premium of 3.29 percent and a corresponding ROE of 11.54 percent. Again, I realize that this is only a single data point. In light of the current market conditions, however, I believe that such information is relevant in forming ROE recommendations.

F. Flotation Cost Recovery

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are associated with the sale of new issues of common stock. These costs include, out-of-pocket expenses for preparation, filing, underwriting, and issuing the stock, and other costs of issuance of common stock.

Q. HOW ARE FLOTATION COSTS REFLECTED IN THE UTILITY'S FINANCIAL STATEMENTS?

A. Out-of-pocket flotation costs are reflected in the equity portion of the balance sheet as a reduction to "paid in capital" or "paid in surplus" to reflect the reduced proceeds from the equity issuance.

Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED ROE?

A. In order to attract and retain new equity investors, a regulated utility must have the opportunity to earn a ROE that is both competitive and compensatory. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) ROE, thereby diminishing its ability to attract adequate equity capital on reasonable terms.

Q. HAS OTTER TAIL CORPORATION RECENTLY ISSUED COMMON STOCK THAT IS USED TO FUND OTP?

A. Yes. On September 18, 2008 OTC closed the sale of 4,500,000 shares of its common stock (excluding the underwriters' overallotment of 675,000 shares) at a price of $30.00 per share ($135 million).[23] The net proceeds of that issuance (after taking into consideration offering expenses), on a per-share basis, was $28.9125,[24] resulting in flotation costs of approximately 3.625 percent.

Q. ARE FURTHER EQUITY ISSUANCES BY OTC LIKELY TO OCCUR?

A. Yes. The Company's substantial capital investment plans suggest the need for future equity issuances. As is discussed in Mr. Moug's testimony, it is probable that OTP will require additional external equity to finance its upcoming investments.[25]

Q. ARE FLOTATION COSTS ON EQUITY ISSUANCES COMPARABLE TO ISSUANCE COSTS FOR DEBT?

A. Yes. The need to reimburse investors for equity issuance costs is recognized by the academic and financial communities for the same reasons that investors are reimbursed for the costs of issuing debt. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. … Flotation costs can be accounted for either by amortizing the costs, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[26]

Q. ARE ISSUANCE COSTS FOR DEBT TYPICALLY RECOVERED IN THE COST OF SERVICE?

A. Yes. Issuance costs for debt are routinely included in the cost of debt in rate case proceedings. Flotation costs related to equity issuances should be recovered for the

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[23] Otter Tail Power Corporation, SEC Form 8-K, dated September 18, 2008, at 2.
[24] Ibid.
[25] DirectTestimony and Schedules of Kevin C. Moug, at 7.

same reasons. Flotation costs, like investments in rate base or the issuance costs of long-term debt, are incurred over time. As a result, the great majority of a utility's flotation costs are incurred prior to the test year, but remain part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes.

Q. ARE FLOTATION COSTS LIMITED TO ISSUANCES THAT HAVE OCCURED DURING THE TEST YEAR?

A. No. Flotation costs are not limited to issuances that occur in the test year because they are not expenses that flow through the income statement or through "operating cash flow" as Dr. Pratt notes. They are not current expenses and therefore are not reflected on the income statement. Rather, flotation costs reduce the permanent capital of the issuer and are thus reflected in the balance sheet. They are comparable to capital investments. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet of the utility in "paid in capital". Recovery of capital investments is not limited to the year in which the investment is made, and neither should the recovery of flotation costs. Common equity has an indefinite life, and due to the indeterminate life of an equity issuance, flotation costs should be recovered through a return adjustment, regardless of whether or not an issuance occurs during, or is planned for, the test year.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED BECAUSE OTP IS NOW A DIVISION OF OTC?

A. No. OTP is currently a division of OTC and may become a wholly owned subsidiary and is thus a part of the issuing entity. In both situations, OTP will depend on its parent for infusions of equity, including newly issued common stock. In both situations, there are issuance costs that must be recovered. As noted in the Prospectus relating to the recent sale of common equity, the proceeds of that issuance were used,

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[26] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

in part, to pay down $82.5 million of short-term debt at OTP.[27] This short-term debt was directly related to OTP's very substantial investment program, including the Ashtabula Wind Project. To deny recovery of issuance costs associated with the capital that is invested in OTP ultimately will penalize the investors that fund the utility operations, and will inhibit the utility's ability to obtain new equity capital at a reasonable cost.

Q. DO THE DCF AND CAPM MODELS REFLECT INVESTOR EXPECTATIONS OF A ROE THAT COMPENSATES FOR FLOTATION COSTS?

A. No. These models do not take into consideration flotation costs. All the models used to estimate the appropriate return on equity assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the CAPM).

Q. HAVE YOU CALCULATED THE EFFECT OF FLOTATION COSTS ON THE ROE?

A. Yes. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Based on the issuance costs provided in Exhibit __ (RBH-1), Schedule 6, an adjustment of 0.16 percent is (*i.e.*, 16 basis points) reflective of flotation costs for OTP. Table 5, below, presents the DCF results including flotation costs.

[27] Otter Tail Corporation Prospectus Supplement dated September 19, 2008, at S-20.

Table 5: DCF Results Including Flotation Costs

	Low Mean DCF Results	Mean DCF Results	High Mean DCF Results
Constant Growth DCF – 30-day Avg. Stock Price	11.08%	12.19%	13.31%
Constant Growth DCF – 90-day Avg. Stock Price	10.98%	12.10%	13.21%
Constant Growth DCF – 180-day Avg. Stock Price	10.90%	12.01%	13.13%

VII. BUSINESS AND ECONOMIC RISKS

Q. DO THE MEAN DCF AND CAPM RESULTS FOR THE PROXY GROUP PROVIDE AN APPROPRIATE ESTIMATE FOR THE COST OF EQUITY FOR OTP?

A. No, the mean analytical results do not necessarily represent the Company's cost of equity. There are several factors that must be considered to develop a meaningful and usable result. These factors are associated with: (1) the business risks faced by OTP; (2) general economic risks; and (3) the relatively small size of OTP.

A. Business Risks

Q. WHAT ARE THE PRIMARY BUSINESS RISKS THAT OTP CURRENTLY FACES?

A. The principal business risks facing OTP are: (i) the need for a very substantial level of capital expenditures, which are far higher than historical levels of investment, and higher than the comparable group; (ii) a more highly concentrated service area, (iii) a high dependence on commercial customers; and (iv) the absence of economic diversity within the service territory.

Q. HAVE THESE TYPES OF BUSINESS RISKS BEEN RECOGNIZED BY THE FINANCIAL COMMUNITY?

A. Yes. Recent equity analyst reports demonstrate that the financial community has recognized and is evaluating these types of business risks facing the regulated utility sector, generally, and OTP specifically, in the current market and economic environment. In a recent review of the electric utility segment, KeyBanc Capital Markets noted that:

> On the regulated side, higher pricing for fuel offers a challenge for those players without timely and full fuel recovery mechanisms ... Other commodity costs (cement, steel and copper) are driving up the costs of infrastructure replacement and pose the risk of sticker shock when these capital expenditures are presented for recovery in a rate case proceeding. We have already seen New York State issue a punitive rate outcome to Consolidated Edison, Inc. with prior capital expenditures exposed to a prudence audit. If this sort of outcome were to become more prevalent, we would expect increased investor concern over restrictive regulation to intensify.[28]

Capital Expenditures

Q. PLEASE SUMMARIZE OTP'S CAPITAL EXPENDITURE FORECAST.

A. The OTC Form 10-Q filed with the Securities and Exchange Commission ("SEC") for the quarter ended June 30, 2008 provides the OTP capital expenditure forecast for the period 2008 through 2012.[29] That forecast indicates that the Company plans approximately $880 million for electric construction over that period. Mr. Thomas R. Brause and Mr. Kevin Moug discuss OTP's capital expenditure program in more detail in their testimonies.

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[28] *Electric Utilities Quarterly 1Q08*, KeyBanc Capital Markets, June 11, 2008, at 7.

[29] Otter Tail Corp, Form 10-Q, Quarterly Report. Filed August 8, 2008 for period ending June 30, 2008, at 43.

Q. HOW IS OTP'S RISK PROFILE AFFECTED BY THE SUBSTANTIAL INCREASE IN ITS PLANNED CAPTIAL EXPENDITURES?

A. As with any utility faced with a substantial capital expenditure plan, OTP's risk profile is adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery, or the delayed recovery of the invested capital, and (2) an inadequate authorized return will put downward pressure on key credit metrics.

Q. HAVE THE RISKS ASSOCIATED WITH ELEVATED CAPITAL EXPENDITURES BEEN RECOGNIZED BY THE FINANCIAL COMMUNITY?

A. Yes, they have. Rating agencies, for example, have consistently focused on the detrimental effect on cash flows and corresponding pressure on credit metrics resulting from elevated capital expenditures. In effect, the additional pressure on cash flows exerts corresponding pressure on credit metrics and, therefore, credit ratings. In fact, Standard & Poor's commented on this concern in its August 2007 analysis of the electric utility industry:

> Utilities are aggressively investing in generation facilities to address rising demand and replace retiring assets, in transmission plants to replace and build out an aging grid, and in distribution systems that need to be expanded and made more efficient.[30]

Equity investors also recognize the pressure on cash flows associated with relatively high levels of capital expenditures, and the resulting effect on the cost of equity:

> Using the last capital cycle as a guide, this should lead to higher prices to end users, increasing regulatory risks, and *higher equity risks premiums/lower group valuations.*[31]

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[30] Standard and Poor's, *Electric Utilities Industry Survey*, August 9, 2007, at 6.

[31] Lehman Brothers, Regulated Utilities, *Industry Overview, Consequences of the CapEx Cycle*, June 4, 2008, at 2. *Emphasis Added.*

Q. HOW DOES THE LEVEL OF OTP'S EXPECTED CAPITAL EXPENDITURES COMPARE TO THE PROXY GROUP?

A. In order to reasonably make that comparison, I calculated the ratio of expected capital expenditures to net assets[32] for each of the proxy group companies. For the projected period from 2008-2013, I performed that calculation at the operating company level for OTP using OTP's projected capital expenditures and its total net assets as of December 31, 2007. It is clear from this analysis that OTP's relative level of capital expenditures is materially greater than the capital expenditures of the proxy group companies.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF OTP'S CAPITAL SPENDING PLANS ON ITS RISK PROFILE?

A. First, it is clear that on a relative basis, OTP has an aggressive capital expenditure program. It also is clear that the financial community recognizes the additional risks associated with substantial capital expenditures and that those risks are reflected in market valuation multiples. In my view, these factors suggest a comparatively high level of risk vis-à-vis the proxy group.

Service Area and Customer Concentration

Q. HOW DOES OTP'S CONCENTRATED SERVICE AREA AND CUSTOMER CONCENTRATION AFFECT ITS BUSINESS RISK?

A. OTP's customer base is largely comprised of commercial and industrial customers. Approximately 60 percent of its total revenues are attributable to sales to commercial and industrial customers.[33] Compared to the proxy group, OTP has the highest commercial customer concentration by percent of revenues. OTP's dependence on sales to commercial users subjects its operations to greater cash flow volatility and risk of demand destruction and bypass. Although OTP currently believes its rates are

[32] Source: Value Line and SEC Forms 10-K. See Exhibit ___(RBH-1), Schedule 7.

[33] SNL Financial.

sufficiently competitive to retain its commercial customers, OTP remains highly exposed to these risks.

Q. DOES THE ABSENCE OF ECONOMIC DIVERSITY IN OTP'S SERVICE TERRITORY AFFECT THE COMPANY'S RISK?

A. Yes. The territory served by OTP is largely agricultural.[34] It generally is understood that diversity is an important factor in the economic stability of a given market area. That is, a diversified economy is less susceptible to the economic cycles of, or shocks associated with, a single industry. Consequently, a relatively undiversified market, such as that served by OTP, represents meaningful financial risks to the host utility.

Q. BASED ON THE BUSINESS RISKS IDENTIFIED ABOVE, HOW WOULD YOU CLASSIFY OTP'S RISK LEVEL RELATIVE TO THE OTHERS IN THE PROXY GROUP?

A. As discussed above, OTP faces a higher than average level of business risk relative to the companies in the proxy group associated with substantially higher investment levels and a concentrated service area, its dependence on commercial customers and the absence of economic diversity in its service territory. Consequently, I believe that OTP has somewhat greater business risks relative to the proxy group.

B. Small Size

Q. PLEASE EXPLAIN THE RISK ASSOCIATED WITH SMALL SIZE.

A. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect."[35] While empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, Ibbotson Associates noted:

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[34] Otter Tail Corp, SEC Form 10-Q. Filed August 8, 2008 for period ending June 30, 2008, at 4.

[35] *See* Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset

> For small utilities, investors face additional obstacles, such as smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[36]

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (*i.e.*, the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and, (2) fundamental business risks.

Q. HOW DOES OTP COMPARE IN SIZE TO THE PROXY COMPANIES?

A. OTP, and for that matter OTC, are substantially smaller than the average for the proxy group companies both in terms of numbers of customers and market capitalization. Exhibit __ (RBH-1), Schedule 8 provides the actual market capitalization (based on a 30-day average stock price and the current number of common shares outstanding) for OTC, and estimates the implied market capitalization for OTP (*i.e.*, the implied market capitalization if OTP were a stand-alone, publicly traded entity). That is, since OTP is a division of OTC, an estimated stand-alone market capitalization for OTP must be calculated. To do so, I applied the average market to book ratio for the eleven member proxy group to OTP's stockholder's Equity of $229.633 million.[37] The implied market capitalization based on that calculation is $243.411 million, which is far below any member of the proxy group. In fact, the median market capitalization for the proxy group would be more than eleven times the size of OTP.

Q. HOW DOES THE SMALLER SIZE OF OTP AFFECT ITS BUSINESS RISKS RELATIVE TO THE PROXY GROUP OF COMPANIES?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater

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[36] Management 2, March 2002, at 368-397, for a review of literature relating to the size effect. Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments such as system maintenance and replacements will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q. HAVE YOU CONSIDERED THE SMALLER SIZE OF OTP IN YOUR RECOMMENDED RETURN ON EQUITY FOR THIS COMPANY?

A. Yes. While I have quantified the small size effect, rather than proposing a specific premium, I have considered the small size of OTP in my assessment of business risks in order to determine where within a reasonable range of returns, OTP's required ROE rightly falls.

Q. HOW DID YOU ESTIMATE THE SIZE PREMIUM FOR OTP?

A. In its *Risk Premia over Time Report: 2008,* Morningstar presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. An additional estimate of the size premium associated with OTP, therefore, is the difference in the Ibbotson size risk premia for the proxy group median market capitalization relative to the implied market capitalization for OTP.

As shown on Exhibit __ (RBH-1), Schedule 8, according to recent market data, the median market capitalization of the proxy group was approximately $3.08 billion, which corresponds to the 5th decile of Morningstar market capitalization data. Based on the Morningstar analysis, that decile corresponds to a size premium of 1.47 percent (or 147 basis points). The implied market capitalization for OTP is approximately $243.41 million, which falls within the 10th decile and corresponds to a size premium of 3.99 percent (or 399 basis points). The difference between those size premia is 252 basis points (3.99 percent – 1.47 percent).

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[37] See Exhibit_(KGM-1) Schedule 2, to Mr. Moug's Direct Testimony

Even if we were to use OTC's market capitalization, the size premium would be substantial. As of October 17, 2008, OTC's market capitalization was approximately $671.33 million, which corresponds to the 9th decile of the Morningstar risk premium data. That decile has a reported size premium of 2.56 percent (256 basis points), resulting in a size premium of 1.09 percent (2.56 percent – 1.47 percent). In either case, the size premium is meaningful and suggests that my ROE recommendation is reasonable.

Q. ARE THERE OTHER FACTORS THAT OFFSET THE RISKS ASSOCIATED WITH OTP'S RELATIVELY SMALL SIZE?

A. I do not believe so. The Commission has noted the possibility that other factors may offset the added risk of smaller size for a particular utility. I considered that possibility, but concluded that OTP does not have advantages over balance of the proxy group that would offset the added risk of smaller size.

VIII. CAPITAL STRUCTURE

Q. WHAT IS THE COMPANY'S PROJECTED CAPITAL STRUCTURE?

A. Company's requested capital structure consists of 53.30 percent common equity, 3.60 percent preferred stock, 40.30 percent long-term debt, 2.80 percent short-term debt. The proportions of the capital structure are discussed in detail in the direct testimony of Mr. Moug.

Q. PLEASE DISCUSS YOUR ANALYSIS OF THE CAPITAL STRUCTURES OF THE PROXY GROUP COMPANIES.

A. In order to assess the reasonableness of the Company's proposed capital structure, I reviewed the year-end 2007 capitalization ratios of the individual utility operating companies owned and operated (and for which separate financial information is filed with the SEC) by the respective proxy group companies. As shown in

Exhibit__ (RBH-1), Schedule 9 the Company's proposed 53.30 percent equity ratio is well within the range of equity ratios for that group, and is only somewhat above the mean equity ratio of approximately 52.06 percent. Of the remaining capital components, the Company's proposed preferred stock ratio is above the group mean, while its total debt ratio (*i.e.*, including both short and long-term debt) is somewhat below the mean. In both cases (*i.e.*, preferred stock and total debt), the Company's proposed capital structure ratios are within the range of the proxy group utility company group.

I also considered the Company's proposed capital structure in the context of its capital investment plan (which was summarized earlier in my testimony and which is discussed in the Direct Testimonies of Messrs. Brause and Moug). As Mr. Moug points out, in light of the Company's substantial capital spending plan and given current market conditions, it will be important to maintain the financial flexibility required to optimally finance those investments. As such, while the Company's proposed equity ratio is somewhat above the group average (although well within the group range), it is reasonable and appropriate to maintain the incremental financial flexibility associated with the proposed capital structure.

IX. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CALCULATED COST OF EQUITY, TAKING INTO CONSIDERATION THE ISSUES DISCUSSED ABOVE.

A. As shown in Table 6 below, the range of ROE mean estimates is between approximately 11.00 percent and 13.00 percent (both of which are based on DCF results), including flotation costs and before considering any incremental risk factors. The CAPM and Risk Premium results are somewhat lower, but even giving equal consideration to those results would lead to a range of 10.75 percent to 12.00 percent.

Table 6: ROE Estimate Summary

	Mean Low Results	Mean Results	Mean High Results
Constant Growth DCF Model (flotation cost adjusted)			
30-day Avg. Stock Price	11.08%	12.19%	13.31%
90-day Avg. Stock Price	10.98%	12.10%	13.21%
180-day Avg. Stock Price	10.90%	12.01%	13.13%
Capital Asset Pricing Model (including 16 basis point flotation cost adjustment)			
4.22% -30-day average of the 30 year Treasury Yield	10.20%	10.48%	10.77%
4.45% -90-day average of the 30 year Treasury Yield	10.44%	10.72%	11.00%
4.47% -180-day average of the 30 year Treasury Yield	10.45%	10.74%	11.02%
4.65% -Blue Chip Forecast 30-year Treasury Bond Yield	10.63%	10.92%	11.20%
Supporting Analyses			
Risk Premium	10.82%	10.93%	11.05%

Q. DID THE USE OF DATA THROUGH OCTOBER 13, 2008 HAVE A SIGNIFICANT EFFECT ON YOUR RECOMMENDATION?

A. No, it did not. I recognize that both the broad market and the utility sector were affected by the very unusual economic events that occurred between September 30 through October 13, 2008.[38] However, the use of both 90 and 180-day averaging periods, in addition to the 30-day analysis, substantially moderates the effect of those nine trading days. Therefore, even if I had ended my analyses as of September 30, the results would have fully supported my 11.25 percent ROE recommendation. As Table 7 (below) demonstrates, the DCF and CAPM results for the longer average periods (i.e., 90 and 180 days) for data ended September 30, 2008 are not materially different than the results based on data ended October 13, 2008, and the 30 day results also

[38] In fact, both the Dow Jones Industrial Average and the Dow Jones Utility Average declined by approximately 13.48% during that time.

support my recommendation. My recommendation is well within the range of my analytical results using both September 30, 2008 and October 13, 2008 end dates, and my recommendation continues to be at the low end of my DCF results. Consequently, my decision to update data through October 13, 2008 did not affect my 11.25 percent ROE recommendation.

Table 7: DCF and CAPM Results as of September 30, 2008

	Mean Low Results	**Mean Results**	**Mean High Results**
Constant Growth DCF Model (flotation cost adjusted)			
30-day Avg. Stock Price	10.89%	11.99%	13.08%
90-day Avg. Stock Price	10.92%	12.01%	13.11%
180-day Avg. Stock Price	10.84%	11.94%	13.03%
Capital Asset Pricing Model (including 16 basis point flotation cost adjustment)			
4.31% -30-day average of the 30 year Treasury Yield	10.23%	10.44%	10.65%
4.51% -90-day average of the 30 year Treasury Yield	10.43%	10.64%	10.85%
4.48% -180-day average of the 30 year Treasury Yield	10.40%	10.61%	10.82%
4.65% -Blue Chip Forecast 30-year Treasury Bond Yield	10.57%	10.78%	10.99%

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR OTP?

A. A rate of return in the range of 11.00 percent to 11.75 percent represents a reasonable range of equity investors' required rate of return for investment in OTP in today's capital markets. As discussed earlier in my testimony, OTP's business risks and smaller size, along with other economic factors, justifies an ROE above the mean of the range. As such, my recommended 11.25 percent ROE is a reasonable estimate of the Company's cost of equity.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-____

AFFIDAVIT OF ROBERT B. HEVERT

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Robert B. Hevert

Subscribed and sworn to before me,
this 24th day of October, 2008.

NOTARY PUBLIC

KIMBERLY H. DAO
Notary Public
Commonwealth of Massachusetts
My Commission Expires
April 16, 2015

Robert B. Hevert, CFA
President

Mr. Hevert is an economic and financial consultant with broad experience in the energy industry. He has an extensive background in the areas of corporate strategic planning, energy market assessment, corporate finance, mergers, and acquisitions, asset-based transactions, asset and business unit valuation, market entry strategies, strategic alliances, project development, feasibility and due diligence analyses. Mr. Hevert has significant management experience with both operating and professional services companies.

REPRESENTATIVE PROJECT EXPERIENCE

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises. Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Representative non-confidential clients have included:

- Conectiv generation asset divestiture
- Eastern Utilities Associates (prior to acquisition by National Grid, PLC) generation asset divestiture
- Niagara Mohawk – sale of Niagara Mohawk Energy
- Potomac Electric Company generation asset divestiture

Representative confidential engagements have included:

- Buy-side valuation and assessment of merchant generation assets in Midwestern U.S.
- Buy-side due diligence and valuation of wholesale energy marketing companies in Eastern and Midwestern U.S.
- Buy-side due diligence of natural gas distribution assets in Northeastern U.S.
- Financial feasibility study of natural gas pipeline in upper Midwestern U.S.

- Financial valuation of natural gas pipeline in Southwestern U.S.

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Also performed rate of return and cost of service analyses for municipally owned gas and electric utilities. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last resort obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Representative engagements have included:

- Performing rate of return analyses for use in cost of service analyses on behalf of municipally owned gas and electric utilities in the Southeastern and Midwestern U.S.
- Developing merchant function exit strategies for Northeastern U.S. natural gas distribution companies
- Developing regulatory and ratemaking strategy for mergers including several Northeastern natural gas distribution companies

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including the proposed transfer of power purchase agreements, procurement of residual service electric supply, the legal separation of generation assets, and specific financing transactions. Services provided also included collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the U.S. and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Representative engagements have included:

- Managing assessments of the NYPOOL, NEPOOL and PJM markets for major North American energy companies considering entering or expanding their presence in those markets
- Assessment of ECAR, MAPP, MAIN and SPP markets for a large U.S. integrated utility considering acquisition of additional electric generation assets
- Assessment of natural gas pipeline and storage capacity in the SERC and FRCC markets for a major international energy company

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, Energy Ventures, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

Representative engagements have included:

- Developing and facilitating executive level strategic planning retreats for Northeastern natural gas distribution companies
- Developing organization and business process redesign plans for municipally owned gas/electric/water utility in the Southeastern U.S.
- Reviewing and revising corporate merchant generation business plans for Canadian and U.S. integrated utilities
- Advising client personnel in development of business unit level strategic plans for various natural gas distribution companies

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PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
President

Navigant Consulting, Inc. (1997 – 2001)
Managing Director (2000 – 2001)
Director (1998 – 2000)
Vice President, REED Consulting Group (1997 – 1998)

REED Consulting Group (1997)
Vice President

Bay State Gas Company (1987 – 1997)
Vice President, Energy Ventures and Assistant Treasurer

Boston College (1986 – 1987)
Financial Analyst

General Telephone Company of the South (1984 – 1986)
Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts at Amherst, 1984
B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991
Association for Investment Management and Research
Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics, including:

- Generation Asset Valuation and the Use of Real Options
- Retail and Wholesale Market Entry Strategies
- The Use Strategic Alliances in Restructured Energy Markets
- Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
- Nuclear Asset Valuation and the Divestiture Process

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

EXPERT TESTIMONY OF ROBERT B. HEVERT

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Public Service Company Of New Mexico	09/08	Public Service Company Of New Mexico	Case No. 08-00273-UT	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity
Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc. ("Unitil"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Texas Gas	Docket No. 9791	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E017/GR-07-1178	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Computation of proxy companies for determining gas and oil pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Xcel Energy	07/07	Southwestern Public Service Company	Docket No. 07-00319 - UT	Return on Equity
Sea Robin Pipeline L.L.C.	06/07	Sea Robin Pipeline L.L.C.	Docket No. RP07-513-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas	01/07	Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
Xcel Energy	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity

Case No. PU-08-___
Exhibit ___ (RBH-1), Schedule 2
Page 1 of 3

EXPERT TESTIMONY OF ROBERT B. HEVERT

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Pepco Holdings, Inc.	09/06	Atlantic City Electric	Docket No. EMO6090638 (New Jersey)	Divestiture and Valuation of Electric Generating Assets
Columbia Gas Of Virginia, Inc.	06/06	Columbia Gas Of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Xcel Energy	05/06	Southwestern Public Service	SOAH Docket No. 473-06-2536 Docket No. 32766	Return on Equity (electric)
Xcel Energy	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket No. 7175 and 7176 (Vermont)	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket No. 7109 and 7160 (Vermont)	Return on Equity (gas)
Pepco Holdings, Inc.	12/05	Atlantic City Electric	BPU Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Xcel Energy	11/05	NSP-Minnesota	Docket No. E002/GR-05-1428 (Minnesota)	Return on Equity (electric)
Xcel Energy	08/05	Public Service Company of Colorado	Advice Letter No. 94-Steam (Colorado)	Return on Equity (steam)
Xcel Energy	05/05	Public Service Company of Colorado	Docket No. 05-264G (Colorado)	Return on Equity (gas)
NSTAR Electric	09/04	NSTAR Electric	D.T.E 04-85 (Massachusetts)	Divestiture of Power Purchase Agreement
Xcel Energy	09/04	NSP Minnesota	G002/GR-04-1511 (Minnesota)	Cost of Capital (gas)
NSTAR Electric	08/04	NSTAR Electric	D.T.E 04-78 (Massachusetts)	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	D.T.E 04-68 (Massachusetts)	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	D.T.E 04-61 (Massachusetts)	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	D.T.E 04-60 (Massachusetts)	Divestiture of Power Purchase Agreement

EXPERT TESTIMONY OF ROBERT B. HEVERT

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Unitil Corporation	01/04	Fitchburg Gas and Electric	D.T.E. 03-52 (Massachusetts)	Integrated Resource Plan; Gas Demand Forecast
Conectiv	06/03	Atlantic City Electric Company	BPU EO03020091 (New Jersey)	Market Value of Electric Generation Assets; Auction Process
Dominion Resources	10/01	Virginia Electric and Power Company	PUE000584 (Virginia)	Corporate Structure and Electric Generation Strategy
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	NY PSC Case 01-E	Power Purchase and Sale Agreement; Standard Offer Service Agreement
GPU International and Aquila	11/00	GPU International	EC01-24-000 (FERC)	Market Power Study
Northern Utilities, Inc.	07/95	Northern Utilities	Maine PUC	Gas Distribution System Expansion
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Long Term Debt Financing
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Long Term Debt Financing

30 DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] Value Line EPS Growth	[7] Average Growth Rate	[8] Low DCF ROE	[9] Mean DCF ROE	[10] High DCF ROE
PROXY GROUP ELECTRIC UTILITIES											
American Electric Power	AEP	$1.64	$36.32	4.52%	4.67%	6.30%	7.50%	6.90%	10.96%	11.57%	12.18%
Cleco Corp.	CNL	$0.90	$24.69	3.65%	3.87%	14.00%	10.50%	12.25%	14.34%	16.12%	17.90%
Edison International	EIX	$1.22	$39.59	3.08%	3.19%	8.80%	5.00%	6.90%	8.16%	10.09%	12.02%
Empire District Electric	EDE	$1.28	$21.02	6.09%	6.39%	-	10.00%	10.00%	16.39%	16.39%	16.39%
Entergy Corp.	ETR	$3.00	$89.49	3.35%	3.53%	11.50%	10.00%	10.75%	13.52%	14.28%	15.05%
IDACORP, Inc.	IDA	$1.20	$29.13	4.12%	4.20%	6.00%	2.00%	4.00%	6.16%	8.20%	10.24%
Northeast Utilities	NU	$0.85	$24.97	3.40%	3.59%	10.00%	11.50%	10.75%	13.57%	14.34%	15.10%
Pinnacle West Capital	PNW	$2.10	$34.41	6.10%	6.23%	6.70%	2.00%	4.35%	8.16%	10.58%	13.01%
Portland General	POR	$0.98	$23.80	4.12%	4.26%	6.50%	7.00%	6.75%	10.75%	11.01%	11.26%
Progress Energy	PGN	$2.46	$42.91	5.73%	5.88%	5.00%	5.00%	5.00%	10.88%	10.88%	10.88%
Westar Energy	WR	$1.16	$22.36	5.19%	5.28%	5.30%	2.00%	3.65%	7.24%	8.93%	10.63%
		PROXY GROUP MEAN		4.49%	4.65%	8.01%	6.59%	7.39%	10.92%	12.04%	13.15%
								Flotation Adjustment	0.16%	0.16%	0.16%
								Adjusted Mean ROE	11.08%	12.19%	13.31%
								Adjusted Median ROE	10.88%	11.01%	12.18%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [7])))/Col. [2]
[5] Source: Zacks
[6] Source: Value Line
[7] Equals Avg (Col. [5], [6])
[8] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6])))) + Minimum (Col. [5], [6])
[9] Equals Col. [4] + Col. [5]
[10] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6])))) + Maximum (Col. [5], [6])

90 DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] Value Line EPS Growth	[7] Average Growth Rate	[8] Low DCF ROE	[9] Mean DCF ROE	[10] High DCF ROE
PROXY GROUP ELECTRIC UTILITIES											
American Electric Power	AEP	$1.64	$38.79	4.23%	4.37%	6.30%	7.50%	6.90%	10.66%	11.27%	11.89%
Cleco Corp.	CNL	$0.90	$24.73	3.64%	3.86%	14.00%	10.50%	12.25%	14.33%	16.11%	17.89%
Edison International	EIX	$1.22	$45.92	2.66%	2.75%	8.80%	5.00%	6.90%	7.72%	9.65%	11.57%
Empire District Electric	EDE	$1.28	$20.43	6.27%	6.58%	-	10.00%	10.00%	16.58%	16.58%	16.58%
Entergy Corp.	ETR	$3.00	$104.48	2.87%	3.03%	11.50%	10.00%	10.75%	13.01%	13.78%	14.54%
IDACORP, Inc.	IDA	$1.20	$29.84	4.02%	4.10%	6.00%	2.00%	4.00%	6.06%	8.10%	10.14%
Northeast Utilities	NU	$0.85	$25.73	3.30%	3.48%	10.00%	11.50%	10.75%	13.47%	14.23%	14.99%
Pinnacle West Capital	PNW	$2.10	$33.40	6.29%	6.42%	6.70%	2.00%	4.35%	8.35%	10.77%	13.20%
Portland General	POR	$0.98	$23.80	4.12%	4.26%	6.50%	7.00%	6.75%	10.75%	11.01%	11.26%
Progress Energy	PGN	$2.46	$42.67	5.77%	5.91%	5.00%	5.00%	5.00%	10.91%	10.91%	10.91%
Westar Energy	WR	$1.16	$22.37	5.19%	5.28%	5.30%	2.00%	3.65%	7.24%	8.93%	10.62%
		PROXY GROUP MEAN		4.39%	4.55%	8.01%	6.59%	7.39%	10.83%	11.94%	13.05%
								Flotation Adjustment	0.16%	0.16%	0.16%
								Adjusted Mean ROE	10.98%	12.10%	13.21%
								Adjusted Median ROE	10.75%	11.01%	11.89%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [7])))/Col. [2]
[5] Source: Zacks
[6] Source: Value Line
[7] Equals Avg (Col. [5], [6])
[8] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6])))) + Minimum (Col. [5], [6])
[9] Equals Col. [4] + Col. [5]
[10] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6])))) + Maximum (Col. [5], [6])

180 DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] Value Line EPS Growth	[7] Average Growth Rate	[8] Low DCF ROE	[9] Mean DCF ROE	[10] High DCF ROE
PROXY GROUP ELECTRIC UTILITIES											
American Electric Power	AEP	$1.64	$40.82	4.02%	4.16%	6.30%	7.50%	6.90%	10.44%	11.06%	11.67%
Cleco Corp.	CNL	$0.90	$24.32	3.70%	3.93%	14.00%	10.50%	12.25%	14.40%	16.18%	17.96%
Edison International	EIX	$1.22	$48.70	2.51%	2.59%	8.80%	5.00%	6.90%	7.57%	9.49%	11.42%
Empire District Electric	EDE	$1.28	$20.72	6.18%	6.49%	-	10.00%	10.00%	16.49%	16.49%	16.49%
Entergy Corp.	ETR	$3.00	$107.78	2.78%	2.93%	11.50%	10.00%	10.75%	12.92%	13.68%	14.44%
IDACORP, Inc.	IDA	$1.20	$30.72	3.91%	3.98%	6.00%	2.00%	4.00%	5.95%	7.98%	10.02%
Northeast Utilities	NU	$0.85	$25.96	3.27%	3.45%	10.00%	11.50%	10.75%	13.44%	14.20%	14.96%
Pinnacle West Capital	PNW	$2.10	$34.49	6.09%	6.22%	6.70%	2.00%	4.35%	8.15%	10.57%	12.99%
Portland General	POR	$0.98	$23.67	4.14%	4.28%	6.50%	7.00%	6.75%	10.78%	11.03%	11.29%
Progress Energy	PGN	$2.46	$42.68	5.76%	5.91%	5.00%	5.00%	5.00%	10.91%	10.91%	10.91%
Westar Energy	WR	$1.16	$22.88	5.07%	5.16%	5.30%	2.00%	3.65%	7.12%	8.81%	10.50%
		PROXY GROUP MEAN		4.31%	4.46%	8.01%	6.59%	7.39%	10.74%	11.85%	12.97%
								Flotation Adjustment	0.16%	0.16%	0.16%
								Adjusted Mean ROE	10.90%	12.01%	13.13%
								Adjusted Median ROE	10.78%	11.03%	11.67%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [7])))/Col. [2]
[5] Source: Zacks
[6] Source: Value Line
[7] Equals Avg (Col. [5], [6])
[8] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6])))) + Minimum (Col. [5], [6])
[9] Equals Col. [4] + Col. [5]
[10] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6])))) + Maximum (Col. [5], [6])

CAPITAL ASSET PRICING MODEL - 30 Day Average 30 Year Treasury Bond Yield

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company		Value Line	Bloomberg	Mean Beta	30-Yr Treasury	Market Risk Premium	Low CAPM	CAPM k(e)	High CAPM
American Electric Power	AEP	0.85	0.94	0.90	4.22%	7.10%	10.25%	10.58%	10.91%
Cleco Corp.	CNL	0.90	0.92	0.91	4.22%	7.10%	10.61%	10.69%	10.77%
Edison International	EIX	0.90	0.98	0.94	4.22%	7.10%	10.61%	10.88%	11.16%
Empire District Electric	EDE	0.80	0.85	0.82	4.22%	7.10%	9.90%	10.06%	10.23%
Entergy Corp.	ETR	0.80	0.97	0.89	4.22%	7.10%	9.90%	10.50%	11.11%
IDACORP, Inc.	IDA	0.90	0.85	0.87	4.22%	7.10%	10.22%	10.41%	10.61%
Northeast Utilities	NU	0.75	0.93	0.84	4.22%	7.10%	9.54%	10.17%	10.80%
Pinnacle West Capital	PNW	0.80	0.78	0.79	4.22%	7.10%	9.75%	9.82%	9.90%
Portland General	POR	0.80	0.85	0.82	4.22%	7.10%	9.90%	10.07%	10.24%
Progress Energy	PGN	0.75	0.85	0.80	4.22%	7.10%	9.54%	9.89%	10.24%
Westar Energy	WR	0.85	0.92	0.88	4.22%	7.10%	10.25%	10.49%	10.73%
MEAN		0.83	0.89	0.86			10.04%	10.32%	10.61%
						Flotation Adjustment	0.16%	0.16%	0.16%
						Adjusted Mean ROE	10.20%	10.48%	10.77%

Notes
[1] Source: Value Line
[2] Source: Bloomberg
[3] Equals mean of Cols. [1], [2]
[4] Source: Blue Chip Financial Forecast, October 1, 2008
[5] Source: Morningstar, Inc.
[6] Equals Col [4] + (Min (Cols [1], [2]) x Col [5])
[7] Equals Col. [4] +(Col. [3] x Col [5])
[8] Equals Col [4] + (Max (Cols [1], [2]) x Col [5])

CAPITAL ASSET PRICING MODEL - 90 Day Average 30 Year Treasury Bond Yield

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company		Value Line	Bloomberg	Mean Beta	30-Yr Treasury	Market Risk Premium	Low CAPM	CAPM k(e)	High CAPM
American Electric Power	AEP	0.85	0.94	0.90	4.45%	7.10%	10.49%	10.82%	11.15%
Cleco Corp.	CNL	0.90	0.92	0.91	4.45%	7.10%	10.84%	10.93%	11.01%
Edison International	EIX	0.90	0.98	0.94	4.45%	7.10%	10.84%	11.12%	11.40%
Empire District Electric	EDE	0.80	0.85	0.82	4.45%	7.10%	10.13%	10.30%	10.47%
Entergy Corp.	ETR	0.80	0.97	0.89	4.45%	7.10%	10.13%	10.74%	11.35%
IDACORP, Inc.	IDA	0.90	0.85	0.87	4.45%	7.10%	10.45%	10.65%	10.84%
Northeast Utilities	NU	0.75	0.93	0.84	4.45%	7.10%	9.78%	10.41%	11.04%
Pinnacle West Capital	PNW	0.80	0.78	0.79	4.45%	7.10%	9.98%	10.06%	10.13%
Portland General	POR	0.80	0.85	0.82	4.45%	7.10%	10.13%	10.31%	10.48%
Progress Energy	PGN	0.75	0.85	0.80	4.45%	7.10%	9.78%	10.13%	10.48%
Westar Energy	WR	0.85	0.92	0.88	4.45%	7.10%	10.49%	10.73%	10.96%
MEAN		0.83	0.89	0.86			10.28%	10.56%	10.85%
						Flotation Adjustment	0.16%	0.16%	0.16%
						Adjusted Mean ROE	10.44%	10.72%	11.00%

Notes
[1] Source: Value Line
[2] Source: Bloomberg
[3] Equals mean of Cols. [1], [2]
[4] Source: Blue Chip Financial Forecast, October 1, 2008
[5] Source: Morningstar, Inc.
[6] Equals Col [4] + (Min (Cols [1], [2]) x Col [5])
[7] Equals Col. [4] +(Col. [3] x Col [5])
[8] Equals Col [4] + (Max (Cols [1], [2]) x Col [5])

CAPITAL ASSET PRICING MODEL - 180 Day Average 30 Year Treasury Bond Yield

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company		Value Line	Bloomberg	Mean Beta	30-Yr Treasury	Market Risk Premium	Low CAPM	CAPM k(e)	High CAPM
American Electric Power	AEP	0.85	0.94	0.90	4.47%	7.10%	10.51%	10.84%	11.17%
Cleco Corp.	CNL	0.90	0.92	0.91	4.47%	7.10%	10.86%	10.94%	11.02%
Edison International	EIX	0.90	0.98	0.94	4.47%	7.10%	10.86%	11.14%	11.41%
Empire District Electric	EDE	0.80	0.85	0.82	4.47%	7.10%	10.15%	10.32%	10.48%
Entergy Corp.	ETR	0.80	0.97	0.89	4.47%	7.10%	10.15%	10.76%	11.37%
IDACORP, Inc.	IDA	0.90	0.85	0.87	4.47%	7.10%	10.47%	10.67%	10.86%
Northeast Utilities	NU	0.75	0.93	0.84	4.47%	7.10%	9.80%	10.42%	11.05%
Pinnacle West Capital	PNW	0.80	0.78	0.79	4.47%	7.10%	10.00%	10.08%	10.15%
Portland General	POR	0.80	0.85	0.82	4.47%	7.10%	10.15%	10.33%	10.50%
Progress Energy	PGN	0.75	0.85	0.80	4.47%	7.10%	9.80%	10.15%	10.50%
Westar Energy	WR	0.85	0.92	0.88	4.47%	7.10%	10.51%	10.74%	10.98%
MEAN		0.83	0.89	0.86			10.30%	10.58%	10.86%
						Flotation Adjustment	0.16%	0.16%	0.16%
						Adjusted Mean ROE	10.45%	10.74%	11.02%

Notes
[1] Source: Value Line
[2] Source: Bloomberg
[3] Equals mean of Cols. [1], [2]
[4] Source: Blue Chip Financial Forecast, October 1, 2008
[5] Source: Morningstar, Inc.
[6] Equals Col [4] + (Min (Cols [1], [2]) x Col [5])
[7] Equals Col. [4] +(Col. [3] x Col [5])
[8] Equals Col [4] + (Max (Cols [1], [2]) x Col [5])

CAPITAL ASSET PRICING MODEL - Projected Treasury Bond Yield

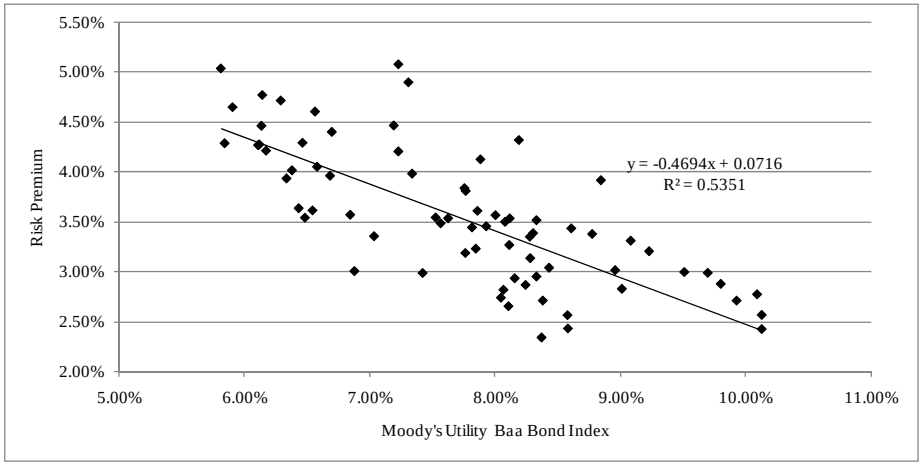
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company		Value Line	Bloomberg	Mean Beta	30-Yr Treasury	Market Risk Premium	Low CAPM	CAPM k(e)	High CAPM
American Electric Power	AEP	0.85	0.94	0.90	4.65%	7.10%	10.69%	11.02%	11.35%
Cleco Corp.	CNL	0.90	0.92	0.91	4.65%	7.10%	11.04%	11.12%	11.20%
Edison International	EIX	0.90	0.98	0.94	4.65%	7.10%	11.04%	11.32%	11.59%
Empire District Electric	EDE	0.80	0.85	0.82	4.65%	7.10%	10.33%	10.50%	10.66%
Entergy Corp.	ETR	0.80	0.97	0.89	4.65%	7.10%	10.33%	10.94%	11.54%
IDACORP, Inc.	IDA	0.90	0.85	0.87	4.65%	7.10%	10.65%	10.84%	11.04%
Northeast Utilities	NU	0.75	0.93	0.84	4.65%	7.10%	9.98%	10.60%	11.23%
Pinnacle West Capital	PNW	0.80	0.78	0.79	4.65%	7.10%	10.18%	10.26%	10.33%
Portland General	POR	0.80	0.85	0.82	4.65%	7.10%	10.33%	10.50%	10.68%
Progress Energy	PGN	0.75	0.85	0.80	4.65%	7.10%	9.98%	10.33%	10.68%
Westar Energy	WR	0.85	0.92	0.88	4.65%	7.10%	10.69%	10.92%	11.16%
MEAN		0.83	0.89	0.86			10.47%	10.76%	11.04%
						Flotation Adjustment	0.16%	0.16%	0.16%
						Adjusted Mean ROE	10.63%	10.92%	11.20%

Notes
[1] Source: Value Line
[2] Source: Bloomberg
[3] Equals mean of Cols. [1], [2]
[4] Source: Blue Chip Financial Forecast, October 1, 2008
[5] Source: Morningstar, Inc.
[6] Equals Col [4] + (Min (Cols [1], [2]) x Col [5])
[7] Equals Col. [4] +(Col. [3] x Col [5])
[8] Equals Col [4] + (Max (Cols [1], [2]) x Col [5])

Risk Premium Analysis

Quarter	Average Authorized Electric Utility ROE [1]	Average Moody's Utility Baa Bond Index [2]	Risk Premium (ROE-Moody's Utility Baa Index)
1990.1	12.62%	9.92%	2.70%
1990.2	12.85%	10.08%	2.77%
1990.3	12.54%	10.12%	2.42%
1990.4	12.68%	10.12%	2.56%
1991.1	12.66%	9.79%	2.87%
1991.2	12.67%	9.69%	2.98%
1991.3	12.49%	9.50%	2.99%
1991.4	12.42%	9.22%	3.20%
1992.1	12.38%	9.08%	3.30%
1992.2	11.83%	9.01%	2.82%
1992.3	12.03%	8.60%	3.43%
1992.4	12.14%	8.77%	3.37%
1993.1	11.84%	8.33%	3.51%
1993.2	11.64%	8.11%	3.53%
1993.3	11.15%	7.62%	3.53%
1993.4	11.04%	7.56%	3.48%
1994.1	11.07%	7.84%	3.22%
1994.2	11.13%	8.57%	2.56%
1994.3	12.75%	8.84%	3.91%
1994.4	11.24%	9.25%	1.99%
1995.1	11.96%	8.95%	3.01%
1995.2	11.27%	8.33%	2.94%
1995.3	11.37%	8.11%	3.26%
1995.4	11.58%	7.75%	3.83%
1996.1	11.46%	7.86%	3.60%
1996.2	11.46%	8.43%	3.03%
1996.3	10.70%	8.37%	2.33%
1996.4	11.56%	8.00%	3.56%
1997.1	11.08%	8.15%	2.93%
1997.2	11.62%	8.27%	3.34%
1997.3	12.00%	7.88%	4.12%
1997.4	11.06%	7.52%	3.54%
1998.1	11.31%	7.34%	3.98%
1998.2	12.20%	7.31%	4.89%
1998.3	11.65%	7.19%	4.46%
1998.4	12.30%	7.23%	5.07%
1999.1	10.40%	7.42%	2.98%
1999.2	10.94%	7.76%	3.18%
1999.3	10.75%	8.10%	2.65%
1999.4	11.10%	8.24%	2.86%
2000.1	11.08%	8.38%	2.70%
2000.2	11.00%	8.58%	2.42%
2000.3	11.68%	8.30%	3.38%
2000.4	12.50%	8.19%	4.31%
2001.1	11.38%	7.93%	3.45%
2001.2	10.88%	8.06%	2.81%
2001.3	10.78%	8.04%	2.73%
2001.4	11.57%	8.08%	3.49%
2002.1	10.05%	8.21%	1.84%
2002.2	11.41%	8.28%	3.13%
2002.3	11.25%	7.81%	3.44%
2002.4	11.57%	7.76%	3.80%
2003.1	11.43%	7.23%	4.20%
2003.2	11.16%	6.56%	4.60%
2003.3	9.88%	6.88%	3.00%
2003.4	11.09%	6.70%	4.40%
2004.1	11.00%	6.29%	4.71%
2004.2	10.64%	6.68%	3.96%
2004.3	10.75%	6.46%	4.29%
2004.4	10.91%	6.14%	4.77%
2005.1	10.55%	5.91%	4.64%
2005.2	10.13%	5.84%	4.28%
2005.3	10.85%	5.81%	5.03%
2005.4	10.59%	6.14%	4.46%
2006.1	10.38%	6.17%	4.21%
2006.2	10.63%	6.58%	4.05%
2006.3	10.06%	6.43%	3.63%
2006.4	10.37%	6.11%	4.26%
2007.1	10.39%	6.12%	4.27%
2007.2	10.27%	6.34%	3.93%
2007.3	10.02%	6.48%	3.53%
2007.4	10.39%	6.38%	4.01%
2008.1	10.15%	6.54%	3.61%
2008.2	10.41%	6.84%	3.56%
2008.3	10.38%	7.03%	3.35%
Mean	*11.29%*	*7.78%*	*3.51%*

Risk Premium Analysis



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.73153943
R Square	0.535149937
Adjusted R Square	0.528782128
Standard Error	0.004991817
Observations	75

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.002094126	0.002094126	84.03988409	9.04854E-14
Residual	73	0.001819032	2.49182E-05		
Total	74	0.003913158			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.071581274	0.004025424	17.78229367	3.03486E-28	0.063558615	0.07960393	0.063558615	0.079603933
X Variable 1	-0.469400894	0.051203682	-9.167326987	9.04854E-14	-0.571449684	-0.36735211	-0.571449684	-0.367352105

Scenario (Moody's Utility Baa Bond Index)	Moodys Utility Baa Bond Rate	Risk Premium [3]	ROE
30-day average as of 10/10/2008	7.34%	3.71%	11.05%
90-day average as of 10/10/08	7.09%	3.83%	10.92%
180-day average as of 10/10/2008	6.90%	3.92%	10.82%
MEAN		3.82%	10.93%
Current Baa-Rated Utility Issuance Level as of 10/15/2008	8.25%	3.29%	11.54%

NOTES

[1] Source: Regulatory Research Associates, Rate Case Statistics, accessed October 13, 2008.

[2] Source: Bloomberg Professional Service. Quarterly bond yields are the average of each month's average yield.

[3] Independent variable = Moody's Utility Baa Bond Yield; Dependent Variable = Risk Premium.

[4] Current Baa-Rated Utility Issuance Level based on Ohio Edison 8.25% issuance due 10/15/2038, announced 10/15/2008

Risk Premium Analysis

AREG

MODEL: MOD_1

Model Description:

Variable: RISKPREM
Regressors: MOODUBAA

95.00 percent confidence intervals will be generated.

Split group number: 1 Series length: 75
No missing data.

Termination criteria:
Parameter epsilon: .001
Maximum number of iterations: 10

Initial values:

Estimate of Autocorrelation Coefficient

Rho 0

Prais-Winsten Estimates

Multiple R .73153944
R-Squared .53514995
Adjusted R-Squared .52878214
Standard Error .00499182
Durbin-Watson 1.6693075

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	1	.00209413	.00209413
Residuals	73	.00181903	.00002492

Variables in the Equation:

	B	SEB	BETA	T	SIG T
MOODUBAA	-.46940090	.05120368	-.73153944	-9.167327	.0000000
CONSTANT	.07158127	.00402542	.	17.782294	.0000000

Iteration History:

Iteration	Rho	SE Rho	DW	MSE
1	.15716032	.11638661	2.0249237	.00002463
2	.15845398	.11636224	2.0278521	.00002463

Conclusion of estimation phase.
Estimation terminated at iteration number 3 because:
All parameter estimates changed by less than .001

FINAL PARAMETERS:

Estimate of Autocorrelation Coefficient

Rho .15847096
Standard Error of Rho .11636192

Prais-Winsten Estimates

Multiple R .6846677
R-Squared .46876986
Adjusted R-Squared .45401347
Standard Error .00496239
Durbin-Watson 2.0278905

Analysis of Variance:

	DF	Sum of Squares	Mean Square
Regression	1	.00156456	.00156456
Residuals	72	.00177302	.00002463

Variables in the Equation:

	B	SEB	BETA	T	SIG T
MOODUBAA	-.47633171	.05975920	-.68466770	-7.970852	.000000
CONSTANT	.07211313	.00470101	.	15.339907	.0000000

The following new variables are being created:

Name	Label
FIT_1	Fit for RISKPREM from AREG, MOD_1
ERR_1	Error for RISKPREM from AREG, MOD_1
LCL_1	95% LCL for RISKPREM from AREG, MOD_1
UCL_1	95% UCL for RISKPREM from AREG, MOD_1
SEP_1	SE of fit for RISKPREM from AREG, MOD_1

FLOTATION COST ADJUSTMENT

Flotation Costs (two most recent common stock issuances per company, if available)

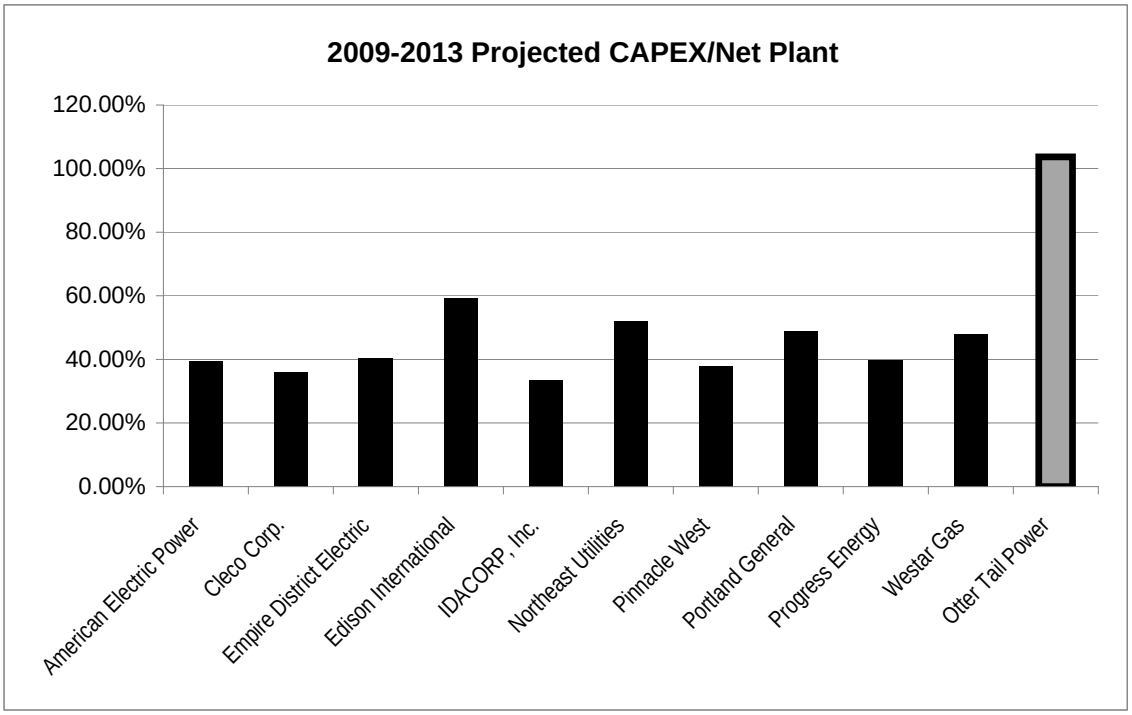
Date	Issuing Entity	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage
Open Market Issuances										
9/19/2008	Otter Tail Corporation	4,500,000	$30.00	$1.0875	$400,000	$28.824	$5,293,750	$135,000,000	$129,706,250	3.921%
12/7/2004	Otter Tail Corporation	2,900,000	$25.45	$0.9500	$300,000	$24.397	$3,055,000	$73,805,000	$70,750,000	4.139%
2/27/2003	American Electric Power	50,000,000	$20.95	$0.6285	$550,000	$20.311	$31,975,000	$1,047,500,000	$1,015,525,000	3.053%
6/5/2002	American Electric Power	16,000,000	$40.90	$1.2270	$370,000	$39.650	$20,002,000	$654,400,000	$634,398,000	3.057%
8/14/2006	Cleco Corporation	6,000,000	$23.75	$0.8900	$225,000	$22.823	$5,565,000	$142,500,000	$136,935,000	3.905%
11/9/2004	Cleco Corporation	1,750,000	$18.50	$0.6475	$200,000	$17.738	$1,333,125	$32,375,000	$31,041,875	4.118%
12/12/2007	Empire District Electric	3,000,000	$23.00	$0.9775	$250,000	$21.939	$3,182,500	$69,000,000	$65,817,500	4.612%
6/16/2006	Empire District Electric	3,300,000	$20.25	$0.8600	$250,000	$19.314	$3,088,000	$66,825,000	$63,737,000	4.621%
10/31/2007	IDACORP	3,500,000	$30.00	$1.2000	$300,000	$28.714	$4,500,000	$105,000,000	$100,500,000	4.286%
12/12/2005	Northeast Utilities	20,000,000	$19.09	$0.6200	$340,000	$18.453	$12,740,000	$381,800,000	$369,060,000	3.337%
4/27/2005	Pinnacle West Capital Corporation	5,300,000	$42.00	$1.3650	$250,000	$40.588	$7,484,500	$222,600,000	$215,115,500	3.362%
12/17/2002	Pinnacle West Capital Corporation	5,700,000	$31.50	$1.1030	$102,750	$30.379	$6,389,850	$179,550,000	$173,160,150	3.559%
6/12/2007	Portland General	21,000,000	$26.00	$0.7800	$700,000	$25.187	$17,080,000	$546,000,000	$528,920,000	3.128%
11/6/2002	Progress Energy	14,670,000	$41.90	$1.0000	$625,000	$40.857	$15,295,000	$614,673,000	$599,378,000	2.488%
8/16/2001	Progress Energy	11,000,000	$40.00	$1.4000	$750,000	$38.532	$16,150,000	$440,000,000	$423,850,000	3.670%
5/29/2008	Westar Energy	6,000,000	$24.28	$0.8498	$325,000	$23.376	$5,423,800	$145,680,000	$140,256,200	3.723%
9/15/2007	Westar Energy	7,600,000	$25.25	$0.88375	$325,000	$24.323	$7,041,500	$191,900,000	$184,858,500	3.669%
Weighted Average Flotation Costs							$165,599,025	$5,048,608,000	$4,883,008,975	3.280%
								FLOTATION COSTS		3.28%

Flotation Cost Adjustment - Gas Proxy Group

		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Expected Dividend Yield Adjusted for Flotation Costs	[6] Zacks EPS Growth	[7] Value Line EPS Growth	[8] Average Growth Estimate	[9] DCF k(e)	[10] Flotation Adjusted DCF k(e)
ELECTRIC UTILITIES											
American Electric Power	AEP	$1.64	$36.32	4.52%	4.67%	4.83%	6.30%	7.50%	6.90%	11.57%	11.73%
Cleco Corp.	CNL	$0.90	$24.69	3.65%	3.87%	4.00%	14.00%	10.50%	12.25%	16.12%	16.25%
Edison International	EIX	$1.22	$39.59	3.08%	3.19%	3.30%	8.80%	5.00%	6.90%	10.09%	10.20%
Empire District Electric	EDE	$1.28	$21.02	6.09%	6.39%	6.61%	-	10.00%	10.00%	16.39%	16.61%
Entergy Corp.	ETR	$3.00	$89.49	3.35%	3.53%	3.65%	11.50%	10.00%	10.75%	14.28%	14.40%
IDACORP, Inc.	IDA	$1.20	$29.13	4.12%	4.20%	4.34%	6.00%	2.00%	4.00%	8.20%	8.34%
Northeast Utilities	NU	$0.85	$24.97	3.40%	3.59%	3.71%	10.00%	11.50%	10.75%	14.34%	14.46%
Pinnacle West Capital	PNW	$2.10	$34.41	6.10%	6.23%	6.45%	6.70%	2.00%	4.35%	10.58%	10.80%
Portland General	POR	$0.98	$23.80	4.12%	4.26%	4.40%	6.50%	7.00%	6.75%	11.01%	11.15%
Progress Energy	PGN	$2.46	$42.91	5.73%	5.88%	6.08%	5.00%	5.00%	5.00%	10.88%	11.08%
Westar Energy	WR	$1.16	$22.36	5.19%	5.28%	5.46%	5.30%	2.00%	3.65%	8.93%	9.11%
MEAN										12.04%	12.19%

MEAN	12.04%	12.19%	
UNADJUSTED CONSTANT GROWTH DCF MEAN		12.04%	
DIFFERENCE (FLOTATION COST ADJUSTMENT)		0.16%	[11]

[1] Source: Bloomberg
[2] Source: Bloomberg, 30 day average price as of October 13, 2008
[3] = [1] / [2] or [Annualized Dividend] / [Price]
[4] = [3] x [1+ .5g] or [Dividend Yield] x [1 + (.5 x average growth rate)]
[5] = [Expected Dividend Yield] / [1- Flotation Cost Percentage]
[6] Source: Zacks
[7] Source: Value Line
[8] Average of columns [6] and [7]
[9] = Column [4] + Column [8]
[10] = Column [5] + Column [8]
[11] Equals Mean Adjusted DCF, Column [10] - Mean Unadjusted DCF, Column [9]



Projected CAPEX / 2007 Net Plant

Company[1]	2009-2013[2]
American Electric Power	39.59%
Cleco Corp.	36.09%
Empire District Electric	40.33%
Edison International	59.19%
IDACORP, Inc.	33.47%
Northeast Utilities	51.92%
Pinnacle West	37.95%
Portland General	48.90%
Progress Energy	39.70%
Westar Gas	48.06%
Otter Tail Power	103.68%

Notes:

[1] Value Line does not have current projections for Entergy Corp.

[2] Otter Tail Power Capital expenditures are projected for 2009 through 2012, however Value Line projects capital expenditures for 2009 and 2011 through 2013.

PROXY GROUP MEDIAN MARKET CAPITALIZATION

Company Name (Ticker)	Ticker	Customers (Mil) [1]	Market Cap ($Bil) [2]	Market to Book Ratio [2]
American Electric Power	AEP	5.2	$ 12.1	1.11
Cleco Corp.	CNL	0.3	$ 1.3	1.18
Edison International	EIX	4.8	$ 10.7	1.21
Empire Dist. Elec.	EDE	0.2	$ 0.6	1.06
Entergy Corp.	ETR	2.6	$ 14.8	1.91
IDACORP, Inc.	IDA	0.5	$ 1.2	0.91
Northeast Utilities	NU	1.9	$ 3.2	1.02
Pinnacle West Capital	PNW	1.1	$ 3.1	0.80
Portland General	POR	0.8	$ 1.2	0.86
Progress Energy	PGN	3.1	$ 9.5	1.09
Westar Energy	WR	0.7	$ 1.9	0.92
MEDIAN		1.1	$ 3.08	1.06
MEAN		1.9	$ 5.4	1.10

SIZE PREMIUM CALCULATION

OTP Equity ($ Millions)	$	229.633	[3]
Median Market to Book for Comp Group	$	1.06	
OTP Implied Market Cap ($ Millions)	$	243.411	

	Market Capitalization (in $millions)			
Decile	Low		High	Size Premium [4]
2	$ 9,274.049	$	20,234.526	0.68%
3	$ 5,025.807	$	9,206.713	0.76%
4	$ 3,426.586	$	5,012.577	0.93%
5	$ 2,413.583	$	3,422.743	1.47%
6	$ 1,633.668	$	2,411.794	1.60%
7	$ 1,129.192	$	1,633.320	1.50%
8	$ 725.267	$	1,128.765	2.20%
9	$ 363.549	$	723.258	2.56%
10a	$ 211.628	$	363.479	3.99%
10b	$ 1.922	$	211.590	9.73%
Proxy Group Median		$	3,080.000	1.47%
OTP Implied Market Capitalization		$	243.411	3.99%
Difference from Proxy Group Median				2.52% [5]

NOTES

[1] Includes electric and gas. Source: Company Form 10-Ks.
[2] Yahoo! Finance, as of October 16, 2008
[3] Direct Testimony and Schedules of Kevin Moug, Exhibit___(KGM-1)
[4] Source: 2008 Morningstar Risk Premia Over Time Report; Estimates for 1926 - 2007
[5] Equals 3.99%-1.47%

Equity Ratio

Summary Data

Company Name	Ticker	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3	Overall Average
American Electric Power	AEP	46.95%	46.71%	47.12%	47.29%	47.18%	47.62%	47.68%	49.22%	47.47%
Cleco Corp.	CNL	46.53%	49.25%	58.50%	58.65%	55.45%	54.09%	53.18%	52.58%	53.53%
Edison International	EIX	53.59%	55.04%	56.14%	56.92%	55.00%	54.63%	53.57%	54.73%	54.95%
Empire District Electric	EDE	52.85%	53.78%	55.65%	51.21%	51.61%	52.06%	54.46%	56.60%	53.53%
Entergy Corp.	ETR	47.28%	46.97%	47.24%	49.84%	49.55%	49.49%	48.46%	49.58%	48.55%
IDACORP, Inc.	IDA	45.33%	45.79%	46.54%	45.61%	47.92%	49.39%	49.73%	49.10%	47.43%
Northeast Utilities	NU	48.63%	48.20%	49.03%	46.25%	46.54%	46.80%	46.96%	47.23%	47.45%
Pinnacle West Capital	PNW	54.50%	52.22%	51.87%	52.66%	52.52%	52.56%	52.61%	51.50%	52.56%
Portland General	POR	50.92%	51.42%	50.06%	51.28%	53.93%	54.95%	53.02%	54.40%	52.50%
Progress Energy	PGN	47.54%	50.55%	50.13%	49.76%	50.88%	50.34%	49.71%	49.69%	49.83%
Westar Energy	WR	63.29%	65.12%	64.55%	68.10%	67.24%	67.94%	67.89%	54.84%	64.87%
Proxy Group Average										52.06%

Underlying Data

		Equity Ratio							
Company Name	Ticker	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3
AEP Texas Central Company	AEP	42.09%	37.40%	40.57%	39.84%	38.16%	37.70%	37.63%	41.44%
AEP Texas North Company	AEP	47.34%	50.15%	52.50%	54.67%	49.98%	52.16%	52.71%	53.13%
Appalachian Power Company	AEP	42.16%	40.03%	40.38%	40.48%	42.34%	44.10%	44.02%	42.75%
Columbus Southern Power Company	AEP	45.93%	45.92%	45.57%	46.28%	47.54%	47.36%	46.91%	47.56%
Indiana Michigan Power Company	AEP	46.11%	46.18%	46.39%	46.42%	45.96%	45.03%	44.12%	47.00%
Kentucky Power Company	AEP	44.62%	44.57%	45.29%	36.97%	44.30%	44.60%	43.63%	43.57%
Kingsport Power Company	AEP	56.38%	55.90%	56.03%	55.75%	55.01%	54.81%	54.63%	55.27%
Ohio Power Company	AEP	49.00%	48.51%	47.03%	46.48%	46.38%	46.23%	47.77%	49.76%
Public Service Company of Oklahoma	AEP	41.85%	41.04%	41.30%	43.96%	40.67%	42.27%	44.18%	47.45%
Southwestern Electric Power Company	AEP	41.52%	45.69%	46.21%	47.84%	46.16%	46.77%	48.23%	54.80%
Wheeling Power Co	AEP	59.50%	58.44%	57.06%	61.53%	62.46%	62.83%	60.66%	58.67%
Cleco Power LLC	CNL	46.53%	49.25%	58.50%	58.65%	55.45%	54.09%	53.18%	52.58%
Southern California Edison Co.	EIX	53.59%	55.04%	56.14%	56.92%	55.00%	54.63%	53.57%	54.73%
Empire District Electric Company	EDE	52.85%	53.78%	55.65%	51.21%	51.61%	52.06%	54.46%	56.60%
Entergy Arkansas, Inc.	ETR	52.11%	53.54%	53.31%	52.33%	54.59%	54.41%	54.27%	54.80%
Entergy Gulf States Louisiana, LLC	ETR	37.02%	35.62%	35.61%	49.77%	49.07%	48.87%	48.97%	49.15%
Entergy Louisiana, LLC	ETR	55.52%	57.80%	57.51%	57.42%	56.18%	55.68%	55.27%	55.69%
Entergy Mississippi, Inc.	ETR	49.17%	50.29%	50.42%	50.28%	49.63%	49.10%	45.65%	45.76%
Entergy New Orleans, Inc.	ETR	41.62%	40.29%	39.36%	39.40%	38.26%	39.39%	38.14%	42.49%
Entergy Texas, Inc.	ETR	48.25%	44.31%						
Idaho Power Co.	IDA	45.33%	45.79%	46.54%	45.61%	47.92%	49.39%	49.73%	49.10%
Connecticut Light and Power Company	NU	48.92%	51.02%	51.75%	46.15%	47.60%	48.40%	46.91%	48.30%
Public Service Company of New Hampshir	NU	45.96%	46.84%	47.34%	47.80%	46.71%	47.38%	46.24%	46.66%
Western Massachusetts Electric Company	NU	51.01%	46.74%	47.99%	44.80%	45.31%	44.62%	47.73%	46.72%
Arizona Public Service Company	PNW	54.50%	52.22%	51.87%	52.66%	52.52%	52.56%	52.61%	51.50%
Portland General Electric Company	POR	50.92%	51.42%	50.06%	51.28%	53.93%	54.95%	53.02%	54.40%
Carolina Power & Light Company	PGN	54.15%	51.43%	51.74%	51.45%	49.03%	48.60%	47.87%	47.89%
Florida Power Corporation	PGN	40.93%	49.67%	48.53%	48.08%	52.72%	52.08%	51.56%	51.49%
Kansas Gas and Electric Company	WR	64.72%	70.90%	70.84%	79.01%	78.57%	78.43%	78.65%	53.06%
Westar Energy (KPL)	WR	61.86%	59.34%	58.26%	57.19%	55.91%	57.45%	57.14%	56.63%

Long Term Debt Ratio

Summary Data

Company Name	Ticker	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3	Overall Average
American Electric Power	AEP	50.67%	50.03%	51.05%	49.86%	49.89%	49.89%	49.63%	50.21%	50.15%
Cleco Corp.	CNL	53.47%	50.75%	41.50%	41.35%	44.55%	45.91%	46.82%	45.62%	46.25%
Edison International	EIX	40.48%	41.90%	39.93%	43.08%	43.58%	44.39%	46.43%	45.27%	43.13%
Empire District Electric	EDE	46.09%	39.50%	41.23%	42.23%	43.42%	43.94%	37.46%	38.95%	41.60%
Entergy Corp.	ETR	51.59%	53.03%	52.76%	49.74%	50.45%	48.64%	49.26%	49.02%	50.56%
IDACORP, Inc.	IDA	46.03%	46.61%	47.75%	48.17%	51.08%	46.27%	47.74%	49.53%	47.90%
Northeast Utilities	NU	50.74%	47.18%	49.02%	50.23%	45.18%	46.50%	46.64%	48.35%	47.98%
Pinnacle West Capital	PNW	43.98%	44.82%	44.75%	45.00%	47.03%	47.44%	47.39%	48.50%	46.11%
Portland General	POR	49.08%	48.58%	49.94%	48.72%	46.07%	43.79%	43.47%	45.60%	46.91%
Progress Energy	PGN	52.19%	49.45%	48.84%	49.22%	49.09%	49.66%	50.29%	50.30%	49.88%
Westar Energy	WR	36.71%	34.88%	35.45%	31.90%	32.76%	32.06%	32.11%	45.16%	35.13%
Proxy Group Average										45.96%

Underlying Data

		Long Term Debt Ratio							
Company Name	Ticker	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3
AEP Texas Central Company	AEP	57.91%	62.60%	59.43%	60.16%	61.84%	62.30%	62.37%	58.56%
AEP Texas North Company	AEP	52.66%	40.35%	42.23%	43.01%	48.27%	45.99%	47.29%	46.87%
Appalachian Power Company	AEP	55.94%	59.97%	54.36%	59.52%	52.56%	54.17%	55.23%	57.25%
Columbus Southern Power Company	AEP	54.07%	47.79%	50.71%	48.88%	49.79%	52.64%	53.05%	52.44%
Indiana Michigan Power Company	AEP	45.24%	47.80%	52.11%	52.76%	53.53%	53.41%	52.79%	52.01%
Kentucky Power Company	AEP	49.98%	50.86%	52.47%	63.03%	52.23%	52.94%	52.75%	53.50%
Kingsport Power Company	AEP	43.62%	44.10%	43.97%	44.25%	44.99%	45.19%	45.37%	44.73%
Ohio Power Company	AEP	47.57%	49.75%	50.89%	51.71%	53.27%	44.89%	47.92%	48.90%
Public Service Company of Oklahoma	AEP	51.67%	55.22%	58.70%	43.79%	45.06%	48.01%	50.11%	52.55%
Southwestern Electric Power Company	AEP	58.21%	50.35%	53.70%	42.85%	49.74%	52.08%	39.74%	44.20%
Wheeling Power Co	AEP	40.50%	41.56%	42.94%	38.47%	49.74%	37.17%	39.34%	41.33%
Cleco Power LLC	CNL	53.47%	50.75%	41.50%	41.35%	44.55%	45.91%	46.82%	45.62%
Southern California Edison Co.	EIX	40.48%	41.90%	39.93%	43.08%	43.58%	44.39%	46.43%	45.27%
Empire District Electric Company	EDE	46.09%	39.50%	41.23%	42.23%	43.42%	43.94%	37.46%	38.95%
Entergy Arkansas, Inc.	ETR	44.51%	46.46%	46.69%	45.59%	45.41%	45.59%	45.73%	45.20%
Entergy Gulf States Louisiana, LLC	ETR	62.98%	64.38%	64.39%	50.23%	50.93%	51.13%	51.03%	50.85%
Entergy Louisiana, LLC	ETR	44.48%	42.20%	42.49%	42.58%	43.82%	44.32%	44.73%	44.31%
Entergy Mississippi, Inc.	ETR	47.42%	49.71%	49.58%	49.72%	50.37%	50.90%	54.35%	54.24%
Entergy New Orleans, Inc.	ETR	58.38%	59.71%	60.64%	60.60%	61.74%	51.25%	50.46%	50.51%
Entergy Texas, Inc.	ETR	51.75%	55.69%						
Idaho Power Co.	IDA	46.03%	46.61%	47.75%	48.17%	51.08%	46.27%	47.74%	49.53%
Connecticut Light and Power Company	NU	49.83%	45.02%	47.22%	50.18%	47.69%	48.64%	44.21%	46.59%
Public Service Company of New Hampshir	NU	54.04%	49.32%	50.78%	52.20%	46.57%	49.96%	50.15%	52.56%
Western Massachusetts Electric Company	NU	48.35%	47.19%	49.07%	48.29%	41.29%	40.92%	45.56%	45.91%
Arizona Public Service Company	PNW	43.98%	44.82%	44.75%	45.00%	47.03%	47.44%	47.39%	48.50%
Portland General Electric Company	POR	49.08%	48.58%	49.94%	48.72%	46.07%	43.79%	43.47%	45.60%
Carolina Power & Light Company	PGN	45.85%	48.57%	46.21%	46.52%	50.90%	51.40%	52.13%	52.08%
Florida Power Corporation	PGN	58.53%	50.33%	51.47%	51.92%	47.28%	47.92%	48.44%	48.51%
Kansas Gas and Electric Company	WR	35.28%	29.10%	29.16%	20.99%	21.43%	21.57%	21.35%	46.94%
Westar Energy (KPL)	WR	38.14%	40.66%	41.74%	42.81%	44.09%	42.55%	42.86%	43.37%

Short Term Debt Ratio

Summary Data

Company Name	Ticker	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3	Overall Average
American Electric Power	AEP	2.90%	3.98%	2.24%	3.48%	3.58%	3.04%	3.28%	0.70%	2.90%
Cleco Corp.	CNL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.79%	0.22%
Edison International	EIX	5.92%	3.07%	3.93%	0.00%	1.41%	0.98%	0.00%	0.00%	1.91%
Empire District Electric	EDE	1.05%	6.72%	3.12%	6.55%	4.96%	4.00%	8.09%	4.45%	4.87%
Entergy Corp.	ETR	1.13%	0.00%	0.00%	0.42%	0.00%	1.87%	2.28%	1.40%	0.89%
IDACORP, Inc.	IDA	8.64%	7.60%	5.71%	6.21%	1.00%	4.34%	2.53%	1.37%	4.67%
Northeast Utilities	NU	0.63%	4.62%	1.95%	3.53%	8.28%	6.69%	6.40%	4.42%	4.56%
Pinnacle West Capital	PNW	1.52%	2.96%	3.37%	2.33%	0.46%	0.00%	0.00%	0.00%	1.33%
Portland General	POR	0.00%	0.00%	0.00%	0.00%	0.00%	1.26%	3.51%	0.00%	0.60%
Progress Energy	PGN	0.27%	0.00%	1.03%	1.01%	0.03%	0.00%	0.00%	0.01%	0.30%
Westar Energy	WR									
Proxy Group Average										2.23%

Underlying Data

		Short Term Debt Ratio							
Company Name	Ticker	2008 Q2	2008 Q1	2007 Q4	2007 Q3	2007 Q2	2007 Q1	2006 Q4	2006 Q3
AEP Texas Central Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AEP Texas North Company	AEP	0.00%	9.50%	5.26%	2.32%	1.75%	1.86%	0.00%	0.00%
Appalachian Power Company	AEP	1.90%	0.00%	5.26%	0.00%	5.10%	1.73%	0.74%	0.00%
Columbus Southern Power Company	AEP	0.00%	6.29%	3.72%	4.84%	2.66%	0.00%	0.03%	0.00%
Indiana Michigan Power Company	AEP	8.65%	6.03%	1.50%	0.82%	0.51%	1.57%	3.09%	0.99%
Kentucky Power Company	AEP	5.40%	4.57%	2.24%	0.00%	3.47%	2.46%	3.62%	2.93%
Kingsport Power Company	AEP								
Ohio Power Company	AEP	3.43%	1.74%	2.08%	1.81%	0.35%	8.88%	4.31%	1.33%
Public Service Company of Oklahoma	AEP	6.48%	3.74%	0.00%	12.25%	14.27%	9.72%	5.71%	0.00%
Southwestern Electric Power Company	AEP	0.27%	3.95%	0.09%	9.31%	4.10%	1.15%	12.04%	1.01%
Wheeling Power Co	AEP								
Cleco Power LLC	CNL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.79%
Southern California Edison Co.	EIX	5.92%	3.07%	3.93%	0.00%	1.41%	0.98%	0.00%	0.00%
Empire District Electric Company	EDE	1.05%	6.72%	3.12%	6.55%	4.96%	4.00%	8.09%	4.45%
Entergy Arkansas, Inc.	ETR	3.38%	0.00%	0.00%	2.08%	0.00%	0.00%	0.00%	0.00%
Entergy Gulf States Louisiana, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Louisiana, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Mississippi, Inc.	ETR	3.41%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy New Orleans, Inc.	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	9.37%	11.40%	7.00%
Entergy Texas, Inc.	ETR	0.00%	0.00%						
Idaho Power Co.	IDA	8.64%	7.60%	5.71%	6.21%	1.00%	4.34%	2.53%	1.37%
Connecticut Light and Power Company	NU	1.25%	3.96%	1.03%	3.67%	4.71%	2.96%	8.88%	5.10%
Public Service Company of New Hampshir	NU	0.00%	3.84%	1.87%	0.00%	6.72%	2.66%	3.61%	0.78%
Western Massachusetts Electric Company	NU	0.64%	6.07%	2.94%	6.91%	13.40%	14.47%	6.71%	7.38%
Arizona Public Service Company	PNW	1.52%	2.96%	3.37%	2.33%	0.46%	0.00%	0.00%	0.00%
Portland General Electric Company	POR	0.00%	0.00%	0.00%	0.00%	0.00%	1.26%	3.51%	0.00%
Carolina Power & Light Company	PGN	0.00%	0.00%	2.06%	2.03%	0.07%	0.00%	0.00%	0.03%
Florida Power Corporation	PGN	0.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kansas Gas and Electric Company	WR								0.00%
Westar Energy (KPL)	WR								

64 S.Ct. 281
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333
(Cite as: 51 P.U.R.(NS) 193, 64 S.Ct. 281)

Supreme Court of the United States
FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.
Nos. 34 and 35.

Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes

[1] **Public Utilities 317A 120**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and Extent in General. Most Cited Cases
(Formerly 317Ak7.1, 317Ak7)
Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

[2] **Public Utilities 317A 123**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak123 k. Reasonableness of Charges in General. Most Cited Cases
(Formerly 317Ak7.4, 317Ak7)
Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

[3] **Gas 190 14.3(2)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(2) k. Federal Power Commission. Most Cited Cases
(Formerly 190k14(1))
The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, § § 4(a), 5(a), 6, 15 U.S.C.A. § § 717c(a), 717d(a), 717e.

[4] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[5] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges

190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[6] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[7] **Gas 190 14.5(7)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(7) k. Presumptions. Most Cited Cases
(Formerly 190k14(1))
An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[8] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[9] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[10] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[11] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act,

§ § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[12] **Gas 190 14.4(4)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(4) k. Method of Valuation. Most Cited Cases
(Formerly 190k14(1))
A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[13] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[14] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[15] **Gas 190 14.3(4)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(4) k. Findings and Orders. Most Cited Cases
(Formerly 190k14(1))
There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[16] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

[17] **Mines and Minerals 260 92.5(3)**

260 Mines and Minerals
260III Operation of Mines, Quarries, and Wells
260III(A) Statutory and Official Regulations
260k92.5 Federal Law and Regulations
260k92.5(3) k. Oil and Gas. Most Cited Cases
(Formerly 260k92.7, 260k92)
Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

[18] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and

Regulation. Most Cited Cases
(Formerly 190k14(1))
The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, § § 4, 6-10, 14, 15 U.S.C.A. § § 717c, 717e-717i, 717m.

[19] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and Regulation. Most Cited Cases
(Formerly 190k14(1))
Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, § § 4, 5, and § 7 as amended 15 U.S.C.A. § § 717c, 717d, 717f.

[20] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, § § 4, 5, and § 7, as amended, 15 U.S.C.A. § § 717c, 717d, 717f.

[21] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[22] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[23] **Federal Courts 170B 452**

170B Federal Courts
170BVII Supreme Court
170BVII(B) Review of Decisions of Courts of Appeals
170Bk452 k. Certiorari in General. Most Cited Cases
(Formerly 106k383(1))
Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

[24] **Constitutional Law 92 74**

92 Constitutional Law
92III Distribution of Governmental Powers and Functions
92III(B) Judicial Powers and Functions
92k71 Encroachment on Executive
92k74 k. Powers, Duties, and Acts Under Legislative Authority. Most Cited Cases
(Formerly 15Ak226)
Congress has entrusted the administration of the

Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, § § 1 et seq., 19(b), 15 U.S.C.A. § § 717 et seq., 717r(b).

[25] **Gas 190 14.5(3)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(3) k. Decisions Reviewable. Most Cited Cases
(Formerly 190k14(1))
Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

[26] **Gas 190 14.5(4)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(4) k. Persons Entitled to Relief; Parties. Most Cited Cases
(Formerly 190k14(1))
Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

****283 *592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.
***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.
Mr. William B. Cockley, of Cleveland, Ohio, for respondent.
Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.
The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. [FN1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. [FN2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

FN1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

FN2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the

River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia. sales.	11,000,000
East Ohio.	40,000,000
Peoples.	10,000,000
River.	400,000
Fayette.	860,000
Manufacturers.	2,000,000

Local West Virginia

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. [FN3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required ***596** to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

FN3 These required minimum reductions of 7¢ per m.c.f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m.c.f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made ****285** certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses-about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell

Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664-666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve' [FN4] of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. [FN5] The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. [FN6]

FN4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

FN5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

FN6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

Hope's estimate of original cost was about $69,735,000-approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. [FN7] The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to

over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

FN7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription FN8 of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

FN8. Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[1] [2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155-157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523-539, 54 S.Ct. 505, 509-517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. FN9

FN9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic

question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

***602** [3] [4] [5] [6] [7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. ****288**Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** [8] [9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard 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 to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by ***604** the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the ****289** company. It considered the financial history of Hope and a vast

array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements,***605** 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10] [11] [12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13] [14] [15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. FN10 By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. FN11 No more is required. FN12 We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

FN10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

FN11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259-288, 50 S.Ct. 123, 128-138, 74 L.Ed. 390, for an extended analysis of the problem.

FN12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the

> Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. FN13 Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. FN14 Secondly, it is pointed out that West Virginia has a production tax FN15 on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) ****291** exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. ***609** Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

> FN13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

> FN14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

> FN15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. FN16

> FN16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural

Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16] [17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as ***610**State of Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. [FN17] State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. [FN18] These were the types of problems with which those participating in the hearings were pre-occupied. [FN19] Congress addressed itself to those specific evils.

FN17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

FN18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

FN19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

611** The Federal Power Commission was given*292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto [FN20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

FN20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions [FN21] contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

FN21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over***613** 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. [FN22] The Commission was also ****293** directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. [FN23] But it left the protection of ***614** those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

FN22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

FN23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.
The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry [FN24] or to protect the interests of those who sell their gas to the interstate operator. [FN25] The return which ****294** the Commission***615** allowed was the net return after all such charges.

FN24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

FN25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. [FN26] No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

FN26 See note 25, supra.

[21] [22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users [FN27] and domestic consumers. We hardly ***616** can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. [FN28] But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies. [FN29] The ***617** Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. [FN30] But s 4(a) and s 5(a) were not changed. If the standard****295** of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

FN27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

FN28. Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

FN29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

FN30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[23] [24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. FN31 However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

FN31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[25] [26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not

reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' ****296**Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles s.l.r. c/o., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v. United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action-action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.' [FN1] Section 6 [FN2] ****297** throws additional light on the meaning of these words.

FN1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

FN2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:

'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged

with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461-466, 10 S.Ct. 462, 702, 703-705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [FN3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. [FN4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

> FN3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

> FN4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard

by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.
My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress***626** specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as

an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717c(a-d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co. [FN1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

FN1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. [FN2] I disclaim this imputed***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

FN2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case-a very important distinction, as I shall try to make plain.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad,

bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. FN3

FN3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. FN4 Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

FN4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. FN5 The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 'wildcat' wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were 'dry holes.' About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. FN6 Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. FN7 Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

FN5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

FN6. Id. at 62-63.

FN7. Id. at 61.

While for many years natural gas had been distributed on a small scale for lighting, FN8 its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. FN9 Soon monopoly of production or markets developed. FN10 To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. FN11 The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by 'wildcat' drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. FN12

FN8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

FN9 In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

FN10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by

Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

FN12. Id. at 63.

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. FN13

FN13. Id. at 64.

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. FN14 West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction***633** from this Court. FN15 Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. FN16 That Commission held that a company could not abandon a part of its territory and still serve the rest. FN17 Some courts admonished the companies to take action to protect consumers. FN18 Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. FN19 There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. FN20 Public service commissions of consuming states were handicapped, for they had no control of the supply. FN21

FN14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

FN16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

FN17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

FN18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

FN19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

FN20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

FN21 The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of

that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

****303 *634** Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. [FN22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. [FN23]

FN22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

FN23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. [FN24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

FN24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:
Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. [FN25]

FN25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial,***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7. [FN26] Although this spread is less than ****304** in other parts of the United States, [FN27] it can hardly be said to be

self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

FN26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

FN27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State.	Industrial	Domestic
Illinois.	29.2	1.678
Louisiana.	10.4	59.7
Oklahoma.	11.2	41.5
Texas.	13.1	59.7
Alabama.	17.8	1.227
Georgia.	22.9	1.043

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. FN28 ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

FN28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.
The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢ ; second 5,000 feet, 45¢ ; third 5,000 feet, 50¢ ; all above 15,000, 55¢ . This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢ ; next 4 m.c.f., 60¢ ; next 8 m.c.f., 55¢ ; over 15 m.c.f., 50¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.
For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. FN29 Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. FN30 This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate ***638** subsidiaries, FN31 the effect of which, if not the purpose, was to isolate ****305** some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

FN29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.
In 1915, so it was reported to the Governor of West

Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

FN31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

The Natural Gas Act declared the natural gas business to be 'affected with a public interest,' and its regulation 'necessary in the public interest.' FN32 Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' FN33 While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' FN34 The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,' FN35 which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates * * * either as between localities or as between classes of service.' FN36 And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' FN37

FN32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

FN33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

FN34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

FN35 Id., s 717c(e).

FN36 Id., s 717c(b).

FN37 Id., s 717d(a).

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. FN38 I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.'

FN38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

***640** III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery.****306** As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to

certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to ***642** time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' [FN39]

FN39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

****307** The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained***643** the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well

drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. FN40 Of ***644** course, the ****308** Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

FN40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that 'As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.' He analyzes the hypothetical character of accounting and says 'It was no eternal mold for pecuniary verities handed down from on high. It was-like logic or algebra, or the device of analogy in the law-an ingenious contrivance of the human mind to serve a limited and practical purpose.' 'Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.' As to capital account he observes 'In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise,

***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. FN41

FN41 See 2 Bonbright, Valuation of Property (1937) 1112.

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, FN42 and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

FN42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business-to reduce to possession an adequate supply of natural gas-is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-leaseholds and freeholds-operated and unoperated-of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the

components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, [FN43] is not even ****310** urged by the gas company for valuing its fields.

> FN43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

***649** The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and ***650** adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to ***651** regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due ****311** chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate

base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor-a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point ***652** if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform ***653** for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is-a tool, a means, an expedient. In public****312** hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it-price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the ***654** field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to

markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. [FN44] What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

FN44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? [FN45] Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has ***655** if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

FN45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, ****313**Block v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates-a high one for domestic use and a lower one for industrial contracts. [FN46] The Commission can fix two prices for interstate gas as readily as one-a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

FN46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

The Commission's concept of the public interest in natural

gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? FN47 And how much cheaper should industrial***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

> FN47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.
> 'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If

Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

U.S. 1944.
Federal Power Commission v. Hope Natural Gas Co.
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333

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43 S.Ct. 675
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176
(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

Supreme Court of the United States
BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.
No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes

Constitutional Law 92 298(1.5)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(1.5) k. Public Utilities in General. Most Cited Cases
Rates which are not sufficient to yield a reasonable return on the value of the property used in public service 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 Fourteenth Amendment of the Constitution.

Constitutional Law 92 298(3)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(3) k. Water and Irrigation Companies. Most Cited Cases
Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases
It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases
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 such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness

of Charges. Most Cited Cases
Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

Federal Courts 170B 504.1

170B Federal Courts
170BVII Supreme Court
170BVII(E) Review of Decisions of State Courts
170Bk504 Nature of Decisions or Questions Involved
170Bk504.1 k. In General. Most Cited Cases
(Formerly 106k394(6))
A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

****675 *680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.
Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

***683** Mr. Justice BUTLER delivered the opinion of the Court.
Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., ****676** and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See ***684**Oklahoma Natural Gas Co. v. Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer

	on. basis of reproduction new, less. depreciation, at prewar prices.	$ 624,548 00
b.	Estimate by company's engineer on. basis of reproduction new, less. depreciation, at 1920 prices.	1,194,663 00
c.	Testimony of company's engineer. fixing present fair value for rate. making purposes.	900,000 00
d.	Estimate by commissioner's engineer on. basis of reproduction new, less. depreciation at 1915 prices, plus. additions since December 31, 1915, at. actual cost, excluding Bluefield. Valley waterworks, water rights,. and going value.	397,964 38
e.	Report of commission's statistician. showing investment cost less. depreciation.	365,445 13
f.	Commission's valuation, as fixed in. case No. 368 ($360,000), plus gross. additions to capital since made. ($92,520.53).	452,520 53

***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000-a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to 'a,' supra: The commission deducted $204,000 from the estimate (details printed in the margin), [FN1] leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see 'd,' supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

FN1

Difference in depreciation allowed.	$ 49,000
Preliminary organization and development. cost.	14,500
Bluefield Valley waterworks plant.	25,000
Water rights.	50,000
Excess overhead costs.	39,000
Paving over mains.	28,500
	$204,000

***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500. [FN2] This may be compared with its final figure, $460,000.

'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of

FN2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. [FN3] The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

FN3

		Company Engineer.	City Engineer.
1.	Preliminary costs.	$14,455	$1,000
2.	Water rights.	50,000	Nothing
3.	Cutting pavements over. mains.	27,744	233
4.	Pipe lines from gravity. springs.	22,072	15,442
5.	Laying cast iron street. mains.	19,252	15,212
6.	Reproducing Ada springs.	18,558	13,027
7.	Superintendence and. engineering.	20,515	13,621
8.	General contingent cost.	16,415	5,448
		$189,011	$63,983

$324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:
'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2] [3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):
'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'
'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being 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 Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).
'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).
'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).
***691** 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.
'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:
'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. 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 ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A

rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48-50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum-as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:
'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. FN4

FN4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment-the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.
U.S. 1923
Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176

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Volume 2B

Testimony of Witnesses:

Peter Wasberg

Employee Compensation

Before the North Dakota Public Service Commission

State of North Dakota

In the Matter of the Application of Otter Tail Corporation
d/b/a Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-08-_____

Exhibit___

EMPLOYEE COMPENSATION

DIRECT TESTIMONY AND SCHEDULES OF

PETER E. WASBERG

November 3, 2008

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter E. Wasberg. My business address is 215 South Cascade Street, Fergus Falls, MN, 56537.

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

A. I am employed by Otter Tail Power Company ("Otter Tail Power" or "OTP"), a division of Otter Tail Corporation as the Director, Human Resources and Safety.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. A description of my qualifications and experience is attached as Exhibit ___, (PEW-1) Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am providing testimony on behalf of OTP.

Q. WERE THE ATTACHED SCHEDULES PREPARED EITHER BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss matters related to employee compensation and benefits, focusing primarily on OTP. First, I will discuss how the compensation levels provided by OTP compare to the general market. Second, I will briefly describe OTP's current compensation plan, including its two annual incentive plans (collectively the "OTP Annual Incentive Plan"). Third, I will generally describe the compensation and

benefit costs that are included in the revenue requirement. Finally, I will provide a summary of OTP's post retirement medical and pension plans and their reasonableness.

Q. PLEASE SUMMARIZE OTP'S PROPOSAL.

A. As generally described in my testimony and further discussed by Mr. Peter Beithon, OTP requests recovery of: (i) costs of wages and salaries and current employee benefits, including an adjustment to OTP executive salaries made effective April, 2007; (ii) costs of the OTP Annual Incentive Plan based on a five-year average payout level, subject to a cap of 25 percent of individual employees' base salary; and (iii) costs relating to post retirement benefits.

III. COMPENSATION LEVELS AND THE COMPETITIVE MARKET

Q. DOES OTP USE INFORMATION REGARDING COMPENSATION AT OTHER FIRMS IN CONNECTION WITH ITS COMPENSATION DECISIONS?

A. Yes. OTP routinely compares its compensation levels to those of other utilities and some non-utilities, using a number of surveys and information sources including Towers Perrin, Watson Wyatt, Mercer, and Hewitt. Every three years, OTP participates in a benchmark study conducted by Towers Perrin for non-executive employees. The two most recent Benchmark Studies were conducted in 2005 and 2008.

Q. PLEASE EXPLAIN HOW OTP USES THIS INFORMATION.

A. OTP uses this information as the framework for formulating its compensation programs. Salary surveys are reviewed and analyzed to find positions that correspond with the essential job duties, skills, and functions of OTP's positions. The appropriate benchmark market and salary range for OTP positions are then derived from the median of the applicable survey data. While the market based compensation for a position is based on the median, it is not limited to the single data point of the median. Rather, the relevant market for a position includes a range above and below the median. The compensation

for OTP non-union employees is ultimately determined by a combination of market data and the employee's responsibilities, performance, and experience.

Q. PLEASE FURTHER EXPLAIN THE MOST RECENT TOWERS PERRIN BENCHMARK STUDIES.

A. In 2005 and 2008, Benchmark Studies were conducted by Towers Perrin for non-executive employees that included compensation for a broad sample of positions. OTP compensation levels were compared using a combination of general industry, energy/utility industry, and north central regional data to reflect the labor markets in which OTP competes.

Q. WHAT WERE THE RESULTS OF THE BENCHMARK STUDY?

A. The 2005 and 2008 Towers Perrin Benchmark Studies showed the following:

1. In the 2005 Study, OTP base salaries overall were 5 percent below the competitive median; and, in the 2008 Benchmark Study, base salaries were 1.9 percent below the competitive median; and
2. Total cash compensation (base salary plus annual incentive) overall were 4 percent below the competitive median in the 2005 Benchmark Study and 5.8 percent below the competitive median in the 2008 Benchmark Study.

Q. WHAT DID YOU CONCLUDE FROM THESE RESULTS?

A. We are using a 2007 test year with known and measurable changes. The 2005 and 2008 Benchmark Studies indicate that our salary structure included in our rate request for non-executive employees is competitive, although slightly below the market median.

Q. DID TOWERS PERRIN ALSO CONDUCT A STUDY OF OTP EXECUTIVE COMPENSATION?

A. Yes. In 2007, Towers Perrin conducted a study of executive compensation for OTP, which included consideration of a number of topics, including the following:

1. Base salary levels were compared to competitive market base salaries;
2. Annual incentive targets were compared to market annual incentives;

3. Total cash compensation levels (including base salaries plus annual incentive targets) were compared to competitive market total cash compensation levels; and

4. Total compensation levels (including base salaries, annual incentive compensation, and long-term incentives) were compared to competitive market total compensation levels.

Q. WHAT DID THE STUDY SHOW?

A. The study showed the following:

1) OTP base salaries were 21 percent below the competitive median;

2) OTP's target incentive compensation was below the market median;

3) OTP's actual total cash compensation was 41 percent below the competitive median; and

4) Total compensation was 50 percent below the market median.

As a result, adjustments to compensation for OTP executives were made effective as of April, 2007.

Q. DOES OTP EXECUTIVE COMPENSATION REMAIN BELOW THE COMPETITIVE MARKET MEDIANS AFTER THESE ADJUSTMENTS?

A. Yes. Even with the adjustments made in April, 2007, OTP's overall total cash compensation (including base salary plus *target* annual incentives) for OTP executives is still 21 percent below the competitive market median and total compensation is still 41 percent below the market median. With the 25 percent cap on individual incentive compensation levels that OTP has proposed as a limit for inclusion in the revenue requirement, the portion of OTP's overall total cash compensation (including base salary plus *capped* annual incentive) proposed for recovery in rates is 27 percent below the competitive median.

IV. DESCRIPTION OF OTP COMPENSATION PLAN

Q. PLEASE DESCRIBE OTP'S WORK FORCE.

A. As of December 31, 2007, OTP had 774[1] full-time employees, including approximately 416 union employees and 358 non-union employees (not adjusted for employees of jointly owned plants). These employees provide a wide range of services required to provide electric utility services to our approximately 129,000 customers located in North Dakota, Minnesota, and South Dakota.

Q. WHAT ARE OTP'S COMPENSATION GOALS?

A. OTP's compensation goals are to attract, and thereafter retain and motivate, valuable employees. Such employees are essential to achieve OTP's mission, which is to produce and deliver electricity as reliably, economically and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business. OTP continues to focus on maintaining a compensation program that provides a competitive, performance-based pay system that helps us attract and retain a quality workforce that provides our customers with safe, reliable, and economical service.

Q. PLEASE IDENTIFY THE MAIN COMPONENTS OF OTP'S COMPENSATION.

A. Many OTP employees receive compensation consisting of base salaries and annual incentive compensation, along with standard employee benefit plans providing current benefits such as a retirement savings plan, an employee stock ownership plan, and health and dental plans. OTP also provides post retirement pensions and health benefits. Some executive employees are also eligible for long-term incentives.

Q. PLEASE SUMMARIZE THE OTP ANNUAL INCENTIVE PLAN.

A. The OTP Annual Incentive Plan includes all regular employees who are not represented by a union and who work at the rate of at least 1,000 hours per year. The OTP Annual

[1] The employee count of 714 used in Tom Brause's testimony represents the number of full time equivalent employees, which has been adjusted for jointly owned plants.

Incentive Plan includes separate plans for: (i) employees other than management (the "OTP Key Performance Award Plan" or "OTP KPA Plan"); and (ii) management employees.

Q. PLEASE BRIEFLY DESCRIBE THE OTP KPA PLAN.

A. The OTP KPA Plan includes approximately 358 OTP employees. The target maximum payout level is 6 percent of the respective individual employee's base salary. The OTP KPA Plan includes four operating criteria (safety, customer satisfaction, plant availability, and service reliability) and two financial criteria relating to OTP. Each of these six criteria has an equal target weighting. If the OTP financial criteria are not met, the payouts under the remaining four operating criteria are also reduced.

Q. PLEASE BRIEFLY DESCRIBE THE OTP ANNUAL INCENTIVE PLAN FOR MANAGEMENT EMPLOYEES.

A. The OTP Annual Incentive Plan for management employees (the "OTP Management Plan") includes approximately 18 OTP employees. Four OTP management employees have target maximum payout levels that exceed 25 percent, but OTP is proposing to limit the level of incentive compensation recovered in rates to 25 percent of their individual salaries. The OTP Management Plan includes a number of individual criteria that vary by the employee's job and responsibilities and two overall financial criteria relating to OTP. The target weighting is 40 percent for individual criteria and 60 percent for the overall financial criteria.

Q. HOW DOES THE ANNUAL INCENTIVE PLAN COMPLEMENT OTP'S TOTAL COMPENSATION PLAN?

A. The OTP Annual Incentive Plan is an important part of our total compensation plan. A compensation plan that includes annual cash incentive compensation encourages increased productivity, and enables OTP to first attract, and then retain and motivate, quality employees who are rewarded for providing quality service to our customers. Without annual incentive compensation, the only way to maintain a competitive cash compensation package would be to increase base salaries, which would increase other

costs and substantially reduce both flexibility and incentives for performance. Reliability of our electrical plants and electrical systems is maximized when we have continuity in our workforce. The technical knowledge needed, and the years that it actually takes to acquire the specialized skills for our system, are paramount to our ability to reliably and efficiently provide energy to our customers. Our low turnover rate, helped by a competitive compensation and incentive package, has increased our ability to maintain a strong system without higher employee counts. Our customers also see the advantages of reduced costs associated with the lower recruitment and training requirements associated with a stable workforce. The component of the OTP Annual Incentive Plan tied to financial performance also benefits customers because financial performance depends on the prudent management of costs, which allows electric utility service to be provided at reasonable costs.

Q. WHAT ARE THE PURPOSES OF OTP'S LONG-TERM INCENTIVES?

A. The purposes of OTP's long-term incentives are to: (i) link the long-term success of OTP to qualifying employee compensation; (ii) encourage the retention of management over the long-term; and (iii) provide the opportunity to earn competitive total compensation.

Q. WHAT ARE THE MAIN COMPONENTS OF OTP'S LONG-TERM INCENTIVES?

A. The main components of OTP's long-term incentives are grants of restricted stock and stock options. Qualifying employees are awarded grants and options based on salary, job level, and the price of the stock at the date of grant.

Q. ARE OTP'S LONG-TERM INCENTIVES COMPARED TO THE MARKET?

A. Yes. As described above, the OTP long-term incentives are considered along with other components of compensation when we review compensation levels, including the 2007 Towers Perrin study.

Q. WHAT BENEFITS DO THE OTP LONG-TERM INCENTIVES PROVIDE TO RATEPAYERS?

A. As I previously discussed, long-term incentives are part of OTP's total compensation package, which allow OTP to attract, and thereafter retain, its executive employees and senior-level management. As a further result of OTP's long-term incentives, these employees have an added incentive to innovate and control costs, improve effectiveness, and improve customer satisfaction. As a result, ratepayers receive benefits through better service at a reasonable cost.

V. TEST YEAR REVENUE REQUIREMENT

Q. PLEASE IDENTIFY THE COMPONENTS OF OTP'S COMPENSATION PLAN THAT ARE INCLUDED IN THE REVENUE REQUIREMENT.

A. As further described by Mr. Beithon, OTP is seeking recovery of: (i) costs of base salaries, including the adjustments to salaries for OTP executives made effective April, 2007; (ii) costs of current employee benefit plans; (iii) costs of the Otter Tail Annual Incentive Plans based on five-year average payout levels, subject to a cap based on 25 percent of employees' salaries; (iv) long-term incentives for certain OTP employees; and (v) certain costs relating to post retirement benefits. The 25 percent cap on the levels of annual incentive compensation applies to both OTP employees and Otter Tail Corporation employees, and no long-term incentive compensation costs for Otter Tail Corporation employees have been included.

Q. PLEASE FURTHER DESCRIBE HOW THE PAYOUT LEVELS FOR THE OTP ANNUAL INCENTIVE PLAN WAS DETERMINED.

A. The OTP test year revenue requirement includes an annual incentive compensation amount based on a five-year average payout level for the OTP KPA Plan and the OTP Management Plan for the years 2003 through 2007. The 5-year average is adjusted to remove any amounts over the 25 percent cap on individual employee incentives. These average payout levels are representative of OTP's typical payout levels over time.

Q. WHY DID OTP NOT USE THE ACTUAL PAYOUT LEVELS FOR 2007?

A. We did not use the actual 2007 payout levels for the OTP KPA Plan and the OTP Management Plan because those levels were not typical. We did however give the 2007 payout levels appropriate consideration by including them in the 5-year averages from which we derived our proposed test year adjustment. For the OTP KPA Plan, the average annual payout was less than one-half of the maximum allowed for the 5-year period, 2003 through 2007. By contrast, if the payout levels were based solely on 2007, the incentive payment included in rates would be approximately one-fourth of the maximum paid during that 5-year period. For the OTP Management Plan, the average annual incentive payout was slightly under the target for the 5-year period, 2003 through 2007. And, again by contrast, if 2007 were considered in isolation, the annual incentive payment would be less than two-third of the 2007 target. Clearly, 2007 was not representative of typical annual incentive compensation payouts by OTP.

Q WHY WAS 2007 SO ABNORMALLY LOW?

A. Our earnings in 2007 were below appropriate rates and limited our ability to pay incentive compensation that was otherwise appropriate. Our lower than adequate revenues in 2007 is demonstrated by our filing for an increase in rates in Minnesota, with interim rates taking effect at the end of November 2007, and our filing for an increase in 2008 in North Dakota and South Dakota. Had our revenues been adequate to support the incentive compensation that was otherwise justified, the incentive compensation paid in 2007 would have been equal to or higher than the five year average.

Q. WHY SHOULD THE COSTS OF THE OTP ANNUAL INCENTIVE PLAN BE INCLUDED IN THE REVENUE REQUIREMENT?

A. The costs of the OTP Annual Incentive Plan should be included in the revenue requirement for several reasons. The inclusion of incentive plans in total compensation packages is an established market practice and a necessary cost of doing business. OTP's annual cash compensation levels, including the OTP Annual Incentive Plan, are below competitive market levels. External studies confirm this fact. In addition, the OTP Annual Incentive Plan includes an appropriate range and balance of factors that provide benefits to customers.

VI. POST RETIREMENT MEDICAL AND PENSION PLANS

Q. DOES OTP PROVIDE OTHER POST RETIREMENT EMPLOYEE BENEFITS ("OPEB") AND PENSION PLANS**?**

A. Yes. OTP provides both.

Q. PLEASE DESCRIBE OTP'S PENSION PLANS

A. We have three separate defined benefit pension plans: one for union employees, other than those at the Coyote Station; a separate plan for union employees at Coyote Station; and one plan for nonunion employees. A summary description of OTP's pension plans is provided in Exhibit __ (PEW-1), Schedule 2. The OTP pension plans are funded through an external trustee. Mr. Beithon will also address in more detail the financial aspects of funding arrangements for OTP's pension plans.

Q. PLEASE DESCRIBE THE OPEB.

A. OTP also provides a medical benefits program for retirees (other post employment benefits or OPEB). Participation for non-union employees is limited to persons hired before September 1, 2006. Participation for one of our collective bargaining agreements is limited to persons hired before January 1, 2009. Participation is also limited to persons who are age 55 or older at retirement, have 10 or more years of service (after age 45), and are eligible for or enrolled in the Otter Tail Power medical program as of retirement. The related accounting prescribed by Financial Accounting Standards Board ("FAS") Statement No. 106 will be addressed by Mr. Beithon.

Q. WHAT HAS OTP DONE TO MANAGE THE ESCALATING COST OF ITS OPEB?

A. OTP has taken several steps to control costs of OPEB. As I indicated in the prior answer, we limited the post-retirement medical benefits program for non-union personnel to persons hired before September 1, 2006; and post-retirement medical benefits were limited, within one collective bargaining agreement, to employees starting employment

before January 1, 2009. We have switched from a defined benefit pension plan to a defined contribution pension plan for non-union employees starting employment after August 31, 2006 and for employees within one of our collective bargaining units starting employment after December 31, 2008. We have made substantial efforts to control employee counts, which also reduces post-retirement obligations. We have also negotiated caps and reductions in OTP's obligations in our union contracts. In addition, we have increased the amount of retiree contributions to the costs of the medical benefits program.

Q. YOU HAVE EXPLAINED WHY CURRENT OPEBS ARE REASONABLE, WERE THE OPEBS THAT ARE BEING RECOVERED THROUGH THE FAS 106 TRANSITION AMORTIZATION ALSO REASONABLE?

A. Yes. At the time FAS 106 accrual accounting was put into place in 1993, we were required to convert our future OPEB obligations into a current expense and we were allowed to amortize that expense over a period of years, as discussed by Mr. Beithon. Thus, the current revenue requirement includes the cost of OPEBs that were provided to our employees as part of their employment compensation plan that existed prior to 1993. OTP then, as now, offered a total compensation package, including OPEBs, set at an overall level needed to compete for and retain qualified employees. The OPEBs were limited to medical and life insurance benefits. A review of the OPEBs then available shows them to be very basic, e.g. eligibility was set at age 55 with 10 years of service, a reasonable deductible of $300 per individual was included and payment was limited to 80 percent for the next $7,500 of expenses, and the amount of lifetime payments was capped.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In order to attract and thereafter retain and motivate talented employees necessary to achieve our mission, OTP has structured a competitive total cash compensation and

benefits package. As I have explained, this combination includes base salaries, active and post-retirement benefits, and incentive compensation. OTP's proposed compensation and benefit costs are reasonable, and should be included in rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-_____

AFFIDAVIT OF PETER E. WASBERG

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

SHARI LYNN RIEDEL
NOTARY PUBLIC—MINNESOTA
My Commission Expires JAN. 31, 2011

Peter E. Wasberg

Subscribed and sworn to before me,
this 23rd day of October, 2008.

Shari Riedel
NOTARY PUBLIC

PETER E. WASBERG

EMPLOYMENT

2008 – PRESENT	Otter Tail Power Company	Fergus Falls, MN
Director, Human Resources & Safety		
2004 – 2008	Otter Tail Power Company	Fergus Falls, MN
Manager, Human Resources		
2002 – 2004	Otter Tail Power Company	Crookston, MN
Area Manager, Crookston & Bemidji		
1997 – 2002	Otter Tail Power Company	Hallock, MN
Division Manager, Hallock & Crookston Divisions		Crookston, MN
1995 – 1997	Otter Tail Power Company	Bemidji, MN
Office Manager, Bemidji Division		
1991 – 1995	Otter Tail Power Company	Milbank, SD
Division Accountant, Milbank Division		

EDUCATION

- Executive and Organizational Development — The Levinson Institute
- Management Institute — University of Wisconsin – Madison
  - Coaching & Counseling
  - Full-Range Leadership
- Bachelor of Arts — Concordia College, Moorhead
  - Business Administration
  - Psychology

PROFESSIONAL AFFILIATIONS

- Society of Human Resources Management (SHRM) — Member
- Corporate Leadership Council — Member
- University of Minnesota, Crookston — All-College Advisory Committee (Chair)
- Lake Region Halfway House — Director
- Crookston National Bank — Director

Summary Description of Otter Tail Power Pension Plans

Pension plan – Union Employees (does not apply to Coyote Union Employees)	
Type	Defined Benefit
Eligibility	Age 18 and date of hire
Benefit Accrual Service	1,000 hours service in a year
Formula	(.38(Final Average earnings) + .18(Final Average Earnings – Covered Compensation)) * (Years of service up to 30/30) + 1% for each year of service from 31 – 40 years
Final Average Earnings	Highest 2.5 year average of past 10 years
Covered Compensation	35 year average of SS taxable wage base ending in year prior to Normal Social Security Retirement Age
Vesting	Cliff: 100% after five years of Benefit Accrual Service
Normal retirement age	65
Early retirement age	Age 55 with at least 10 years of service
Early retirement reductions	Age 62 – 64: None Age 57 - 61: 5% per year prior to age 62 Age 55 - 56: 7% per year prior to age 57
Funding	Employer
Form of payment	50% J&S Annuity, 50%/75%/100% Survivor Annuity, 10-year Certain, Reversion Option
Pension Purchase Option	Roll-over portion of Retirement Savings Plan balance – buys additional annuity
Pre-retirement death benefits	Greater of Qualified Pre-retirement Death Benefit on date of death or 25% of pay

Summary Description of Otter Tail Power Pension Plans

Pension plan – Coyote Station Employees (hired before January 1, 2009)	
Type	Defined Benefit
Eligibility	Age 21 and date of hire
Benefit Accrual Service	1,000 hours service in a year
Formula	(.38(Final Average earnings) + .18(Final Average Earnings – Covered Compensation)) * (Years of service up to 30/30) + 1% for each year of service from 31 – 40 years
Final Average Earnings	Highest 3 year average of past 10 years
Covered Compensation	35 year average of SS taxable wage base ending in year prior to Normal Social Security Retirement Age
Vesting	Cliff: 100% after five years of Benefit Accrual Service
Normal retirement age	65
Early retirement age	Age 55 with at least 10 years of service
Early retirement reductions	Age 62 – 64: None Age 57 - 61: 5% per year prior to age 62 Age 55 - 56: 7% per year prior to age 57
Funding	Employer
Form of payment	50% J&S Annuity, 50%/75%/100% Survivor Annuity, 10-year Certain, Reversion Option
Pension Purchase Option	Roll-over portion of Retirement Savings Plan balance – buys additional annuity
Pre-retirement death benefits	Greater of Qualified Pre-retirement Death Benefit on date of death or 25% of pay

Summary Description of Otter Tail Power Pension Plans

Pension plan – Nonunion Employees (hired before September 1, 2006)	
Type	Defined Benefit
Eligibility	Age 18 and date of hire
Benefit Accrual Service	1,000 hours service in a year
Formula	(.38(Final Average earnings) + .18(Final Average Earnings – Covered Compensation)) * (Years of service up to 30/30) + 1% for each year of service from 31 – 40 years
Final Average Earnings	Highest 2.5 year average of past 10 years
Covered Compensation	35 year average of SS taxable wage base ending in year prior to Normal Social Security Retirement Age
Vesting	Cliff: 100% after five years of Benefit Accrual Service
Normal retirement age	65
Early retirement age	Age 55 with at least 10 years of service
Early retirement reductions	Age 62 – 64: None Age 57 - 61: 5% per year prior to age 62 Age 55 - 56: 7% per year prior to age 57
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Form of payment	50% J&S Annuity, 50%/75%/100% Survivor Annuity, 10-year Certain, Reversion Option
Pension Purchase Option	Roll-over portion of Retirement Savings Plan balance – buys additional annuity
Pre-retirement death benefits	Greater of Qualified Pre-retirement Death Benefit on date of death or 25% of pay

Volume 2B

Testimony and Schedules of Witnesses:

David Prazak

Rate Design

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Corporation
d/b/a Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-08-_____

Exhibit___

RATE DESIGN

Direct Testimony and Exhibit of

DAVID G. PRAZAK

November 3, 2008

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. David G. Prazak, 215 South Cascade Street, Fergus Falls, Minnesota 56537.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Otter Tail Power Company ("Otter Tail Power," or "OTP") as Supervisor of Pricing.

Q. PLEASE SUMMARIZE YOUR EDUCATION, WORK EXPERIENCE, QUALIFICATIONS, DUTIES, AND RESPONSIBILITIES.

A. I have a Bachelor of Science degree in Energy Management with a concentration in Industrial Technologies from Minnesota State University Moorhead.

I have nearly 20 years of experience in the energy industry. I have over 11 years of experience in the Regulatory Services Department as Supervisor of Pricing. Previously, I worked for an energy management company, another electric utility, and as a consultant in demand-side management planning, evaluation and training.

As Supervisor of Pricing at OTP, I manage the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates, rate design and all rate schedule provisions.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of OTP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my direct testimony is to: (1) explain the implementation of rate-related policy-driven initiatives that were outlined by Mr. Thomas Brause in his testimony; (2) describe the rate structure objectives that were used in developing the proposed rates; (3) explain the process OTP used to evaluate potential rate structures; (4) describe the proposed rate design for OTP's rate schedules and riders; (5) describe the development of OTP's

proposed changes to base rate schedules and riders; and (6) support the proposed general overhaul of OTP's rate schedule provisions.

The following is a list of the rate schedules and riders addressed in my testimony, I have enumerated them below:

- Residential Service
- Residential Service – Controlled Demand
- Farm Service
- Small General Service (less than 20 kW)
- General Service (20 kW or greater)
- Commercial Demand Control
- Electric Climate Control
- Commercial Time of Use
- Large General Service
- Large General Service – Time of Day
- Large General Service Off-Peak Rider
- Real Time Pricing Rider
- Large General Service Rider
- Irrigation Service
- Outdoor Lighting
- Outdoor Lighting – Energy Only
- Municipal Pumping Service
- Civil Defense-Fire Sirens
- Water Heating Controlled Service Rider
- Controlled Service – Interruptible Load (CT Metering) Rider
- Controlled Service – Interruptible Load (Self-contained metering) Rider
- Standby Service
- Controlled Service – Deferred Load Rider
- Fixed Time of Delivery Rider
- Bulk Interruptible Rider
- Air Conditioning Control Rider
- Renewable Energy Rider
- Released Energy Rider
- Small Power Producer Riders
- WAPA Bill Crediting Program Rider

Q. WERE THE SCHEDULES YOU SPONSOR PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. WHAT REQUIRED SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring a summary of present and proposed revenues by class and a more detailed comparison of present and proposed revenues by rate schedule and rate component. The summary comparisons are included in Exhibit ___(DGP-1), Schedule 1 and Exhibit ___(DGP-1), Schedule 2. In addition, I also sponsor a Summary of Allocations of Inter- and Intra Class, which is Exhibit ___(DGP-1), Schedule 3 and a matrix of Miscellaneous Rate Schedule changes which is Exhibit ___(DGP-1), Schedule 4.

I am also sponsoring OTP's rate book revisions, which are contained in Volume 3. The volume includes proposed final rate schedule sheets and black-lines showing the changes. It also includes OTP's proposed form service agreements for use with rates for which customer agreements are appropriate.

Q. WHAT DOES THE SUMMARY COMPARISON INDICATE CONCERNING THE TEST YEAR REVENUES BY CLASS UNDER THE PRESENT AND PROPOSED RATES?

A. The 2007 test year revenues at present and proposed rates for the Electric Utility-North Dakota jurisdiction are $118,309,177 and $124,393,180 respectively. The difference between these present and proposed rate revenues is $6,084,003. This increase in rate revenues is the revenue deficiency.

Present rates are primarily those authorized in OTP's last electric rate case, Case No. 10334. The test year sales for the test year were applied to both present and proposed rates to obtain these Test Year revenues.

II. RATE SCHEDULE CHANGES RELATING TO OTP POLICY INITIATIVES

CHANGES TO THE FUEL CLAUSE NON-ASSET-BASED WHOLESALE MARGINS

Q. WHAT CHANGES TO THE FUEL CLAUSE RIDER RATE SCHEDULE ARE NEEDED TO IMPLEMENT OTP'S NON-ASSET-BASED WHOLESALE MARGIN PROPOSAL?

A. As discussed by Mr. Brause and Mr. Peter Beithon, we are proposing to pass a portion of the margins from non-asset based wholesale margins through OTP's Fuel Clause Adjustment ("FCA") mechanism. Proposed changes to our FCA rider include:

Calculating and applying fifteen (15) percent of non-asset-based margins annually. The annual calculation protects ratepayers from the risk of any net annual loss on non-asset based wholesale sales. Once the fifteen (15) percent is calculated, OTP will calculate a rate by dividing the fifteen (15) percent margin amount by the sales for the twelve-month (historical) period. Actual margin credits shall be subject to further true-up based on MISO resettlements. The rate will be a credit (subtraction) to the succeeding twelve-month's fuel clause adjustment rate calculation.

The above described credits will apply to all kWh subject to the FCA. I discuss the application of the FCA to OTP rates below.

It should also be noted that we are proposing to simplify the name of our FCA to "Energy Adjustment Rider."

APPLICATION OF FCA TO RATES

Q. WHY IS OTP PROPOSING TO INCLUDE ITS FCA ON ALL ITS ENERGY-BASED RATES?

A. As Mr. Brause explained in his testimony, OTP is not typical of other utilities in that it currently has some rates that do not include a FCA. This means those customers that have been receiving service under these rates have not been paying for recent increases in fuel and purchase power costs that have occurred since OTP's last rate case. Rather, they have been paying for fuel and purchased power at 1982 prices (the test year of OTP's last rate case). OTP believes that by adding the FCA to these rates, it will send more appropriate pricing signals to these customers. In addition to the benefits of price transparency and rate efficiency, such signals are necessary to promote conservation.

An additional benefit of applying the FCA to the non-FCA rates at this time is doing so provides a method by which the wholesale margin credit, described above, can be applied to the rates of all OTP customers. If the FCA is not applied to all rates, those customers

taking service under non-FCA rate will not receive the wholesale margin credit proposed by OTP and described earlier in my testimony.

Q. IS OTP PROPOSING ANY EXCEPTIONS?

A. Yes. Three rate schedules do not have FCA applied: Fire Sirens, Real Time Pricing and a new proposed rate schedule, Large General Service Rider – System Marginal Energy Price (SMEP). The FCA has not been applied to the Fire Sirens rate because there are no energy charges. The charges are based on horsepower (i.e., non-volumetric). The Real Time Pricing and SMEP rates don't include the FCA because they are based on OTP's forecasted hourly costs so fuel costs from these are included in the hourly rates. In other words, to apply the FCA on these hourly-based rates would over collect FCA revenues from these customers.

Q. IS THE PROPOSED ADDITION OF THE FCA TO THESE NON-FCA RATES THE REASON THAT THEY ARE SEEING A LARGER RATE INCREASE THAN OTHER RATES?

A. No. The addition of the FCA isn't causing that increase. The larger percentage increase is due to the fact that these non-FCA rates have been benefiting from very low unadjusted fuel and purchase power costs set in 1982. This is different from the FCA rates, which have been incorporating fuel and purchased power cost increases through the FCA over time.

Even if we weren't proposing to add the FCA to these rates, the non-FCA rates would be subject to the same increases, based upon current fuel and purchased power costs. The only difference that would occur for these rates if the FCA were not added to them is that they would not be subject to variations in fuel and purchased power costs going forward after the conclusion of this case. They would not continue with 1982 fuel and purchased power costs.

ELIMINATION OF DECLINING BLOCK RATES

Q. PLEASE EXPLAIN OTP'S INITIATIVE TO ELIMINATE ITS DECLINING BLOCK RATES.

A. As discussed by Mr. Brause, OTP is proposing to eliminate its current declining block rate structures. Declining block rates are usage-based rates for which the price decreases as usage increases. Such rates are premised on the fact that rates recover both fixed and variable costs and, as usage increases, the fixed costs can be over recovered if the rate does not change (decline) with increased usage. Such rates, however, are out of favor because of a concern that such rates do not adequately promote conservation and follow marginal costing principles. Therefore, we propose to eliminate all OTP's declining block rate structures. This proposal is discussed more fully later in my testimony.

III. RATE STRUCTURE OBJECTIVES

Q. WHAT ARE THE RATE STRUCTURE OBJECTIVES THAT GUIDE OTP'S PROPOSAL IN THIS CASE?

A. OTP identified the following rate structure objectives:

- The rate design should give the utility a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
- The rate design should promote efficient use of resources, conservation and use of renewables. This implies giving consumers price signals that reflect marginal costs, including seasonal differences and, where reasonably possible, time-of-day (TOD) differences.
- Any rate design changes should be gradual where necessary to avoid large bill impacts.

- The rate design should be based on structures that are reasonable and nondiscriminatory. This includes minimizing cross-subsidies within rate classes.
- The rate design should result in rates that are administratively feasible. This includes taking metering and billing system constraints into account and avoiding unnecessary complexity that might confuse customers.
- The rate design should preserve the attractiveness of load control/interruptible riders.

IV. RATE STRUCTURE EVALUATION

Q. PLEASE SUMMARIZE THE MAIN POINTS OF THIS PORTION OF YOUR TESTIMONY.

A. This portion of my testimony makes two main points:

- Consistent with OTP's rate design objectives I based the structure of the rate schedules and riders covered by my testimony on the structure of OTP's marginal costs, tempered by the need to control bill impacts and maintain a suitable inter- and intra-class relationship between the regular rates and riders available to OTP's customers.
- The proposed revenue requirement allocation for the rate schedules and riders that are covered by my testimony was determined by applying the Equal Percentage Marginal Cost (EPMC) methodology. This approach was used to allocate the revenue requirement within major classes. The EPMC methodology follows our rate structure objectives by improving the efficiency of price signals and reducing cross-subsidies.

Q. PLEASE DESCRIBE DR. PARMESANO'S AND NERA ECONOMIC CONSULTING'S (NERA'S) ROLE IN THIS PROCEEDING.

A. As explained in Dr. Parmesano's testimony, OTP engaged NERA to develop, with input from OTP staff, a marginal cost study covering the period 2008-2012, applicable to service

in North Dakota and South Dakota, and to provide advice on the application of the marginal cost results in proposed rates.

Q. PLEASE COMMENT ON THE MARGINAL COST STUDY CONTAINED IN DR. PARMESANO'S TESTIMONY.

A. OTP closely reviewed Dr. Parmesano's marginal cost study. The marginal cost study reflects OTP's planning and operating practices, regional market situation, and system characteristics.

Q. WHAT PROCESS WAS USED TO DESIGN THE PROPOSED RATES AND RIDERS COVERED BY YOUR TESTIMONY?

A. The basic approach was to use the structure and level of marginal costs for each element of electric service, combined with the class revenue requirement allocations described in the testimony of Mr. Pete Beithon. Next, the class revenue requirements within the class level were allocated using the EPMC Methodology to develop rates and riders that produce sufficient revenues, give improved price signals to consumers, and have acceptable bill impacts. We used a four-step process. First, we identified a series of rate structures for each rider or rate that seemed to have the potential to meet OTP's rate structure objectives. Second, we developed sample rates that used the identified structures and would produce the rate's proposed revenue, using 2007 billing determinants. Third, we analyzed these sample rates for consistency with the rate structure objectives and chose the structure for each rate class that seemed most appropriate, including considerations toward consistent rate designs across all jurisdictions. We focused on the efficiency of the price signals, bill impacts, and likely interactions between the sample rates and customer participation in load control/interruptible programs. Fourth, we refined the charges to mitigate bill impacts and achieve the overall revenue target.

Q. PLEASE DEFINE THE EQUAL PERCENT OF MARGINAL COST (EPMC) METHODOLOGY.

A. The EPMC method utilizes marginal cost revenues to efficiently allocate the revenue requirement. Basically it assigns each rate a percentage of the total revenue requirement for a given class equal to that rate's percentage of total marginal cost revenues. The method can be used to allocate the total revenue requirement across classes and/or within the class level. This method was only utilized within the class level.

Q. WHY WAS THE EMPC METHOD USED TO ALLOCATE REVENUE REQUIRMENTS WITHIN THE CLASSES?

A. This method was used because it aligns with our rate structure objectives – efficiency and gradualism. The use of marginal costs sends efficient pricing signals. By using an allocation method that uses marginal costs, one can also allocate efficient revenue targets for rates within a class. In addition, efficient revenue targets may need to be adjusted to promote gradualism – a gradual approach which mitigates large bill impacts. Therefore the purpose of this objective is to minimize abrupt rate changes.

Q. PLEASE DESCRIBE HOW YOU USED THE EPMC METHOD?

A. Recall that the EPMC method is used to allocate the authorized class revenue requirement within the class level. I used the EPMC method within the classes that have more than one rate, except for Lighting and OPA classes. For those classes where the EPMC method was not used, the class allocation was used, as developed and described by the testimony of Mr. Beithon.

As described above, the EPMC allocated the increases to the rates within a class from a marginal cost revenues basis. OTP utilized two EPMC approaches to allocate the revenue within the classes. Both approaches have different levels of gradualism (mitigating the abruptness of rate changes).

1. Method 1 - 50% of EPMC: Under this method, I calculated the revenue increase (from current rates) that would result from using EPMC within a class to set revenue targets

for each rate within that class. To account for gradualism, I then set the revenue target for each of these rates at 50% of the increase that would result from strict application of EPMC. Example – RDC would receive an increase of 29.33% using EPMC within the residential class; Method 1 reduced the revenue increase for this rate to 14.67%.

2. Method 2 - 50% of Difference between EPMC and CCOSS: This method also modifies the results from strict application of EPMC within a class. Only one class used this method. Under this method, the target revenue for a rate is 50% of the difference between (1) the overall percentage revenue increase proposed by Mr. Beithon for the class and (2) the percentage revenue increase that would results from applying EPMC to each rate within the class. This approach also recognizes the objective of gradualism, and also takes into consideration the fact that the class as a whole is receiving a revenue increase. For example – Interruptible Large Dual Fuel rates would see a revenue increase of 50.8% under EPMC. The increase for the Controlled Service Deferred class, based on the testimony of Mr. Beithon, was 35.0%. By using Method 2, the revenue target for this rate was set at 42.92%--half of the difference between 50.8% and 35.0%.

A summary of the CCOS assigned increase by classes and EPMC methods for allocation and gradualism within classes is shown in Table 1 below.

Table 1: Summary of EPMC Methods – Gradualism (DRAFT)

CCOSS Classes	CCOSS Proposed Increase	EPMC Method
Residential	7.50%	Method 1
Farm	7.50%	N/A
Small General Service	0.95%	Method 1
Large General Service	1.00%	N/A
Irrigation	10.00%	Method 1
Lighting	25.0%	N/A
OPA	14.0%	N/A
Water Heating	10.0%	N/A
Interruptible	35.0%	Method 2
Deferred Load	11.0%	Method 1

For further details, please see Exhibit ___(DGP-1), Schedule 3.

Q. WHAT ARE THE RATE STRUCTURES THAT YOU EVALUATED FOR EACH CLASS?

A. The tables below summarize the structures we evaluated for rates (Table 2) and riders (Table 3). The rate structures include various degrees of time-differentiation (seasonal and time-of-day), alternative billing mechanisms to recover local distribution costs, the presence or absence of demand charges, and various forms of declining blocks. Each structure identified for evaluation is designed to move the rate design toward a structure that matches OTP's cost structure.

The structures selected for inclusion in our proposal are shown by the "shaded" gray boxes.

Table 2. Rates Structures Evaluated

Base Rate Schedule	Proposed Rate Structures for Initial Screening											
	Fixed Charges			Energy Charges ($/kWh)					Demand Charges ($/kW)			
Rate or Rider	Customer Charge	Monthly Min Bill	Local Facilities Charge	Non-seasonal	Seasonal	Seasonal TOD	Declining Block	Penalty	Non-Seasonal	Seasonal	Seasonal & TOD	Ratcheted Billing Demand
Residential	C	C		C			C					
1	✓	✓			✓		✓					
2	✓	✓			✓							
3	✓	✓	kWh		✓							
4	✓	✓	Fixed		✓							
Residential Demand Control	C	C		C						C		11-month to winter only
1	✓	✓			✓					✓		11-month to winter only
2	✓	✓	kWh		✓					✓		11-month to winter only
3	✓	✓	kWh		✓					✓		By season
4	✓	✓	Fixed		✓					✓		11-month to winter only
5	✓	✓	Fixed		✓					✓		By season
Farm Service	C	C	>25 kVa	C			C					
1	✓	✓	1 & 3 Phase	✓			✓					
2	✓	✓	1 & 3 Phase		✓							
3	✓	✓	1 & 3 Phase		✓		✓					
Small General Service (less than 20 kW)	C	C	C	C			C					
1	✓	✓	✓		✓		✓					
2	✓	✓	✓		✓							
General Service (20 kW or greater)	C	C	C	C			C					
1	✓	✓	✓		✓		✓					
2	✓	✓	kW		✓							
Large General Service		C		C			C		C			C
1	✓	✓		✓			✓		✓			✓
2	✓	✓	kW		✓		✓			✓		
3	✓	✓	kW		✓					✓		
Commercial Time of Use (NEW)		C	Customer-specific			C						
1	✓	✓	Customer-specific			✓						
2	✓	✓	Customer-specific			✓					✓	
Large General Service – Time of Day	C	C	c			C						
1	✓	✓	✓			✓						
2	✓	✓	✓			✓					✓	
Standby Service - Under & Over 100 kW		C	c			C			C			
1	✓	✓	✓			✓			✓			
2	✓	✓	✓			✓					✓	
3												
Irrigation Service - Option 1 Non-TOD		C	Customer-specific	C								
1	✓	✓	Customer-specific		✓					✓		
2	✓	✓	Customer-specific		✓							
Irrigation Service - Option 2 TOD		C	Customer-specific			C						
1	✓	✓	Customer-specific			✓						
2	✓	✓	Customer-specific			✓					✓	
Outdoor Lighting - Energy Only Dusk to Dawn		C	C	C (option 1)					C (option 2)			
1	✓	✓	✓	(option 1)					(option 2)			
Municipal Pumping Service		C					C					
1	✓	✓	✓	✓								
2	✓	✓	✓		✓							
Civil Defense - Fire Sirens			C	included in Facilities charge								
1	✓	✓	✓	included in Facilities charge								

Legend		- Selected	C	- current rate design	✓	- proposed rate design

Table 3. Rider Structures Evaluated

Rider Schedule	Proposed Rate Structures for Initial Screening											
	Fixed Charges			Energy Charges ($/kWh)					Demand Charges ($/kW)			
Rate or Rider	Customer Charge	Monthly Minimum Bill	Local Facilities Charge ($/design kW)	Non-seasonal	Seasonal	Seasonal & TOD	Declining Block	Penalty kWh	Non-Seasonal	Seasonal	Seasonal & TOD	Ratcheted Billing Demand
Water Heating – Controlled Service	**C**	**C**		**C**								
1	✓	✓			✓							
2	✓	✓	✓		✓							
Real Time Pricing Rider	**C**					Hourly						
1	✓					Hourly						
Large General Service Rider	None											
1	✓											
Controlled Service – Interruptible Load (CT Metering)		**C**	**C**		**C**			**C**				
Option 1a	✓	✓	Fixed $		✓			✓				
Option 1b	✓	✓	kWh		✓			✓				
Option 2a	✓	✓	Fixed $		✓							By season
Option 2b	✓	✓	kWh		✓							By season
Controlled Service – Interruptible Load (Self-Cont. Metering)		**C**	**C**		**C**			**C**				
1	✓	✓	Fixed $		✓			✓				
2	✓	✓	✓		✓			✓				
Controlled Service – Deferred Load Rider	**C**	**C**		**C**				C				
1	✓	✓	Fixed $		✓			✓				
2	✓	✓	kWh		✓			✓				
3	✓	✓										
Fixed Time of Delivery Rider		**C**	**C**	**C**								
1 - 301 thru 303	✓	✓	Fixed $	✓	✓			✓				
2 - 301 thru 303	✓	✓	kWh		✓			✓				
Legend		- Selected			**C**	- current rate design		✓	- proposed rate design			

Q. WERE THERE ANY RATE STRUCTURES THAT DID NOT FOLLOW THE PREVIOUS EVALUATION PROCESS?

A. Yes. The following rate structures did not follow the previous evaluation process because the design for these rates remained the same and/or did not require a change in the current rate process. I will discuss the features of these rate structures later in my testimony.

- Outdoor Lighting
- Outdoor Lighting– Energy Only
- Civil Defense-Fire Sirens
- Water Heating Credit – (relocated to Water Heating Controlled Service Rider)
- Real Time Pricing Rider
- Large General Service Rider (New)

- Bulk Interruptible Rider
- Air Conditioning Control Rider (New)
- Renewable Energy Rider
- Released Energy Rider
- Small Power Producer Riders
- WAPA Bill Crediting Program Rider

V. INDIVIDUAL RATE PROPOSALS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this portion of my testimony I walk through each of the classes and individual rates for which we are proposing rate design changes.

Q. HOW WERE THE PROPOSED REVENUE REQUIREMENTS FOR THE PROPOSED RATE CLASSES AND RIDERS DETERMINED?

A. Mr. Beithon proposes the class revenue allocation in his testimony. As Mr. Beithon explains, OTP's proposed revenue requirements for each rate/rider are based on the results of the embedded cost study he prepared, non-cost considerations of rate continuity, and the desire to mitigate bill impacts.

Q. HOW WERE THE PROPOSED CLASS REVENUE REQUIREMENTS ALLOCATED BETWEEN RATES WITHIN THE CLASS?

A. Most were allocated by the EPMC methodology that I described earlier in my testimony.

Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE RESIDENTIAL CLASS?

A. There are two rate schedules in the Residential Class: Residential Service and Residential – Controlled Demand.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE RESIDENTIAL SERVICE RATE.

A. I am proposing a non-declining rate block structure for the residential class that includes a monthly customer charge, a minimum bill equal to that customer charge, and a flat seasonally-differentiated energy charge. As Table 3 below shows, the energy charges are set at slightly over 80% of marginal cost to meet the revenue requirement not satisfied by the customer charge. The current three blocks have been collapsed into one energy block thereby eliminating the declining block structure. The proposed energy charges, although below marginal cost, provide a more efficient price signal for residential customers, particularly for those using more than 1000 kWh per month. The proposed customer charge is about one-third of marginal cost. The separate facilities charge is a flat charge for all customers. Marginal costs for facilities were developed based on customer usage, a proxy for design demand, tied to transformer and other customer-related distribution equipment. Bill impacts for relatively small customers are controlled by pricing these elements below marginal cost.

This structure eliminates the complexity of the current three declining energy blocks.

Table 4: Comparison of Current and Proposed Residential Rate and Marginal Costs

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month		Energy Charge per kWh All Year	Summer	Winter
Current Rate							
Zone 1		$4.74		First 1,000 kWh:	$0.08240	*	
Zone 9 and Cottages		$5.65		Next 1,000 kWh:	$0.06737		
				Excess 1,000 kWh:	$0.05938		
Water Heating Credit					-$2.00		
4 Proposed Rate	$3.00	$3.00			All kWh	$0.08520	$0.07772
Customer Charge, Seasonal Energy, No Declining Block		+Facilities	$5.00				
Flat Facilities Charge			$5.00				
				Water Heating Credit	-$4.00		
Marginal Costs	$10.11	Cust+Facilities			All kWh	$0.10545	$0.09619
kWh > 1,800 in any month			$11.38				
kWh always < 1,800 per month			$44.92				

*Current Rates Include FCA

Q. THE CURRENT RESIDENTIAL RATE DIFFERENTIATES THE CUSTOMER CHARGE BY ZONE. WHY DOES YOUR PROPOSED RATE ABANDON THIS DIFFERENCE BETWEEN URBAN (ZONE 1) AND RURAL (ZONE 9) CUSTOMERS?

A. The current rate charges a higher price per month to customers in Zone 9 (rural) and cottages. NERA's marginal cost study identified a slightly higher cost of local facilities for rural customers versus urban customers. However, the more striking cost difference is between customers with very large usage requirements and those with more modest usage requirements, regardless of zone, as shown in the marginal costs for facilities (i.e., customers with less than 1,800 kWh/month versus those with greater than 1800 kWh/month). This difference could be reflected in differential facilities charges, but my proposed rate does not include such charges, primarily in order to approach this rate with gradualism.

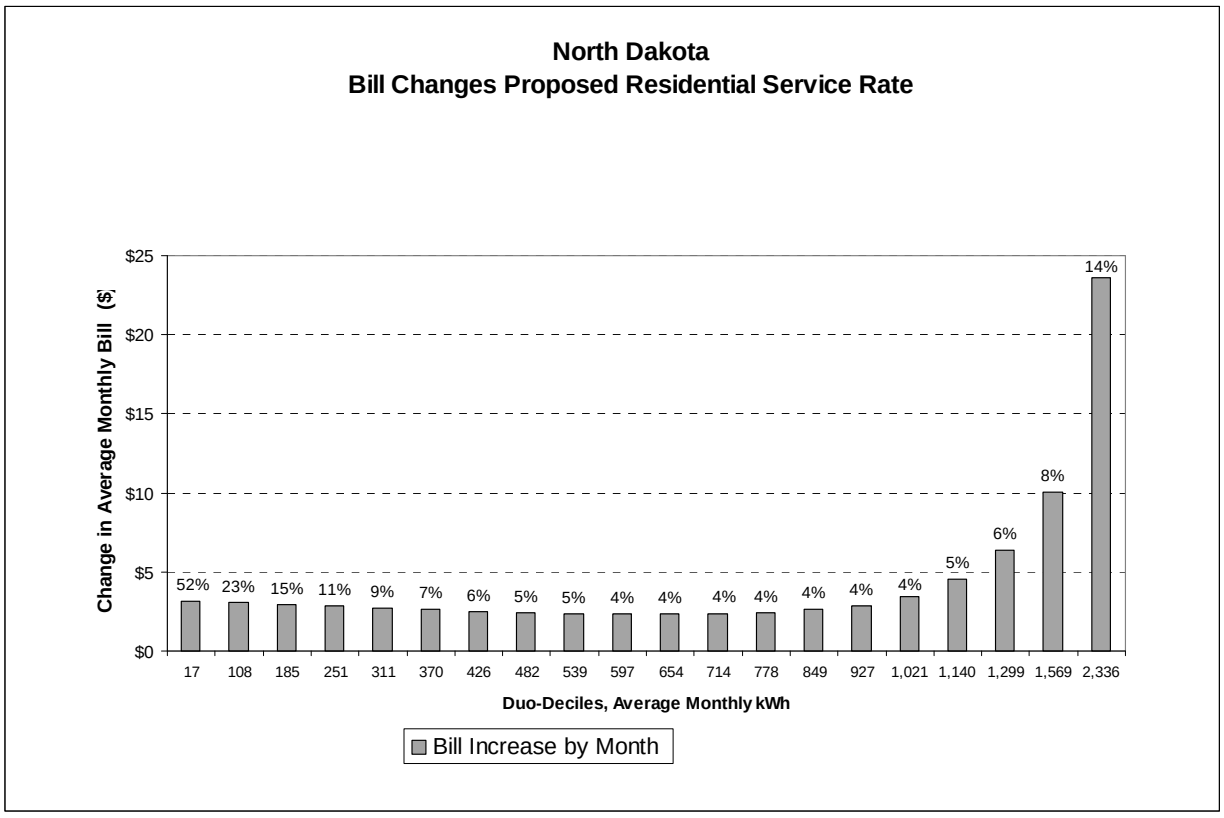
Q. WHAT ARE THE BILL IMPACTS OF YOUR RECOMMENDED RESIDENTIAL RATE?

A. To analyze bill impacts from each of my recommended rates, we computed the bills under current rates and under my proposed rates for every OTP customer account in the class, using 2007 billing information (OTP's test year). We then created bar charts showing the average monthly bill changes (dollar amounts and percentage) for duo-deciles (20 equal segments) of customers, ordered by average monthly kWh use. Each bar represents 5 percent of accounts in the class. It is important to keep in mind that the smallest one or two bars probably include significant numbers of customers who were not on the system for the entire year, are seasonal customers, or are anomalies such as customers who shifted from one rate to another (or shifted load to a rider) during the year.

As the bar chart for residential customers below shows (Figure 1), the average monthly bill impacts are quite modest in dollar terms, except for the largest 5 percent of customers, whose monthly use averages over 2,300 kWh. These large usage customers would lose the benefits of the intra-class subsidy resulting from the two below-cost blocks in the current rates. More than 85% of residential customers will see monthly bill increases of less than

$5, which is very modest considering that OTP has not had a base rate increase in 25 years and the proposed average increase to the residential class is 7.5% percent.

Figure 1: Bill Impacts – Residential Service



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE RESIDENTIAL-CONTROLLED DEMAND RATE.

A. My proposed Residential Controlled Demand rate retains the current customer charge, but adds a flat facilities charge for all customers that is 80% of marginal facilities costs for customers under 5000 kWh/month and about 20% of marginal facilities costs for customers over 5000 kWh/month . My proposal uses seasonal energy charges based on about 55% of marginal cost, to match the revenue requirement for this class. The seasonal energy charges provide a better price signal than the non-seasonal energy charges in the current rate. My proposed rate retains seasonal demand charges, but the summer demand charge is higher than the winter demand charge, reflecting OTP's higher summer marginal capacity costs.

The current demand charges are levied with a 12-month ratchet, using only the winter season. Under my proposal, the demand charges follow the same ratchet as the current demand charges. The demand charges are below marginal cost by approximately the same percentage as the energy charges, to preserve the marginal cost relationships.

Table 5: Comparison of Current and Proposed Residential Controlled Demand and Marginal Costs

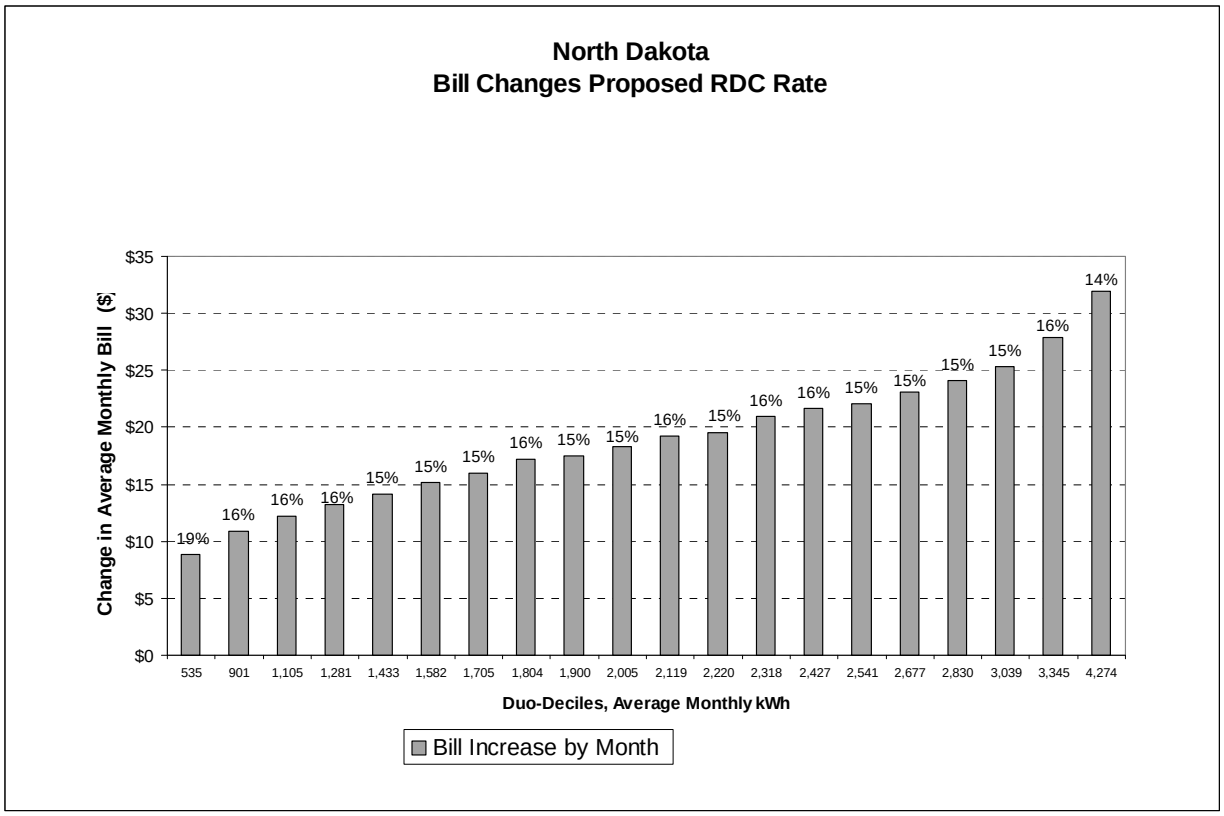
		Customer Charge per month	Minimum Bill per month		Facilities Charge per per KW month		Charge per kWh Summer	Charge per kWh Winter	Demand Charge per kW per mo. Summer	Demand Charge per kW per mo. Winter
Current Rate									per 12-mo. max monthly	
	No Seasonality - 12-month Demand Ratchet	$9.38	Customer Charge		$0.00		$0.04172	$0.04172 *	$3.69	$7.32
									Winter Ratchet	
Rate 4	Seasonal with Flat Facilities Charge, with 12-month Winter Ratchet	$9.38	Customer + Facilities Charge			All kWh:	$0.04887	$0.04934	$6.88	$2.78
				Fixed Facilities	$9.00					
					$9.00					
							Energy Only:		Capacity Only	
Marginal Costs		$16.77	<5000 kWh in all months:		$11.38		Summer $0.08843	Winter $0.08929	Summer $12.45	Winter $5.03
			>5000 kWh in any month:		$44.92					

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED RESIDENTIAL CONTROLLED DEMAND RATE?

A. As Figure 2 shows, the bill impacts are fairly consistent in percentage terms, ranging from 15 – 19%, across groups of customers with increasing average monthly energy consumption. The average customer usage on Residential Controlled Demand is greater than the Residential Service Customer by a factor of 2.85.

Figure 2: Bill Impacts - Residential Controlled Demand



Q. WHAT RATE DESIGN ARE YOU PROPOSING FOR THE FARM CLASS?

A. Farm Service is the only rate in the Farm Class.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE FARM SERVICE RATE.

A. My proposed Farm rate eliminates declining blocks and substitutes seasonal energy charges that are about 70% of marginal cost. All customers on the rate will have the same customer charge, but the rate incorporates a surcharge for customers with three-phase service. The three-phase surcharge, levied per customer per month, is equal to the additional marginal cost of providing three-phase service. The surcharge varies depending on whether the customer is served from overhead or underground facilities and whether the customer's transformer is below 25 kVA or is 25 kVA and greater. This surcharge improves the equity

of the rate by reflecting the higher costs of providing three-phase service and the higher cost of underground three-phase service.

Table 6: Comparison of Current and Proposed Farm Service and Marginal Costs

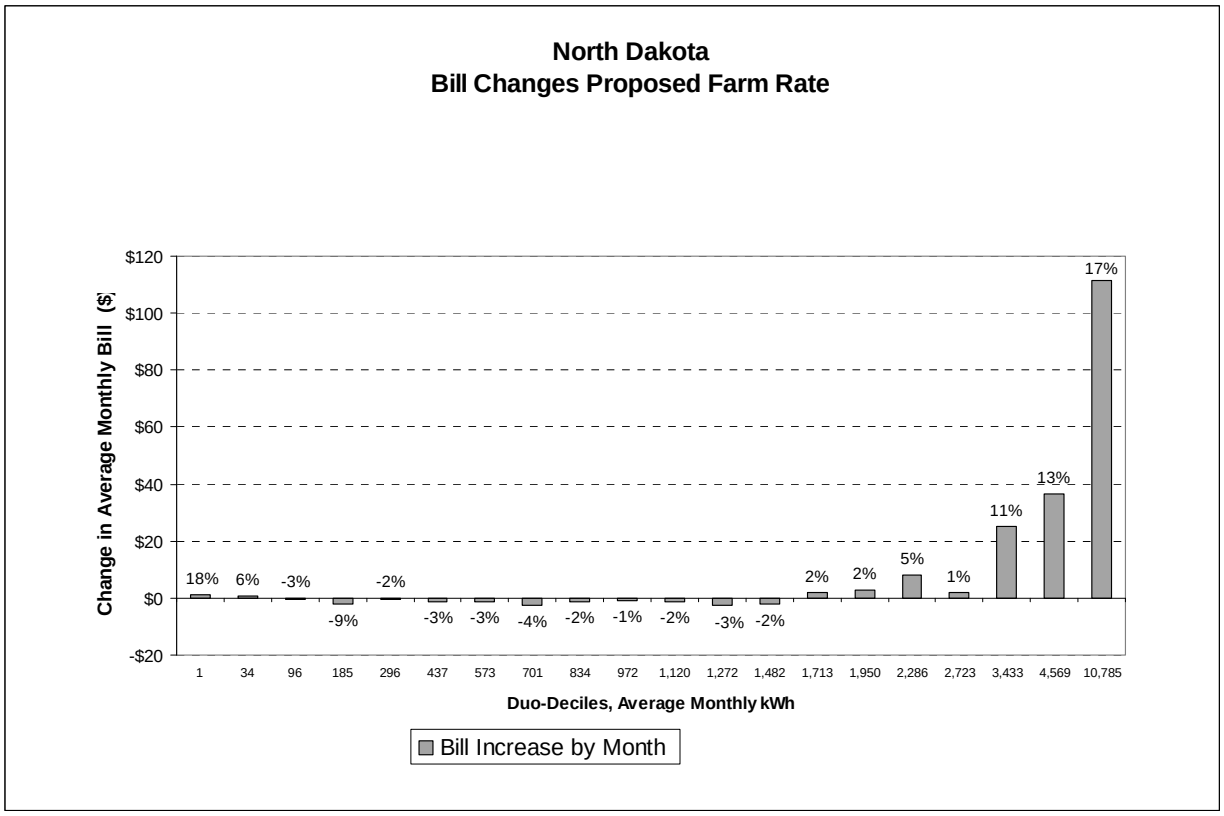
	Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per kVA of Transformer	Energy per kWh Summer	Energy per kWh Winter	Energy per kWh All Year
Current Rates	$7.51	$7.51 + $0.71797 per kVA above 25 kVA		na		1st 150:	0.08702
						Next 1450:	0.06817
						Excess:	0.05730
2				**3-Phase Surcharge per Mo.**			
Proposed Rate	$8.00	Cust + Fac	Overhead		$0.07327	$0.06684	All Energy
No Declining Block			<25 kVA	$4.81			
Seasonal Energy			25 kVA or more	$5.61			
Customer Charge			Underground				
Facilities for 3ph			<25 kVA	$13.42			
			25 kVA or more	$21.56			
Marginal Costs	$12.34				$0.10545	$0.09619	All
				Additional cost for 3-Phase per month			
			Overhead				
			<25 kVA	$9.61			
			25 kVA or more	$11.23			
			Underground				
			<25 kVA	$26.83			
			25 kVA or more	$43.11			

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED FARM RATE?

A. Bill increases are small or negative for most Farm customers. The customers with the largest consumption (the last two duo-deciles) will see increases because they will lose the benefits of the significantly below-cost last block in the current rate.

Figure 3: Bill Impacts – Farm Service



Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE GENERAL SERVICE CLASS?

A. There are five rate designs in the General Service Class: Small General Service (under 20 kW); General Service (20 kW and greater); a new proposal - Commercial Time of Use; and two designs proposed to be eliminated – Commercial Demand Control ("CDC") and Electric Climate Control ("ECC"). The CDC has been an experimental rate for over 20 years and is currently used by 28 customers. The ECC rate has been closed since 1983 and currently has approximately 500 customers.

Q. PLEASE DESCRIBE YOUR OVERALL RATE DESIGN PROPOSAL FOR THE SMALL GENERAL SERVICE (UNDER 20 KW) AND GENERAL SERVICE (20 KW AND GREATER) RATES, AND EXPLAIN THE IMPACT OF ELIMINATING THE CDC AND ECC RATES.

A. My proposal for the General Service class is to divide the class, which now includes customers with demands up to 80 kW, into two parts, with separate rates applicable to customers with demands below 20 kW (Small General Service) and to those with demand of 20 kW and more (General Service). This change allows use of a simpler, more transparent rate structure for the smaller customers in this class.

The elimination plan for the two rates (CDC and ECC) will cause the customer currently using these rates to migrate to other applicable electric rate schedules. In our analyses, each CDC and ECC customer will qualify for either the Small General Service rate or the General Service rate. Their appropriate billing determinants have been included in the Small General Service and General Service rate designs as applicable. In addition, bill impact analyses have been prepared for each of the affected rates. They will be addressed along with the General Service – under 20 kW and 20 kW and greater - sections below.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SMALL GENERAL SERVICE (UNDER 20 KW)

A. My proposed rate for the under-20-kW customers eliminates load factor blocks and institutes a single-block seasonal energy charge structure, which includes capacity costs. My proposed block is set close to 75% of marginal cost. I also propose a customer charge, a facilities charge ($/kW basis), and a minimum bill equal to the customer charge plus the facilities charge. This structure greatly improves the efficiency of the current rate, which has a tail block well below marginal cost.

Table 7: Comparison of Current and Proposed Small General Service Less Than 20 kW and Marginal Costs

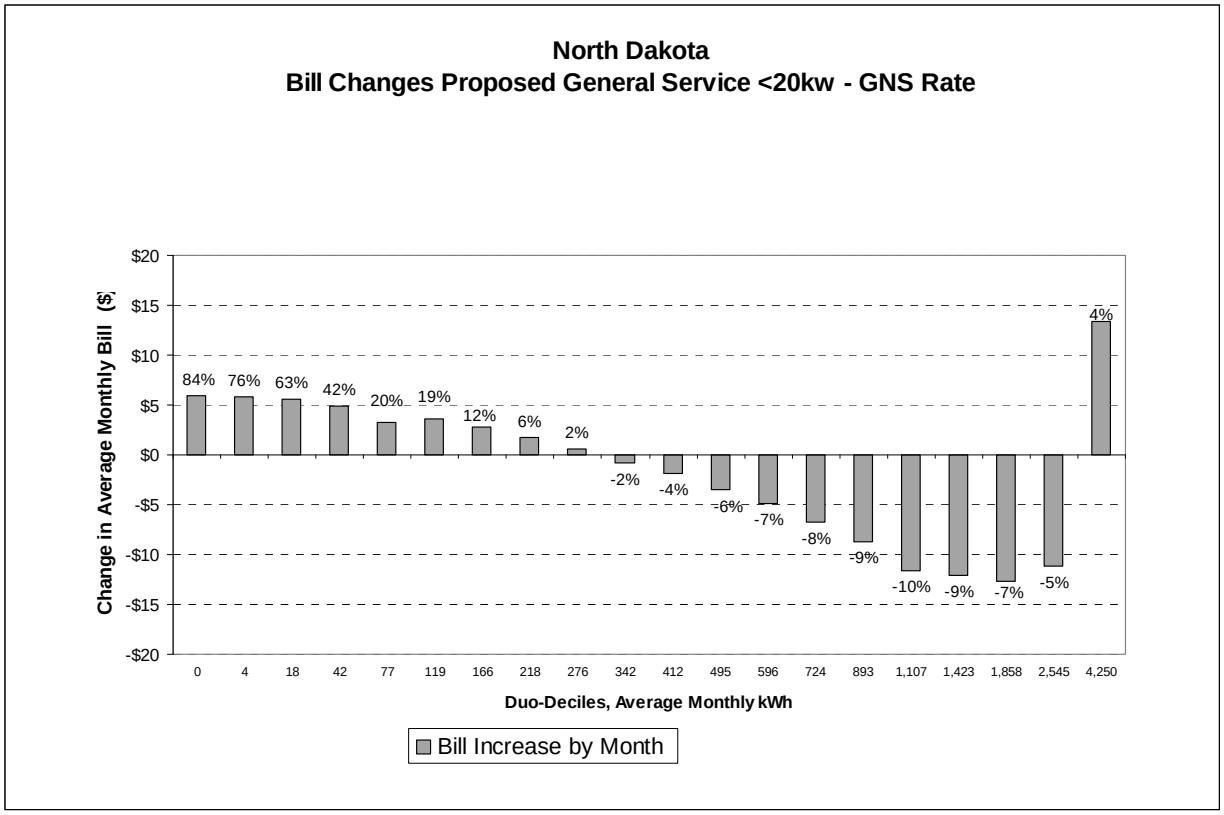
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Winter	All Year
SECONDARY						
Current Rate GS	NA		NA			
Zone 1:	$6.65	$6.65 + $0.57438 per kVA of first 20 kVA of connected load			First 1,000 kwh	$0.10389
Zone 2:	$7.95	kVA of transformer capacity greater than 10.			Next 1,000	$0.09290
					Excess:	$0.07825
				All kWh in excess of 200 per kW of billing demand:		$0.06164
Current CDC Rate	NA	$14.12	$14.12			
					All Energy	$0.04709
			On Peak KW Charge	$5.60	$7.51	
			Off Peak kW Charge	$0.96	$0.96	
Current Electric Climate Control Rate						
					Heating kWh	$0.06068
	$7.90	$7.90	NA		Air Conditioning kWh	$0.06068
					Cooking kWh	$0.06068
					Next 1,000 kWh	$0.11590
					Next 1,000 kWh	$0.10204
					Excess kWh	$0.08443
			All kWh in excess of 200 per kW of billing demand:			$0.06561
2 Proposed Flat Facilities No Declining Block	$10.00	Customer Charge+ Fac	$3.00	$0.08760	$0.07991	
Marginal Costs	$17.51		$5.10	$0.10545 energy plus capacity	$0.09619	
PRIMARY						
Current		5% discount on all charges				
2 **Proposed Flat Facilities No Declining Block**	$10.00	Customer Charge+ Fac	$2.00	$0.08722	$0.07953	
Marginal Costs	$17.51		$3.40	$0.10498 energy plus capacity	$0.09573	

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED SMALL GENERAL SERVICE RATES FOR CUSTOMERS BELOW 20 KW DEMAND?

A. As shown in Figure 4 below, the average bill changes for the under-20 kW customers vary with the first one-half of the class realizing increases under $15/month and the remaining half realizing decreases of up to $15 per month.

Figure 4: Bill Impacts – Small General Service Less Than 20 kW

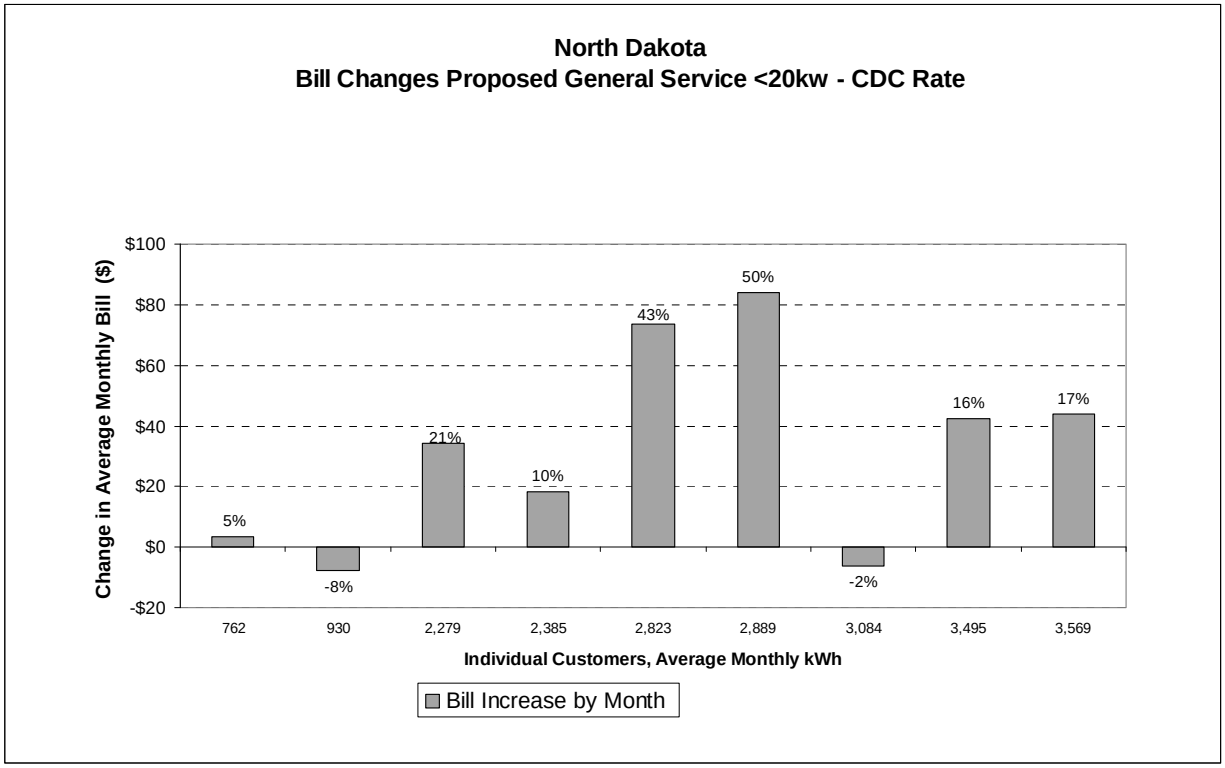


Q. WHAT ARE THE BILL IMPACTS FOR COMMERCIAL DEMAND CONTROL CUSTOMERS BILLED ON YOUR PROPOSED GENERAL SERVICE RATES FOR CUSTOMERS BELOW 20 KW DEMAND?

A. Figure 5 below, describes the bill impacts for the CDC customers for whom the Small General Service rate would apply. These bill impacts assume these particular CDC customers did not change their usage patterns. Therefore, some customers benefit from the rate change to the General Service without changing their usage patterns, others do not. For

those customers who do not benefit from the rate change, other rate options, such as the Commercial Time of Use rate (explained later in my testimony), are available.

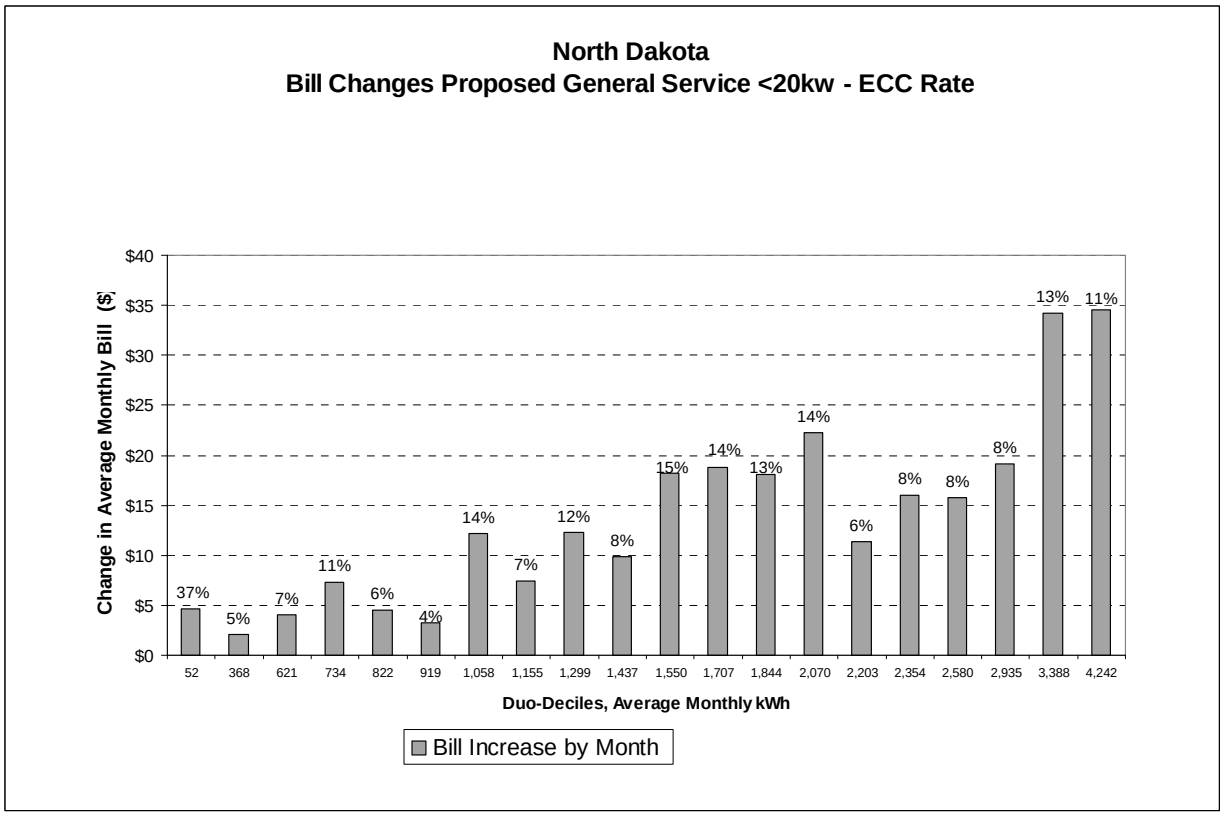
Figure 5: Bill Impacts – Commercial Demand Control Customers Billed on Small General Service Less Than 20 kW



Q. WHAT ARE THE BILL IMPACTS FOR ELECTRIC CLIMATE CONTROL CUSTOMERS BILLED ON YOUR PROPOSED GENERAL SERVICE RATES FOR CUSTOMERS BELOW 20 KW DEMAND?

A. Figure 6 below, describes the bill impacts for the ECC customers for whom the Small General Service rate would apply. In the same manner as described above, these bill impacts assume these particular ECC customers did not change their usage patterns. In this case, no customers saw a rate decrease from the rate change to the General Service. Other rate options, such as the Commercial Time of Use rate (also explained later in my testimony) are available.

Figure 6: Bill Impacts – Electric Climate Control Customers Billed on Small General Service Less Than 20 kW



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR GENERAL SERVICE (20 KW AND GREATER)

A. My proposed rate eliminates load factor blocks and declining energy blocks, which greatly simplifies the structure in the current rate. My proposed energy charge is set just under 75% of marginal cost. The proposed rate for these larger customers includes a customer charge and a facilities charge per kW of maximum annual demand, set at about 53 percent of marginal cost. These charges help improve the equity and efficiency of the rate structure by eliminating from the variable components of the bill those costs that do not vary with usage or demand.

My proposed rates for General Service customers likewise eliminate the zone differences in the current rate, for the same reasons I earlier described for the Residential Rates. My proposal also includes separate charges for secondary and primary customers,

unlike the current rate which simply applies a 5-percent primary discount to the standard bill. My proposal results in more equitable and efficient charges for customers taking service at primary voltage because the proposed rate reflects the marginal cost differences and only those components with marginal costs that differ by voltage level are priced lower for customers taking service at primary voltage.

Table 8: Comparison of Current and Proposed General Service equal to and greater than 20 kW- and Marginal Costs

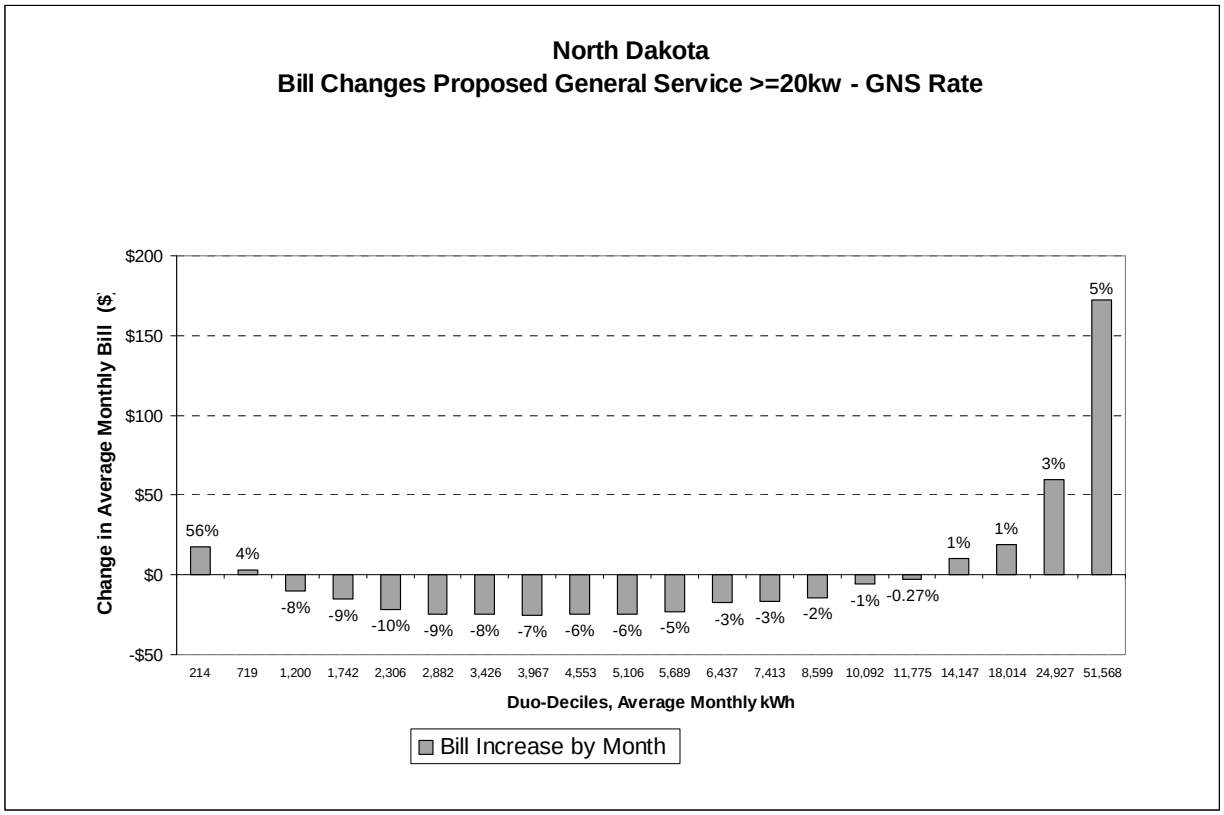
		Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Winter	All Year
SECONDARY							
Current Rate		na		na			
	Zone 1:	$6.65	$6.65 + $0.57438 per kVA of first 20 kVA of connected load			First 1,000 kwh	$0.10389
	Zone 2:	$7.95	kVA of transformer capacity greater than 10.			Next 1,000	$0.09290
						Excess:	$0.07825
					All kWh in excess of 200 per kW of billing demand:		$0.06164
Current CDC Rate		NA	$14.12	$14.12			
						All Energy	$0.04709
				On Peak KW Charge	$5.60	$7.51	
				Off Peak kW Charge	$0.96	$0.96	
Current Electric Climate Control Rate							
						Heating kWh	$0.06068
		$7.90	$7.90	NA		Air Conditioning kWh	$0.06068
						Cooking kWh	$0.06068
						Next 1,000 kWh	$0.11590
						Next 1,000 kWh	$0.10204
						Excess kWh	$0.08443
				All kWh in excess of 200 per kW of billing demand:			$0.06561
2 Proposed Flat Facilities No Declining Block		$12.00	Customer charge+ Fac	$0.52	$0.07798	$0.07114	
Marginal Costs		$26.50		$0.98	$0.10545 energy plus capacity	$0.09619	
PRIMARY							
Current			5% discount on all charges				
2 Proposed Flat Facilities No Declining Block		$12.00	Customer charge+ Fac	$0.38	$0.07764	$0.07080	
Marginal Costs		$26.50		$0.65	$0.10498 energy plus capacity	$0.09573	

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED GENERAL SERVICE RATES FOR CUSTOMERS 20 KW AND GREATER?

A. As shown in Figure 7 below, the average bill changes for the 20 kW or greater customers shows an average decrease for about 70% of the rate class. This is primarily due to the reduction in the energy charge for customers in the first 2000 kWh's. Smaller customers show increases due to the higher customer charge. The larger customers show an increase of up to 5% primarily due to the elimination of the declining block.

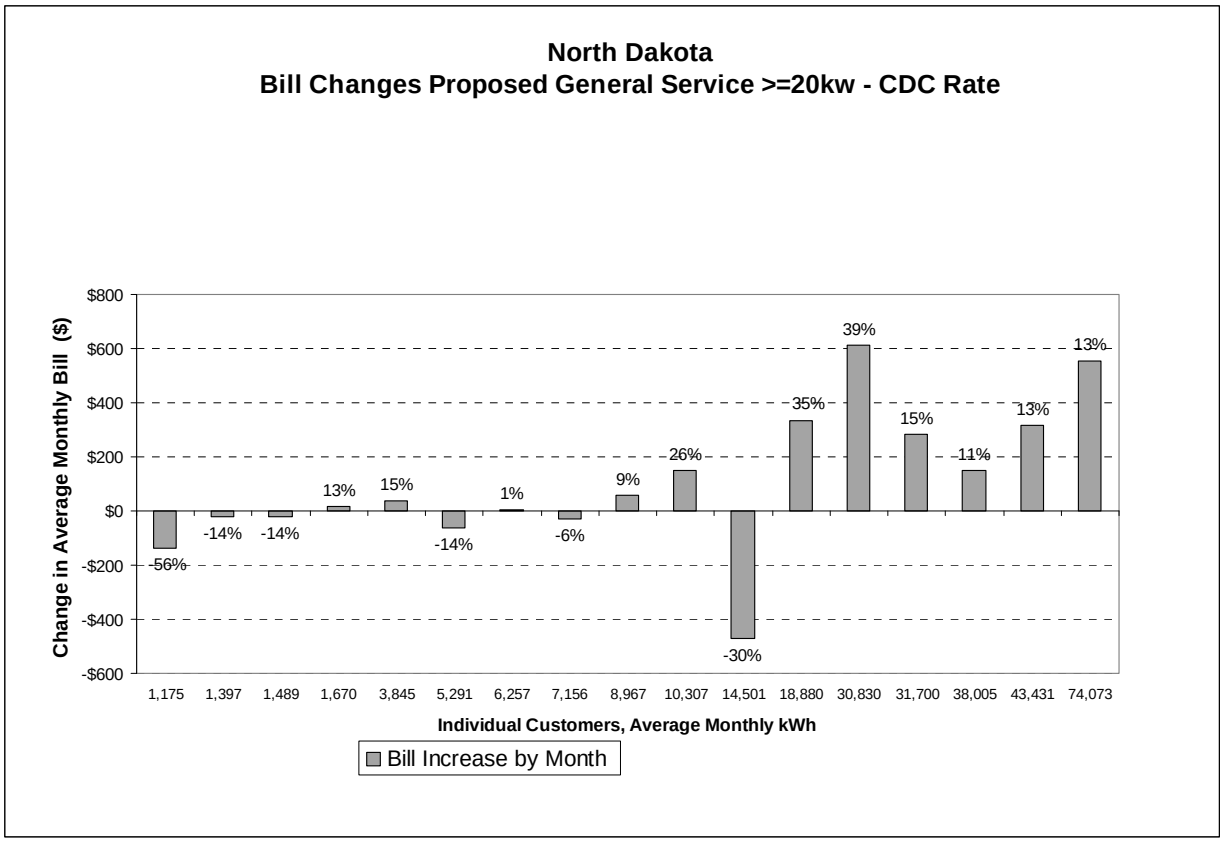
Figure 7: Bill Impacts – Small General Service 20 kW and greater



Q. WHAT ARE THE BILL IMPACTS FOR COMMERCIAL DEMAND CONTROL CUSTOMERS BILLED ON YOUR PROPOSED GENERAL SERVICE RATES FOR CUSTOMERS WITH DEMAND OF 20 KW AND MORE?

A. Figure 8 below, describes the bill impacts for the CDC customers for whom the General Service – Equal to and Greater Than 20 kW rate would be applicable. These bill impacts assume these particular CDC customers would not change their usage patterns. Therefore, some customers benefit from the rate change to the General Service without changing their usage patterns. For those customers who do not benefit from the rate change, other rate options, such as the Commercial Time of Use (explained later in my testimony) are available. Generally, the results are varied due to the small number of customers on the rate and the adjustment in rates from the current rate design to the proposed design.

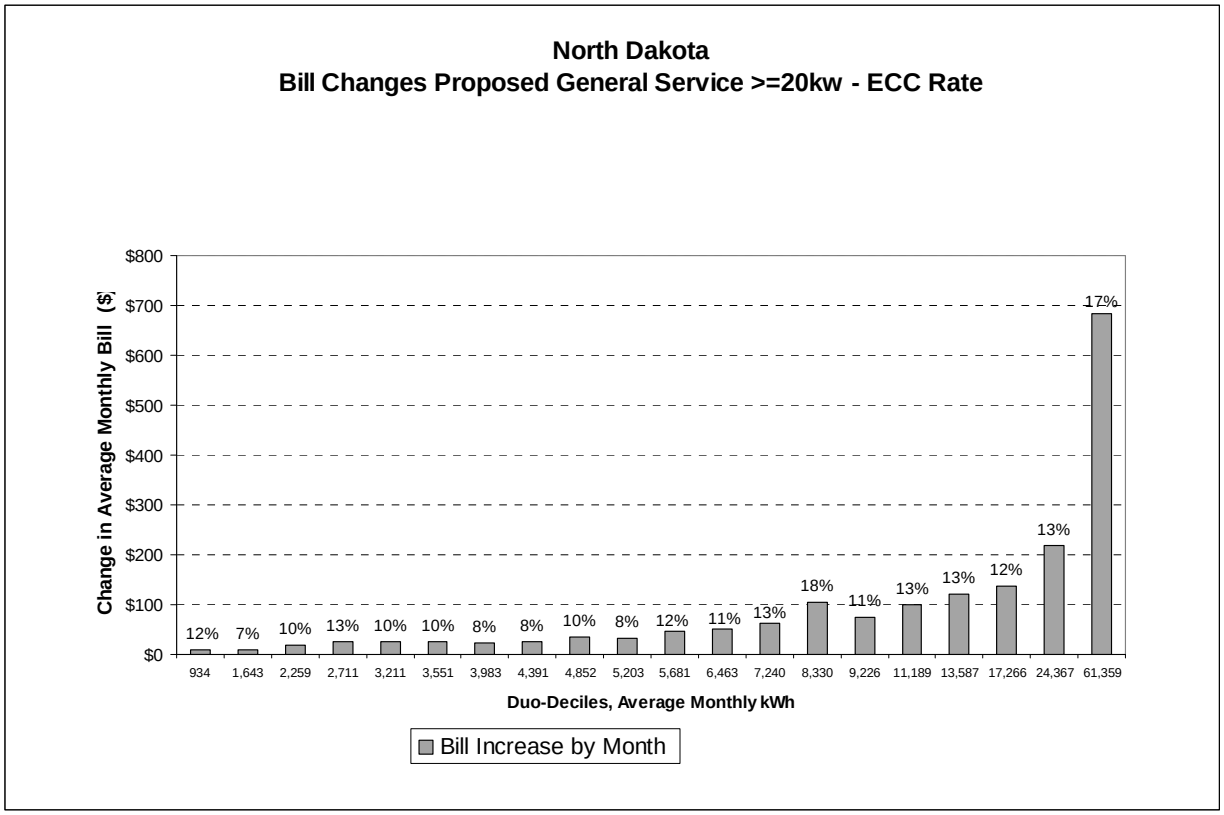
Figure 8: Bill Impacts – Commercial Demand Control Customers Billed on General Service Equal to and Greater Than 20 kW



Q. WHAT ARE THE BILL IMPACTS FOR ELECTRIC CLIMATE CONTROL CUSTOMERS BILLED ON YOUR PROPOSED GENERAL SERVICE RATES FOR CUSTOMERS WITH DEMAND OF 20 KW AND MORE?

A. Figure 9 below, describes the bill impacts for the ECC customers for whom the General Service – Equal to and Greater Than 20 kW rate would apply. These bill impacts assume these particular ECC customers would not change their usage patterns. In this case, no customers see a rate decrease from the rate change to the General Service. Other rate options, such as the Commercial Time of Use (also explained later in my testimony) are available. Generally, these customers will see an average monthly increase in the range of 8-17%.

Figure 9: Bill Impacts – Electric Climate Control Customers Billed on General Service Equal to and Greater Than 20 kW



Q. ARE YOU MAKING ANY ADDITIONAL PROPOSALS FOR THE SMALL GENERAL SERVICE RATE?

A. Yes. In addition, my proposal includes a new rate schedule, Commercial Time of Use Rate. This rate is currently available to OTP customers in Minnesota.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE COMMERCIAL TIME OF USE RATE.

A. This rate is similar to Option 2 of the Irrigation rate shown later in my testimony in that customers pay a high rate in hours defined by OTP to be periods of peak conditions. My proposed rate seasonally differentiates the charges, adds a demand charge in the intermediate period, and sets the on-peak ("declared peak") energy charges at full marginal cost (energy plus demand) expected in the hours likely to be defined as system peak hours. The demand charges are levied without a ratchet. This new structure gives a strong, efficient and transparent price signal to customers during critical hours. The proposed rate also introduces a small customer charge and sets the minimum bill at the sum of the customer charge and customer-specific facilities charge.

Table 9: Comparison of Current and Proposed Commercial TOU Rate and Marginal Costs

		Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW month	Charge per kWh	Summer	Winter	Demand Charge per kW per mo. Summer	Winter
								per seasonal max kW	
Rate 1	Seasonal Energy with Peak, Shoulder, Off Peak	$16.00	Cust+Fac.	$0.52	On	$0.20574	$0.13621	$0.00	$0.00
	Declared Cap in Declared Energy				Shoulder	$0.06974	$0.07068	$2.43	$2.81
					Off	$0.04132	$0.04277	$0.00	$0.00
Marginal Costs		$36.39		$0.98	Energy Only:	$0.27369	$0.18119	Capacity Only $0.00	$0.00
						$0.09277	$0.09402	$3.24	$3.74
						$0.05496	$0.05689	$0.34	$0.14

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM THE PROPOSED COMMERCIAL TOU RATE?

A. This is a new service offering and therefore there are no current customers from which bill impacts could be measured.

Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE LARGE GENERAL SERVICE CLASS?

A. There are four rate designs in the Large General Service Class: Large General Service, a re-designed Large General Service Time of Day Rate; and Real-Time Pricing Rider. The Real-Time Pricing Rider and Large General Service Rider will be discussed in a different section later in my testimony.

Q. PLEASE DESCRIBE YOUR OVERALL RATE DESIGN PROPOSAL FOR THE LARGE GENERAL SERVICE CLASS, INCLUDING THE ELIMINATED RATES.

A. My proposal for the Large General Service class improves price signals, including seasonality, and removes one rate – Large General Service Time of Day, which will be replaced with a new rate design.

The elimination plan for the Large General Service Off-Peak Rider (LGS-Off Peak Rider) will cause these customers to migrate to other applicable rates. In our analyses, each LGS Off-Peak Rider has been analyzed in the Large General Service. In addition, bill impact analyses have been prepared for each of the affected rates. They will be addressed along with the Large General Service section below.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE LARGE GENERAL SERVICE RATE SCHEDULE.

A. My proposal for this rate moves toward a more efficient and straightforward structure. The proposed rate removes declining block and load factor block structures which are replaced by single block seasonal demand and energy charges. These charges are based on marginal costs, but discounted to help match the revenue requirement. Both seasonal demand and energy charges are set at about 57 percent of marginal costs which places these proposed

charges in between the current blocks. The proposed rate also eliminates the current ratchet for billing demand, thereby improving the transparency price signals and making it easier for customers to determine how changes in use in any given hour will affect their bills.

The facilities charge varies by size of secondary customer (in terms of maximum annual kW) and varies by voltage level. These charges are close to 40 percent of marginal cost. The customer charge and the minimum bill is set at the sum of $280 (approximate marginal customer cost) and the facilities charges.

Table 10: Comparison of Current and Proposed Large General Service and Marginal

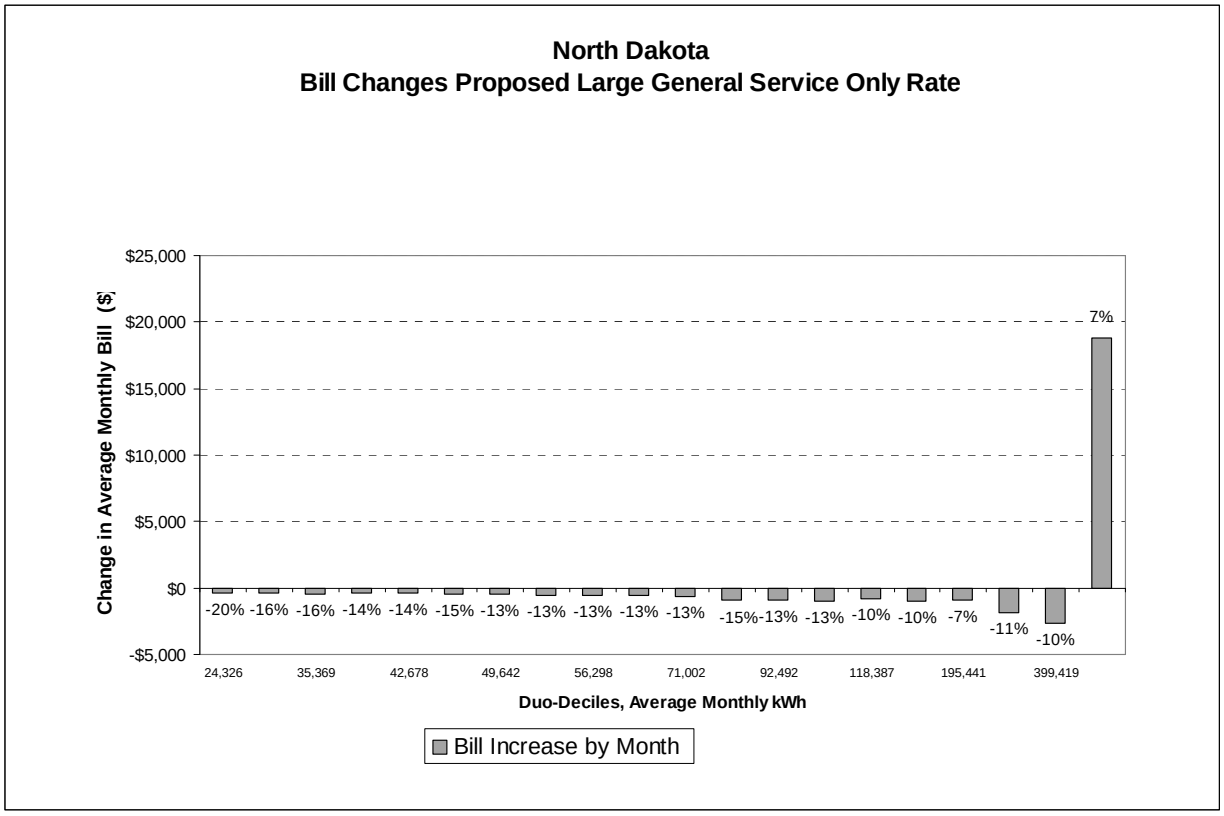
		Customer Charge per month	Minimum Bill per month	per annual max. kW (minimum 80 kw) per month	Energy Charge per kWh			Demand Charge per kW	
						Summer	Winter		
SECONDARY					**All Year**			**All Year**	
	Current Rate								
		na	Demand Charge	All over 360 kWh per kW	$0.04245			1st 100 kW of billing demand:	$8.33
				First 700,000 kWh	$0.05094			Excess kW of billing demand:	$6.80
	Note: Billing demand is ratcheted			Excess kWh	$0.04289				
						Summer	**Winter**	**Summer**	**Winter**
Rate 3	**Seasonal Energ, no decling blocks, Facilities charge, Customer Charge, No Ratchet on Demand.**	$40.00	$240.00 + facilities charges					$7.13	$2.88
			< 1000 kW:	$0.30	All kWh	$0.05065	$0.05113		
			> 1000 kW:	$0.15					
	Marginal Costs	$254.44	< 1000 kW:	$0.79		$0.08843	$0.08929	$12.45	$5.03
			> 1000 kW:	$0.40					
PRIMARY								**All Year**	
	Current Rate								
		na	Demand Charge	All over 360 kWh per kW	$0.04245			1st 100 kW of billing demand:	$8.04
				First 700,000 kWh	$0.05094			Excess kW of billing demand:	$6.51
	Note: Billing demand is ratcheted			Excess kWh	$0.04289				
						Summer	**Winter**	**Summer**	**Winter**
Rate 3	Seasonal Energ, no decling blocks, Facilities charge, Customer Charge, No Ratchet on Demand.	$40.00	$240.00 + facilities charges	$0.11	Al kWh	$0.05045	$0.05090	$7.08	$2.86
	Marginal Costs	$303.69		$0.28		$0.08809	$0.08887	$12.36	$5.00
TRANSMISSION								**All Year**	
	Current Rate								
		na	Demand Charge	All over 360 kWh per kW	$0.04245			1st 100 kW of billing demand:	$7.23
				First 700,000 kWh	$0.05094			Excess kW of billing demand:	$5.65
	Note: Billing demand is ratcheted			Excess kWh	$0.04289				
						Summer	**Winter**	**Summer**	**Winter**
Rate 3	Seasonal Energ, no decling blocks, Facilities charge, Customer Charge, No Ratchet on Demand.	$40.00	$240.00 + facilities charges	$0.00	All kWh	$0.04925	$0.04946	$5.75	$2.43
	Marginal Costs	$384.36		$0.00		$0.06631	$0.06275	$7.02	$5.46

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED LARGE GENERAL SERVICE RATES?

A. Figure 10 below shows the average monthly bill impacts to the Large General Service customers. Ninety-five (95) percent of the customers on this rate will see a rate decrease from the proposed rate. The increase for the 5% with highest usage is primarily due to the removal of the declining demand block and declining energy load factor block structures.

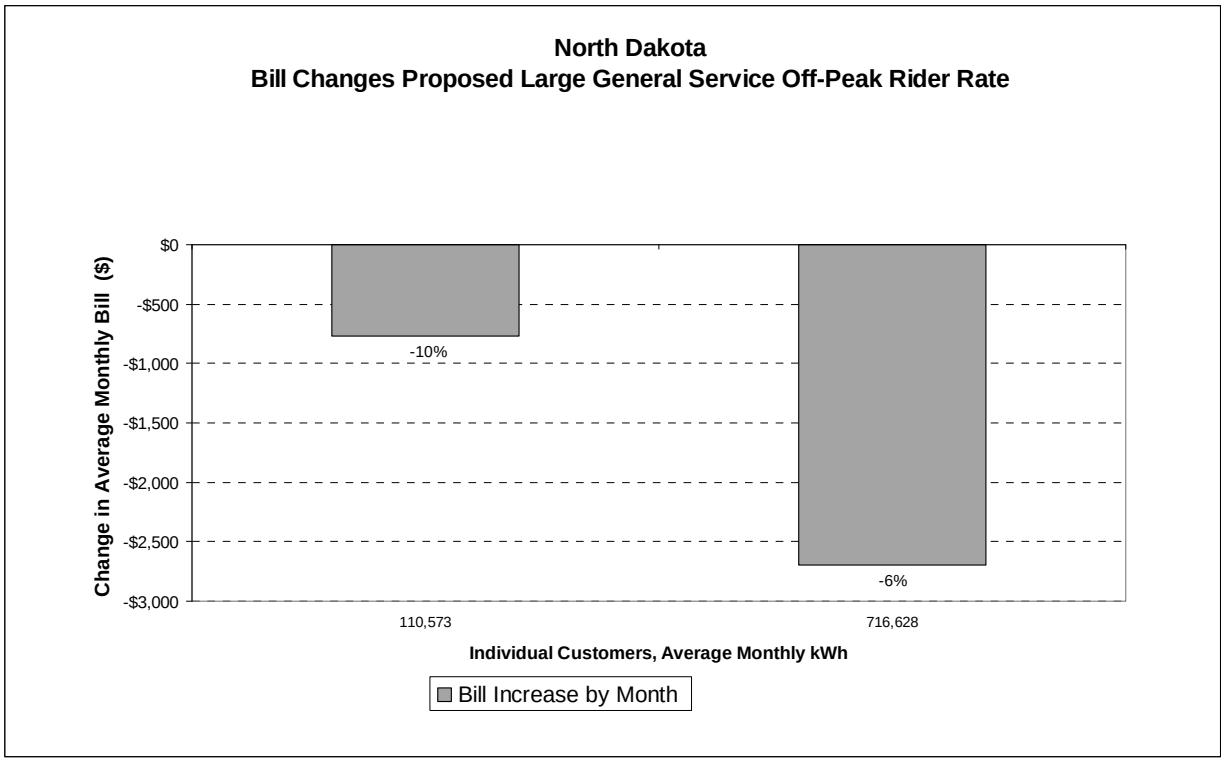
Figure 10: Bill Impacts – Large General Service



Q. WHAT ARE THE BILL IMPACTS FOR LARGE GENERAL SERVICE TIME OF USE RIDER CUSTOMERS BILLED ON YOUR PROPOSED LARGE GENERAL SERVICE RATE?

A. Figure 11 below, describes the bill impacts for the Large General Service Off Peak Rider customers for whom the Large General Service would apply. These bill impacts assume these particular Large General Service Off Peak Rider customers would not change their usage patterns. In this case, both such customers benefit from the rate change to the Large General Service without changing their usage patterns. These customers are also eligible to consider other rate options, such as the Large General Service Time of Day (explained later in my testimony). Both customers show a bill savings when moving to the Large General Service Rate.

Figure 11: Bill Impacts Large General Service Off Peak Rider Customers billed on the Large General Service Rate



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE LARGE GENERAL SERVICE TIME OF DAY RATE.

A. My proposal for this rate is to change the current design from one based on "energy-only" to one that includes separate demand charges. The energy and demand charges for all voltage levels are set close to 60% of marginal energy costs. Customer and facilities costs for all voltage levels are set respectively at about 15 percent and 75 percent (except for Primary, which is set at under 40%).

The Commission approved Otter Tail's current Large General Service Time of Day in Case PU-07-03. No customers are currently taking service on this rate schedule.

Table 11: Comparison of Current and Proposed Large General Service Time of Day and Marginal Costs

	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh						Demand Charge per kW					
				Summer			Winter			Summer			Winter		
				PK	SH	OP	PK	SH	OP	PK	SH	OP	PK	SH	OP
SECONDARY															
LGS TOD with Customer and Facilities Charges	$60.00	$325 + Facilities	$0.30	$0.07803	$0.05981	$0.03562	$0.07002	$0.05695	$0.04020	$5.72	$1.58	$0.00	$2.21	$0.52	$0.00
Marginal Costs	$351.89		$0.79	$0.13276	$0.10176	$0.06061	$0.11914	$0.09690	$0.06840	$9.73	$2.69	$0.04	$3.77	$0.88	$0.38
PRIMARY															
LGS TOD with Customer and Facilities Charges	$60.00	$325 + Facilities	$0.15	$0.07769	$0.05956	$0.03551	$0.06968	$0.05669	$0.04003	$5.68	$1.56	$0.00	$2.20	$0.52	$0.00
Marginal Costs	$400.99		$0.29	$0.13219	$0.1013	$0.06041	$0.11856	$0.09645	$0.06810	$9.66	$2.66	$0.04	$3.74	$0.88	$0.38
SUBTRANSMISSION															
LGS TOD with Customer and Facilities Charges	$60.00	$325 + Facilities	$0.00	$0.07563	$0.05807	$0.03480	$0.06762	$0.05507	$0.03896	$4.83	$1.05	$0.00	$1.99	$0.45	$0.00
Marginal Costs	$400.99		$0.00	$0.1287	$0.09881	$0.05921	$0.1151	$0.0937	$0.0663	$8.22	$1.79	$0.03	$3.39	$0.76	$0.09

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED LARGE GENERAL SERVICE TIME OF DAY RATES?

A. No customer impacts were calculated since there are no customers currently taking service under this rate schedule.

Q. WHAT RATE DESIGN ARE YOU PROPOSING FOR THE IRRIGATION SERVICE CLASS

A. There is only one rate in the Irrigation Class: Irrigation Service.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE IRRIGATION SERVICE RATE.

A. My proposed rate for Irrigation customers maintain the current two options, both of which provide service from April 15 through November 1. My proposal for both Option 1 and Option 2 retain the customer-specific facilities charges included in the current rates.

My proposed Option 1 has seasonal energy charges instead of the uniform energy charges in the current rate. The energy charges are slightly below marginal cost, but closer to marginal cost in the summer period than the current rate. My proposal introduces a small customer charge and dispenses with the horsepower charge.

The current Option 2 rate consists of energy charges for off-peak, intermediate, and on-peak periods. The on-peak hours are defined by OTP when the system is experiencing peak conditions. My proposal for Irrigation Option 2 is to set the price for hours when OTP is experiencing peak conditions at about 57 percent marginal cost (energy plus capacity), thereby giving Option 2 irrigation customers a transparent signal to curtail use during peak periods. These on peak or “declared-peak” marginal costs are the average marginal costs expected in the hours defined to be declared peak by OTP, and they vary by season. In the intermediate hours (which include the remainder of peak period hours and shoulder hours), energy and demand charges will apply. These charges are based on marginal cost but discounted to help match the revenue requirement. In the off-peak hours only energy charges, again based on discounted marginal energy costs, will apply. My proposed Option 2 under this rate also introduces a small customer charge.

Table 12: Comparison of Current and Proposed Irrigation Service Option 1 & 2 and Marginal Costs

	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh Summer			Energy Charge per kWh Winter			Demand Charge per HP Summer			Demand Charge per HP Winter		
SECONDARY															
Current Rate	$0.00		Customer Specific	All kWh		$0.05579				$0.29			$0.29		
OPTION 1															
Rate 2 Option 1 - Seasonal energy with Capacity, Customer-specific facilities charge, Customer Charge	$1.00	Customer + Facilities	Customer specific	$0.06896			$0.05145								
				Declared Peak	**Intermediate**	**Off-Peak**	**Declared Peak**	**Intermediate**	**Off-Peak**	**Declared Peak**	**Intermediate**	**Off-Peak**	**Declared Peak**	**Intermediate**	**Off-Peak**
Current Rate	$0.00		Customer Specific	$ 0.09423	$ 0.07176	$ 0.04306	$ 0.09423	$ 0.07176	$ 0.04306	na	na	na	na	na	na
OPTION 2				**per kWh**						**per kW**					
Rate 2 Option 2 - TOU energy including Capacity, Customer Charge, Customer-specific facilities charge	$5.00	Customer + Facilities	Customer Specific	$0.14443	$0.05438	$0.02641	$0.08755	$0.05108	$0.02704	na	na	na	na	na	na
				Declared Peak	**Intermediate**	**Off-Peak**	**Declared Peak**	**Intermediate**	**Off-Peak**	**Declared Peak**	**Intermediate**	**Off-Peak**	**Declared Peak**	**Intermediate**	**Off-Peak**
Marginal Costs	$23.56			$0.12751	$0.08709	$0.04543	$0.09757	$0.08747	$0.04651						
				Energy & Capacity:											
				$0.24848	$0.09357	$0.04543	$0.15063	$0.08789	$0.04651						

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED IRRIGATION RATES?

A. As the figures below show, bill impacts vary among irrigation customers. This is due to the fact that consumption levels and usage patterns (number of months of irrigation) vary widely among these customers.

Especially in the case of customers on Option 2, these bill impacts assume these particular Irrigation customers would not change their usage patterns. Specifically, declared peak prices were utilized in this analysis which may include customer usage that did not respond to the declared price signal. This does not imply the customers would not respond, but it does simplify the analysis – foregoing potentially complicated assumptions of customer reductions during these declared hours. Customers can certainly be advised by Otter Tail Energy Management personnel to determine which Irrigation rate would provide them the best value for their operating needs.

Figure 12: Bill Impacts - Irrigation Option 1

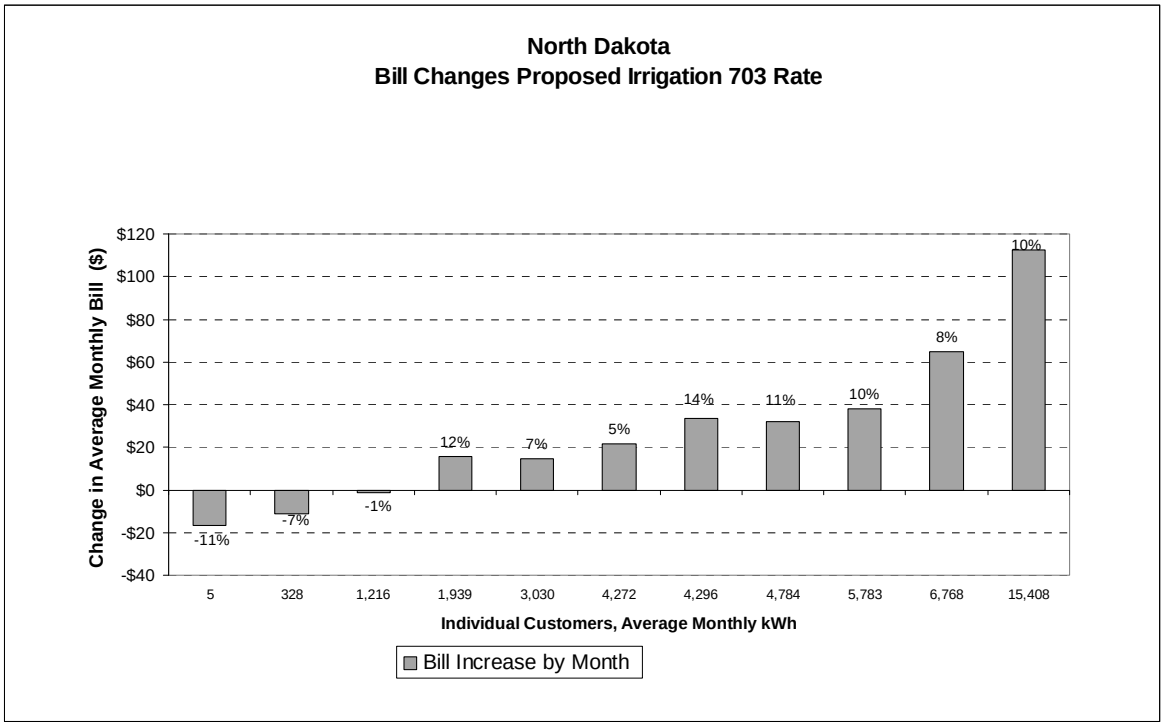
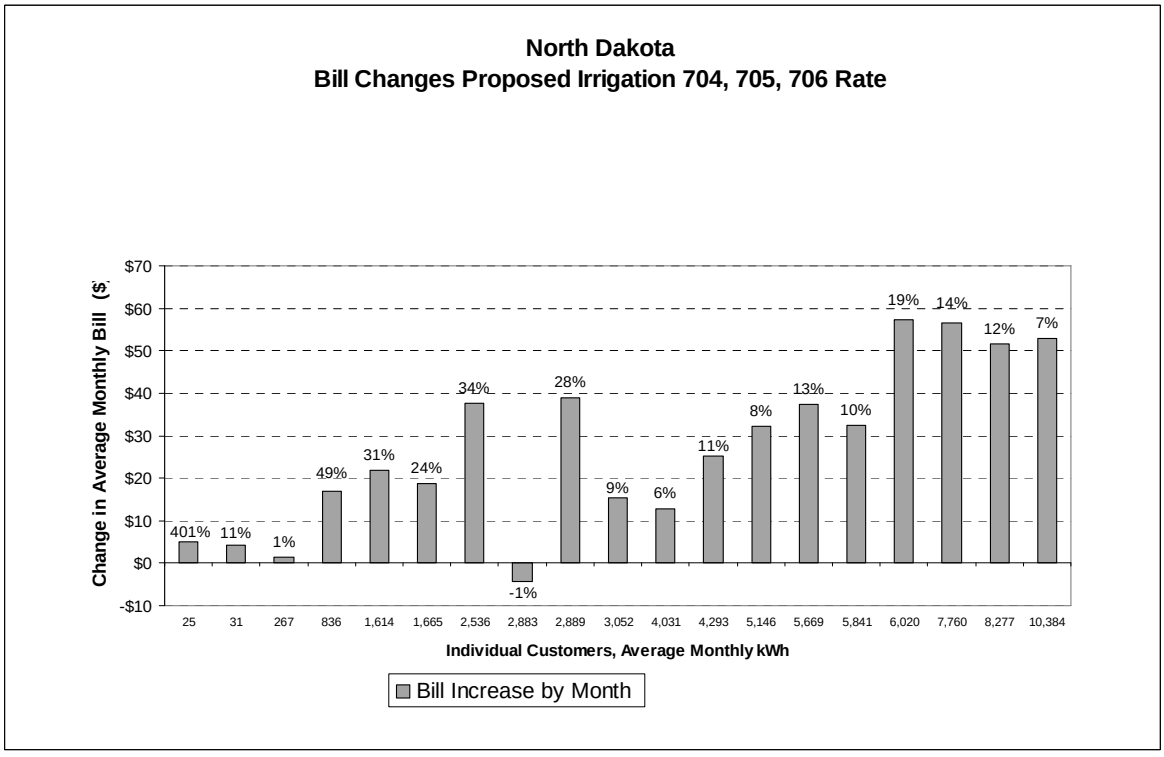


Figure 13: Bill Impacts - Irrigation Option 2



Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE LIGHTING SERVICE CLASS

A. There are two rates in the Outdoor Lighting Class; Outdoor Lighting and Outdoor Lighting – Energy Only.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE OUTDOOR LIGHTING RATE.

A. My proposal introduces proportional increased charges for all lighting fixtures. No lighting fixture offering changes were made to the rate schedule. The Sign Lighting Service (747) will be cancelled and the service moved to the Outdoor Lighting – Energy Only Rate (748-749). This is described later in my testimony.

Table 13 shows a summary of the Outdoor Lighting services and their current and proposed revenues and percent increase. Please refer to the summary comparisons as shown in Rate Schedules (Volume 2).

Table 13: Outdoor Lighting

STREET AND AREA LIGHTING				
	Present Rate 2006		Proposed Rate	
	$1,542,688		$1,928,360	
FLOOD LIGHTING				
	Present Rate		Proposed Rate	
	$391,441		$489,301	
CLOSED NON-STANDARD LIGHTING FACILITIES				
	Present Rate		Proposed Rate	
Total:	Present	$1,989,452	Proposed	$2,486,815

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED OUTDOOR LIGHTING RATE?

A. The bill impacts for each lighting fixture are the same, 25 percent.

Q. WHAT ARE THE FEATURES OF AND RATIONALE FOR THE PROPOSED OUTDOOR LIGHTING-ENERGY ONLY RATE (748 AND 749)?

A. My proposal introduces increased charges for the dusk to dawn energy service. The Customer Charge has increased but is still under marginal customer costs. Instead of requiring a facilities charge, the energy charge per kWh hour was raised slightly above marginal energy costs to meet the class revenue requirement. As mentioned earlier in my testimony, the Sign Lighting Service (747) customers will be moved to this rate. This change improves the organization of dusk to dawn energy services offered by the Company.

Table 14: Comparison of Current and Proposed Outdoor Lighting and Marginal Costs

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh
Metered				
Current Rate	$1.40	$0.00	$0.00	0.05898
Proposed Rate	$2.00	$2.00	$0.00	0.06932
Marginal Costs	$4.26		$4.26	$0.06906
Non-Metered				
Current Rate	Connected kW x	$20.15	Current rate * 4100 hrs/year / 12 months	
Proposed Rate	Connected kW x	$23.68	Current rate * 4100 hrs/year / 12 months	

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED OUTDOOR LIGHTING-ENERGY ONLY RATE.

A. The overall bill impacts for the class is 25 percent.

Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE OTHER PUBLIC AUTHORITY SERVICE CLASS

A. There are two rates in the Other Public Authority Class: Municipal Pumping Service and Civil Defense – Fire Siren Service.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE MUNICIPAL PUMPING SERVICE.

A. The recommended municipal pumping rate eliminates declining blocks, introduces seasonal differences in energy charges, imposes a flat facilities charge per month and increases the monthly minimum bill. This rate improves equity by recovering a portion of local facilities costs on a fixed basis, reducing the subsidy from large to small customers. The recommended energy charges are still below marginal cost to close the revenue gap, and result in charges that fall in between the current declining block structure.

Table 15: Current and Recommended Municipal Pumping Rates and Marginal Costs

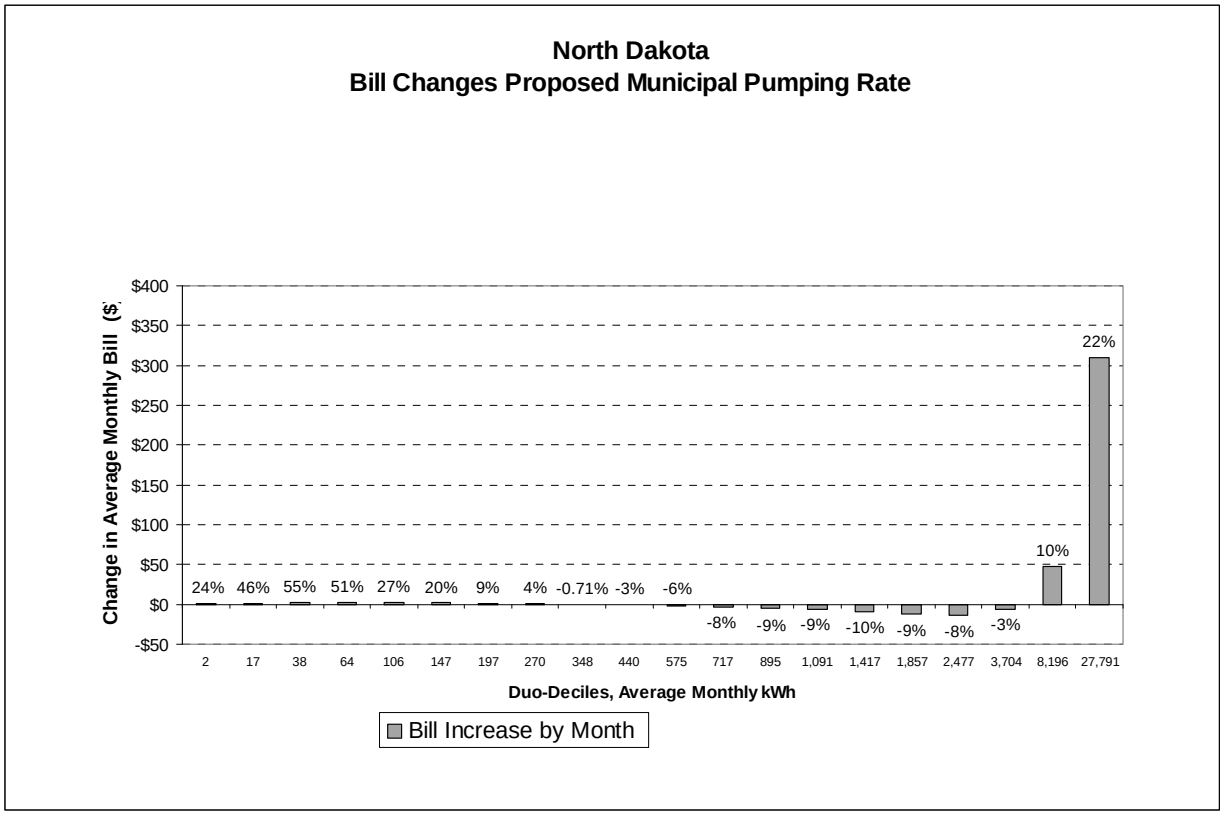
	Customer $ per month	Minimum Bill $ per month	Facilities Charge $ per month	Summer	Winter	All Year
				$ per kWh per month		
Current Rate	na	$3.30 per metering pt.	na	1st 2500:		$0.07152
				Next 1500:		$0.05632
				Excess:		$0.04768
Rate 3 Seasonal Energy, Facilities Charge						
Secondary	$4.00	Cust + Fac	$4.00	$0.06523	$0.05950	all Energy
Primary	$4.00	Cust + Fac	$2.68	$0.06494	$0.05922	all Energy
Marginal Costs	$15.91					
		$64.91				
		$42.57				
				Energy & Demand		
All Season			Secondary	$0.10545	$0.09619	
			Primary	$0.10498	$0.09573	

*Current Rates Include FCA

Q. WHAT ARE THE BILL IMPACTS OF YOUR RECOMMENDED MUNICIPAL PUMPING RATE?

A. As Figure 14 shows, small consumers on this rate would face bill increases that are small in dollar terms but large in percentage terms. Half of the customers would see bill reductions. The 10 percent of municipal pumping customers with the largest usage (last two duo-deciles) would see an average increase in monthly bills of 10 to 22 percent because they would lose the benefit of the below-cost tail block price in the current rate. Their bill increases reflect reduction of the current inter-class subsidy from smaller customers.

Figure 14: Municipal Pumping Bill Impacts from Recommended Rate



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE CIVIL DEFENSE-FIRE SIREN SERVICE RATE.

A. The proposed Civil Defense-Fire Siren Rate introduces a slight decease in the charge per horsepower. The proposed Customer Charge is $1.00 per month which applies to the Monthly Minimum Bill provision. All rate components were designed below marginal costs. A monthly minimum bill was developed to cover distribution facility charges.

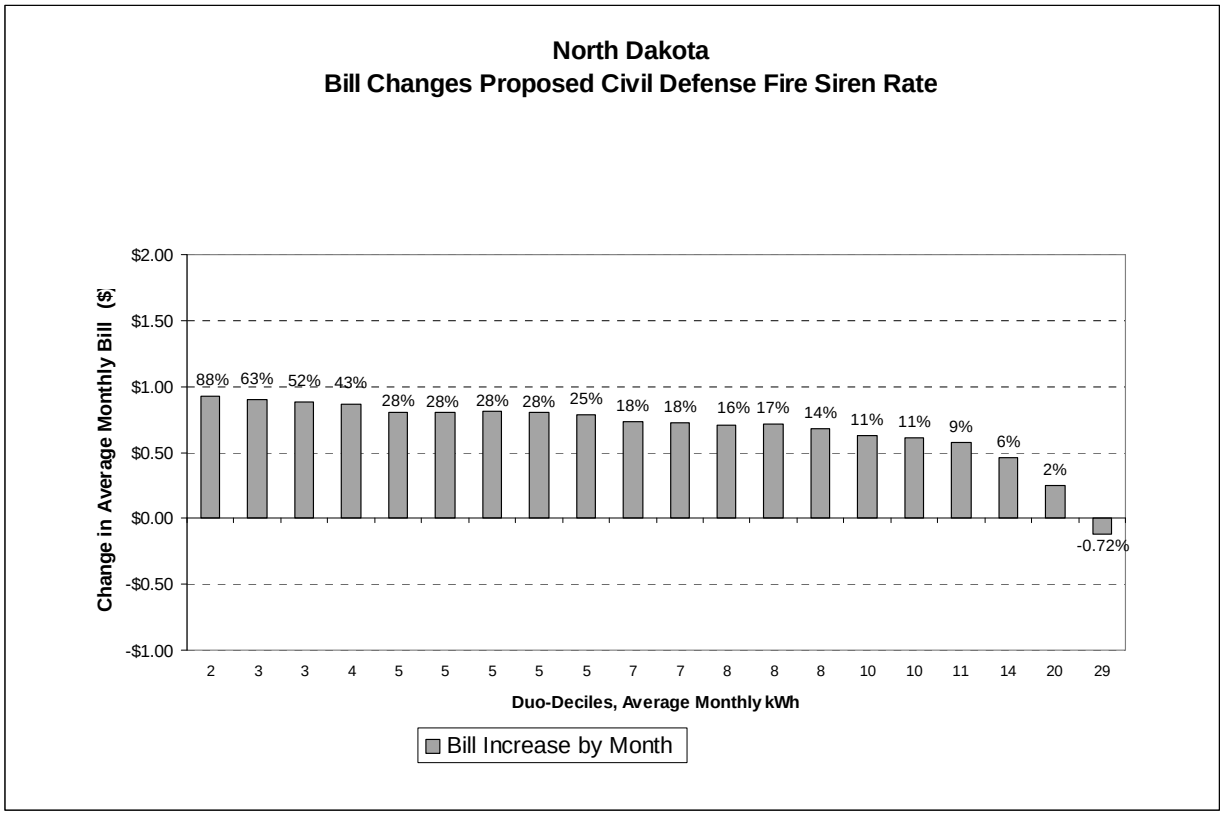
Table 16: Civil Defense-Fire Sire Service

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Charge per HP
SECONDARY				
Current Rate	$0.00	$0.00	$0.00	$0.57
Proposed Rate	$1.00	Customer Charge	$0.00	$0.53193
Marginal Costs	$3.67		Summer Energy+Cap	$0.12647
			Winter Energy+Cap	$0.10139

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED CIVIL DEFENSE-FIRE SIREN SERVICE RATE SCHEDULE?

A. As Figure 15 shows, the bill impacts for nearly all customers will see an average increase of less than $1.00 per month. The largest customers in last duo-decile will see a decrease due to the reduction in the charge per horsepower.

Figure 15: Civil Defense-Fire Sire Service Bill Impacts



Q. WHAT RATE DESIGN ARE YOU PROPOSING FOR THE WATER HEATING SERVICE CLASS

A. There is only one rate in the Water Heating Class: Water Heating – Controlled Service Rider.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE WATER HEATING-CONTROLLED SERVICE RIDER.

A. As Table 17 shows, my proposal slightly reduces the customer charge, adds a facilities charge and calculates the Minimum Bill based on the Customer charge plus the facilities charge, and substitutes seasonal energy charges which are set closer to marginal cost. The marginal costs of providing service to customers on this rate are lower than the marginal cost for standard rates because OTP controls the water heaters during high-cost periods.

Table 17: Current and Proposed Water Heating-Controlled Service Rider and Marginal Costs

		Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh All Year	Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current	Blocked Non-seasonal Plus Customer Charge	$1.34	$1.34	$0.00			
	All Energy				$0.05322		
Rate 2	Seasonal Energy	$1.00	Cust. + Facilities			$0.05773	$0.05638
	Flat Facilities			$1.00			
Marginal Costs		$7.07				$0.07796	$0.07614
				$5.69			

*Current Rates Include FCA

My proposal also includes the addition of the Water Heating Credit service. This service was removed from a number of our current rates and relocated to this rider. The Water Heating Credit is being relocated from these rates and located in this rider for better organization of the water heating services offered by OTP.

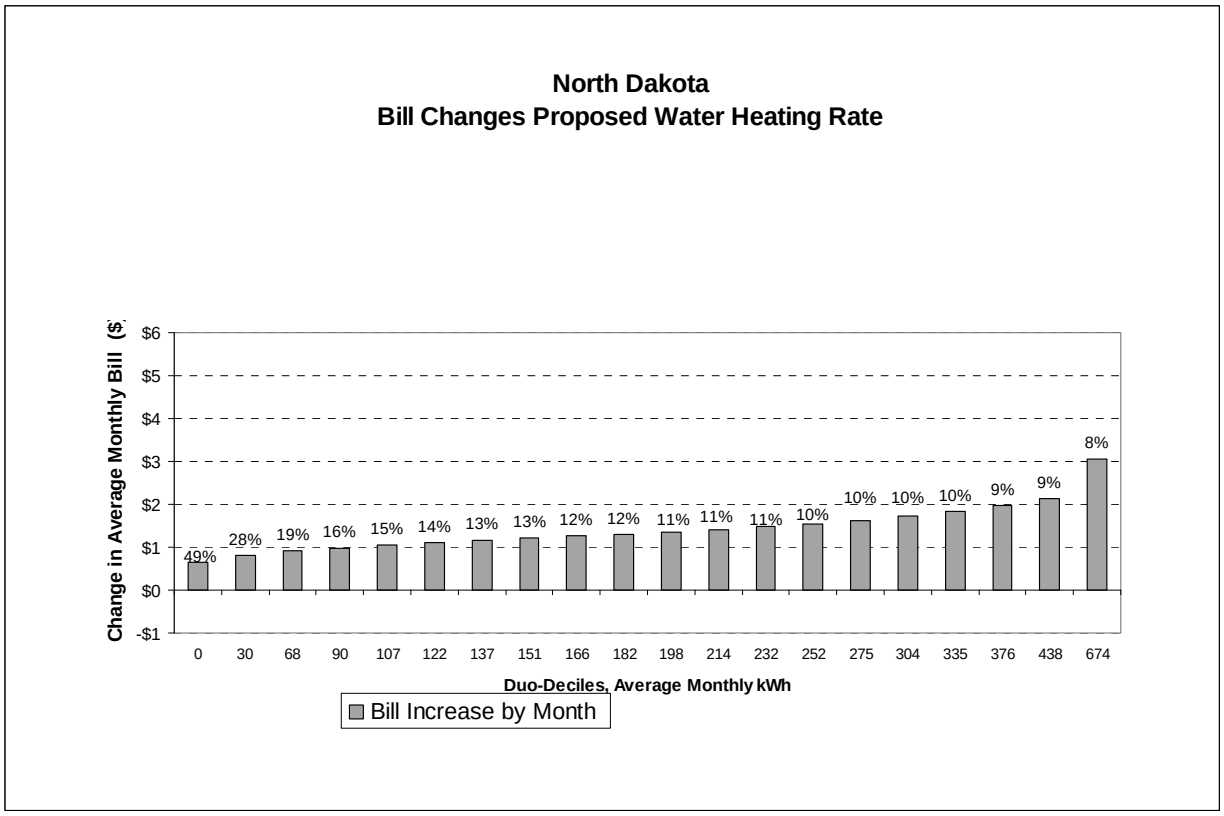
The Water Heating Credit was developed based on the annual savings between the cost of a water heater on the proposed Residential Service and the proposed Water Heating – Controlled Service Rider and then developed into a monthly credit.

The Water Heating Credit is essentially a direct load control program similar to direct load control of central air conditioners. In exchange for allowing the Company to interrupt a customer's water heating service, the Company pays the customer in the form of a bill credit. The proposal increases the credit from $2 to $4 per month.

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED WATER HEATING-CONTROLLED SERVICE RIDER?

A. Figure 16 shows customers below the bill impacts from the proposed rate are modest—with the highest average monthly increase less than $2.00 for 90 percent of customers and the remaining 10 percent of customers will see an increase at slightly over $3.00 or less.

Figure 16: Bill Impacts from Proposed Water Heating –Controlled Service Rider



The bill impacts for the Water Heating Credit service will reduce the customers' bill from the current $2 to $4 per month.

Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE INTERRUPTIBLE SERVICE CLASS?

A. There are four current rates in the Interruptible Service Class: Controlled Service – Interruptible Load (CT Metering) Rider and Controlled Service – Interruptible Load (Self-contained metering) and two Standby Service rate schedules (Less than 100 kW and Equal to or Greater than 100 kW). The current Standby rate schedules will be replaced with a completely new rate design concept described later in my testimony.

I am proposing a new option for Controlled Service – Interruptible Load (CT Metering – Option B). This option will allow motor load up to 5 percent of the metered maximum demand. This option is in contrast to the current option (Option A) which only allows motor

load, used to distribute the heat, to be connected separately to the appropriate General Service (firm) rate schedule. By adding this new option, customers will have more flexibility in how they configure their motor load which distributes the heat.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER.

A. The proposed Rider 170 slightly reduces the current customer charge and introduces seasonal energy charges that better reflect marginal cost. A facilities charge is added on a $/kW basis to better reflect these costs by customer size. The penalty rate for energy consumed during control periods is based on the total marginal cost over a year and separated into summer and winter seasons. The penalty rate per kWh was calculated based on the hourly marginal costs when usage would be controlled. Fundamentally, the penalty rate charges customers for unauthorized use during control periods.

Table 18: Current and Proposed – Option A Controlled Service-Interruptible Load (CT Metering) Rider 170 and Marginal Costs

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge	Energy Charge per kWh Summer	Energy Charge per kWh Winter
SECONDARY					
Current Rate	$4.74			$0.02253	$0.02253
Rate 3 Seasonal Energy, Flat Facilities	$4.00	Customer + Facilities charge			
			All kWh	$0.03418	$0.03286
			Penalty kWh rate 199	$0.42614	$0.15769
			per annual max. kW per month		
			$0.08		
			$0.08		
Marginal Costs	$34.17	<300 kW	$0.79	$0.0777	$0.0747
		>=300 kW	$0.46		

Table 19: Proposed Option B - Controlled Service-Interruptible Load (CT Metering) Rider 170 and Marginal Costs

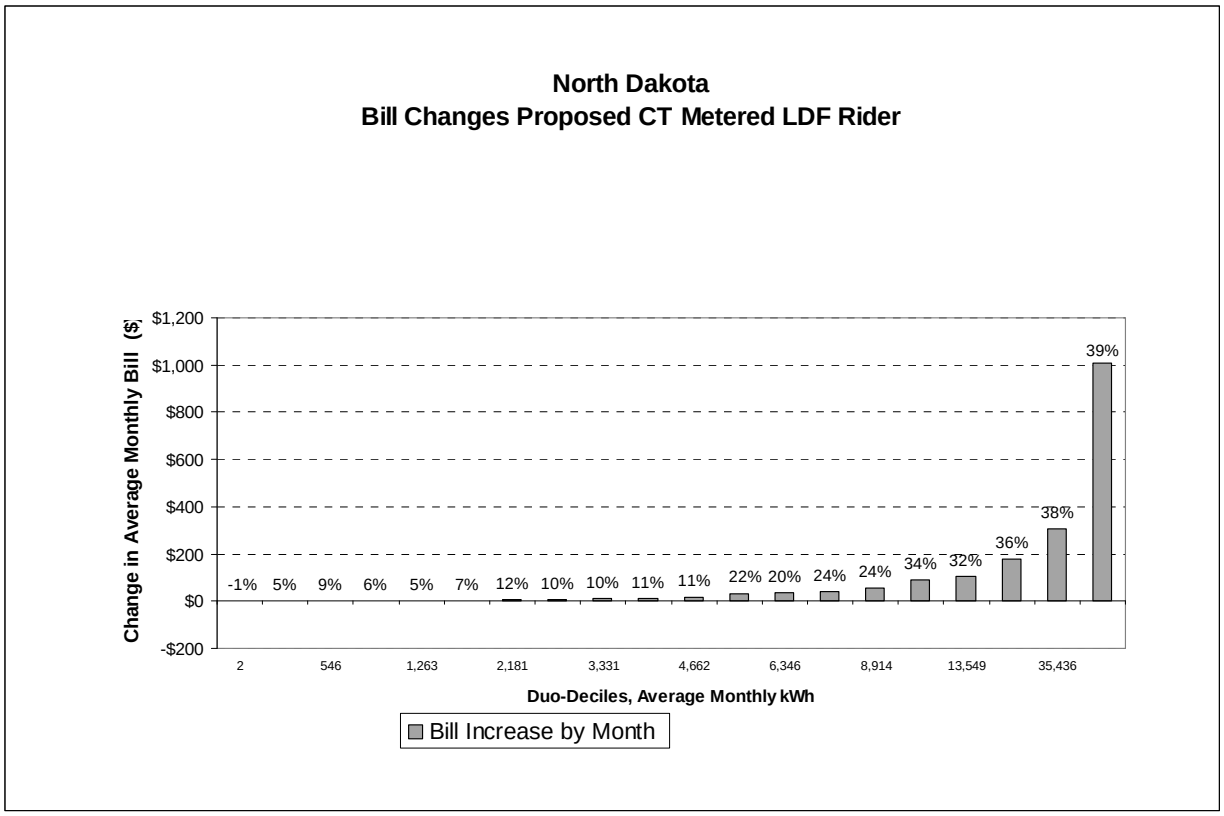
SECONDARY	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
Rate 1 Seasonal Energy, kW Facilities All kWh	$5.00	Customer + Facilities charge	per annual max. kW per month	$0.03613	$0.03474	$7.13	$2.88
		per kW	$0.08				
Marginal Costs	$34.17	<300 kW >=300 kW	$0.79 $0.46	$0.07771 (Plus 5% firm energy charge)	$0.07472	ND LGS Sec. kW Charge	

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED CONTROLLED INTERRUPTIBLE LOAD (CT METERING) RIDER – OPTION A AND THE NEW OPTION B?

A. The bill impacts, below, from the proposed rate (Option A) show more than half of the customers with increases less than 12 percent and the rest of the customers with increases in a range from 20 to 39 percent.

As I described earlier in my testimony, much of the increase for this rate relates to the fact that this service does not currently include an FCA. Therefore, these customers have not paid for increases in fuel and purchase power costs that have occurred since 1982. Consequently, this relatively large increase is primarily due to resetting the cost of fuel for the rate.

Figure 17: Option A Bill Impacts from Proposed Controlled Service-Interruptible Load (CT Metering) Rider



Since Controlled Service-Interruptible Load (CT Metering) Rider Option B is a new service, no impacts were calculated.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE CONTROLLED SERVICE-INTERRUPTIBLE LOAD (SELF-CONTAINED METERING) RIDER.

A. My proposal for this rate reduces the customer charge, adds a flat monthly facilities charge, eliminates the declining block structure, and increases the seasonal energy charges as well as the seasonal differential in those charges to better reflect marginal costs. The penalty for energy used during a control period is intended to deter customers from unauthorized use during control periods.

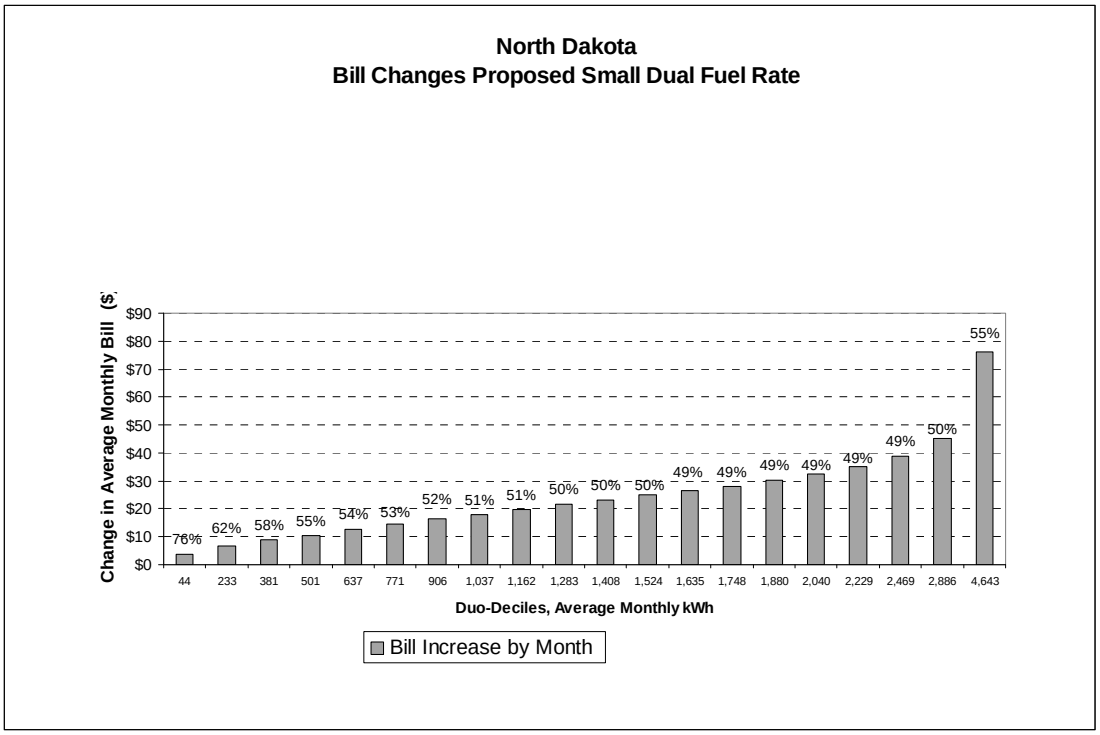
Table 20: Current and Proposed Controlled Service-Interruptible Load (Self-Contained) Rider and Marginal Costs

SECONDARY	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per customer per month		Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current Rate	**$3.78**			First 5,000		**$0.03097**
				Excess		**$0.02815**
				First 1,500	**$0.02956**	
				Excess	**$0.02675**	
Rate 1 Seasonal Energy Fixed Facilities	$2.00	Customer + Facilities charge	Fixed Facilities	$5.00		
All kWh					$0.03983	$0.03756
				Penalty kWh	$0.42265	$0.16375
Marginal Costs	$7.80		<5000 kWh in all months	$11.38	$0.0798	$0.0753
			> 5000 kWh in any month	$44.92		

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED CONTROLLED INTERRUPTIBLE LOAD (SELF-CONTAINED) RIDER?

A. As Figure 18 shows, the percentage bill impacts are very uniform across levels of consumption. About 45% of the customers have bill impacts under $20 per month. The remaining 55% will see increases of between $20 and $75 per month. Again, the relatively large increase for this rate is related to the fact that it does not currently have an FCA. As explained in the previous rate discussion, most of this increase is the result of updating the costs of fuel and purchased power for the rate.

Figure 18: Bill Impacts from Proposed Controlled Service-Interruptible Load (Self-Contained) Rider



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE STANDBY RATE.

A. My proposal for this rate introduces a new design with many improvements. The new design sends more efficient price signals for customers who choose this service. The basis of the updated design utilizes the proposed Large General Service-Time of Day Rate.

Unlike the current Standby Service rate, the proposed Standby Service rate provides three services under one rate schedule. These services are Backup, Scheduled Maintenance, and Supplemental Service. Below are the definitions of these services:

- Backup Services is the energy and demand supplied by the utility during unscheduled outages of the Customer's generator.
- Scheduled Maintenance Service is defined as the energy and demand supplied by the utility during scheduled outages.
- Supplemental Service is the energy and demand supplied by the utility in addition to the capability of the on-site generator.

A summary of proposed changes are shown below:

- The rate offers two additional levels of service voltage options – Primary and Transmission
- The rate has season changes: Summer from 6 months to 4 months, Winter from 6 months to 8 months.
- The rate adds a shoulder period for improved pricing signals
- The rate provides an additional choice for Backup Service customers to choose a Firm or Non-Firm option to better fit the customer's expected operation schedule
- An increase in overall hours for Standby from 800 hours per season (1600 hours annual) to the following hours for option A) Firm Service – 8400 annual hours (only 360 on peak hours allowed per year), and B) Non-Firm Service of 5700 annual hours (i.e. no on-peak hours of operation allowed).

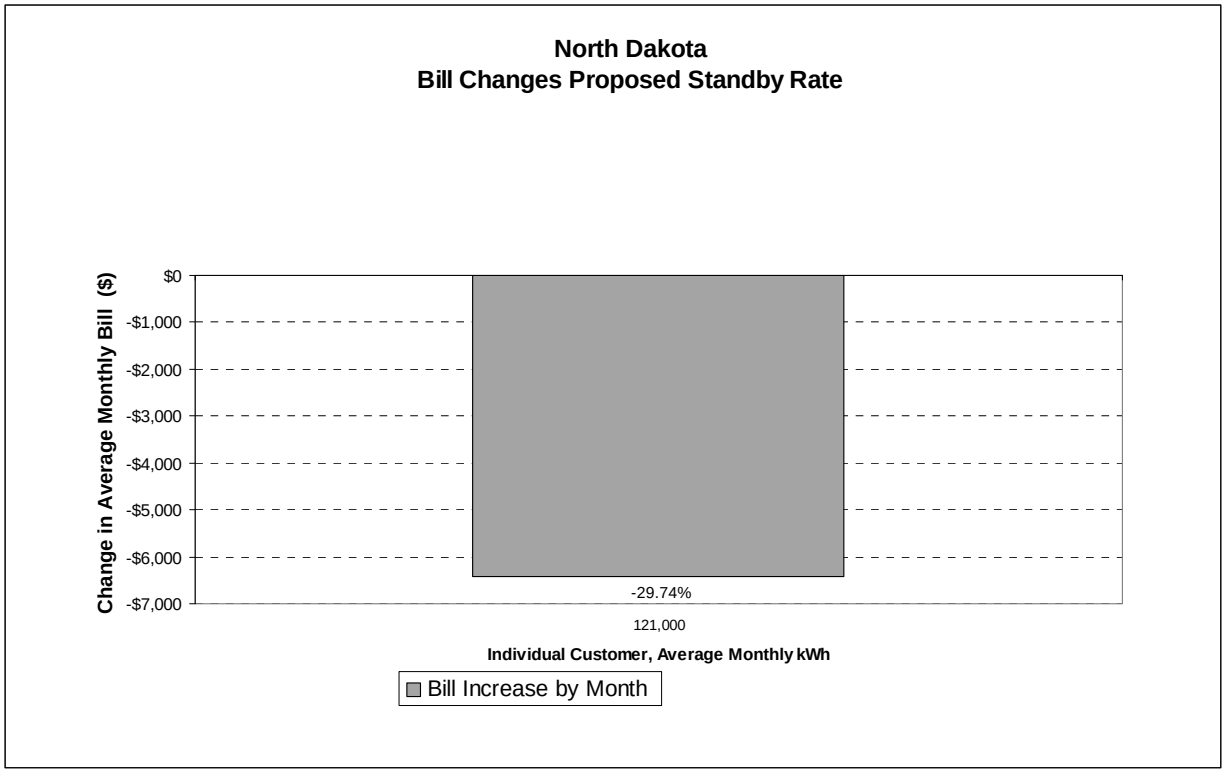
Table 21: Comparison of Current and Proposed Standby Service and Marginal Costs

	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh Summer PK	Summer SH	Summer OP	Winter PK	Winter SH	Winter OP	Demand Charge per kW Summer PK	Summer SH	Summer OP	Winter PK	Winter SH	Winter OP
SECONDARY															
LGS TOD with Customer and Facilities Charges	$199.00	$325 + Facilities	$0.30	$0.07803	$0.05981	$0.03562	$0.07002	$0.05695	$0.04020	$0.49	$0.00	$0.00	$0.32	$0.00	$0.00
		Reserve Charge per kW		$0.8507			$0.0970			$0.4908			$0.3219	$ per kW per day	
Marginal Costs	$351.89		$0.79	$0.13276	$0.10176	$0.06061	$0.11914	$0.09690	$0.06840	$0.49	$0.00	$0.00	$0.32	$0.00	$0.00
PRIMARY															
LGS TOD with Customer and Facilities Charges	$199.00	$325 + Facilities	$0.15	$0.07769	$0.05956	$0.03551	$0.06968	$0.05669	$0.04003	$0.49	$0.00	$0.00	$0.32	$0.00	$0.00
		Reserve Charge per kW		$0.8459			$0.0963			$0.4868			$0.3198	$ per kW per day	
Marginal Costs	$400.99		$0.29	$0.13219	$0.1013	$0.06041	$0.11856	$0.09645	$0.06810	$0.49	$0.00	$0.00	$0.32	$0.00	$0.00
TRANSMISSION															
LGS TOD with Customer and Facilities Charges	$199.00	$325 + Facilities	$0.00	$0.07563	$0.05807	$0.03480	$0.06762	$0.05507	$0.03896	$0.36	$0.00	$0.00	$0.29	$0.00	$0.00
		Reserve Charge per kW		$0.82			$0.29			$0.36			$0.29	$ per kW per day	
Marginal Costs	$400.99		$0.00	$0.1287	$0.09881	$0.05921	$0.1151	$0.0937	$0.0663	$0.36	$0.00	$0.00	$0.29	$0.00	$0.00

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED STANDBY SERVICE RATES?

A. Figure 19 below, describes the bill impacts for the Standby Service customers. OTP has 1 customer currently taking Standby Service These bill impacts assume this particular Standby customer would not change their usage patterns. In this case, the customer benefited from the rate change to the proposed Standby Service.

Figure 19: Bill Impacts from Proposed Standby Rate



Q. WHAT RATE DESIGNS ARE YOU PROPOSING FOR THE DEFERRED LOAD SERVICE CLASS?

A. There are two rates in the Deferred Load Service Class: Controlled Service – Deferred Load Rider and Fixed Time of Delivery Rider.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE DEFERRED LOAD SERVICE RIDER.

A. The proposed Deferred Load Service Rider increases the customer charge to $3.00 per month and adds a flat facilities charge. Seasonally-differentiated energy charges were added and adjusted to about 66 percent of marginal costs.

This proposal better reflects the marginal costs incurred to serve customers on this rider compared to the current charges. The penalty for energy used during a control period is intended to deter customers from unauthorized use during control periods.

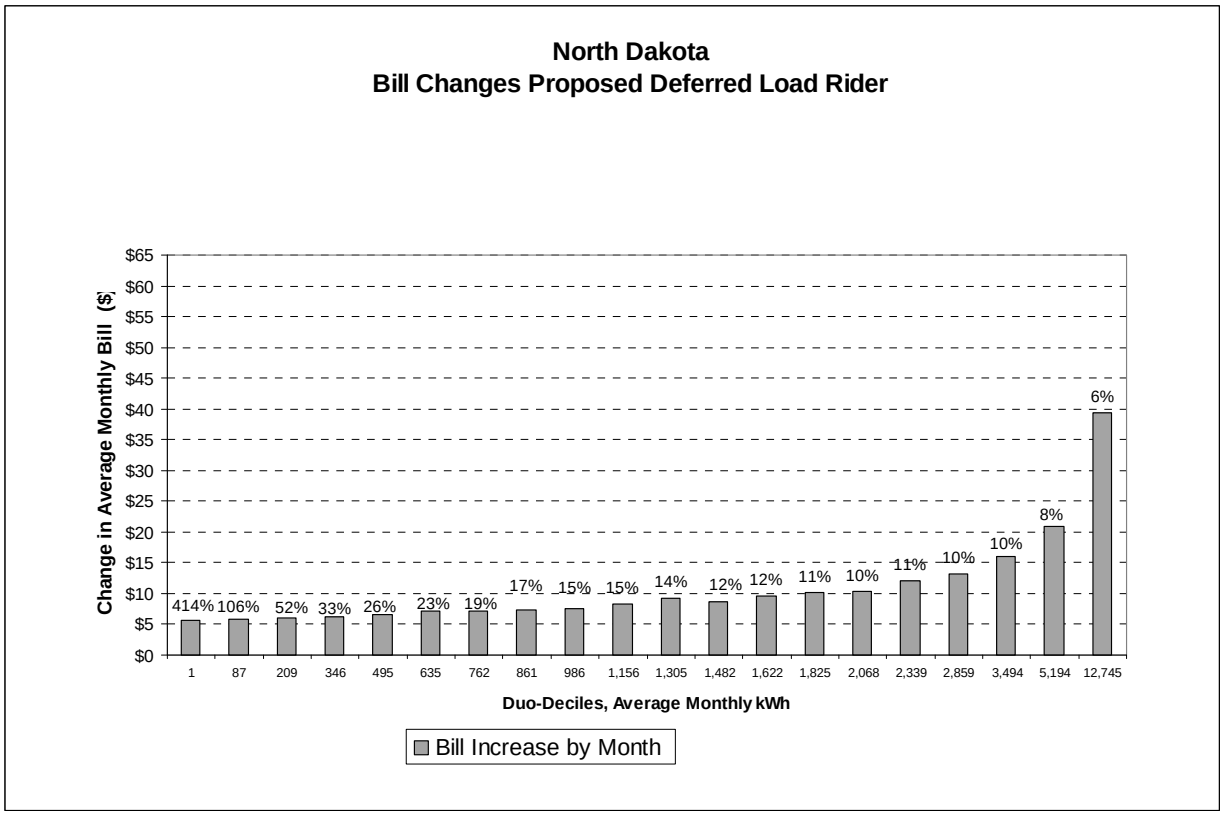
Table 22: Current and Proposed Deferred Load Rider Rates and Marginal Costs.

		Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per month	Energy Charge per kWh All Year	Summer	Winter
Current Deferred Load Rate		$1.34	$1.34				$0.04807	$0.04807
						Penalty	$0.10088	$0.10088
Rate 3	Seasonal Energy and Customer Charge Facilities based on Flat Fixed Charge	$3.00	Customer Charge+Facilities		$4.00		$0.05153	$0.05000
					Penalty kWh		$0.38956	$0.16512
Marginal Costs		$17.23		<5000 kWh in all months >5000 kWh in any month	$11.38 $44.92		$0.07783	$0.07553

Q. WHAT ARE THE BILL IMPACTS OF PROPOSED DEFERRED LOAD RIDER?

A. As Figure 20 shows, 75% of the customers on this rider, those with up to an average of about 2000 kWh's of monthly consumption, will see bill increases of about $10 or less. The remaining 25 percent of the customers with larger consumption will see average monthly bill increases of 6-11 percent.

Figure 20: Bill Impacts from Proposed Deferred Load Rider



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE FIXED TIME OF DELIVERY RIDER

A. The proposed Fixed Time of Delivery rider introduces small customer charges and changes to the facilities charges as compared to the current rate. This allows the seasonal energy charges to be set closer to the marginal cost expected in the hours when customers will receive service under this rider.

Additionally, the proposal moves the hours of operation back one hour from the current 11 pm - 7am to the proposed 10 pm - 6 am. This change will better align with the new costing periods developed by NERA as described in Dr. Parmesano's testimony.

Table 23: Current and Recommended Fixed Time of Delivery Rider and Marginal Costs

		Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per Customer per month	Energy Charge per kWh	
SECONDARY						
Current Rate						
			Facilities Charge			
	Secondary < 100 kW (301)			$3.78	$0.02722	
	Secondary > 100 kW (302)			$8.18	$0.02346	
	Primary (303)			$77.88	$0.02180	
2	Seasonal Energy with a Fixed Facility Charge		Cust+Fac		**Summer**	**Winter**
	Secondary < 100 kW (301)	$1.00		$3.00	$0.02781	$0.02945
	Secondary > 100 kW (302)	$1.50		$19.00	$0.02781	$0.02945
				Penalty kWh	$0.12174	$0.10322
	Primary (303)	$3.00		$9.00	$0.02770	$0.02933
				Penalty kWh	$0.12163	$0.10311
Marginal Costs				per kVA		
	Secondary < 100 kW (301)	$10.82		$0.98	$0.04792	$0.05073
	Secondary > 100 kW (302)	$17.23		$0.63	$0.04792	$0.05073
	Primary (303)	$34.17		$0.28	$0.04773	$0.05053

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED FIXED TIME OF DELIVERY RIDER?

A. As Figure 21 shows for customers taking service using self-contained metering, bill impacts from the proposed Fixed Time of Delivery Rider are under $10 per month for all but the five percent of customers with the highest average monthly use.

As Figure 22 shows for customers taking service using current-transformer (CT) metering, bill impacts from the proposed Fixed Time of Delivery Rider are higher than the self-contained metering customers. This is primarily due to increases in the energy and facility charges, which better follow the cost structures. Smaller customers that move up to an average under 2000 kWh per month particularly see large percentage increases, which translates to increases of about $20 or less on a monthly basis. Customers that average more

than 70,000 kWh, or about thirty percent of customers see average increases of over $50 per month.

Figure 21: Bill Impacts from Proposed Fixed Time of Delivery (Self-Contained Meter) Rider

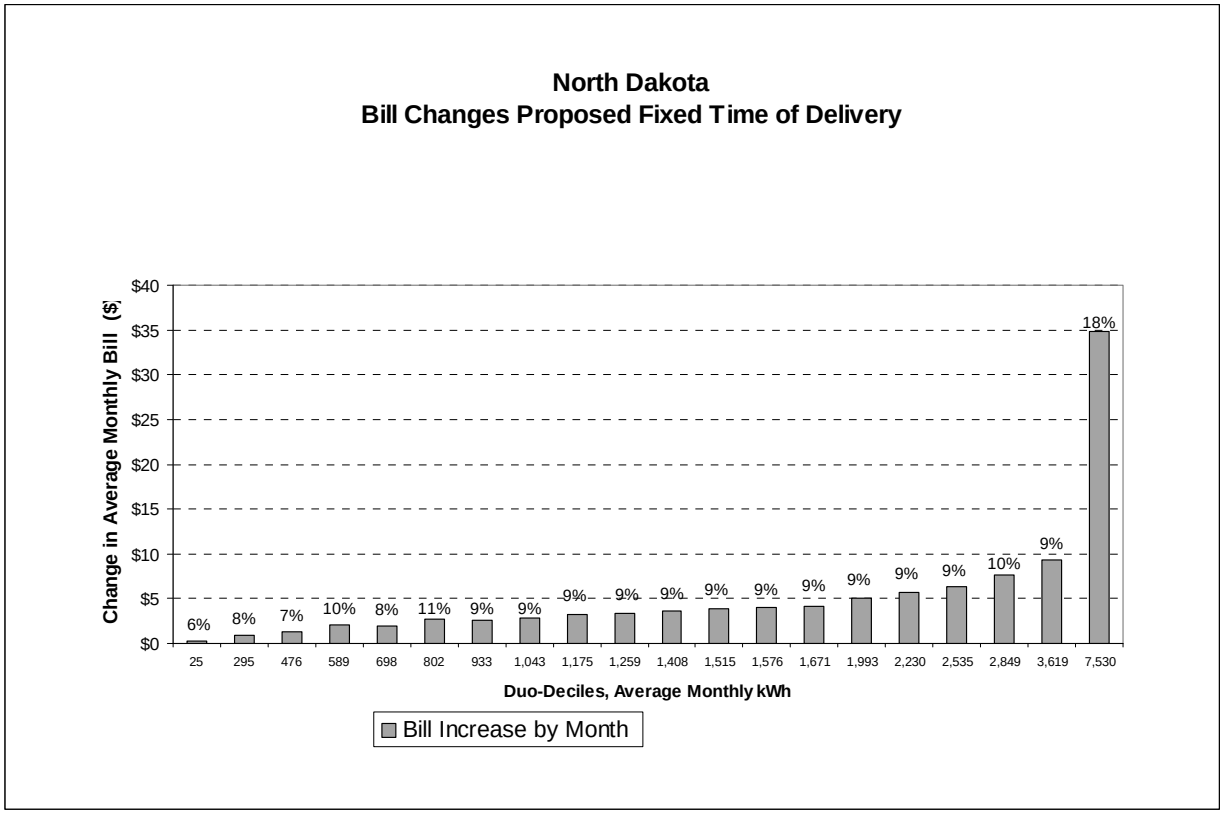
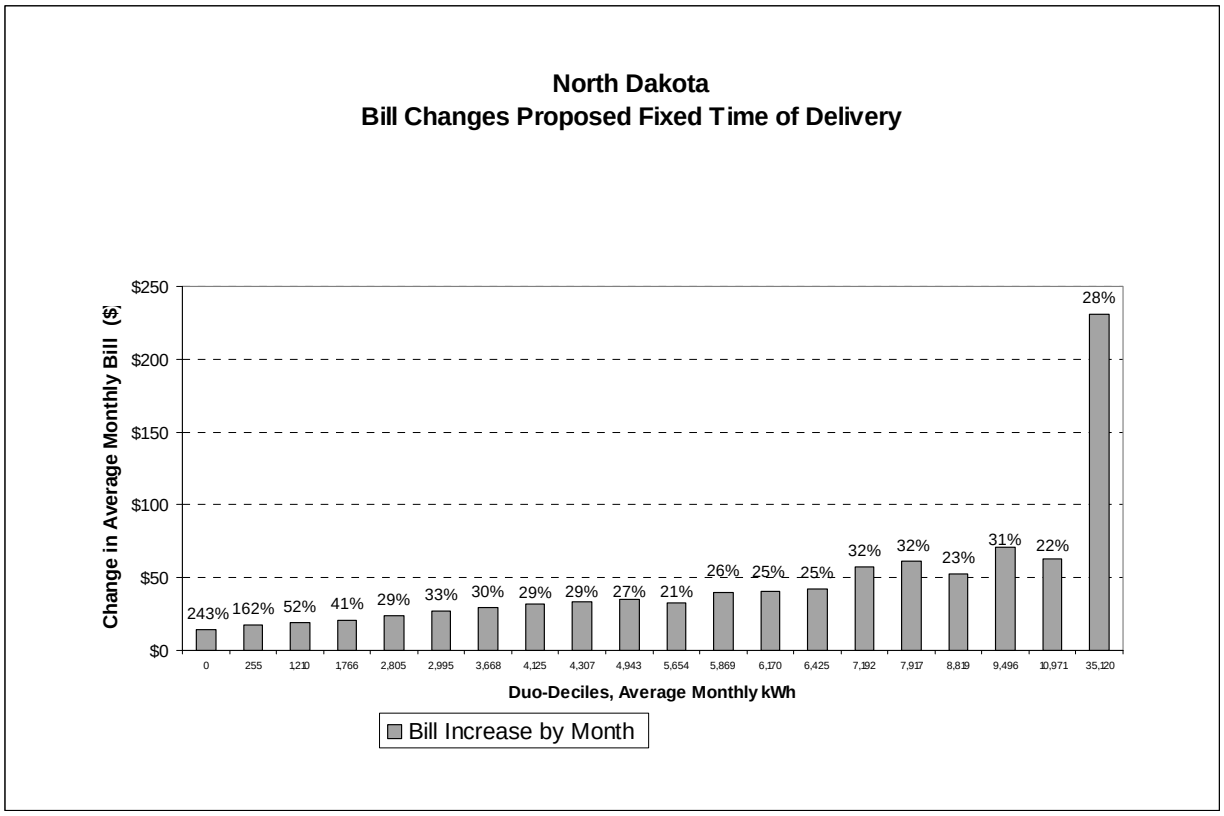


Figure 22: Bill Impacts from Proposed Fixed Time of Delivery (CT Meter) Rider



Q. ARE THERE ANY OTHER RATE DESIGN PROPOSALS?

A. Yes. I will also cover the rate design proposals for the following riders: Real-Time Pricing Rider, Large General Service Rider (new service), Air Conditioning Control Rider (new service), Renewable Energy Rider, and Released Energy Rider.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE REAL-TIME PRICING RIDER.

A. My proposal increases the administrative charge from $180 per month to $199 per month.

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED REAL-TIME PRICING RIDER?

A. The overall bill impacts for any single Real Time Pricing customer would be difficult to predict as there are many variables relating to bill impacts, including but not limited to:

customer operations, energy use decisions and the pricing signals sent to the customer. However, one bill impact that can be measured is the increased administrative charge which would increase by 10.5 percent.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE LARGE GENERAL SERVICE RIDER ("LGS RIDER").

A. This is a new rate proposal designed for improving interruptible capabilities in North Dakota. The LGS Rider offers contracted options for customers and Otter Tail and require individual approval of the Commission.

Originally introduced in Minnesota in the 1995, this Rider has undergone a number of improvements which provide larger customers with flexible pricing options. The LGS Rider offers the following features, which are further described in the proposed rate schedule found in Rate Schedules Volume 3.

- Custom fixed or hourly pricing options over a Customer Baseline Load (CBL)
- Special short-term capacity purchases and buybacks
- Interruptible Load over the Customer Baseline Load (CBL)

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED LARGE GENERAL SERVICE RIDER?

A. This is a new service; therefore there are no current customers on this Rider. Generally, customers would take service on this Rider in order to allow the company to interrupt load above the CBL. Customers would see savings since the rate structure would discount demand charges. Savings would be determined on a customer-by-customer basis.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE BULK INTERRUPTIBLE RIDER.

A. The Bulk Interruptible Rider is a contract-based rate for which each contract would be approved by the Commission. My proposal only adds the fuel cost adjustment to this rate, similar to other rates described in my testimony.

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED BULK INTERRUPTIBLE RIDER?

A. The bill impacts for the Bulk Interruptible Rider would charge the overall costs in proportion to the month-by-month change in the fuel cost adjustment (FCA) rate. To illustrate, if a Bulk Interruptible rate was $0.04/kWh, a positive FCA rate of $0.005/kWh would increase the customers overall cost by 12.5%. Likewise, if the FCA was a negative $0.005 kWh, the customer would realize a decrease of 12.5%.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE AIR CONDITIONING CONTROL RIDER.

A. This is another new rate proposal for North Dakota. For a number of years, Otter Tail has offered cycling of air conditioners in Minnesota to aid in reducing peak demands during the summer. My proposal provides a bill credit of $7 per month for customers who participate in this program. This credit is offered in the months starting in June through September. The Air Conditioning Control Rider Credit was developed based on our current credit and credits offered by other utilities.

Q. WHAT IS THE BILL IMPACT OF THE PROPOSED AIR CONDITIONING CONTROL RIDER?

A. This is a new service; therefore there are no current customers on this Rider. However, the bill impact for the Air Conditioning Control Rider will reduce enrolled customers' bills by $7 per month.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE VOLUNTARY RENEWABLE ENERGY RIDER.

A. My proposal updates the energy rate (kWh per 100 kWh block) to $1.30 per 100 kWh-block. This is a reduction of 30 cents per 100-kWh block.

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED RENEWABLE ENERGY RIDER?

A. The bill impacts for the Renewable Energy Rider will show a reduction of 30 cents per 100 kWh-block.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE RELEASED ENERGY RIDER.

A. There are no changes contemplated for this rider.

Q. ARE THERE ANY RATE SCHEDULES OR RIDERS THAT OTP PROPOSES NOT CHANGE AS PART OF THIS RATE CASE FILING?

A. Yes. Pursuant to scheduling controlled by statute or other authority, the following riders found in Section 12 and Section 14 of the Rate Book will be addressed in a separate filing by December 31, 2008. The reasons for not including the updates are twofold:

1) Important cost information is not currently available, and
2) The end of year filing will coincide with our current schedule in North Dakota.

- Small Power Producer Rider - Occasional Delivery Energy Service, (Net Energy Billing Rate).
- Small Power Producer Rider (Time of Delivery Service).
- Small Power Producer Rider (Dependable Service).
- WAPA Bill Crediting Rider.

Q. DOES THIS END YOUR TESTIMONY REGARDING RATE DESIGN?

A. Yes it does.

VI. RATE SCHEDULE CHANGES OTHER THAN RATES.

Q. IS OTP PROPOSING RATE SCHEDULE CHANGES OTHER THAN THOSE RELATING TO RATES DESCRIBED PREVIOUSLY?

A. Yes. OTP's current rate book is being updated in several ways. Many common provisions have been moved to the General Rules and Regulations. And there have been numerous other changes to the individual rate schedules. I describe those changes in this portion of my testimony. A number of the changes are reflected in a matrix of Miscellaneous Rate Schedule changes, which is Ex. __ (DGP-1), Schedule 4, of my testimony. The pagination references on the matrix refer to the black-lined rate schedule sheets contained in Volume 3. In addition to the matrix in Schedule 1, pages 1 through 5 of the Index for the rate schedule book contain a column that lists the prior sheet for current rates schedules. This is intended to help identify each applicable proposed rate schedule with the corresponding current rate schedule.

RIDER APPLICABILITY MATRICES

Q. DESCRIBE THE RIDER APPLICABILITY MATRICES?

A. The Rider Applicability Matrices are organized into three schedules: Purchase Power Riders, Mandatory Riders, and Voluntary Riders. Each matrix designates which rider is applicable to the basic rate. They are designed to serve as a compliance record for OTP and the Commission as well as an explanation tool for OTP customer service personnel in assisting customers.

For example, riders contained in the Mandatory Riders – Applicability Matrix will show the list of mandatory riders and how they apply to each rate schedule. The same concept applies to both the Purchase Power Riders – Applicability Matrix and Voluntary Riders – Applicability Matrix.

The matrices are located in Sections 12.00 – 14.00 of the Electric Rate Schedule Volume 3.

RATE SCHEDULE – RATE SCHEDULES TO BE CANCELLED OR MOVED

Q. IS OTP PROPOSING TO CANCEL OR MOVE RATE SCHEDULE-RATE SCHEDULES?

A. Yes, as shown below in Table 24.

Table 24. PROPOSED TO BE CANCELLED

ELECTRIC SERVICE – NORTH DAKOTA

RATE SCHEDULE DESCRIPTION	Rate Designation	Sheet No.
GENERAL AND COMMERCIAL SERVICE		
Electric Climate Control (Nonresidential General Service) (Closed)	G-93N	29
General Service (Controlled Demand)	G-02N	20.1
Large General Service (Off-Peak Rider)	C-04N	30.2
INTERRUPTIBLE SERVICE		
Fixed Time of Delivery		
100 kW or More	I-04N	50.4
- Moved-combined with tariff I-04N, Sheet 50.3, Fixed Time of Delivery - Less than 100 kW		
Primary Service	I-04N	50.5
- Moved-combined with tariff I-04N, Sheet 50.3, Fixed Time of Delivery - Less than 100 kW		
PURCHASE POWER RATE SCHEDULES		
Standby Service (Under 100 kW Capacity)	P-12N	71.1
- Moved-combined with another rate schedule (OTP new Section 11.01)		
Standby Service (100 kW Capacity or More)	P-13N	71.21
- Moved-combined with another rate schedule (OTP new Section 11.01)		
MOVED TO GENERAL RULES & REGULATIONS		
MISCELLANEOUS ELECTRIC RATE SCHEDULES		
Payment Policy	M-62N	98.2
Deposits and Guarantees	M-63N	98.3
Testing Plan for kWh Meters		101

CANCELLED RATE CODES

The Water Heating Rate Codes from Residential, Farm and General Service Rate were moved to Water Heating – Controlled Service R-91N (now Section 14.01) and combined into rate codes 50-191 and 50-192. In addition, OTP proposes to cancel rate code 44-180, which is the Controlled Loads Less Than 80 kW Capacity With Credit-Closed to New Customers. This rate code offers customers a credit for the first three years of service under this rate. This rate code was closed to new customers as of January 1, 2006. Customers are automatically switched from rate code 44-180 to 44-190 when the first three years has been reached. OTP will no longer have any customers on this rate code as of January 1, 2009.

Q. WHY ARE THESE RATES BEING CANCELLED OR RELOCATED?

A. The rates are being canceled because they were: previously closed or they were duplicative of our proposed rates. The rates are being relocated due to inefficient placement in our tariff.

Q. WHY IS THE ELECTRIC CLIMATE CONTROL (NONRESIDENTIAL GENERAL SERVICE) (CLOSED) RATE BEING CANCELLED.

A. This option was closed to new customers in 1983 and there are a total of 453 customers on the 44-493 rate and 52 on the 44-494 rate. This rate is a very complicated rate for customers to understand as well as OTP's inability to determine and control the types of equipment and systems connected on the customer's side of the meter. Therefore, OTP proposes cancelling this rate and transferring the remaining customers impacted by the elimination of this rate to the appropriate available rate.

Q. PLEASE DESCRIBE HOW THE NUMBER OF CUSTOMERS ON THIS RATE HAS CHANGED SINCE THE RATE WAS CLOSED IN 1983.

A. As of December 31, 1983, there was a total of 1,166 customers on the 493 rate and there was a total of 255 customers on the 494 rate. As customers on this rate discontinue service or there is a change in ownership at a given location, new customers at the these locations are offered an appropriate available rate.

Q. BASED ON THE ATTRITION OF CUSTOMERS FROM THIS RATE SINCE 1983, HOW MANY YEARS WOULD IT TAKE FOR ALL CUSTOMERS TO BE MOVED OFF OF THIS CLOSED RATE?

A. The average number of customers moved off of the 493 rate has been just over 25 customers per year and just over 8 customers per year for the 494 rate. Based on this average, it would take approximately 16 more years to move all customers off the 493 rate and another 6 years to move customers off the 494 rate. A large portion of the customers

would not migrate off the rate for these two reasons. There will be customers that remain on the rate indefinitely due to customer locations never changing hands. Therefore, due to the complexities of this rate, OTP's inability to control the types of equipment connected on the customer's side of the meter and the additional length of time to offer a closed rate, OTP proposes to cancel the Electric Climate Control rate and move the remaining customers to the appropriate available rate.

Q. HOW MANY CUSTOMERS ARE CURRENTLY ON RATES 493 AND 494?

A. As of September 30, 2008, there was a total of 452 customers on the 493 rate and 52 customers on the 494 rate.

Q. WHAT ARE THE BILL IMPACTS TO THE CUSTOMERS CURRENTLY ON THESE RATES?

A. The bill impacts for both of these customers are discussed earlier in my testimony. See Figure 6 and 9 for further information.

Q. WHY IS THE GENERAL SERVICE (CONTROLLED DEMAND –EXPERIMENTAL) RATE BEING CANCELLED?

A. The Controlled-Demand Experimental Rate is being cancelled due to the rate design being incompatible with our current cost structure. The newly proposed Commercial Time of Use better fits our cost structure and provides better price signals to customers who want to shift load and reduce energy costs.

Q. WHAT ARE THE BILL IMPACTS TO THE CUSTOMERS CURRENTLY ON THESE RATES?

A. The bill impacts for both of these customers are discussed earlier in my testimony. See Figure 5 and 8 for further information.

GENERAL RULES AND REGULATIONS

Q. IS OTP PROPOSING CHANGES TO ITS GENERAL RULES AND REGULATIONS?

A. Yes. OTP is filing a new set of General Rules and Regulations to replace in its entirety the existing General Rules and Regulations section of our rate schedule.

Q. WHAT IS THE REASON FOR FILING ENTIRELY NEW RULES AND REGULATIONS, RATHER THAN AMENDING THE EXISTING RULES AND REGULATIONS?

A. When we compared our current general terms and conditions section of the rate schedule with those of other utilities we realized that it would be more efficient to start fresh than attempting to edit around existing language. An entirely new and greatly expanded general terms and condition section allowed us to meet the following three goals:

First, writing new General Rules and Regulations allowed OTP to consolidate and incorporate standard terms and conditions that affect multiple, if not all, services, into a single location (the General Rules and Regulations) while removing these terms from the individual service rate sheets. An example of this set of changes is billing and payment terms. This results in a more comprehensive, uniform, and readily accessible set of generally applicable terms and conditions controlling OTP's provision of service.

Second, in preparing the new General Rules and Regulations, OTP reviewed, analyzed and incorporated the applicable North Dakota statutes and Commission rules governing the provision of electric service. This assured that OTP's rate schedule complies with current laws and regulations.

Third, creating a new General Rules and Regulations section allowed OTP to include new provisions addressing generally occurring situations that it encounters in its operations, and to clarify the terms and conditions that apply to its provision of services in those circumstances. OTP looked both to the experience and knowledge of its own personnel, and to the rate schedule provisions adopted by other electric service providers in North Dakota, in developing these portions of its General Rules and Regulations.

ARTICLE 1: GENERAL SERVICE RULES

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 1 OF THE NEW RULES AND REGULATIONS.

A. The four sections in Article 1 of the General Rules and Regulations address the scope of the rules and regulations, and certain aspects of initiating service.

Section 1.01, Scope of General Rules and Regulations, is essentially the same provision as that contained in OTP's current General Rules and Regulations Section 1, with the new provision expanded to clarify how differences between the terms of the General Rules and Regulations, statutes, or the Commission Rules will be resolved. This Section also points out that a glossary of terms has been added to the General Rules and Regulations, in Section 8.0.

Section 1.02, Application for Service, is nearly identical to the first paragraph of Section 2 of OTP's current General Rules and Regulations, with minor clarifying edits. A new provision in the Application for Service is the requirement that an applicant for service is required to be age of 18. This requirement is intended to ensure OTP is entering into an agreement to provide service with a customer who is capable of entering into a legally binding contract. The age of majority in the state of North Dakota is 18.

Section 1.03, Deposits, Guarantees, is similar to, and replaces, OTP's Miscellaneous Service Rate Schedule M-63N. The new Section incorporates the requirements of the Commission's Rules on Deposits and Guarantees covered in North Dakota Administrative Rule 69-09-02-04. The new section also includes a provision where, with reasonable written notice, OTP may require a new or additional deposit if a customer's credit standing becomes unsatisfactory after a deposit has been refunded or if the deposit is inadequate to cover the estimated charge for furnishing service for a 60-day period. The applicability of the new or additional deposit is consistent with the rate schedule provisions of other North Dakota electric utilities.

Section 1.04, Customer Connection Charge, has been moved from OTP's current Miscellaneous Service Rate Schedule M-62N, with further clarification to explain when connection charges will apply and at what rates. Both the applicability of the charges and the proposed service charge rates are consistent with the rate schedule provisions of other

North Dakota electric utilities. In Case No. PU-04-59, OTP provided justification to increase the Customer Connection Charge to an amount greater than $15.00. However, we did not request to make a change to this charge in that case. Costs associated with connecting and reconnecting customers have increased since 2005 and OTP has recalculated these costs. OTP's average cost to connect or reconnect a customer is currently $17.85. Therefore, in order to move this charge closer to cost, OTP proposes to increase the Customer Connection Charge from $9.00 to $15.00 in this rate case.

ARTICLE 2 - RATE APPLICATION

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 2 OF THE NEW RULES AND REGULATIONS.

A. Section 2.01, Assisting Customers in Rate Selection, is a new provision reflecting OTP's obligation under North Dakota Administrative Rules 69-09-02-02.1(5) to assist customers in selecting safe and efficient service. The Section clarifies that OTP does not guarantee that charges under a different available rate could not be lower. This is reasonable because small changes in consumption can, in some cases, result in changes in the most advantageous rate.

Section 2.02, Service Classification, is similar to Section 14 under OTP's now-filed General Rules and Regulations. The new provision updates references to applicable statutes and Rules, and provides clarifications to better explain service classifications.

ARTICLE 3 - CURTAILMENT OR INTERRUPTION OF SERVICE

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 3 OF THE NEW RULES AND REGULATIONS.

A. This Article addresses OTP's and customers' respective rights and obligations concerning disconnection, curtailment and interruption of service.

Section 3.01, Disconnection of Service, identifies and incorporates the Commission's Rules governing OTP's ability to disconnect service. OTP's current rate schedule does not address these matters.

Section 3.02, Curtailment or Interruption of Service, provides a statement of OTP's rights to curtail or interrupt service when needed to protect the integrity of its electrical system, or to respond to the request of a regional reliability authority. This Section also identifies OTP's remedies if it determines a customer has tampered with OTP facilities.

Section 3.03, is reserved for future use

Section 3.04, is reserved for future use.

Section 3.05, Continuity of Service, is a restatement of Section 5 in OTP's current General Rules and Regulations. The language in Section 3.05 more explicitly and accurately reflects industry standard rate schedule language limiting OTP's liability as a result of service interruptions or delays.

ARTICLE 4 - METERING AND BILLING

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 4 OF THE NEW RULES AND REGULATIONS.

A. This Article contains the generally applicable provisions on service metering, billing, and payment matters.

Section 4.01, Meter and Service Installations, addresses OTP's and the customer's obligations for meter and service installations. OTP's current General Rules and Regulations, Section 3, refers customers to a "Meter Manual" for information on meter and service installations. The information in the Meter Manual has been placed into this Section (and in other provisions of Article 4). OTP also updated and clarified some information in new Section 4.01.

Section 4.02, Meter Reading, explains OTP's obligations and rights with respect to meter reading. The provision on self-read meters reflects Section 11 of OTP's current General Rules and Regulations (Rural Meter Reading), which allows OTP employees to verify the meter readings of self-read customers at intervals of approximately twelve months. As of August 31, 2008, OTP had 230 customer accounts coded as self-read accounts, which consisted of 312 self-read meters. Due to the distance and the amount of time involved in reading all 312 self-read meters at least once every three months verses

once every 12 months, OTP requests to continue the practice of reading self-read meters at least once within a 12 month period.

Section 4.03, Estimated Readings, is a restatement of Section 18 of OTP's current General Rules and Regulations and also states OTP's and customers' respective rights and obligations concerning estimated meter readings. The Section is consistent with the current North Dakota Administrative Rule 69-09-02-11(3).

Section 4.04, Meter Testing, is also a new provision. Consistent with current Commission Rules, the Section states rights and obligations (including for billing adjustments) where a customer's meter registers more than 2% fast or slow. This Section also identifies charges if a customer requests retesting of a meter within one year of a previous test, and on retesting the meter is found to register accurately. The concept of charging for retesting under these circumstances, is consistent with the current North Dakota Administrative Rule 69-09-02-26(7).

Section 4.05, Access to Customer Premises, is a restatement of Section 12 in OTP's current General Rules and Regulations, with changes to correctly identify rights and obligations under the Commission's Rules governing OTP's access to customer premises. The provision also identifies OTP's right of entry to remove its equipment from customer property, as part of its normal course of business.

Section 4.06, Establishing Demands, restates with clarifying language the first paragraph of OTP's current General Rules and Regulations, Section 17.

Section 4.07, Monthly Billing Period and Prorated Bills, in part restates Section 19 of OTP's current General Rules and Regulations. The new provision more accurately reflects the current North Dakota Administrative Rule 69-09-02-10(1), and consistent with those Rules explains what a normal billing period is.

Section 4.08, Electric Service Bill - Identification of Amounts and Meter Reading, follows OTP's current Section 15 of its General Rules and Regulations, with non-substantive, clarifying edits. This Section also states the provisions contained in Section 20 of the current General Rules and Regulations, concerning adjustments for payments to Municipalities. Finally, the Section identifies that OTP will collect from customers, and the

service bill will itemize, any sales, use, excise or other taxes and fees that are applicable to the service provided.

Section 4.09, Billing Adjustments, is a new provision. This Section identifies when and how adjustments to customer bills will be made by OTP. The Section is consistent with the current North Dakota Administrative Rule 69-09-02-12(1) & (2).

Section 4.10, Payment Policy, this section reflects OTP's current Miscellaneous Service Rate Schedule M-62N, with clarifying language changes and is consistent with the current North Dakota Administrative Rule 69-09-02-01(1)(a). OTP also proposes to increase the charge for checks returned to OTP for Non-Sufficient Funds "NSF". Both the applicability of this charge and the proposed rate is consistent with the rate schedule provisions and rate of other North Dakota electric utilities. Currently OTP is charged $6.00 from its bank when a Customer's check is returned to OTP. OTP has estimated the cost for paying any bank charges from its bank and to process an NSF check to be $16.04. Therefore, in order to move this charge closer to cost, OTP proposes to increase the NSF check charge from $5.00 to $15.00 in this rate case.

Section 4.11, Even Monthly Payment, describes OTP's optional program permitting Residential and Commercial service customers to choose to budget their electric service expenses over a twelve (12) month period. This Section explains how billings are determined, and commits OTP to pay interest on any accrued credit balance.

Section 4.12, Summary Billing Service, describes a customer's ability to consolidate multiple billed accounts into a master bill with a single billing date.

Section 4.13, Account History Charge, is a new provision intended to address the expense incurred by OTP where a single customer frequently requests multiple account history reports. Both the concept of the charge and the amount of the charge shown is consistent with the rate schedule provisions of other electric service providers in North Dakota.

Section 4.14, Combined Metering, this is a new provision and is intended to allow customers with contiguous property and with a minimum entrance rating of 750 kVa to combine multiple service and metering points into one meter reading. This allows OTP to bill the customer as one large load for billing on one rate.

ARTICLE 5 - STANDARD INSTALLATION AND EXTENSION RULES

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 5 OF THE NEW RULES AND REGULATIONS.

A. Section 5.01, Extension Rules and Minimum Revenue Guarantee, follows Section 6 in OTP's current General Rules and Regulations, with clarifying language to better explain application of the Rule.

Section 5.02, Special Facilities, originates in Section 10 of OTP's current General Rules and Regulations. The new Section better explains how and when a customer may incur Excess Expenditure charges for the installation of Special Facilities. The Section addresses a set of generally occurring situations that OTP encounters in its operations, and clarifies what terms and conditions will apply to its provision of services in those circumstances. OTP looked both to the experience and knowledge of its own personnel, and to the rate schedule provisions adopted by other electric service providers in North Dakota, in developing this Section.

Section 5.03, Temporary Services, rewrites Section 7 in OTP's current General Rules and Regulations to comply with the current North Dakota Administrative Rule 69-09-02-01(1)(j).

Section 5.04, Standard Installation, is new and explains how and when OTP will provide service at Secondary and Primary Voltage, and at Transmission Voltage, capacities. In developing this Section, OTP looked both to the experience and knowledge of its own personnel, and to the rate schedule provisions adopted by other electric service providers in North Dakota.

Section 5.05, Service Connection, incorporates many of the terms and conditions OTP has historically stated in its service contracts with customers. These terms define the respective rights and obligations of OTP and customers concerning the installation, maintenance, and ownership of lines and equipment supplied by OTP to provide electric service to the customer.

ARTICLE 6 - USE OF SERVICE RULES

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 6 OF THE NEW RULES AND REGULATIONS.

A. Section 6.01, Customer Equipment, is based upon the second paragraph of Section 10 in OTP's current filed General Rules and Regulations. This section addresses a set of generally occurring situations that OTP encounters in its operations, and clarifies the terms and conditions that will apply to its provision of services in those circumstances. In developing this Section, OTP looked both to the experience and knowledge of its own personnel, and to the rate schedule provisions adopted by other electric service providers in North Dakota.

Section 6.02, Use of Service, essentially follows Section 16 in OTP's current General Rules and Regulations, with non-substantive clarifying edits.

ARTICLE 7 - COMPANY'S RIGHTS

Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 7 OF THE NEW RULES AND REGULATIONS.

A. Section 7.01, Waiver of Rights or Default, restates Section 21 in OTP's current General Rules and Regulations.

Section 7.02, Modifications of Rates, Rules and Regulations, states that OTP has the right to modify its rates, rule and regulations in the future, in any manner permitted by law.

ARTICLE 8 - GLOSSARY AND DEFINITION OF SYMBOLS

Q. PLEASE DESCRIBE THE CONTENTS OF SECTION 8.01 GLOSSARY.

A. Section 8.01 defines commonly used terms in the above-discussed provisions of the General Rules and Regulation using the commonly accepted meaning of those terms in the industry.

Q. PLEASE DESCRIBE THE CONTENTS OF SECTION 8.02 DEFINITION OF SYMBOLS.

A. Section 8.02 provides the key showing the meaning of the symbols which will be used in the rate schedule as revisions are made in the future.

Q. ARE THERE PROVISIONS IN OTP'S CURRENTLY FILED GENERAL RULES AND REGULATIONS THAT ARE NOT CONTAINED IN THE PROPOSED GENERAL RULES AND REGULATIONS, OR OTHERWISE CONTAINED IN OTP'S NEW RATE SCHEDULE FILINGS?

A. Yes, Section 9, Gaseous Tube Lighting.

OTP determined that Section 9 is unnecessary for its operations in North Dakota and therefore eliminated this provision.

OTHER RATE SCHEDULE REVISIONS

Q. IS OTP PROPOSING OTHER REVISIONS TO ITS RATE SCHEDULES?

A. Yes. We are proposing a number of formatting changes and reference revisions for the rate schedules.

Header Information Shown on all Rate Schedule Sheets

Q WHAT CHANGES ARE YOU PROPOSING WITH RESPECT TO THE HEADER INFORMATION SHOWN ON OTP'S RATE SCHEDULE SHEETS?

A. We are proposing to update the rate schedule sheets to a standardized format with a header that includes: 1) OTP's logo that references the location of our main office in Fergus Falls Minnesota; 2) The section number of the rate schedule sheet; 3) The name of the rate schedule; 4) The page number(s); and 5) The date of the last revision.

Reordering of Sections

Q. ARE YOU PROPOSING CHANGES TO THE ORDER OF INFORMATION SHOWN ON THE RATE SCHEDULE SHEETS?

A. Yes. The "Regulations" provisions of each section have been relocated to the beginning of each section. The order of presenting the remaining common provisions listed in each

section has been standardized as much as possible to follow the same format for all services.

Relocation of sections to the Rules and Regulations Document

Q. ARE YOU PROPOSING TO REMOVE REQUIREMENTS THAT ARE COMMON TO ALL SERVICES AND INSTEAD ADDRESS THOSE REQUIREMENTS IN THE RULES AND REGULATION SECTION OF THE RATE SCHEDULE?

A. Yes. Because the Rules and Regulations uniformly apply to all services, when possible, the terms and conditions contained in the individual rate sections have been limited so as to avoid duplication. These moved provisions are discussed more fully in my earlier testimony regarding revisions to OTP's general rules and regulations.

Rate Schedule Reference – Names, Numbers and Codes

Q. WHAT CHANGES ARE BEING PROPOSED WITH RESPECT TO SERVICE IDENTIFICATION?

A. OTP is proposing to use the descriptive names of each service as the primary identifier. Services are currently referenced by the descriptive name, the *Rate Designation* number and the *Rate Code*. We are proposing eliminating the *Rate Designation* number and replacing this numbering system with one that reorders the rate schedules into more logical groupings or sections making it easer for the reader to locate specific rate schedule sheets.

Q. WHAT WILL BE THE IMPACT TO THE COMMISSION AND THE CUSTOMERS CAUSED BY THE ELIMINATION OF THE RATE DESIGNATION NUMBER?

A. The Rate Designation number is currently being used only as an indexing tool by OTP's Rate Department and although that number is referenced along with the other identifiers on the rate schedule sheets and OTP's web site, it is not commonly used by the Commission or customers.

Q. IS OTP PROPOSING ANY CHANGES TO CURRENT RATE CODES?

A. Yes. The rate code for the Penalty on the Controlled Service Interruptible Load (80 kW capacity and greater), Controlled Service Interruptible Load (Less than 80 kW Capacity)

and Controlled Service Deferred Load is currently 44-199. In order for OTP to determine which of these rates the Penalty billing is associated, we propose to change the Penalty rates as follows:

Controlled Service Interruptible Load (80 kW capacity and greater) – 50-169

Controlled Service Interruptible Load (Less than 80 kW Capacity) – 50-189

Controlled Service Deferred Load – 50-196.

Q. HAS OTP PROPOSED ANY OTHER CHANGES TO ITS RATE CODES?

A. Yes. We are also proposing to change the rate level from 44 to 50 in order to accommodate the transition from interim to final rates with our customer information system.

Changes to Residential Service –
Section 9, Rate Codes 44-101, 44-109, 44-111, and 44-119 (R-01N)

Q. PLEASE DESCRIBE THE CHANGES BEING PROPOSED TO THE RESIDENTIAL SERVICE, SECTION 9.

A. We are proposing to remove any distinction between cottages and other residences, to eliminate additional requirements for Electric Homes and to eliminate the power requirement restrictions.

Q. WHY ARE YOU PROPOSING ELIMINATING THE REFERENCE TO COTTAGES?

A. Currently, we charge premises identified as summer cottages a higher monthly minimum bill, however, there does not appear to be any meaningful way to distinguish "cottages" from other residences. Also, there is little or no cost justification for distinguishing between customers who have a second home for summer use ("cottages") and those that close their primary residence for the winter.

Q. PLEASE EXPLAIN THE CHANGES PROPOSED RELATED TO ELECTRIC HOMES.

A. With respect to Section One – Building Construction, current building codes properly address the efficiency standards that should be used in home construction regardless of the type of heat that is utilized, and we do not believe that OTP has the authority necessary to monitor or enforce the requirements as currently stated. With respect to voltage reduction,

OTP's load management system lacks the capability in it's present configuration to reduce voltage to any connected load and therefore it is unable to implement the level of control expressed in part two of this section. Since the loads addressed in this section are served on this firm service rate schedule and since these loads are not physically separated from customers' other electric loads, OTP is recommending that this restriction be removed from the rate schedule.

Q. PLEASE EXPLAIN THE CHANGES PROPOSED RELATED TO THE TYPE OF POWER ALTERNATIVES AVAILABLE TO RESIDENTIAL CUSTOMERS.

A. Currently, residential customers are limited to 120/240 volts, single phase, 60-cycle alternating current. Although it is unlikely that the service voltage for a residential customer will be something other that 120/240 single phase, OTP proposes they have the flexibility to respond to non-standard requests for different power without having to characterize the customer as taking a different service. Therefore it is recommended that this section be removed from the rate schedule.

Residential Demand Control (Commonly Identified as RDC) – Rate Code 44 – 241 (R-03N)

Q. WHAT CHANGES ARE PROPOSED FOR RESIDENTIAL DEMAND CONTROL SERVICE?

A. We are proposing the following: elimination of the restrictions stated in the Applications of Schedule section of this rate; designation of three (3) kW as the default demand for new customers taking service under this rate; elimination of additional requirements for Electric Homes; elimination of OTP's authority to inspect the home and oversee equipment selection; and elimination of the reference to typical control times.

Q. WHAT RESTRICTIONS ARE BEING REMOVED AND WHY?

A. The Application section contains a list of possible end uses. The intent of the Residential Demand Control rate is to provide the total electrical requirements for homes taking service under its provisions. Since the rate does not place any restrictions on the type of end use

loads customers may choose to purchase and install in their homes, there is no functional reason to include a list of allowable loads in the rate.

Q. WHY IS A MINIMUM DEMAND OF 3 KW BEING INCLUDED FOR NEW CUSTOMERS?

A. Until a level of demand can be determined based on actual usage, it is necessary to establish a reasonable proxy level. In order to assure the fair and consistent application of this rate, OTP is proposing to designate three (3) kW as the initial default setting for all new customers taking service under this rate. Our records indicate that the average established demand for all customers taking service under this rate is 5 kW with 21% of customers choosing to maintain a demand of 3 kW or less. Defaulting new customers at a demand level of 3 kW will provide adequate financial protection for OTP until the customer's actual demand is recorded during a control period.

Q. WHY IS THE CROSS REFERENCE TO THE ELECTRIC HOMES PROVISION IN THE APPLICATION SECTION OF THE RATE SCHEDULE SHEET BEING ELIMINATED?

A. OTP proposes removing the reference to Electric Heat restrictions from the Application of Schedule section as well as the companion conditions of service listed at the end of the rate schedule sheet. OTP lacks the authority necessary to monitor or enforce the requirements as stated.

Also, OTP's load management system lacks the capability, in its present configuration, to implement the level of control expressed in part two of the requirements section (i.e. the right to reduce voltage and/or control demand) for space heating units. Since the loads addressed in this section are served using this firm service rate and since these loads are not physically separated from the customers' other electric loads, OTP is recommending that this restriction be removed from the rate schedule.

Q. WHY ARE YOU PROPOSING ELIMINATING THE RIGHT TO INSPECT THE HOME AND OVERSEE EQUIPMENT SELECTION?

A. This right is currently provided in the 3rd paragraph of the conditions set forth at the end of the rate schedule sheet. However, OTP lacks the ability to effectively monitor or enforce the requirements as stated in this section. Further, we believe that better results can be accomplished through training and education. The Residential Demand Control rate schedule is designed to provide customers with pricing signals based on their electrical usage during control periods. In order to take full advantage of this rate schedule customers require a level of knowledge on the consequences of their usage patterns that is different than customers on OTP's other firm residential rate. OTP is staffed to provide design support and training on a reactive basis when requested, and does not believe that it is necessary to retain oversight authority.

Q. PLEASE EXPLAIN THE REASON FOR ELIMINATING THE CURRENT RESTRICTION ON CONTROL PERIODS.

A. The current language states that control periods will typically occur when the temperature is below zero in the winter and not occur on Sundays and that water heaters may be controlled during the summer months. Although the current language does not limit load control to those specific periods, inclusion of this statement in the rate schedule creates those expectations. The need to control loads cannot effectively be based on these parameters, and since load control can and does occur outside of these limits, OTP recommends removing this language from the rate schedule.

Farm Service –
Rate Codes 44-361, 44-241, 44-361, and 44-701 (F-61N)

Q. WHAT CHANGES ARE PROPOSED FOR FARM SERVICE?

A. OTP is recommending the following changes to the Farm Service terms and conditions: elimination of OTP's authority to restrict the specific customer owned end uses equipment; removal of the Option II Rates section; a provision for alternative Residential Service for farm homes; and elimination of the *Regulations Applying to Water Heating* section of this rate schedule.

Q. WHY ARE YOU PROPOSING TO ELIMINATE THE LIST OF POSSIBLE END-USES FROM THE AVAILABILITY SECTION?

A. We are not attempting to regulate how farm customers use the energy. Nor is it practical to list each potential end use of the energy.

Q. WHY IS OTP PROPOSING TO ELIMINATE THE OPTION II RATES?

A. This option was closed to new customers in 1975 and there is just one remaining customer receiving service under this option. Therefore, OTP proposes removing this rate option and transferring the one remaining customer impacted by the elimination of this option to the appropriate available rate.

Q. WHAT CHANGES ARE PROPOSED WITH RESPECT TO SERVING A FARM RESIDENCE?

A. We propose allowing farm customers to elect separate Residential Service or Residential Demand Control Service for their homes. OTP takes the position that a farm customer should have the same rate options as other residential customers for that portion of their service dedicated to serving their home. In order to offer this option to these customers OTP has proposed changes to this rate schedule to address facilities necessary to provide service under this specific rate as well as the minimum required for service under the second Residential rate that is chosen by the customer.

Q. WHY IS OTP PROPOSING TO ELIMINATE THE ELECTRIC WATER HEATER DESIGN CHARACTERISTICS?

A. Currently paragraph 5 of the rate schedule requires that water heaters meet certain requirements (e.g. wattage limitations). However, OTP lacks the ability to effectively monitor or enforce these requirements. Further, based on its current load control capabilities, OTP does not have the ability to separate the water heating load from the other controlled service loads. For these reasons OTP is requesting that this section be removed from the rate schedule.

Large General Service –
Rate Codes 44-632, 44-602, 44-603 (C-02N)

Q. WHAT CHANGES ARE OTP REQUESTING WITH RESPECT TO LARGE GENERAL SERVICE?

A. OTP is recommending the following changes: elimination of the customer's option to request this rate as stated in the Application Section; elimination of the reference to three-phase or single-phase power from the Application Section of this rate; modification of the billing demand determination section to clarify the determination of the billing demand, and elimination of the Special Billing Demand Option.

Q. WHY IS OTP ELIMINATING THE WORD "REQUEST" FROM THE LANGUAGE OF THIS RATE SCHEDULE?

A. The goal of OTP customer service personnel is to minimize misapplication of the rate schedule, which improves customer satisfaction and reduces excess administrative duties such as bill complaints and adjustments.

To better reflect that OTP customer service personnel assists its customers in the appropriate selection of service offerings. Retaining the word "request" inaccurately suggests the selection is solely left to the customer.

Q. WHY IS OTP PROPOSING TO ELIMINATE FROM THE RATE SCHEDULE THE REFERENCE TO "SINGLE PHASE OR THREE PHASE SERVICE"?

A. The language is unnecessary and removing it will not change in any respect the service offered.

Q. WHY IS THE BILLING DEMAND DETERMINATION SECTION BEING AMENDED?

A. OTP is proposing to modify the language in the first paragraph of the Determination of Billing Demand section of this rate schedule to improve the ease and consistency of application.

Large Commercial Service – Time of Day
Rate Codes 44-611, 44-615, 44-613, 44-610, 44-614, 44-612
44-639, 44-637, 44-640 (C-05N)

Q. WHAT CHANGES ARE PROPOSED FOR THE LARGE COMMERCIAL SERVICE-TIME OF DAY SERVICE?

A. OTP is proposing to eliminate the customer's option to request this rate as stated in the Application Section.

Q. WHY IS OTP PROPOSING TO ELIMINATE FROM THE RATE SCHEDULE THE REFERENCE TO "THREE PHASE OR SINGLE PHASE SERVICE"?

A. As stated above, the language is unnecessary and removing it will not change in any respect the service offered.

Interruptible Load Rider – Commonly Identified as Large Dual Fuel
Rate Code 44-170, 44-165, 44-199 (I-01N)

Q. WHAT CHANGES ARE PROPOSED WITH RESPECT TO THE INTERRUPTIBLE LOAD RIDER?

A. OTP is recommending the following changes: a change to the name of this rider to add the commonly identified name; removal of reference to zone 1 and zone 9; a clarification on the correct application of the rider, an explanation of penalty periods modified; elimination of language related to recommended installed capacity of heating; and elimination of language related to OTP's right to control.

Q. WHY IS OTP CHANGING THE NAME OF THIS SERVICE?

A. OTP is proposing to add the commonly used identifier, "Large Dual Fuel" to aid customers in identifying the purpose and use of this rider. We also added "CT Metering Rider" to the name of the service.

Q. WHY IS OTP REMOVING THE REFERENCE TO ZONES 1 AND 9?

A. This rate is equally available to customers in all zones without a price differential. Therefore, the language referencing zones is inconsistent with the availability of the service.

Q. WHAT CLARIFICATION HAS BEEN ADDED ON THE AVAILABILITY OF THE RIDER?

A. OTP has added two options regarding fans, pumps and other ancillary equipment loads used to distribute conditioned air and/or water. Option 1 requires all fans, pumps and other ancillary equipment to be connected to the Customer's firm service meter. Option 2 allows the customer to have a minimal amount of equipment load for the distribution of conditioned air and/or water to be on during a control period. Option 2 allows OTP to address situations where equipment design or the infeasibility of separate wiring makes this wiring structure necessary but clarifies it is intended to constitute minimal total load served through this rider. Additional language is included explaining that the exemption for pump and fan loads does not include grain drying or circulation pumps.

Additional language has been added to address the applications related to Option 1 and Option. These options were discussed earlier in my testimony. To illustrate, Option 2 introduces different control and demand billing measurements, therefore new language has been added to address these expanded services.

Q. PLEASE EXPLAIN THE CHANGES TO THE PENALTY PERIODS.

A. The clarifying language is proposed to impose a penalty when OTP signals to curtail load and customer's equipment does not in fact curtail load. Additional language indicates that the penalty charges are not intended as a means for a customer to "buy through" control but instead constitutes an unauthorized use of electricity.

Q. WHY HAS THE LOCATION OF THE CONTROL DEVICES BEEN REMOVED FROM THE RATE SCHEDULE?

A. Location of control devices has been moved to the General Rules and Regulations section of the rate schedule because it is relevant to more services than just this one.

Q. WHY ARE YOU RECOMMENDING THE ELIMINATION OF LANGUAGE RELATING TO RECOMMENDED INSTALLED CAPACITY OF HEATING EQUIPMENT?

A. The recommendation in the current rate schedule is not a condition of service and therefore it is not appropriate for inclusion. Such matters are better addressed through building codes and construction standards.

Q. WHY HAVE YOU ELIMINATED THE OTHER RECOMMENDATIONS?

A. These recommendations have been eliminated from the rate schedule, but both have been retained in the General Rules and Regulations. Conditions for control and the issue of liability are general topics better addressed in the General Rules and Regulations.

Interruptible Load Rider – Commonly Identified as Small Dual Fuel
Rate Code 44-190, 44-185, 44-199 (I-02N)

Q. WHAT CHANGES ARE PROPOSED WITH RESPECT TO THE INTERRUPTIBLE LOAD RIDER -- COMMONLY IDENTIFIED AS SMALL DUAL FUEL?

A. OTP is recommending the following changes to this rider: a change of the name of this rider to add commonly identified name, removal of the subhead reference to zone 1 and zone 9, clarification on the correct application of the rider, explanation of penalty periods modified, elimination of language related to recommended installed capacity of heating, and elimination of language from this rate schedule related to OTP's right to control.

Q. WHY ARE YOU PROPOSING TO CHANGE THE NAME?

A. OTP is proposing to add the commonly used identifier, "Small Dual Fuel" to aid customers in identifying the purpose and use of this rider. We have also added "Self-Contained Metering Rider" to the name.

Q. WHY IS THE REFERENCE TO ZONE 1 AND ZONE 9 PROPOSED FOR REMOVAL?

A. This rate is equally available to customers in all zones without a price differential, therefore, language referencing zones is unnecessary.

Q. WHAT CLARIFICATION HAS BEEN ADDED ON THE APPLICATION OF THE RIDER?

A. OTP has added clarifying language allowing minimal fan and pump load to be served under the interruptible rate even when that load is not subject to interruption to allow the operation of the controlled service system. OTP added this language to address situations where equipment design or the infeasibility of separate wiring makes this wiring structure necessary but clarifies it is intended to constitute minimal total load served through this rider. Additional language is included explaining that the exemption for pump and fan loads does not include grain drying or circulation pumps or other ancillary equipment.

Q. PLEASE EXPLAIN THE CHANGES TO THE PENALTY PERIODS?

A. The clarifying language is proposed to impose a penalty when OTP signals to curtail load and customer's equipment does not in fact curtail load. Additional language indicates that the penalty charges are not intended as a means for a customer to "buy through" control but instead constitutes an unauthorized use of electricity.

Q. WHY HAVE THE RECOMMENDED INSTALLED CAPACITY PROVISIONS BEEN ELIMINATED?

A. The current recommendations for installed heating capacity (Other Provisions paragraphs 1 and 2) are not a condition for taking service under this rider and are more appropriately addressed in building codes and standards.

Q. WHY ARE YOU RECOMMENDING ELIMINATING THE PROVISIONS REGARDING RIGHT TO CONTROL AND LIABILITY?

A. These recommendations have been eliminated from the rate schedule, but both have been retained in the General Rules and Regulations. Conditions for control and the issue of liability are more appropriately addressed within the General Rules and Regulations because they apply to riders other than this particular service rider.

Controlled Service Deferred Load Rider – Commonly Identified as Thermal Storage – Rate Code, 44-197, 44-195, 44-199 (I-03N)

Q. WHAT CHANGES ARE PROPOSED WITH RESPECT TO THE CONTROLLED SERVICE DEFERRED LOAD RIDER?

A. OTP is recommending the following substantive changes to this rider: a change of the name of this rider to add its commonly identified name; removal of the subhead reference to zone 1 and zone 9; clarification on the correct application of the rider; explanation of penalty periods modified; elimination of language related to recommended installed capacity of heating; and elimination of language from this rate schedule related to OTP's right to control.

Q. PLEASE DESCRIBE THE CHANGES IN THE DESCRIPTIVE NAME.

A. OTP is proposing to add the commonly used identifier for this rider, "Thermal Storage" to aid customers in identifying the purpose and use of this rider.

Q. WHY HAS THE REFERENCE TO ZONE 1 AND ZONE 9 BEEN REMOVED?

A. This rate is equally available to customers in all zones without a price differential. Therefore, language referencing zones is unnecessary.

Q. IS ANY CLARIFYING LANGUAGE REGARDING THE APPLICATION OF THE RIDER PROPOSED?

A. Yes. OTP has added clarifying language notating that minimal fan and pump load may be served under the interruptible rider to allow for the operation of the controlled service system. OTP added this language to address situations where equipment design or the

unfeasibility of separate wiring makes this wiring structure necessary but clarifies it is intended to constitute minimal total load served through this rider. Additional language is included explaining that the exemption for pump and fan loads does not include grain drying or circulation pumps and other ancillary equipment, as these are significantly sized loads where installed on this service. Grain drying load is intended to constitute a fully interruptible load with fans representing a significant portion of the load.

Q. PLEASE EXPLAIN THE MODIFICATIONS PROPOSED WITH RESPECT TO THE PENALTY PERIODS.

A. OTP proposes clarifying language to make conditions under which the penalty will apply to customers. This further explanation indicates that a penalty period exists when OTP signals to curtail load and the customer does not shed load. The added language indicates that the penalty charges are not intended as a means to "buy through" control but instead constitutes the unauthorized use of electricity.

Q. WHY HAVE YOU PROPOSED ELIMINATING THE RECOMMENDATION RELATING TO INSTALLED HEATING CAPACITY?

A. The current recommendations for installed heating capacity (Other Provisions paragraphs 1 and 2) are not a limitation for taking service under this rider and are issues best addressed through building codes and standards.

Q. WHY ARE THE OTHER PROVISIONS PROPOSED TO BE ELIMINATED?

A. These recommendations have been eliminated from the rate schedule, but both have been retained in the General Rules and Regulations. Conditions for control and the issue of liability apply to multiple riders and rate and are more appropriately addressed within the General Rules and Regulations.

Fixed Time of Delivery Rider –
Rate Codes 44-301, 44-302, 44-303 (I-04N)

Q. WHAT CHANGES ARE PROPOSED FOR THE FIXED TIME OF DELIVERY SERVICE RIDER?

A. OTP is recommending the following changes to these riders: combining the three Fixed Time of Delivery riders into one and adding a section to address monthly minimum bill for this rider.

Q. WHY ARE YOU PROPOSING TO COMBINE THE THREE FIXED TIME OF DELIVERY RIDERS?

A. This is reflected in the list of the three services and associated rate codes as part of the Description. The primary differentiating factors between the three existing riders are the thresholds of application and their corresponding facility and energy charges. These differences are continued in the proposed single rider. Combining the three individual riders into one schedule is recommended as a means of rate schedule efficiency and will provide for a smoother transition as customers increase or decrease the amount of storage heat or cooling that is installed in their facility.

Q. IS OTP PROPOSING MINIMUM CHARGES?

A. Yes. The existing rates contain monthly minimum charges and the rider is designed to continue those minimums, as adjusted due to this rate proceeding. Because the vast majority of loads served on this rider are seasonal and have little of no usage during the summer months this charge is designed to recover OTP's fixed cost of the facilities and the operational expenses associated with this rider.

Q. IS OTP PROPOSING TO ADD A PENALTY TO THIS RATE SCHEDULE?

A. As I stated earlier in my testimony, OTP added the penalty language to this rate schedule to be consistent with Small Dual Fuel, Large Dual Fuel and Thermal Storage.

Irrigation Service –
Rate Code 44-703, 44-704, 44-705, and 44-706 (M-03N)

Q. ARE YOU PROPOSING ANY CHANGES TO THE IRRIGATION TIME OF USE SERVICE RIDER?

A. Yes. OTP is recommending the following changes to this rider: a change in the name of the service; removal of the reference to excess capacity; the provision of an alternative to the existing fixed charge requirement; removal of the reference to the expected number of peak hours; and removal of references to unnecessary restrictions.

Q. WHAT LANGUAGE IS BEING PROPOSED FOR REMOVAL FROM THE CHARACTER AND CONDITIONS OF SERVICE PROVISION?

A. OTP is proposing to remove the language that identified excess seasonal capacity as a justification for the rates for this service.

Q. WHY ARE YOU PROPOSING AN ALTERNATIVE RATE FOR RECOVERING THE DISTRIBUTION FACILITY COSTS?

A. Based on the input from customers, OTP is proposing a revenue neutral option that will allow customers to reduce the annual electric portion of their operating costs by making a one-time up-front payment to offset capital costs required to install service. This proposal separates the fixed charge into two components. The first component includes all of the charges associated with the costs to install the service and the second component includes the annual costs associated with the ongoing operation and maintenance.

Q. PLEASE EXPLAIN THE REASON FOR REMOVING THE STATEMENT CONCERNING EXPECTED PEAK HOURS.

A. The rate schedule currently contains a statement that "The number of hours at peak level is not expected to exceed 300 hours per season." That statement is no longer accurate and we are unable to accurately predict the number of peak hours to support inserting a different number of peak hours. For this reason OTP is proposing to remove this reference.

Q. IS OTP PROPOSING TO REMOVE THE RULES AND REGULATIONS PROVISIONS, AND IF SO WHY?

A. Yes. OTP is proposing to remove the section entitled Rules and Regulations for Irrigation Service and eliminate the items that are unnecessary, restrictive or no longer necessary for the proper application of this rate. The remaining items that are still valid have been incorporated into the rate schedule, addressed in the Irrigation Agreement, or are in OTP's General Rules and Regulations.

Municipal Pumping Service
Rate Codes 44-872 (M-54N)

Q, IS OTP PROPOSING CHANGES TO THE MUNICIPAL PUMPING SERVICE RIDER?

A. Yes. OTP recommends eliminating the statement that requires the customer to make an additional investment for three-phase service.

Q. WHY IS OTP REMOVING THE PROVISION ADDRESSING CUSTOMER OBLIGATIONS WITH RESPECT TO WIRING AND EQUIPMENT FOR THE CUSTOMER'S SINGLE-PHASE REQUIREMENTS?

A. Any additional equipment required to provide single-phase power from a three-phase service would be installed on the customer's side of the meter. Consequently, it is not part of OTP's service and the language is unnecessary.

Controlled Water Heating Rider
Rate Code 44 – 191 (R-91N)

Q. ARE CHANGES PROPOSED FOR THE CONTROLLED WATER HEATING RIDER?

A. Yes. OTP is recommending the following substantive changes to this rider: elimination of reference to the Rate Zone applicable to this rider; elimination of requirements governing customer owned equipment; and establishment of a recovery time between control periods that occur on consecutive days.

Q. WHY ARE YOU PROPOSING THE ELIMINATION OF THE RATE ZONE REFERENCES?

A. Since this rider applies to both Rate Zone 1 and Rate Zone 9, this reference to rate zones is irrelevant.

Q. WHY HAS OTP PROPOSED ELIMINATING THE PROVISIONS RELATED TO THE DIFFERENT TYPES OF WATER HEATING EQUIPMENT?

A. Currently the portion of the rider entitled Additional Regulations Applying To Water Heating, Controlled Service, lists a number of limitations on the type of water heaters (their size and wattage) that are appropriate for use under this rider. OTP recommends removal of those conditions as we lack the ability to adequately police them and will seek to accomplish the same goals through discussions with customers during their decision-making process.

Q. WHY HAS OTP PROPOSED A RECOVERY PERIOD AFTER EXTENDED PERIOD OF CONTROL?

A. Language has been added stating that after control periods have approached 14 continuous hours, OTP will, under normal conditions, schedule a recovery period. This is to increase customer satisfaction.

Outdoor Lighting Rider –
Rate Code 44-741, 44-743, and 44-744 (M-42N)

Q. IS OTP PROPOSING ANY CHANGES TO THE OUTDOOR LIGHTING RIDER?

A. Yes. OTP is recommending the following changes to this rider: redefine the output ratings of the outdoor lighting fixtures; redirect sign lighting customers to the energy only rate schedule; restriction of the use of overhead service to fiberglass poles; removal of the reference to fluorescent fixtures; and the addition enabling termination of service to fixtures damaged by vandals.

Q. WHY HAS WATTAGE BEEN ADDED TO THE OUTPUT RATINGS?

A. OTP is proposing to add "wattage" to the lighting fixture rating to make it easier for customers to equate the fixture output with other lighting products.

Q. WHAT RATE DOES OTP PROPOSE FOR SIGN LIGHTING?

A. Since OTP currently has an energy only rider on file with the Commission that properly addresses the costs of providing service for sign lighting, OTP proposes to have that portion of the rider moved to the energy only rider.

Q. WHY ARE YOU PROPOSING TO RESTRICT THE USE OF OVERHEAD SERVICE TO FIBERGLASS POLES?

A. Due to material restrictions, it is not feasible to install overhead service to pole top lighting fixtures mounted on fiberglass poles. For this reason OTP is proposing to remove this reference from the rider.

Q. WHY HAS THE REFERENCE TO FLUORESCENT FIXTURES BEEN REMOVED?

A. Due to obsolescence, OTP is proposing to remove the reference dealing with fluorescent outdoor fixtures.

Q. IS VANDALISM OF OUTDOOR LIGHTING A POTENTIAL PROBLEM, AND IF SO HOW DOES OTP PROPOSE TO ADDRESS THAT ISSUE?

A. Yes, vandalism is a problem. OTP is proposing to provide for the possible discontinuation of service to fixtures damaged as a result of vandalism.

Standard Service Agreements

Q. WHAT STANDARD FORM SERVICE AGREEMENTS ARE YOU SPONSORING?

A. The form service agreements I am sponsoring are in our revised rate book, Volume 3. We are proposing three standard form electric service agreements: (1) an Electric Service Agreement, (2) an Outdoor Lighting and Municipal Services Agreement, and (3) an Irrigation Electric Service Agreement. We are also proposing two customer service

agreement forms: (1) a Guarantee in lieu of deposit form, and (2) a Summary Billing Service Contract.

Q. PLEASE DESCRIBE THE THREE STANDARD FORM ELECTRIC SERVICE AGREEMENTS.

A. The three standard form electric service agreements are intended for use with customers taking service under OTP Rate Schedules, and therefore they include blanks to be filled in with customer-specific information which may be necessary for OTP to adequately anticipate customer requirements. By using the proposed form agreements, both OTP and customer expectations can be determined at the earliest possible time in the provision of service. This will allow OTP to ensure that expectations are met and customers are satisfied.

The Electric Service Agreement is intended for use with OTP's Residential and Farm Services Rate Schedules (Sections 9.01-9.03) and Small General Service, General Service and Large General Service Rate Schedules (Sections 10.01-10.03), where appropriate. It allows for customer specifications to be included to identify single- or three-phase service, nominal voltage, demand classification and amount, load factor and any special facilities that may be required.

The Outdoor Lighting and Municipal Services Agreement Form includes places for the entry of customer specifications appropriate for the provision of Outdoor Lighting, Municipal Pumping and/or Fire Sirens Rate Schedules (Sections 11.03-11.06).

The Irrigation Electric Service Agreement includes places for the entry of customer specifications associated with service under OTP's Irrigation Service Rate Schedule (Section 11.02)

Q. PLEASE DESCRIBE THE TWO STANDARD FORM CUSTOMER SERVICE AGREEMENTS.

A. These two agreement forms are referenced in OTP's proposed General Rules and Regulations. Section 1.04 of the General Rules and Regulations offers customers the option of providing a guaranty rather than a deposit. The standard form Guarantee in lieu

of deposit is the form agreement to be executed by the guarantor and customer. It binds the guarantor and provides credit assurance to OTP.

Section 4.12 of the General Rules and Regulations describes the Summary billing service that may be useful for customers with multiple OTP accounts. The Summary Billing Services Contract outlines OTP and customer expectations and provides for a clear indication of what accounts are to be included in the summary billing.

VII. SUMMARY AND RECOMMENDATIONS FOR FURTHER RATE STRUCTURE CHANGES IN FUTURE RATE CASES

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony has covered numerous rate design and other rate schedule related changes being proposed by OTP, including (1) FCA changes to implement OTP's proposal for passing through non-asset based wholesale margins; (2) application of the FCA to OTP's current non-FCA rates; (3) our evaluation of and proposals for rate design changes, most notably those relating to OTP's elimination of the declining-block pricing from its rates; and (4) the substantial proposed update to OTP's rate book. These changes will help OTP achieve policy driven initiatives which Mr. Brause described in his testimony. Additionally, the changes will result in rates and options that are fair to OTP's customers. It is expected that in future rate cases OTP will continue to pursue in its rate design proposals the goals that I have discussed throughout my testimony.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-____

AFFIDAVIT OF DAVID G. PRAZAK

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

SHARI LYNN RIEDEL
NOTARY PUBLIC—MINNESOTA
My Commission Expires JAN. 31, 2011

David G. Prazak

Subscribed and sworn to before me,
this 23rd day of October, 2008.

Shari Lynn Riedel
NOTARY PUBLIC

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Case No. PU-08-____**
Electric Utility - State of North Dakota **Exhibit ____ (DGP-1)**
PROPOSED RATE SCHEDULE **Schedule 1**
SUMMARY COMPARISON OF OPERATING REVENUE
UNDER PRESENT AND PROPOSED RATES FOR THE TEST YEAR

Service Schedule

	Average	kWh Sales	Annual Revenue		Increase	
Residential	**Customers**	**Annual**	**Present**	**Proposed**	**Amount**	**Percent**
Residential Service	41,297	363,213,626	$31,114,448	$33,050,961	$1,936,513	6.22%
Residential Demand Control	3,753	94,191,264	$5,540,781	$6,353,410	$812,629	14.67%
Farm Service	1,017	22,040,877	$1,514,276	$1,627,847	$113,571	7.50%
Small Commercial						
General Service < 20 kW	8,331	78,591,827	$7,924,082	$7,770,404	-$153,678	-1.94%
Commercial Demand Control < 20 kW	9	267,633	$19,944	$23,423	$3,479	17.44%
Electric Climate Control <20 kW	169	3,423,858	$276,277	$305,585	$29,308	10.61%
General Service >= 20 kW	2,579	290,406,932	$22,645,691	$22,630,264	-$15,428	-0.07%
Commercial Demand Control >= 20 kW	17	4,047,528	$274,606	$306,638	$32,033	11.66%
Electric Climate Control >= 20 kW	358	42,175,165	$2,871,550	$3,297,765	$426,215	14.84%
Commercial Time of Use	-	-	$0	$0	$0	
Large Commercial						
Large General Service	132	555,574,413	$32,622,026	$32,999,448	$377,423	1.16%
Large General Service Time of Day	-	-	$0	$0		
Real Time Pricing	1	58,538,439	$2,962,156	$2,991,777	$29,622	1.00%
Large General Service Rider	-	-	$0	$0		
Large General Service Off-Peak Rider	2	9,906,458	$647,626	$602,926	-$44,701	-6.90%
Irrigation Services						
Irrigation Option #1	7	286,564	$23,576	$25,266	$1,690	7.17%
Irrigation Option #2	10	370,817	$22,387	$25,293	$2,906	12.98%
Outdoor Lighting						
Outdoor Lighting - Energy Only	32	1,750,137	$111,656	$139,570	$27,914	25.00%
Outdoor Lighting Non-Metered		21,242,916	$1,983,990	$2,479,987	$495,997	25.00%
Other Public Authorities						
Municipal Pumping Service	557	16,990,520	$963,913	$1,098,862	$134,949	14.00%
Civil Defense - Fire Sirens	63		$3,655	$4,167	$512	14.00%
Water Heating, Controlled	7,560	19,762,890	$1,185,332	$1,303,866	$118,534	10.00%
Interruptible Loads						
Interruptible Load CT Metering	419	66,186,502	$1,570,442	$2,248,372	$677,930	43.17%
Interruptible Load Self Contained Metering	5,491	97,137,681	$3,152,409	$4,141,415	$989,006	31.37%
Bulk Interruptible Load	-	-	$0	$0	$0	
Standby Service	1	121,000	$21,570	$15,155	-$6,416	-29.74%
Heat Storage						
Deferred Load Controlled Service	615	14,986,587	$731,923	$802,379	$70,456	9.63%
Fix Time of Delivery Service	1,605	4,571,746	$124,877	$148,417	$23,540	18.85%
Small Power Producer Rider	1	(2,960)	-$17	-$17	$0	0.00%
Total	74,027	1,765,782,420	118,309,177	124,393,180	$6,084,003	5.14%

9.01 Residential Service

Present Rate - Actual Year 2007		Units		Rate Per Unit	Amount
Minimum	Zone 1	490,272	Bills	$4.74	$2,323,891
Minimum	Zone 9	5,285	Bills	$5.65	$29,863
Zone 9 Season Charge		9	Cust	$4.74	$43
Direct Control Water Heating Credit		1,500	Bills	-$2.00	-$3,000
TailWinds Revenue		451,924	kWh	$0.01600	$7,231
First 1,000 kWh		286,275,003	kWh	$0.06977	$19,973,407
Next 1,000 kwh		53,577,040	kWh	$0.05474	$2,932,807
Excess kWh		21,618,966	kWh	$0.04675	$1,010,687
Unbilled kWh		1,742,617			$55,667
MISO Adjustment					$165,417
Cost of Energy Adjustment		362,761,702	kWh	0.01270	$4,618,436
					$31,114,448

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Minimum	495,665	Bills	$3.00	$1,486,995
Cottage Turn on charge	9	Bills	$32.00	$288
Facilities Charge	495,665	Bills	$5.00	$2,478,325
Direct Control Water Heating Credit	1,500	Bills	-$4.00	-$6,000
TailWinds Revenue	451,924	kWh	$0.01300	$5,875
Energy (June - Sept.)	114,617,368	kWh	$0.08520	$9,765,003
Energy (Oct. - May)	248,596,258	kWh	$0.07772	$19,320,475
				$33,050,961

9.02 Residential Service - Demand Control

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Minimum	45,041	Bills	$9.38	$422,488
TailWinds Revenue	96,900	kWh	$0.01600	$1,550
All kWh	93,739,355	kWh	$0.02909	$2,726,878
All kW (Nov. - Apr.)	107,025	kW	$7.32	$783,426
All kW (May - Oct.)	107,025	kW	$3.69	$394,924
Unbilled kWh	451,909			$14,436
MISO Adjustment				$42,897
Cost of Energy Adjustment	94,094,364			$1,154,182
				$5,540,781

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Minimum	45,041	Bills	$9.38	$422,488
Facilities Charge	45,041	Bills	$9.00	$405,372
TailWinds Revenue	96,900	kWh	$0.01300	$1,260
All kWh (June - Sept.)	17,672,139	kWh	$0.04887	$863,656
All kWh (Oct. - May)	76,519,125	kWh	$0.04934	$3,775,539
All kW (June - Sept.)	70,634	kW	$6.88	$486,088
All kW (Oct. - May)	143,417	kW	$2.78	$399,007
				$6,353,410

9.03 Farm Service

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Customer Charge	12,209	Bills	$7.51	$91,690
Additional Minimum Bill Revenues	7.51 or .71797 per additional kva			$14,288
TailWinds Revenue	3,600	kWh	$0.01600	$58
First 150 kWh	1,417,823	kWh	$0.08	$108,421
Next 1450 kWh	8,520,100	kWh	$0.05762	$490,928
Excess kWh	12,031,623	kWh	$0.04675	$562,478
Unbilled kWh	71,331			$3,075
MISO Adjustment				$10,855
Cost of Energy Adjustment	22,037,277	kWh		$232,483
				$1,514,276

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	12,209	Bills	$8.00	$97,672
Single Phase:	9,660	kVA	$0.00	$0
Three Phase				
Overhead <= 25 kVA	489	kVA	$4.81	$2,350
> 25 kVA	1,571	kVA	$5.61	$8,820
Underground <= 25 kVA	81	kVA	$13.42	$1,093
> 25 kVA	407	kVA	$21.56	$8,781
TailWinds Revenue	3,600	kWh	$0.01300	$47
All kWh (June - Sept.)	5,592,426	kWh	$0.07327	$409,740
All kWh (Oct. - May)	16,448,451	kWh	$0.06684	$1,099,345
				$1,627,847

10.01 General Service - Less than 20 kW

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Minimum Zone 1	98,149	Bills	$6.65	$652,691
Minimum Zone 9	1,824	Bills	$7.95	$14,501
Additional Minimum Revenues	0.57438 per kva or .71797 per kva			$8,478
Direct Control Water Heating Credit	96	Bills	-$2.00	-$192
TailWinds Revenue	78,000	kWh	$0.01600	$1,248
Secondary First 1,000 kWh	43,406,416	kWh	$0.09153	$3,972,989
SecondaryNext 1,000 kWh	13,869,199	kWh	$0.08054	$1,117,025
Secondary Excess kWh	4,996,680	kWh	$0.06589	$329,231
Sec. kWh in excess of 200 kWh per kW	15,979,022	kWh	$0.04928	$787,446
Primary 1,000 kWh	9,176	kWh	$0.08695	$798
Primary Next 1,000 kWh	3,960	kWh	$0.07651	$303
Primary Excess kWh	-	kWh	$0.06260	$0
Primary Energy over 200 x kW	13,620	kWh	$0.04682	$638
Unbilled kWh	313,754	kWh		$12,246
MISO Adjustment				$18,779
Cost of Energy Adjustment	78,513,827	kWh		$1,007,900
				$7,924,082

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge Secondary	99,961	Bills	$10.00	$999,610.00
Facilities Charge	99,961	Bills	$3.00	$299,883.00
TailWinds Revenue	78,000	kWh	$0.01300	$1,014
Energy Secondary (June-Sept.)	24,640,219	kWh	$0.08760	$2,158,562.27
Energy Secondary (Oct.-May)	53,924,852	kWh	$0.07991	$4,309,334.83
Direct Water Heating Control	96	Bills	-$4.00	-$384.00
Customer Charge Primary	12	Bills	$10.00	$120.00
Facilities Charge	12	Bills	$2.00	$24.00
Energy Primary (June-Sept.)	14,561	kWh	$0.08721	$1,269.94
Energy Primary (Oct.-May)	12,195	kWh	$0.07953	$969.86
				$7,770,404

CANCELED General Service - Controlled Demand Less than 20 kW

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Facilities Charge	108	Bills	$14.12	$1,525
TailWinds Revenue	12,000	kWh	$0.01600	$192
All kWh	266,565	kWh	$0.03473	$9,258
On-Peak kW (Nov. - Apr.)	375	kW	$7.51	$2,817
Off-Peak kW (Nov. - Apr.)	757	kW	$0.96	$726
On-Peak kW (May - October)	288	kW	$5.60	$1,613
Off-Peak kW (May - October)	553	kW	$0.96	$531
Unbilled kWh	1,068			$42
MISO Adjustment				$64
Cost of Energy Adjustment	255,633			$3,176
				$19,944

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	108	Bills	$10.00	$1,080
Facilities Charge	108	Bills	$3.00	$324
TailWinds Revenue	12,000	kWh	$0.01300	$156
All kWh (June - Sept.)	61,854	kWh	$0.08760	$5,419
All kWh (Oct. - May)	205,779	kWh	$0.07991	$16,445
				$23,423

CANCELED Electric Climate Control - Less than 20 kW

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Customer Charge	2,026	Bills	$7.90	$16,005
Heating, Air Conditioning, Cooking kWhs	2,037,366	kWh	$0.04832	$98,446
Next 1,000 kWh	646,458	kWh	$0.10354	$66,934
Next 1,000 kWh	291,121	kWh	$0.08968	$26,108
Excess	84,274	kWh	$0.07207	$6,074
Sec. kWh in excess of 200 kWh per kW	351,090	kWh	$0.05325	$18,696
Unbilled kWh	13,550	kWh		$529
MISO Adjustment				$811
Cost of Energy Adjustment	3,423,858	kWh		$42,675
				$276,277

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	2,026	Bills	$10.00	$20,260
Facilities Charge	2,026	Bills	$3.00	$6,078
TailWinds Revenue		kWh	$0.01300	$0
All kWh (June - Sept.)	732,698	kWh	$0.08760	$64,187
All kWh (Oct. - May)	2,691,160	kWh	$0.07991	$215,061
				$305,585

10.02 General Service - 20 kW and Greater

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Minimum Zone 1	30,250	Bills	$6.65	$201,163
Minimum Zone 9	694	Bills	$7.95	$5,517
Additional Minimum Revenues	0.57438 per kva or .71797 per kva			$10,757
TailWinds Revenue	-	kWh	$0.01600	$0
Direct Control Water Heating Credit	24	Bills	-$2.00	-$48
Secondary First 1,000 kWh	27,788,362	kWh	$0.09153	$2,543,469
SecondaryNext 1,000 kWh	24,552,163	kWh	$0.08054	$1,977,431
Secondary Excess kWh	154,699,416	kWh	$0.06589	$10,193,145
Sec. kWh in excess of 200 kWh per kW	81,816,129	kWh	$0.04928	$4,031,899
Primary 1,000 kWh	32,400	kWh	$0.08695	$2,817
Primary Next 1,000 kWh	25,640	kWh	$0.07651	$1,962
Primary Excess kWh	125,960	kWh	$0.06260	$7,885
Primary Energy over 200 x kW	207,500	kWh	$0.04682	$9,714
Unbilled kWh	1,159,362	kWh		$45,252
MISO Adjustment		kWh		$69,392
Cost of Energy Adjustment	290,406,932	kWh		$3,545,338
				$22,645,691.45

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge Secondary	30,908	Bills	$12.00	$370,896
Facilities Charge	1,891,303	kW	$0.52	$983,477
TailWinds Revenue	-	kWh	$0.01300	$0
Energy Secondary (June-Sept.)	89,916,639	kWh	$0.07798	$7,011,934
Energy Secondary (Oct.-May)	200,098,793	kWh	$0.07114	$14,234,541
Direct Water Heating Control	24	kW	-$4.00	-$96
Customer Charge Primary	36	kWh	$12.00	$432
Facilities Charge	1,810	kWh	$0.38	$688
Energy Primary (June-Sept.)	98,752	kWh	$0.07764	$7,667
Energy Primary (Oct.-May)	292,748	kWh	$0.07080	$20,725
				$22,630,264

CANCELED General Service - Controlled Demand - 20 kW and Greater

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Facilities Charge	207	Bills	$14.12	$2,923
TailWinds Revenue		kWh		$0
All kWh	4,031,369	kWh	$0.03473	$140,009
On-Peak kW (Nov. - Apr.)	4,881	kW	$7.51	$36,658
Off-Peak kW (Nov. - Apr.)	8,154	kW	$0.96	$7,828
On-Peak kW (May - October)	4,011	kW	$5.60	$22,460
Off-Peak kW (May - October)	7,056	kW	$0.96	$6,774
Unbilled kWh	16,159	kWh		$631
MISO Adjustment				$967
Cost of Energy Adjustment	4,047,528	kWh		$56,355
				$274,606

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	207	Bills	$12.00	$2,484
Facilities Charge	16,097	kW	$0.52	$8,370
TailWinds Revenue	-	kWh	$0.01300	$0
Energy Secondary (June-Sept.)	1,147,177	kWh	$0.07798	$89,460
Energy Secondary (Oct.-May)	2,900,351	kWh	$0.07114	$206,324
				$306,638

CANCELED Electric Climate Control - 20 kW and Greater

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Minimum Zone 1	4,295	Bills	$7.90	$33,931
TailWinds Revenue	-	kWh	$0.01600	$0
Heating, Air Conditioning, Cooking kWhs	30,006,352	kWh	$0.04832	$1,449,907
Next 1,000 kWh	1,006,361	kWh	$0.10354	$104,199
Next 1,000 kWh	747,554	kWh	$0.08968	$67,041
Excess	7,007,282	kWh	$0.07207	$505,015
Sec. kWh in excess of 200 kWh per kW	3,239,125	kWh	$0.05325	$172,483
Unbilled kWh	168,491	kWh		$6,576
MISO Adjustment		kWh		$10,085
Cost of Energy Adjustment	42,175,165	kWh		$522,314
				$2,871,550.16

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	4,295	Bills	$12.00	$51,540
Facilities Charge	360,098	kW	$0.52	$187,251
TailWinds Revenue	-	kWh	$0.01300	$0
Energy Secondary (June-Sept.)	8,580,788	kWh	$0.07798	$669,152
Energy Secondary (Oct.-May)	33,594,377	kWh	$0.07114	$2,389,822
				$3,297,765

10.03 Large General Service

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Secondary	Energy over 360 per kW	113,192,890	kWh	$0.02935	$3,322,211
	First 700,000 kWh	155,805,630	kWh	$0.03784	$5,895,685
	Excess kWh	102,552,256	kWh	$0.02979	$3,055,032
	First 100 kW of demand	139,916	kW	$8.33	$1,165,500
	Excess kW of demand	585,733	kW	$6.80	$3,982,984
	TailWinds Revenue		kWh	$0.01600	$0
Primary	Energy over 360 per kW	79,883,763	kWh	$0.02935	$2,344,588
	First 700,000 kWh	23,382,633	kWh	$0.03784	$884,799
	Excess kWh	81,708,724	kWh	$0.02979	$2,434,103
	First 100 kW of demand	53,915	kW	$8.04	$433,475
	Excess kW of demand	232,905	kW	$6.51	$1,516,210
Transmission	Energy over 360 per kW		kWh	$0.02935	$0
	First 700,000 kWh		kWh	$0.03784	$0
	Excess kWh		kWh	$0.02979	$0
	First 100 kW of demand		kW	$7.23	$0
	Excess kW of demand		kW	$5.65	$0
	Unbilled kWh	(951,483)	kWh		$44,000
	MISO Adjustment				$256,128
	Cost of Energy Adjustment	555,574,413			$7,287,310
					$32,622,026

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Secondary	Customer Charge	1505	Bills	$40.00	$60,200
	Facilities Charge <1000 kW	343,844	kW	$0.30	$103,153
	Facilities Charge >=1000 kW	502,868	kW	$0.15	$75,430
	Energy (June - Sept.)	133,483,932	kWh	$0.05064	$6,759,177
	Energy (Oct. - May)	237,431,610	kWh	$0.05112	$12,138,381
	Demand per kW (June - Sept.)	264,134	kW	$7.13	$1,883,396
	Demand per kW (Oct. - May)	461,515	kW	$2.88	$1,330,388
	TailWinds Revenue		kWh	$0.01300	$0

10.03 Large General Service

Primary	Customer Charge	84	Bills	$40.00	$3,360
	Facilities Charge: All kW	266,914	kW	$0.11	$29,361
	Energy (June - Sept.)	65,689,609	kWh	$0.05044	$3,313,374
	Energy (Oct. - May)	118,969,262	kWh	$0.05089	$6,054,023
	Demand per kW (June - Sept.)	101,583	kW	$7.08	$719,062
	Demand per kW (Oct. - May)	185,237	kW	$2.86	$530,142
Transmission	Customer Charge	-	Bills	$40.00	$0
	Facilities Charge: All kW	-	kW	$0.00	$0
	Energy (June - Sept.)	-	kWh	$0.04924	$0
	Energy (Oct. - May)	-	kWh	$0.04945	$0
	Demand per kW (June - Sept.)	-	kW	$5.75	$0
	Demand per kW (Oct. - May)	-	kW	$2.43	$0
					$32,999,448

10.04 General Service - Time-of-Use (Commercial TOU)

New Rate No Billing Determinants

Proposed Rate - Test Year 2007	Units	Rate Per Unit	Amount
Customer Charge	Bills	$16.00	$0
Energy (June-Sept.) Declared-Peak	kWh	$0.20574	$0
Energy (June-Sept.) Intermediate	kWh	$0.06974	$0
Energy (June-Sept.) Off-Peak	kWh	$0.04132	$0
Energy (Oct. - May) Declared-Peak	kWh	$0.13621	$0
Energy (Oct. - May) Intermediate	kWh	$0.07068	$0
Energy (Oct. - May) Off-Peak	kWh	$0.04277	$0
Demand (June-Sept.) Declared-Peak	kW	$0.00	$0
Demand (June-Sept.) Intermediate	kW	$2.43	$0
Demand (June-Sept.) Off-Peak	kW	$0.00	$0
Demand (Oct. - May) Declared-Peak	kW	$0.00	$0
Demand (Oct. - May) Intermediate	kW	$2.81	$0
Demand (Oct. - May) Off-Peak	kW	$0.00	$0
			$0

10.05 Large Gerneral Service Time-of-Day

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Secondary	Customer Charge:		Bills	$119.00	
	Facilities Charge: <150 kW		kW	$0.29	
	Facilities Charge: 150-299 kW		kW	$0.20	
	Facilities Charge: 300-499 kW		kW	$0.16	
	Facilities Charge: Greater than 500 kW		kW	$0.13	
	Energy On-Peak Winter		kWh	$0.06240	
	Energy Shoulder Winter		kWh	$0.04270	
	Energy Off-Peak Winter		kWh	$0.01190	
	Energy On-Peak Summer		kWh	$0.09000	
	Energy Shoulder Summer		kWh	$0.03220	
	Energy Off-Peak Summer		kWh	$0.01060	
Primary	Customer Charge:		Bills	$135.00	
	Facilities Charge:		kW	NA	
	Energy On-Peak Winter		kWh	$0.06850	
	Energy Shoulder Winter		kWh	$0.04710	
	Energy Off-Peak Winter		kWh	$0.01390	
	Energy On-Peak Summer		kWh	$0.10490	
	Energy Shoulder Summer		kWh	$0.03660	
	Energy Off-Peak Summer		kWh	$0.01270	
Transmission	Customer Charge:		Bills	$135.00	
	Facilities Charge:		kW	NA	
	Energy On-Peak Winter		kWh	$0.06920	
	Energy Shoulder Winter		kWh	$0.04760	
	Energy Off-Peak Winter	-	kWh	$0.01400	
	Energy On-Peak Summer		kWh	$0.10610	
	Energy Shoulder Summer		kWh	$0.03690	
	Energy Off-Peak Summer		kWh	$0.01290	
					$0.00

10.05 Large Gerneral Service Time-of-Day

	Proposed Rate - Test Year 2007	Units	Rate Per Unit	Amount
Secondary	Customer Charge:	Bills	$60.00	
	Facilities Charge: < 1,000 kW	kW	$0.30	
	Facilities Charge: >= 1,000 kW	kW	$0.15	
	Energy (June-Sept.) Peak	kWh	$0.07803	
	Energy (June-Sept.) Shoulder	kWh	$0.05981	
	Energy (June-Sept.) Off-Peak	kWh	$0.03562	
	Energy (Oct. - May) Peak	kWh	$0.07002	
	Energy (Oct. - May) Shoulder	kWh	$0.05695	
	Energy (Oct. - May) Off-Peak	kWh	$0.04020	
	Demand per kW (June-Sept.) Peak	kW	$5.72	
	Demand per kW (June-Sept.) Shoulder	kW	$1.58	
	Demand per kW (June-Sept.) Off-Peak	kW	$0.00	
	Demand per kW (Oct. - May) Peak	kW	$2.21	
	Demand per kW (Oct. - May) Shoulder	kW	$0.52	
	Demand per kW (Oct. - May) Off-Peak	kW	$0.00	
Primary	Customer Charge:	Bills	$60.00	
	Facilities Charge:	kW	$0.11	
	Energy (June-Sept.) Peak	kWh	$0.07769	
	Energy (June-Sept.) Shoulder	kWh	$0.05956	
	Energy (June-Sept.) Off-Peak	kWh	$0.03551	
	Energy (Oct. - May) Peak	kWh	$0.06968	
	Energy (Oct. - May) Shoulder	kWh	$0.05669	
	Energy (Oct. - May) Off-Peak	kWh	$0.04003	
	Demand per kW (June-Sept.) Peak	kW	$5.68	
	Demand per kW (June-Sept.) Shoulder	kW	$1.56	
	Demand per kW (June-Sept.) Off-Peak	kW	$0.00	
	Demand per kW (Oct. - May) Peak	kW	$2.20	
	Demand per kW (Oct. - May) Shoulder	kW	$0.52	
	Demand per kW (Oct. - May) Off-Peak	kW	$0.00	
Transmission	Customer Charge:	Bills	$60.00	
	Facilities Charge:	kW	$0.00	
	Energy (June-Sept.) Peak	kWh	$0.07563	
	Energy (June-Sept.) Shoulder	kWh	$0.05807	
	Energy (June-Sept.) Off-Peak	kWh	$0.03480	
	Energy (Oct. - May) Peak	kWh	$0.06762	
	Energy (Oct. - May) Shoulder	kWh	$0.05507	
	Energy (Oct. - May) Off-Peak	kWh	$0.03896	

10.05 Large Gerneral Service Time-of-Day

Demand per kW (June-Sept.) Peak	kW	$4.83	
Demand per kW (June-Sept.) Shoulder	kW	$1.05	
Demand per kW (June-Sept.) Off-Peak	kW	$0.00	
Demand per kW (Oct. - May) Peak	kW	$1.99	
Demand per kW (Oct. - May) Shoulder	kW	$0.45	
Demand per kW (Oct. - May) Off-Peak	kW	$0.00	
			$0.00

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14.02 Real Time Pricing

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Secondary	Administrative Charge	0	Bills	$180.00	$0
	Consumption Change from CBL (RTP)	0	kWh		$0
Primary	Administrative Charge	12	Bills	$180.00	$2,160
	Energy over 360 per kW	11,100,000	kWh	$0.02935	$325,785
	First 700,000 kWh	8,400,000	kWh	$0.03784	$317,856
	Excess kWh	2,400,000	kWh	$0.02979	$71,496
	First 100 kW of demand	1,200	kW	$8.04	$9,648
	Excess kW of demand	28,800	kW	$6.51	$187,488
	VAR Penalty kW	2,404	kW	$6.51	$15,650
	Consumption Change Above CBL (RTP)	36,859,093	kWh	$0.04635	$1,708,341
	Consumption Change Below CBL (RTP)	(102,707)	kWh	$0.03847	($3,951)
Transmission	Administrative Charge	0	Bills	$180.00	$0
	Consumption Change from CBL (RTP)	0	kWh		$0
	Unbilled kWh	(117,947)			$6,650
	MISO Adjustment				$38,708
	Cost of Energy Adjustment	21,782,053	kWh		$282,325
					$2,962,156

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Secondary	Administrative Charge	0	Bills	$199.00	$0
	Consumption Change from CBL (RTP)	0	kWh		$0
Primary	Administrative Charge	12	Bills	$199.00	$2,388
	Energy (June - Sept.)	7,340,684	kWh	$0.05044	$370,263
	Energy (Oct. - May)	14,441,369	kWh	$0.05089	$734,882
	Demand per kW (June - Sept.)	10,871	kW	$7.08	$76,951
	Demand per kW (Oct. - May)	21,533	kW	$2.86	$61,627
	Consumption Change from CBL (RTP)	36,859,093	kWh		$1,750,388
	Consumption Change Below CBL (RTP)	(102,707)	kWh		($4,722)
Transmission	Administrative Charge	0	Bills	$199.00	$0
	Consumption Change from CBL (RTP)	0	kWh		$0
					$2,991,777

14.03 Large General Service Rider

NEW TO NORTH DAKOTA

Large General Service Off-Peak Rider

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Secondary	Energy over 360 per kW	1,856,407	kWh	$0.02935	$54,486
	First 700,000 kWh	8,070,011	kWh	$0.03784	$305,369
	Excess kWh	-	kWh	$0.02979	$0
	First 100 kW of demand	2,400	kW	$8.33	$19,992
	Excess kW of demand	20,292	kW	$6.80	$137,984
	TailWinds Revenue		kWh	$0.01600	$0
Primary	Energy over 360 per kW		kWh	$0.02935	$0
	First 700,000 kWh		kWh	$0.03784	$0
	Excess kWh		kWh	$0.02979	$0
	First 100 kW of demand		kW	$8.04	$0
	Excess kW of demand		kW	$6.51	$0
Transmission	Energy over 360 per kW		kWh	$0.02935	$0
	First 700,000 kWh		kWh	$0.03784	$0
	Excess kWh		kWh	$0.02979	$0
	First 100 kW of demand		kW	$7.23	$0
	Excess kW of demand		kW	$5.65	$0
	Unbilled kWh	(19,960)			$1,125
	MISO Adjustment				6,551
	Cost of Energy Adjustment	9,906,458	kWh		122,120
					$647,626

Large General Service Tariff

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Secondary	Customer Charge	24	Bills	$40.00	$960
	Facilities Charge <1000 kW	5,878	kW	$0.30	$1,763
	Facilities Charge >=1000 kW		kW	$0.15	$0
	Energy (June - Sept.)	2,754,863	kWh	$0.05064	$139,497
	Energy (Oct. - May)	7,151,595	kWh	$0.05112	$365,616
	Demand per kW (June - Sept.)	6,986	kW	$7.13	$49,816
	Demand per kW (Oct. - May)	15,705	kW	$2.88	$45,273
Primary	Customer Charge		Bills	$40.00	
	Facilities Charge: All kW		kW	$0.11	$0
	Energy (June - Sept.)		kWh	$0.05044	$0
	Energy (Oct. - May)		kWh	$0.05089	$0

Large General Service Off-Peak Rider

	Demand per kW (June - Sept.)	kW	$7.08	$0
	Demand per kW (Oct. - May)	kW	$2.86	$0
Transmission	Customer Charge	Bills	$40.00	
	Facilities Charge	kW	$0.00	$0
	Energy (June - Sept.)	kWh	$0.04924	$0
	Energy (Oct. - May)	kWh	$0.04945	$0
	Demand per kW (June - Sept.)	kW	$5.75	$0
	Demand per kW (Oct. - May)	kW	$2.43	$0
				$602,926

11.02 Irrigation Service

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Option 1	Load Charge:	5,600	HP	$0.29	$1,624
	Energy Charge:	286,259	kWh	$0.03912	$11,198
	18% Return of Distribution Facilities				$6,026
	Unbilled kWh	305			$38
	MISO Adjustment				$132
	Cost of Energy Adjustment	286,564			$4,556
Option 2	Off-Peak Energy	275,357	kWh	$0.02639	$7,267
	Intermediate Peak Energy	78,717	kWh	$0.05508	$4,336
	On-Peak Energy	16,349	kWh	$0.07756	$1,268
	18% Return of Distribution Facilities				$3,401
	Unbilled kWh	394			$50
	MISO Adjustment				$171
	Cost of Energy Adjustment	370,817			$5,896
					$45,963

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Option 1	Customer Charge:	88	Bills	$1.00	$88
	Energy Charge (June-Sept.)	251,739	kWh	$0.06896	$17,360
	Energy Charge (Oct.- May)	34,825	kWh	$0.05145	$1,792
	18% Return of Distribution Facilities				$6,026
Option 2	Customer Charge:	114	Bills	$5.00	$570
	Energy (June-Sept.) Declared Peak	57,974	kWh	$0.14443	$8,373
	Energy (June-Sept.) Intermediate	150,739	kWh	$0.05438	$8,198
	Energy (June-Sept.) Off-Peak	130,956	kWh	$0.02641	$3,458
	Energy (Oct. - May) Declared	-	kWh	$0.08755	$0
	Energy (Oct. - May) Intermediate	18,772	kWh	$0.05108	$959
	Energy (Oct. - May) Off-Peak	12,376	kWh	$0.02704	$335
	18% Return of Distribution Facilities				$3,401
					$50,559

11.03 Outdoor Lighting Energy Only

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Facilities Charge:	383	Bills	$1.40	$536
Energy	477,874	kWh	$0.05898	$28,185
Non-Metered	2,622	kW	$20.15	$52,832
Non-Metered (Sign)	1,649	kW	$15.80	$26,060
Unbilled kWh	(27,957)			$4,043
MISO Adjustment				$0
				$111,656

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge:	383	Bills	$2.00	$766
Energy	449,917	kWh	$0.07270	$32,709
Non-Metered	2,622	kW	$24.84	$65,126
Non-Metered (Sign)	1,649	kW	$24.84	$40,969
				$139,570

11.04 Outdoor Lighting

STREET AND AREA LIGHTING

			Present Rate 2007		Proposed Rate	
Rate Code	TYPE	QTY	Rate	Amount	Rate	Amount
741	MV-6	138,623	$5.84	$809,558	$7.30	$1,011,947
741	MV-6PT	3,118	$8.33	$25,972	$10.41	$32,465
741	MV-11	432	$10.58	$4,572	$13.23	$5,716
741	MV-21	1,630	$13.93	$22,712	$17.41	$28,390
741	MV-35	-	$20.44		$25.55	$0
741	MV-55	376	$26.13	$9,831	$32.66	$12,289
741	MA-8		$7.05		$8.81	$0
741	MA-14		$13.42		$16.78	$0
741	MA-20		$15.32		$19.15	$0
741	MA-36		$15.00		$18.75	$0
741	MA-110		$32.01		$40.01	$0
741	HPS-9	55,239	$6.27	$346,349	$7.84	$432,936
741	HPS-9PT	2,073	$8.10	$16,792	$10.13	$20,990
741	HPS-14	3,411	$9.76	$33,294	$12.20	$41,618
741	HPS-14PT	126	$10.44	$1,315	$13.05	$1,644
741	HPS-19	2,171	$11.34	$24,614	$14.18	$30,767
741	HPS-23	9,710	$12.83	$124,576	$16.04	$155,720
741	HPS-44	7,644	$15.84	$121,082	$19.80	$151,352
741	UMV6	172	$7.47	$1,281	$9.34	$1,602
741	UHPS9	72	$7.90	$569	$9.88	$711
741	UHPS19	2	$12.97	$26	$16.21	$32
741	UHPS23	10	$14.46	$145	$18.08	$181
				$1,542,688		$1,928,360

FLOOD LIGHTING

			Present Rate		Proposed Rate	
Rate Code	TYPE	QTY	Rate	Amount	Rate	Amount
743	400MVF	2,345	$14.46	$33,906	$18.08	$42,383
743	400MAF	6,618	$15.41	$101,988	$19.26	$127,485
743	400HPSF	10,275	$15.75	$161,824	$19.69	$202,280
743	1000MVF	43	$25.37	$1,095	$31.71	$1,368
743	1000MAF	3,461	$26.76	$92,628	$33.45	$115,785
				$391,441		$489,301

11.04 Outdoor Lighting

CLOSED NON-STANDARD LIGHTING FACILITIES

			Present Rate		Proposed Rate	
Rate Code	TYPE	QTY	Rate	Amount	Rate	Amount
741	400HPSF	36		$567		$709
741	500Q	12		$98		$123
741	CABLETV	701		$15,050		$18,812
741	CALIGHT	3396		$22,274		$27,842
741	EGYONLY	760		$4,297		$5,372
741	FIXEDCH	64		$1,137		$1,422
741	HPS33	48		$369		$461
741	INCAND	241		$731		$913
741	MV6SM	84		$598		$747
741	PHBOOTH	24		$247		$309
741	SIGN	18		$85		$107
741	SIGNAL	60		$535		$669
741	SIRN5.0	12		$34		$43
743	1M-HPSF	24		$687		$859
743	HPS23	24		$244		$305
743	HPS44	12		$96		$119
743	HPS9	12		$75		$94
743	MV11	24		$140		$175
743	MV21	50		$361		$451
743	MV6	48		$280		$350
743	U1M-MAF	100		$1,886		$2,358
745	MV6	11		$68		$85
				$49,861		$62,326
		Total:	Present	$1,983,990	Proposed	$2,479,987

11.05 Municipal Pumping

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
	Energy first 2500 kWh	5,531,493	kWh	$0.05809	$321,324
	Next 1500 kWh	1,378,102	kWh	$0.04289	$59,107
	Excess kWh	10,091,638	kWh	$0.03425	$345,639
	Unbilled kWh	(10,713)			$1,859
	MISO Adjustment				$7,817
	Cost of Energy Adjustment	16,990,520			$228,168
					$963,913

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Secondary	Customer Charge	6,685	Bills	$4.00	$26,740
	Facilies Charge:	6,685	Bills	$4.00	$26,740
	All kWh (June - Sept.)	6,009,895	kWh	$0.06523	$392,011
	All kWh (Oct. - May)	10,980,625	kWh	$0.05950	$653,371
Primary	Customer Charge	-	Bills	$4.00	$0
	Facilies Charge:	-	Bills	$2.68	$0
	All kWh (June - Sept.)	-	kWh	$0.06494	$0
	All kWh (Oct. - May)	-	kWh	$0.05922	$0
					$1,098,862

11.06 Civil Defense - Fire Sirens

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Load Charge:	6,412	HP	$0.57	$3,655
				$3,655

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	756	Bills	$1.00	$756
Load Charge:	6,412	HP	$0.53193	$3,411
				$4,167

14.01 Water Heating - Controlled Service

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Customer Charge	90,722	Bills	$1.34	$121,567
TailWinds Revenue	1,200	kWh	$0.01600	$19
All kWh	19,786,036	kWh	$0.04015	$794,409
Unbilled kWh	(23,146)	kWh		$2,276
MISO Adjustment				$9,126
Cost of Energy Adjustment	19,784,836	kWh		$257,934
				$1,185,332

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge	90,722	Bills	$1.00	$90,722
Facilities Charge	90,722	Bills	$1.00	$90,722
TailWinds Revenue	1,200	kWh	$0.01300	$16
All kWh (June - Sept.)	6,103,831	kWh	$0.05773	$352,355
All kWh (Oct. - May)	13,659,059	kWh	$0.05638	$770,051
				$1,303,866

14.04 Controlled Service - Interruptible Load Rider - CT Metering

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
>= 80 kW	Facilities Charge:	2,010	Bills	$4.74	$9,529
< 80 kW	Facilities Charge:	3,016	Bills	$3.78	$11,399
>= 80 kW	Energy (Nov. - April)	42,383,820	kWh	$0.02253	$954,907
>= 80 kW	Energy (May - Oct.)	14,192,376	kWh	$0.02253	$319,754
< 80 kW	Energy First 5,000 kWhs (Nov. - April)	3,765,107	kWh	$0.03097	$116,605
< 80 kW	Energy Excess kWhs (Nov. - April)	3,033,972	kWh	$0.02815	$85,406
< 80 kW	Energy First 1,500 kWhs (May - October)	982,991	kWh	$0.02956	$29,057
< 80 kW	Energy Excess kWhs (May - October)	1,361,594	kWh	$0.02675	$36,423
	Penalty kWh	36,179	kWh	$0.10088	$3,650
	Unbilled kWh	430,463	kWh		$3,711
	Cost of Energy Adjustment	NA			$0
					$1,570,442
		66,186,502	kWhs		

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
	Customer Charge:	5,026.00	Bills	$4.00	$20,104
	Facilies Charge:	387,825	kW	$0.08	$30,293
	All kWh (June - Sept.)	9,853,878	kWh	$0.03424	$337,424
	All kWh (Oct. - May)	56,296,445	kWh	$0.03292	$1,853,399
	Penalty kWh (June - Sept.)	5,389	kWh	$0.42614	$2,297
	Penalty kWh (Oct. - May)	30,790	kWh	$0.15769	$4,855
					$2,248,372

14.04 Controlled Service - Interruptible Load Rider CT-Metered Option B

NEW RATE TO NORTH DAKOTA

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Facilities Charge:	-	Bills		$0
Energy	-	kWh		$0
				$0

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge:	-	Bills	$5.00	$0
Facilies Charge:	-	kW	$0.08	$0
All kWh (June - Sept.)	-	kWh	$0.03619	$0
All kWh (Oct. - May)	-	kWh	$0.03480	$0
All kW (June - Sept.) During Control Period	-	kWh	$7.13000	$0
All kW (Oct. - May) During Control Period	-	kWh	$2.87838	$0
				$0

14.05 Controlled Service - Interruptible Load Rider - Self-Contained Metering

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
>= 80 kW	Facilities Charge:	132	Bills	$4.74	$625
< 80 kW	Facilities Charge:	65,760	Bills	$3.78	$248,574
>= 80 kW	Energy (Nov. - April)	5,174,663	kWh	$0.02253	$116,585
>= 80 kW	Energy (May - Oct.)	168,436	kWh	$0.02253	$3,795
< 80 kW	Energy First 5,000 kWhs (Nov. - April)	67,646,064	kWh	$0.03097	$2,094,999
< 80 kW	Energy Excess kWhs (Nov. - April)	5,360,590	kWh	$0.02815	$150,901
< 80 kW	Energy First 1,500 kWhs (May - October)	16,301,836	kWh	$0.02956	$481,882
< 80 kW	Energy Excess kWhs (May - October)	1,854,328	kWh	$0.02675	$49,603
	Penalty kWh		kWh	$0.10088	$0
	Unbilled kWh	631,764	kWh		$5,446
	Cost of Energy Adjustment	NA			$0
					$3,152,409

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
	Customer Charge:	65,892.00	Bills	$2.00	$131,784
	Facilies Charge:	65,892	Bills	$5.00	$329,460
	TailWinds Revenue	1,200	kWh	$0.01300	$16
	All kWh (June - Sept.)	9,666,460	kWh	$0.03993	$386,019
	All kWh (Oct. - May)	87,471,221	kWh	$0.03766	$3,294,136
	Penalty kWh (June - Sept.)	-		$0.42265	$0
	Penalty kWh (Oct. - May)	-		$0.16375	$0
					$4,141,415

11.01 Standby Service

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
< 100kW	Facilities Charge	0	Bills	$10.34	$0
	Demand All kW	0	kW	$3.22	$0
	Energy All kWh	0	kWh	$0.01736	$0
	Facilities for Temperature - Time of Day	0	kW	$12.06	$0
	Temperature - Time of Day Summer (On Peak)	0	kWh	$0.02111	$0
	Temperature - Time of Day Summer (Off Peak)	0	kWh	$0.01538	$0
	Temperature - Time of Day Winter (On Peak)	0	kWh	$0.02393	$0
	Temperature - Time of Day Winter (Off Peak)	0	kWh	$0.01802	$0
>= 100 kW	Facilities Charge	12	Bills	$25.18	$302
	Secondary Demand Charge	0	kW	$5.55	$0
	Primary Demand Charge	0	kW	$5.22	$0
	Transmission Demand Charge	5,400	kW	$3.54	$19,116
	Temperature - Time of Day Summer (On Peak)	18,152	kWh	$0.02111	$383
	Temperature - Time of Day Summer (Off Peak)	43,348	kWh	$0.01538	$667
	Temperature - Time of Day Winter (On Peak)	5,100	kWh	$0.02393	$122
	Temperature - Time of Day Winter (Off Peak)	54,400	kWh	$0.01802	$980
					$21,570

	Proposed Rate - Test Year 2007	Units		Rate Per Un	Amount
Option A Firm					
Secondary	Customer Charge per Month	0	Bills	199	$0
	Facilities Charge per month per kW of Backup	0	kW	$0.30	$0
	Reservation Charge per kW of Contracted Backup Summer	0	kW	$0.85069	$0
	Reservation Charge per kW of Contracted Backup Winter	0	kW	$0.09697	$0
	Metered Demand per day per kVA On-Peak Backup Sum.	0	kW	$0.49076	$0
	Metered Demand per day per kVA On-Peak Backup Wint.	0	kW	$0.32187	$0
	Energy (June-Sept.) On-Peak	0	kWh	$0.07803	$0
	Energy (June-Sept.) Shoulder	0	kWh	$0.05981	$0
	Energy (June-Sept.) Off-Peak	0	kWh	$0.03562	$0
	Energy (Oct. - May) On-Peak	0	kWh	$0.07002	$0
	Energy (Oct. - May) Shoulder	0	kWh	$0.05695	$0
	Energy (Oct. - May) Off-Peak	0	kWh	$0.04020	$0

11.01 Standby Service

Primary	Customer Charge per Month	0	Bills	$199	$0
	Facilities Charge per month per kW of Backup	0	kW	$0.11	$0
	Reservation Charge per kW of Contracted Backup Summer	0	kW	$0.84590	$0
	Reservation Charge per kW of Contracted Backup Winter	0	kW	$0.09634	$0
	Metered Demand per day per kW On-Peak Backup Sum.	0	kW	$0.48683	$0
	Metered Demand per day per kW On-Peak Backup Wint.	0	kW	$0.31978	$0
	Energy (June-Sept.) On-Peak	0	kWh	$0.07769	$0
	Energy (June-Sept.) Shoulder	0	kWh	$0.05956	$0
	Energy (June-Sept.) Off-Peak	0	kWh	$0.03551	$0
	Energy (Oct. - May) On-Peak	0	kWh	$0.06968	$0
	Energy (Oct. - May) Shoulder	0	kWh	$0.05669	$0
	Energy (Oct. - May) Off-Peak	0	kWh	$0.04003	$0
Transmission	Customer Charge per Month	12	Bills	$199	$2,388
	Facilities Charge per month per kW of Backup	0	kW	NA	
	Reservation Charge per kW of Contracted Backup Summer	2,000	kW	$0.81704	$1,634
	Reservation Charge per kW of Contracted Backup Winter	4,000	kW	$0.09254	$370
	Metered Demand per day per kW On-Peak Backup Sum.	5,183	kW	$0.35865	$1,859
	Metered Demand per day per kW On-Peak Backup Wint.	9,114	kW	$0.28694	$2,615
	Energy (June-Sept.) On-Peak	15,400	kWh	$0.07563	$1,165
	Energy (June-Sept.) Shoulder	15,260	kWh	$0.05807	$886
	Energy (June-Sept.) Off-Peak	19,215	kWh	$0.03480	$669
	Energy (Oct. - May) On-Peak	17,175	kWh	$0.06762	$1,161
	Energy (Oct. - May) Shoulder	18,953	kWh	$0.05507	$1,044
	Energy (Oct. - May) Off-Peak	34,997	kWh	$0.03896	$1,364
					$15,155

Option B Non-Firm

Secondary	Customer Charge per Month	0	Bills	$199	$0
	Facilities Charge per month per kW of Backup	0	kW	$0.30	$0
	Metered Demand per day per kW On-Peak Backup Sum.	0	kW	NA	
	Metered Demand per day per kW On-Peak Backup Wint.	0	kW	NA	
	Energy (June-Sept.) On-Peak	0	kWh	NA	
	Energy (June-Sept.) Shoulder	0	kWh	$0.05981	$0
	Energy (June-Sept.) Off-Peak	0	kWh	$0.03562	$0
	Energy (Oct. - May) On-Peak	0	kWh	NA	
	Energy (Oct. - May) Shoulder	0	kWh	$0.05695	$0
	Energy (Oct. - May) Off-Peak	0	kWh	$0.04020	$0
Primary	Customer Charge per Month	0	Bills	$199	$0
	Facilities Charge per month per kW of Backup	0	kW	$0.11	$0
	Metered Demand per day per kW On-Peak Backup Sum.	0	kW	NA	
	Metered Demand per day per kW On-Peak Backup Wint.	0	kW	NA	

11.01 Standby Service

	Energy (June-Sept.) On-Peak	0	kWh	NA	
	Energy (June-Sept.) Shoulder	0	kWh	$0.05956	$0
	Energy (June-Sept.) Off-Peak	0	kWh	$0.03551	$0
	Energy (Oct. - May) On-Peak	0	kWh	NA	
	Energy (Oct. - May) Shoulder	0	kWh	$0.05669	$0
	Energy (Oct. - May) Off-Peak	0	kWh	$0.04003	$0
Transmission	Customer Charge per Month	0	Bills	$199	$0
	Facilities Charge per month per kW of Backup	0	kW	NA	
	Metered Demand per day per kW On-Peak Backup Sum.	0	kW	NA	
	Metered Demand per day per kW On-Peak Backup Wint.	0	kW	NA	
	Energy (June-Sept.) On-Peak	0	kWh	NA	
	Energy (June-Sept.) Shoulder	0	kWh	$0.05807	$0
	Energy (June-Sept.) Off-Peak	0	kWh	$0.03480	$0
	Energy (Oct. - May) On-Peak	0	kWh	NA	
	Energy (Oct. - May) Shoulder	0	kWh	$0.05507	$0
	Energy (Oct. - May) Off-Peak	0	kWh	$0.03896	$0
					$0

14.12 Controlled Service - Bulk Interruptible

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Facilities Charge 18%	-	Bills	per Contract	
All kWh	-	kWh		
Unbilled kWh	-	kWh		
Cost of Energy Adjustment	NA			
				$0

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Facilities Charge	-	Bills	per Contract	
All kWh	-	kWh		
				$0

14.06 Controlled Service - Deferred Load Rider

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Customer Charge:	7,378	Bills	$1.40	$10,329
Energy All kWh	14,856,088	kWh	$0.03643	$541,207
Unbilled kWh	130,499	kWh		$1,246
MISO Adjustment				$5,236
Cost of Energy Adjustment	14,986,587			$173,905
				$731,923

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Customer Charge:	7,378	Bills	$3.00	$22,134
Facilies Charge:	7,378	Bills	$4.00	$29,512
All kWh (June - Sept.)	909,617	kWh	$0.05153	$46,868
All kWh (Oct. - May)	14,076,970	kWh	$0.05000	$703,865
Penalty kWh (June - Sept.)	-	kWh	$0.38956	$0
Penalty kWh (Oct. - May)	-	kWh	$0.16512	$0
				$802,379

14.07 Fixed Time of Delivery Rider

	Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
< 100 kW	Facilities Charge:	1,389	Bills	$3.78	$5,250
	Energy Charge:	2,543,852	kWh	$0.02722	$69,244
> 100 kW	Facilities Charge:	216	Bills	$8.18	$1,765
	Energy Charge:	1,988,084	kWh	$0.02346	$46,640
Primary	Facilities Charge:	-	Bills	$77.88	$0
	Energy Charge:	-	kWh	$0.02018	$0
	Unbilled kWh	39,810	kWh		$380
	MISO Adjustment				$1,597
	Cost of Energy Adjustment	N/A			$0
					$124,877

	Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Self Contained	Customer Charge:	1,151	Bills	$1.00	$1,151
	Facilities Charge:	1,151	Bills	$3.00	$3,453
	Energy Charge (June-Sept.)	28,616	kWh	$0.02781	$796
	Energy Charge (Oct.- May)	1,664,318	kWh	$0.02945	$49,008
	Penalty kWh (June - Sept.)	-	kWh	$0.12174	$0
	Penalty kWh (Oct. - May)	-	kWh	$0.10322	$0
CT-Metered	Customer Charge:	454	Bills	$1.50	$681
	Facilities Charge:	454	Bills	$19.00	$8,626
	Energy Charge (June-Sept.)	42,231	kWh	$0.02781	$1,175
	Energy Charge (Oct.- May)	2,836,581	kWh	$0.02945	$83,527
	Penalty kWh (June - Sept.)	-	kWh	$0.12174	$0
	Penalty kWh (Oct. - May)	-	kWh	$0.10322	$0
Primary	Customer Charge:	-	Bills	$3.00	$0
	Facilities Charge:	-	Bills	$9.00	$0
	Energy Charge (June-Sept.)	-	kWh	$0.02770	$0
	Energy Charge (Oct.- May)	-	kWh	$0.02933	$0
	Penalty kWh (June - Sept.)	-	kWh	$0.12163	$0
	Penalty kWh (Oct. - May)	-	kWh	$0.10311	$0
					$148,417

12.01 Small Power Producer Rider

Present Rate - Actual Year 2007	Units		Rate Per Unit	Amount
Base Avoided Costs	-2960.00	kWh	$0.02361	-$16.89

Proposed Rate - Test Year 2007	Units		Rate Per Unit	Amount
Base Avoided Costs	-2960.00	kWh	$0.02361	-$16.89

Summary of Proposed Inter and Intra Class Allocations

Class	Proposed Class Increase	EPMC Method	Rate Schedule Descriptions	Proposed Intra-Class Increase	Results By Class
Residential	7.50%	Method 1			7.50%
			Residential Service	6.22%	
			Residential Demand Control	14.67%	
Farm	7.50%	N/A			7.50%
			Farm Service	7.5%	
Small General Service	0.95%	Method 1			0.95%
			General Service: < 20 kW	-1.47%	
			General Service: >= 20 kW	1.72%	
Large General Service	1.00%	N/A			1.00%
			Large General Service (LGS)	1.00%	
			Real Time Pricing Rider	1.00%	
			LGS - Off Peak Rider	1.00%	
			LGS - Time of Day	0.00%	
Irrigation	10.0%	Method 1			10.0%
			Irrigation Service - Option 1	9.16%	
			Irrigation Service - Option 2	10.86%	
Lighting	25.0%	N/A			25.0%
			Lighting - Energy Only - Service	25.0%	
			Outdoor Lighting Service	25.0%	
OPA	14.0%	N/A			14.0%
		N/A	Municipal Pumping Service	14.0%	
			Civil Defense - Fire Siren Service	14.0%	
Water Heating	10.0%	N/A			10.0%
			Water Heating - Controlled Service	10.0%	
Interruptible	35.0%	Method 2			35.0%
			Large Dual Fuel Rider - Option 1	57.27%	
			Large Dual Fuel Rider - Option 2	0.00%	
			Small Dual Fuel Rider	26.37%	
			Bulk Interruptible Rider	0.00%	
			Standby Service	-64.12%	
Deferred Load	10.97%	Method 1			10.97%
			Deferred Load Rider	9.66%	
			Fixed Time of Delivery Rider	18.87%	

(R-01N) - RESIDENTIAL SERVICE, Section 9.01

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Rate Code Description Section	Eliminated zones distinctions.
Rate Code Description Section	Information placed into a table to simplify readability.
Rate Code Description Section	Rate Zone Codes 121, 129, 201, 209, 211, 219, 221, 231, and 239 eliminated due to being obsolete and no longer used for tracking purposes (customers will be transferred to the remaining rate).
Rules and Regulations	Verbage moved to front of tariff sheet and updated to include General Rules and Regulations governing.
Rate	Created table to simplify readability; combined zones 1 and 9.
Monthly Minimum Charge Section	Eliminated as stand alone section. Included in rate table. Combined all customers into one charge.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Water Heating Credit	Eliminated the language for controlled service water heating option from this rate and combined it as an option with a new rate code in the Controlled Service Water Heating Rider.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.
Definition of Seasons	Added a section to define the summer and winter season months.
Additional Rates, Rules and Regulations for Seasonal and Lake Cottage Service, and Residential Service in Rural Areas	Changed title to Seasonal Residential Service.
Additional Rates, Rules and Regulations for Seasonal and Lake Cottage Service, and Residential Service in Rural Areas	Clarified charges that apply to seasonal account at hook up (one time $X charge) and at the start of each season ($X).
Additional Rates, Rules and Regulations for Seasonal and Lake Cottage Service, and Residential Service in Rural Areas	Eliminated all remaining text related to service as these are covered in Rules and Regulations.

(R-03N) - RESIDENTIAL DEMAND CONTROL SERVICE (RDC), Section 9.02

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Added "Commonly identified as RDC" to allow billing to name as RDC.
Rate Code Description Section	Eliminated zones distinctions.
Rate Code Description Section	Information placed into a table to simplify readability.
Rules and Regulations	Verbage moved to front of tariff sheet and updated to include General Rules and Regulations governing.
Application of Schedule	Simplified to clarify its availability to residential and farm customer.
Rate	Created table to simplify readability.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Monthly Minimum Charge	Section was eliminated from text. It is defined in the rate table.
Billing Demand Determination	Added a provision of a 3 kW demand set for customers new to rate until demand is established.
Control Criteria Section	Renamed "Demand Signal." Updated control period wording for simplified language.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.
Requirements before rate will be applied	This section was eliminated.

(F-61N) - FARM SERVICE, Section 9.03

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Rate Zone 9	Eliminated specific rate zone designation.
Description	Recommend deleting Option II- Two Meters - Home use (RDC) and Farm Use. This is a closed rate, and people should be transitioned to the standard rates.
Rules and Regulations	Verbage moved to front of tariff sheet and updated to include General Rules and Regulations governing.
Availability	Added three-phase option, added the options for residential service and RDC at customer choice.
Rate	Eliminated several tariff codes and restructured rate into a table.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Option I and II Rates	Eliminated from text.
Water Heating Credit	Eliminated water heating credit from the tariff. It is included in a voluntary rider for controlled service water heating.
Monthly Minimum Charge	Eliminated.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.
Additional Rules and Regulations Applying to Rural Customers	Eliminated.
Regulations Applying to Water Heating	Eliminated.

SMALL GENERAL SERVICE - Under 20 kW, Section 10.01

Location/Section	Description of Change
Small General Service Under 20 kW	New Tariff

(G-01N) - GENERAL SERVICE - 20 kW or Greater, Section 10.02

Location/Section	Description of Change
Header	New logo added, page numbers, volume dropped.
Footer	Font changed; signer name and information/date changed.
Title	Subheader added to clarify application is intended for "20 kW or Greater" loads.
Rate Code Description Section	Eliminated zones distinctions.
Rate Code Description Section	Information placed into a table to simplify readability.
Rate Code Description Section	New tariff code (403) added for Primary service option. For 20 kW and Greater - 10.02 only.
Rules and Regulations	Verbage moved to front of tariff sheet and updated to include General Rules and Regulations governing.
Application of Schedule	Includes three-phase residential customers and all nonresidential as candidates for this rate. Voltage information was deleted as it is not the true identifier for application.
Rate	Info placed into a table to simplify and reordered to reflect actual billing application.
Rate	Minimum monthly charge identified in charges section; Monthly Minimum Charge Sections from within the text were eliminated.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Terms and Conditions	**New Rate** added indicating customers with demand less than 20 kW for 12 consecutive months will have the option of changing rates.
Water Heating Credit	Eliminated water heating credit from the tariff. It is included in a voluntary rider for controlled service water heating.
Monthly Minimum Charge	Moved to Rate section.
Monthly Minimum Charge	Horsepower and kva based charges are not policable. Dropped for accuracy and ease of administration.
Monthly Minimum Charge	Zone distinctions are eliminated and minimum monthly charge will be a single price point.
Determination of Demand	Demand charges will be either measured or estimated but never less than 20 kW for a 20 kW and greater customer. The minimum was increased from 3 kW (that size load will be in a separate tariff).
Determination of Monthly Facilities Charge	Added this section to show that monthly measured demand will be based on the maximum 15 consecutive minute period in order to base the Facilities charge.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10 and 4.11.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(C-02N) - LARGE GENERAL SERVICE, Section 10.03

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Eliminated zones distinctions in subheader.
Rate Code Description Section	Information placed into a table to simplify readability.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Application of Schedule	Included mention of load factor. Eliminated language regarding the type of equipment served.
Rate	Information placed into 3 tables to simplify readability for each service type (secondary, primary, and transmission).
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Monthly Minimum Charge	This section was cut from text and the content moved to rate table.
Determination of Billing Demand	Added clarification that billing demand.
Determination of Billing Demand	Subsections containing a "Standard minimum" formula calculation of demand and a "Special minimum" negotiated demand formula were deleted.
Adjustment for Excess Reactive Demand	Inserted word "measured" and reordered section to match Minnesota tariff.
Metering	Revised and moved to General Rules and Regulations.
Emergency, Supplementary or Standby Service	Revised and moved to General Rules and Regulations.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

COMMERCIAL SERVICE - TIME OF USE, Section 10.04

Location/Section	Description of Change
Commercial Service - Time of Use	New Tariff.

(C-05N) - LARGE GENERAL SERVICE - TIME OF DAY, Section 10.06

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Changed title to Time of DAY; eliminated Zone distinctions.
Rate Code Description Section	Information placed into a table to simplify readability.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Application of Schedule	Simplified to nonresidential and with load of at least 80 kW.
Rate	Three rate codes added for Shoulder period distinction. Information placed into a table to simplify readability.
Rate	Set into tables by service type.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Metered and Established Demand Section	New section added because of demand charges added to the rate.
Rate Definitions	Section eliminated. (Terms defined where applicable in the tariff, moved to Rules and Regs, or no longer required due to change in rate structure in this tariff.)
Adjustment for Excess Reactive Demand	New section added because of demand charges added to the rate.
Special Billing Demand	New section added because of demand charges added to the rate.
Definition of On-Peak, Shoulder and Off-Peak Periods by Season	Added definition of shoulder, applied new season definitions and new peak, off-peak, and shoulder definitions.
Contract Period	Language simplified to state terms will be outlined in an agreement.
Customer Connection Charge	Revised and moved to Section 1.04.
Determination of Monthly Facilities Charge	Added this section to show that monthly measured demand will be based on the maximum 15 consecutive minute period in order to base the Facilities charge.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(P-13N) - STANDBY SERVICE, Section 11.01

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title Section: Standby Service 100kW or More	Combined with other Standby Tariff. This single Standby Service tariff applies to all customers that are 60 kW or greater. No breakpoint of over or under 100 kW anymore.
Rate Code Description Section	Information moved to table format. 14 additional rate codes were added tied to each level of service defined in the rate sheet.
Rules and Regulations	Moved the Regulations section to Rules and Regulations toward top of document from the bottom.
Application of Schedule	Defines availability as based in request, use of extended parallel generation systems of greater than 60 kW, and enters into a contract. Language regarding equipment voltage was eliminated.
Rate	Pricing was placed into a table and divided between firm and non-firm and by transmission, primary, and secondary service. Rate codes are applied to each level of service.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Minimum Charge	This section was eliminated from the text and moved to the Rates tables as the Minimum Monthly Bill.
Determination of Metered Demand	Changed so Metered Demand shall be based on the maximum kW registered over any period of one hour during the month in which the bill is rendered.
Contract Period	Included language to discuss Options A and B; changed initial contract period from three years to one year. Moved above Definitions Section.
Payment	Revised and moved to Section 4.10.
Terms and Conditions	Modified the number of hours of firm service from 180 hours per season to 120 on-peak hours in summer season and up to 240 on-peak hours during winter season.
Terms and Conditions	Introduced guidelines for non-firm service availability during shoulder and off-peak periods.
Definitions and Useful Terms	Modified to bring terms current.
Adjustment for Municipal Payments	Removed this section.

(M-03N) - IRRIGATION SERVICE, Section 11.02

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Eliminated zone distinction in the subheader.
Rate Code Description Section	Information placed into a table to simplify readability. Codes renamed as Declared Peak, Intermediate, and Off-Peak.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Application of Schedule	Changed Available to Applicable.
Character and Conditions of Service	Section eliminated.
Rate	Moved to table for ease of understanding.
Facilities Charge	Added section outlying facilities charge as related to company investment in facilities.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Character and Conditions of Service	Section eliminated.
Definition of Declared, Intermediate, and Off-Peak Periods by Season	Section added to define Declared, Intermediate, and Off-Peak Periods by Season, Definitions are added.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Contract Period and Agreement	An explanation of why a 5 year contract period is needed based on investment by company and with terms for handling superceding rates.
Seasonal Service	Eliminated. Would be covered in contract.
Adjustment for Municipal Payment	Revised and moved to Section 4.08.
Rules and Regulations for Irrigation Service	Eliminated. Would be covered in contract or in General Rules and Regulations.

(M-41N) - OUTDOOR LIGHTING - ENERGY ONLY DUSK TO DAWN, Section 11.03

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	"Dusk to Dawn" subheader added.
Title	Eliminated zones distinctions.
Rate Code Description Section	Rate codes placed into a table for ease of reading.
Rate Code Description Section	Added Sign Lighting Rate Code 744. This was moved from M42-N.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Application of Tariff	Deleted "both private and governmental entities." Replaced with "all customers." Added clarification that tariff is available only for dusk to dawn operated lighting fixtures.
Rate	Added Rate tables for clarity.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate. Refers to matrix for rate applicability.
Service Conditions	Limitations added indicating that company owned property cannot be attached to customer owned property.
Payment	Revised and moved to Section 4.10.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(M-42N) - OUTDOOR LIGHTING DUSK TO DAWN, Section 11.04

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	"Dusk to Dawn" subheader added.
Title	Eliminated zones distinctions.
Rate Code Description Section	Rate codes placed into a table for ease of reading.
Rate Code Description Section	Removed Sign Lighting from tariff.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Application of Tariff	Added clarification that tariff is available only for dusk to dawn operated lighting fixtures.
Rate	Wattage column was added to rates table.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate. Refers to matrix for rate applicability.
Sign Lighting	Moved to 11.03 (M-41N) Outdoor Lighting Energy Only.
Underground Service	Clarified footage for the standard amount of wire the Company will supply.
Equipment and Service Supplied by the Company	Added explanation of fixture types.
Mounting Locations	Eliminated this section; the mounting location concerning pole ownership is already covered in the language under Equipment and Service Supplied by the Company.
Service Conditions	Limits that company owned property cannot be attached to customer owned property. Discretion to discontinue service in cases of vandalism was added.
Contract Period	Revised and moved to Section 1.02.
Payment	Revised and moved to Section 4.10.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(M-54N) - MUNICIPAL PUMPING SERVICE, Section 11.05

Location/Section	Description of Change
Header	New logo added, page numbers, volume dropped.
Footer	Font changed; signer name and information/date changed.
Footer	Updated for current regulatory action.
Title	Eliminated zones distinctions.
Rate Code Description Section	Added Primary Service 50-874.
Rate Code Description Section	Placed in table for ease of reading.
Rules and Regulations	Moved to top to refer to General Rules and Regulations document.
Application of Schedule	Discount for losses not appropriate. Dropped.
Application of Schedule	Deleted exception to municipal buildings adjacent to, but not incidental to the pumping operation, may not be served on this rate. Added stipulation that the company reserves the right to totalize loads.
Rate	Pricing for each rate was placed into a table with monthly minimum billing defined in the table.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Monthly Minimum Charge	Removed as a separate section. Included in rate pricing table.
Cost of Energy	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.
Definitions of Seasons	Added a section to define the summer and winter season months.

(M-59N) - CIVIL DEFENSE - FIRE SIRENS, Section 11.06

Location/Section	Description of Change
Header	New logo added, page numbers, volume dropped.
Footer	Updated for current regulatory action.
Title	Eliminated zones distinctions.
Title	Renamed as "Civil Defense Fire Sirens."
Rules and Regulations	Added the reference to General Rules and Regulations.
Rate	Placed in rate box for readability.
Rate	Added Monthly Minimum to rate box.
Rate	Added Seasons to the rate box.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Other Siren Services	Modified to remove addition of demand for sirens served with other tariff services.
Service Conditions	Section added to indicate that additional charges will apply when nonstandard distribution services are needed. Also provides right for periodic review of loads.
Payment	Revised and moved to Section 4.10.
Adjustment of Municipal Payments	Revised and moved to Section 4.08.

PURCHASE POWER RIDERS - APPLICABILITY MATRIX, Section 12.00

Location/Section	Description of Change
Purchase Power Riders	Added the applicability matrix of Purchase Power Riders.

(P-09N) - SMALL POWER PRODUCER RIDER NET ENERGY BILLING, Section 12.01

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Subheader "Net Energy Billing" was added.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Payment Schedule	Combine Zones 1 & 9 - No distinguishable cost difference.
Payment Schedule	Information placed into a table to simplify readability and consistency.
Special Conditions of Service	Title changed to include "and Contract Period."
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.

(P-10N) - SMALL POWER PRODUCER RIDER TIME OF DELIVERY ENERGY SERVICE
Section 12.02

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Rate Code Description Section	Eliminated zones distinctions.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Payment Schedule	Combine Zones 1 & 9 - No distinguishable cost difference.
Payment Schedule	Information placed into a table to simplify readability and consistency.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.

(P-11N) - SMALL POWER PRODUCER RIDER DEPENDABLE SERVICE, Section 12.03

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Rate Code Description Section	Eliminated zones distinctions.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Payment Schedule	Combine Zones 1 & 9 - No distinguishable cost difference.
Definitions	Definitions were removed from the tariff.

MANDATORY RIDERS - APPLICABILITY MATRIX, Section 13.00

Location/Section	Description of Change
Mandatory Riders	Added the applicability matrix of Mandatory Riders.

(M-60N) - ENERGY ADJUSTMENT RIDER, Section 13.01

Location/Section	Description of Change
Header	New logo added, page numbers, volume dropped, rate designation dropped.
Footer	Font changed; signer name and information/date changed.
Title	Name changed to indicate status as a rider.
Adjustment	Base cost of energy adjusted to reflect current costs.
Current Costs	Proposal to share 15% of non-asset based margins.

(M-60N) - ENERGY ADJUSTMENT RIDER, Section 13.04

Location/Section	Description of Change
Header	New logo added, page numbers, volume dropped, rate designation dropped.
Footer	Font changed; signer name and information/date changed.

VOLUNTARY RIDERS - AVAILABILITY MATRIX, Section 14.00

Location/Section	Description of Change
Voluntary Riders	Added the applicability matrix of Voluntary Riders.

(R-91N) - WATER HEATING CONTROL RIDER, Section 14.01

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Renamed as Water Heating Control Rider for clarity and organization.
Rate Code Description Section	Eliminated zones distinctions; created table for readability.
Application of Schedule	Simplified to clarify its availability to residential and nonresidential alike.
Application of Schedule	Removed limitations on water heaters that may be served on this rate.
Rate	Created table to simplify readability; added a new rate code (192) for non-metered controlled water heaters.
Monthly Minimum Charge	Moved to rate table.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Terms and Conditions for Rate 191	Added section to indicate that Rate 191 requires a separate meter.
Terms and Conditions for Rate 192	Added section to indicate that Rate 192 does not require a separate meter and consists of a bill credit.
Control Criteria	A new section was added and control limitations pulled in from the application of schedule section to aid understanding of terms.
Definitions of Seasons	Added a section to define the summer and winter season months.
Equipment Supplied	Provides commitment that company will supply and maintain control equipment.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.
Additional Regulations Applying to Water Heating, Controlled Service	Limitations were removed as they related to equipment choices or are covered in General Rules and Regulations.

(C-03N) - REAL TIME PRICING RIDER, Section 14.02

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Eliminated zones distinctions in subheader.
Rules and Regulations	Moved toward top. Reworded for consistency across tariffs.
Availability	Combined requirements listed in "Applicability" section and eliminated that section. Removed excluded rates as they are discussed elsewhere.
Rate	Information placed into a table to simplify readability.
Rate	Organized in table format.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Administrative Charge	Moved toward top. Added phrase "plus any other applicable tariff charges."
CBL Adjustments	Removed reference to Conservation Improvement Program (no longer in North Dakota).

LARGE GENERAL SERVICE RIDER, Section 14.03

Location/Section	Description of Change
Large General Service Rider	Added Tariff in ND.

(I-01N) - CONTROLLED SERVICE - INTERRUPTIBLE LOAD RIDER - CT METERING (Large Dual Fuel), Section 14.04

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Changed title name to reference CT Metering Rider, added commonly used name.
Title	Removed subheader zones distinction and load size distinctions.
Rate Code Description Section	Rate codes added to table to simplify readability.
Rate Code Description Section	Limitation by load size (80 kW) removed and replaced with distinction that CT metering will be in use.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Changed header name to Availability for uniformity with other riders.
Availability	Changed language to allow minimum loads to allow for manufacturers' restrictions.
Rate	Charges placed into a table to make more understandable. Penalty periods defined within its own section (moved below Definitions of Seasons Section).
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Penalty Periods	Added text to a separate section to clarify that the penalty rate is not intended as a ride through control option.
Control Criteria	Changed language to clarify the hours of control and variations by season.
Determination of Monthly Facilities Charge	Added this section to show that monthly measured demand will be based on the maximum 15 consecutive minute period in order to base the Facilities charge.
Determination of Control Period Demand - Option 2 only	Added text to a separate section to clarify demand period under option 2.
Monthly Minimum Charge	Removed as a separate section. Included in rate pricing table.
Equipment Supplied	Section simplified to indicate company will supply metering and control equipment.
Other Provisions	Removed provisions related to equipment recommendations and limitations. Some provisions moved to General Rules and Regulations
Customer Connection Charge	Revised and moved to Section 1.04.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(I-02N) - CONTROLLED SERVICE - INTERRUPTIBLE LOAD SELF RIDER CONTAINED METERING (Small Dual Fuel), Section 14.05

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Changed to eliminate duplicate titles with size differentiation only; added commonly used name, and referenced to self-contained metering.
Title	Removed subheader zones distinction and load size distinctions.
Rate Code Description Section	Rate codes added to table to simplify readability.
Rate Code Description Section	Limitation by load size (less than 80 kW) removed and replaced with distinction that self-contained metering will be in use.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Changed header name to Availability for uniformity with other riders.
Availability	Changed language to allow minimum loads to allow for manufacturers' restrictions.
Availability	New language added stating that if backup is not automatic a waiver needs to be signed.
Rate	Charges placed into a table to make more understandable.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Penalty Periods	Added text to a separate section to clarify that the penalty rate is not intended as a ride through control option.
Control Criteria	Changed language to clarify the hours that are controlled and changed seasons.
Cost of Energy Adjustment	Section and exception to cost of energy charges removed.
Monthly Minimum Charge	Removed as a separate section. Included in rate pricing table.
First Three Years	Section removed.
Equipment Supplied	Section simplified to indicate company will supply metering and control equipment.
Other Provisions	Section removed. Eliminated those that pertain to building codes. Remaining are covered in General Rules and Regulations.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(I-03N) - CONTROLLED SERVICE - DEFERRED LOAD RIDER (Thermal Storage), Section 14.06

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Changed to add "Rider" and commonly used name "thermal storage."
Title	Eliminated zones distinctions in subheader.
Rate Code Description Section	Rate codes placed in table for ease of reading.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Changed header name to Availability for uniformity with other riders.
Availability	Clarified availability for residential and nonresidential.
Availability	Electric water heating added to primary load types.
Availability	Deleted, "used for both heating and cooling."
Availability	Changed language to include minimum loads to allow for manufacturers' restrictions.
Rate	Information placed into a table to simplify readability.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Penalty Periods	Added text to a separate section to clarify that the penalty rate is not intended as a ride through control option.
Control Criteria	Changed language to clarify the hours that are controlled.
Monthly Minimum Charge	Removed as a separate section. Included in rate pricing table.
Equipment Supplied	Section simplified to indicate company will supply metering and control equipment.
Other Provisions	Eliminated those that pertain to building codes. Remaining are covered in General Rules and Regulations.
Cost of Energy Adjustment	Revised and moved to Section 13.00.
Customer Connection Charge	Revised and moved to Section 1.04.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

(I-04N) - FIXED TIME OF DELIVERY RIDER (Fixed TOD), Section 14.07

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed
Title	Changed to add "Rider" reference and commonly identified name Fixed TOD.
Title	Removed subheads as three rider schedules are being combined into one. Distinction by zones eliminated in subheader.
Rate Code Description Section	Information for three levels of service were combined for ease of reading.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Reworked to make for broader availability across various load sizes.
Rate	Pricing for each rate was placed into a table with monthly minimum billing defined in the table.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Definitions of Seasons	Added a section to define the summer and winter season months.
Penalty Periods	Added text to a separate section to clarify that a penalty applies for unauthorized use of electricity.
Control Criteria	Changed language to clarify the hours energy is provided. Hours have been adjusted 11 pm to 7 am to 10 pm to 6 am.
Equipment Supplied	Section simplified to indicate company will supply metering and control equipment.
Other Provisions	Eliminated those that pertain to building codes. Remaining are covered in General Rules and Regulations.
Customer Connection Charge	Revised and moved to Section 1.04.
Payment	Revised and moved to Section 4.10.
Contract Period	Revised and moved to Section 1.02.
Adjustment for Municipal Payments	Revised and moved to Section 4.08.

AIR CONDITIONING CONTROL RIDER (Cool Savings), Section 14.08

Location/Section	Description of Change
Air Conditioning Control Rider	Added Rider in ND.

(M-15N) - VOLUNTARY RENEWABLE ENERGY RIDER (Tail*Winds* Program), Section 14.09

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Added commonly identified name Tail*Winds* Program.
Title	Removed subheaders as three rider schedules are being combined into one. Distinction by zones eliminated in subheader.
Rate Code Description Section	Created table for easier readability.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Added 100 kWhs or more of usage per month stipulation.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.
Rate	Added "contracted block."
Payment	Revised and moved to Section 4.10.
Terms and Conditions	Revised this section for better understanding.

(M-33N) - WAPA BILL CREDITING PROGRAM RIDER, Section 14.10

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Eliminated zone distinctions in subheader.
Rate Code Description Section	Created table for easier readability.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Removed references to other tariffs in this section.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate. Refers to matrix for rate applicability.
Pricing Methodology	Added that the company's composite rate will be recalculated annually and that Western's composite rate will be changed as Western updates it.
Cost of Energy Adjustment	Renamed to Energy Adjustment Rider. Reference section was updated for this filing.

(M-10N) - RELEASED ENERGY ACCESS PROGRAM (REAP) RIDER, Section 14.11

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Changed title terminology from "Tariff" to "Rider."
Title	Eliminated zone distinctions in subheader.
Rate Code Description Section	Created table for easier readability.
Rules and Regulations	Added the reference to General Rules and Regulations toward top of document.
Application	Changed title to Availability.
10. Penalty for Insufficient Load Control	Restructured language for explaining Customer's liability concerning replacement energy.

(I-06N) - BULK INTERRUPTIBLE SERVICE, Section 14.12

Location/Section	Description of Change
Header	New logo added, page numbers and formatting changed.
Footer	Font changed; signer name and information/date changed.
Title	Added term "Rider." Removed subhead zones distinction.
Rules and Regulations	Moved the reference to General Rules and Regulations toward top of document from the bottom.
Availability	Changed from Application of Schedule to Availability.
Rate	Information placed into a table to simplify readability.
Mandatory and Voluntary Riders	Added a section to indicate that total billing may be affected by riders attached to the use of this rate.

COMMUNITIES SERVED, Section 15.00

Location/Section	Description of Change
Header	New logo added, page numbers, volume number, and formatting changed.
Footer	Font changed; signer name and information/date changed.
Rate Zone	Removed designation as zones distinctions are not used elsewhere.
Listing	List organized alphabetically and moved communities located outside of the North Dakota service area to their respective states' Communities Served sections.

Volume 2B

Testimony and Schedules of Witnesses:

Hethie Parmesano

Marginal Cost Study

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STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

In the Matter of the Application of
OTTER TAIL POWER CORPORATION d/b/a
OTTER TAIL POWER COMPANY
For authority to Increase Rates for Electric Service
in North Dakota

Case No. PU-08-__

Direct Testimony of

DR. HETHIE S. PARMESANO, PH.D.

Senior Vice President

NERA Economic Consulting

MARGINAL COST STUDY

November 3, 2008

OTP Exhibit ___

Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dr. Hethie S. Parmesano, Ph.D. My business address is 777 South Figueroa Street, Suite 1950, Los Angeles, California 90017.

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

A. I am a Senior Vice President at NERA Economic Consulting ("NERA").

Q. On whose behalf are you submitting direct testimony in this proceeding?

A. I am submitting testimony on behalf of Otter Tail Power Company ("OTP" or the "Company").

Q. What was your role in the development of OTP's proposed rates?

A. OTP engaged NERA to develop, with input from OTP staff, a marginal cost study covering the period 2008-2012, applicable to service in North Dakota and South Dakota, and to provide advice on the application of the marginal cost results in developing the proposed rates.

Q. What are the purposes of your direct testimony in this proceeding?

A. My direct testimony has six overall purposes:

- To describe the contribution that use of marginal cost information in rate design can make to the achievement of OTP's ratemaking objectives.
- To describe in general terms how OTP used marginal costs in its rate design process.
- To review the North Dakota Public Service Commission's ("Commission") past policies regarding use of the marginal costs in rate design and describe changes since those policies were set.
- To describe the methods used in the marginal cost study and summarize the results.
- To comment on the implications of the marginal cost results for OTP rates.
- To describe likely efficiency improvements from the proposed rates.

Q. Please summarize the main points of your direct testimony.

A. My testimony makes five main points:

- OTP's use of marginal cost in apportioning to individual rates the embedded-cost-based revenue requirement allocated to major customer classes, and for designing the structure of each rate, is consistent with the company's ratemaking objectives.

- Although the Commission rejected the use of marginal costs in rate setting in 1981, the many changes in the electricity sector and in the country's energy goals in the years since that time resolve many of the Commission's concerns in 1981 and make a compelling case today for using marginal costs.

- OTP has used the results of a comprehensive marginal cost study that reflects its membership in the regional wholesale energy market, as well as its planning and operating practices regarding distribution and customer-related activities.

- The marginal cost study suggests that OTP could improve the efficiency and equity of its rate structures by: incorporating seasonality in all rates, eliminating declining blocks, significantly raising the energy charges in rates not currently subject to the cost of energy adjustment, introducing fixed charges that are closer to marginal customer and local facilities costs, and correcting the seasonality of demand charges for Residential Demand Control service.

- OTP's proposed rate structures are likely to improve the efficiency of its customers' consumption decisions by moving prices for marginal consumption closer to marginal cost.

Q. Are you sponsoring any attachments to your direct testimony?

A. Yes, summary sheets from the marginal cost study that NERA prepared for OTP are located in Exhibit ____(HSP-1), Schedule 1 and a copy of my curriculum vitae is attached hereto as Exhibit ___, (HSP-1) Schedule 2.

II. BACKGROUND AND QUALIFICATIONS

Q. Please describe your education and professional background.

A. My B.A. is from Colby College, where I majored in economics. I have M.A. and Ph.D. degrees in economics from Cornell University. Since 1980, I have worked for NERA, specializing in utility costing, pricing, strategic planning and regulatory reform. I have testified widely on these matters.

For more than two decades, I have taught seminars on electricity marginal costing and rate design. Attendees include staffs of utilities and regulatory commissions, as well

as occasional commissioners. I have also participated regularly in the University of Florida Public Utility Research Center/World Bank International Training Program on Utility Regulation and Strategy, where I present sessions on electricity tariff design.

Since 1982, I have directed NERA's Marginal Cost Working Group, a utility group that is dedicated to improving methods for estimating and using marginal cost information in a variety of utility applications.

I have been involved in planning for and implementation of energy sector restructuring and rate reform in many jurisdictions around the world, including California, New York, Ohio, New Mexico, Maine, Illinois, Maryland, Massachusetts, Minnesota, North Dakota, Arizona, Oregon, Alberta, Ontario, British Columbia, Newfoundland and Labrador, Manitoba, India, Barbados, Brazil, Argentina, El Salvador, Mexico, Saudi Arabia, Spain, Greece, Ireland, Kenya, Cambodia, Japan and the UK.

My *curriculum vitae*, Exhibit___(HSP-1), Schedule 2, contains more details on my credentials.

Q. Have you previously testified before the Commission?

A. In 2007 I submitted prefiled direct testimony on OTP's behalf in NDPSC Case No. PU-07-03 regarding OTP's proposed Large Commercial Time of Day Tariff. The case settled before hearings were held.

III. RATE STRUCTURE OBJECTIVES AND ROLE OF MARGINAL COSTS

Q. What are the rate structure objectives that guide OTP's proposal in this case?

A. As described in the direct testimony of OTP witness David Prazak, OTP's rate structure proposal is designed to address the following objectives:

- Give the utility a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
- Promote efficient use of resources, conservation and use of renewables. This implies giving consumers price signals that reflect marginal costs, including seasonal differences and, where reasonably possible, time-of-day ("TOD") differences.

- Change rate designs gradually if necessary to avoid large bill impacts.
- Use rate structures that are reasonable and nondiscriminatory. This includes minimizing cross-subsidies within rate classes.
- Ensure that rates are administratively feasible. This includes taking metering and billing system constraints into account and avoiding unnecessary complexity that might confuse customers.
- Preserve the attractiveness of cost-effective load control/interruptible riders.

Q. You mentioned that several of the rate structure objectives imply using marginal costs for rate design. What are the reasons for basing rate structures on marginal cost?

A. A primary reason for using marginal costs as the basis for rates is to encourage customers to make economically efficient energy decisions; that is, to use an increment of electricity only if it has value to the consumer that is equal to or greater than the cost of supplying that increment of electricity (the marginal cost). Because the marginal cost of supplying electricity varies by season and time of day, time-differentiated rates result in more efficient electricity consumption decisions than rates that are not time-differentiated.

Q. Is there a second reason for using marginal costs as the basis for rate design?

A. Yes. A second reason is to reduce cross-subsidies. Cross-subsidies arise when costs attributable to consumption by one customer or group of customers are recovered from another customer or group of customers. For example, if the tail block price of a declining block rate were significantly below marginal cost, a customer large enough to consume in the tail block who increased use would pay less for the additional electricity than it costs OTP to provide the increment. Someone else must make up the difference – OTP's shareholders and/or its other customers. Neither alternative is fair or likely to result in customers' receiving high quality service or in the economic use of electricity. Another example is the use of non-seasonally differentiated rates in circumstances when customers' shares of consumption in winter and summer vary significantly. If high summer costs are recovered partly in winter months because rates are the same year-round, customers with relatively high air conditioning use in summer and who use gas to

heat in winter are subsidized by customers who use relatively little air conditioning in summer but heat with electricity in winter.

Q. Is there a third reason for basing rate structures on marginal costs.

A. Yes. A third reason is that when rate structures are based on marginal cost, the utility's revenues are more likely to track its total costs as electricity consumption changes. For example, if energy charges are set at marginal cost, differences in energy consumption from the forecast used in the rate case will lead to changes in revenues that match changes in costs, giving the utility a reasonable opportunity to earn its authorized rate of return.

Q. What are the components of a marginal cost-based rate structure?

A. A full marginal-cost based rate structure has the following rate components: [1]

- A monthly customer charge to recover marginal customer-related costs (meter, service drop, customer-related expenses such as meter reading, billing, customer accounting, and customer information).

- A monthly distribution facilities charge per kW of design demand to recover the marginal costs of local distribution facilities (local primary, transformers, secondary lines). These facilities must be in place to serve one customer (or a small number of neighboring customers) all year, even though the customer(s) may not be making full use of the full capacity every month.[2]

- Seasonal and TOD charges to recover time-differentiated generation, transmission and distribution substation/trunkline marginal costs.

Practical considerations such as the capability of customers' meters, limitations on customer characteristics in the billing system, and the objective of gradualism often require modifications to this structure.

[1] The rate structure for large customers should also include a cost-based charge for power factor deviations outside of normal limits. OTP's current and proposed rates do include such a charge.

[2] For example, some farm customers have extremely low consumption in some months.

IV. OTP'S USE OF MARGINAL COSTS IN THIS CASE

Q. In this rate case has OTP used marginal costs to compute its requested total revenue requirement?

A. No. As in most jurisdictions, OTP's proposed total revenue requirement is based on the utility's test-year embedded costs, with known and measurable changes.

Q. In this rate case has OTP used marginal costs to compute its revenue requirement for the major customer classes?

A. No. Rates overall must be set to recover embedded costs, but each customer class' revenue allocation could be based on something else, as it is in many states. OTP's proposed major class revenue allocations are based on the results of an embedded class cost of service study, but with modifications necessary to take into consideration rate design goals such as gradualism and fairness. The direct testimony of OTP witness Pete Beithon discusses the Company's proposed class revenue allocations.

Q. In this rate case has OTP used marginal costs to apportion to individual rates within a major customer class the revenue requirement allocated to that class?

A. Yes. In keeping with the objectives of improving the efficiency of price signals and reducing cross-subsidies, OTP analyzed the 2009 marginal cost of serving customers on each rate (i.e., the revenues that would be generated by charging marginal costs) within a class. Charging each rate a share of total class allocated revenue requirement equal to the rate's share of total class marginal cost revenue would be an application of the equal percentage of marginal cost ("EPMC") approach. However, to avoid unacceptable bill impacts, the EPMC shares of class revenue requirement were modified as a first step toward a more efficient and equitable allocation of class revenue requirement among rates.

Q. In this rate case has OTP used marginal costs to guide the design of individual rates?

A. Yes. As explained by OTP witness David Prazak, OTP began its rate design exercise by populating its rate model with 2009 marginal costs as tentative charges, and calculating

the revenues those charges would produce when applied to test-year billing determinants. OTP then modified the tentative charges until the revenues from those charges produced the revenue target for that rate. These modifications generally used the following principles:

- Set the customer charges and the facilities charges below marginal cost.
- Keep the energy and demand charges as close as possible to full marginal cost.
- When making reductions below marginal cost for demand and energy charges, maintain the marginal cost relationships, to the extent feasible. For example, if energy and demand charges must be set below marginal cost to achieve the target revenue for a rate, reduce both energy and demand charges by approximately the same percent.
- Eliminate declining blocks.
- Strive to maintain a logical relationship among the charges in closely-related rates (such as general service and large general service).

Q. How do rate structures with declining blocks fit with OTP's rate structure objectives?

A. Declining block rates, which price successive blocks of energy (or demand) at reduced prices, are generally not compatible with OTP's rate structure objectives. Rate structures with declining blocks are often not efficient or cost justified. Such rates give the impression that cost per unit declines as consumption (or load factor) increases, which may not be the case. When the lower-cost blocks are priced below marginal cost, consumption beyond the economically efficient level is promoted, leading to inefficient investment in capacity expansion and inefficient use of fuel and other resources.[3] Furthermore, pricing below marginal cost can lead to financial problems for the utility when usage in the below-cost blocks is greater than expected at the time the rates were set: the unanticipated revenues do not cover the unanticipated (marginal) costs. Declining blocks are unreasonable and discriminatory and create cross-subsidies within a rate class

[3] This is also true of the other blocks that are priced below marginal cost, to the extent that customers' usage ends in those blocks, but the effect is greater for the lower-cost blocks.

if large users, who benefit from low-priced blocks, do not have a lower cost of service than smaller customers within the class. Finally, declining blocks are viewed by some as antithetical to local, state, national and international efforts to counter global climate change by improving energy efficiency and promoting conservation.

V. COMMISSION'S PREVIOUS POSITION ON USE OF MARGINAL COSTS IN RATES

Q. Has the Commission, in a prior proceeding, commented on the use of marginal costs in setting revenue targets for individual rates within a class and structuring the charges within a rate?

A. Yes, the Commission decided in a 1981 proceeding to rely on embedded rather than on marginal costs in setting rates. The issue has not been readdressed comprehensively for many years. The 1981 hearings were on the PURPA Rate Design Standards. One of those standards—the Cost of Service Standard—is as follows:

> Sec. 111(d)(1) Cost of Service. Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class, as determined under section 115(a).
>
> Section 115(a) Cost of Service. In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determine on the basis of methods prescribed by the State regulatory authority…. Such methods shall to the maximum extent practicable—
>
> (1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and
>
> (2) permit identification of differences in cost-incurrence attributable to differences in customer demand and, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to a electric utility are likely to change if—
>
> a. additional capacity is added to meet peak demand relative to base demand; and
>
> b. additional kilowatt-hours of electric energy are delivered to electric consumers.

At that time the Commission recognized that according to economic theory, "marginal cost provides the correct price signal because it reflects the cost of resources necessary to supply one unit more or less of a product," and that "[t]here is no question that marginal cost pricing is the logically correct way to price in terms of economic efficiency, if the assumption of the theory are correct." [Order in NDPSC Cases No. 10,222, 10,223, 10,224, p.5) However, the Commission concluded that, although they were adopting the cost of service standard, they were interpreting it as not requiring use of marginal cost analysis as the basis for setting rates. "In the judgment of this Commission, marginal cost analysis as a basis for determining costs upon which rates are established is not now appropriate for implementation in North Dakota for numerous reasons." (ibid., p. 5)

The Commission cited six reasons for rejecting marginal cost analysis for use in setting electric rates in North Dakota (paraphrasing):

1. It is possible that, given price distortions in the electricity sector, pricing electricity using marginal costs might result in a further distortion of the price signals to consumers.
2. The gap between allowed revenues and marginal cost revenues, which requires adjustments in charges away from marginal cost, may mean that the theoretical benefits of marginal cost pricing are lost.
3. The means of implementing marginal cost-based rates proposed by the proponents of this approach would serve to further compound this imprecision.
4. It would be burdensome for the utilities to implement marginal cost pricing approaches and for the Commission staff to monitor these efforts.
5. Using marginal cost analysis in setting rates would be an abrogation of the Commission's rate-setting function (which involves "historical intuitive analysis of costs and exercise of sound judgment").
6. Using marginal costs to set rates does not satisfactorily meet the tests of simplicity and familiarity to utility consumers. [Ibid., p. 6]

However, the Commission also said it would require the electric utilities

> to do a marginal cost study along with an embedded cost study in their next general rate case, and to show what rates would result from their marginal cost studies in order that the Commission can examine the resulting differences of the two methods of rate design. We are not rejecting marginal costs out of hand in spite of what we say in this decision. Added experience with marginal cost-of-service studies may reveal that such studies can be an important tool, along with embedded costs, in designing electric rates. [Ibid, p. 7]

Q. In the 27 years since the Commission's PURPA Cost-of-Service Standard decision, have there been changes that the Commission should consider with respect to the use of marginal costs in rate setting in North Dakota?

A. Yes. There have been numerous changes including:

- New rate standards added to PURPA by Congress
- National focus on energy efficiency and reduction in greenhouse gases
- Development of competitive wholesale markets for natural gas and electricity
- General agreement by electricity cost analysts that the marginal cost of generation is the market price in regions with competitive wholesale markets
- The development of mechanisms to preserve efficient price signals for marginal consumption, even in the presence of a marginal/embedded cost revenue gap
- Training and experience at utilities in marginal cost analysis and rate design using marginal costs
- Understanding that using marginal costs in rate design does not replace the exercise of judgment by regulators in designing appropriate rates; i.e., using marginal costs in rate design is not done in a cookbook fashion.
- Increased consumer sophistication regarding complex pricing mechanisms.

Q. What new rate standards were added to PURPA?

A. Concerned about energy efficiency, renewable energy and other energy-related matters, Congress passed the Energy Policy Act of 2005 ("EPAct"),[4] which included a variety of energy efficiency and demand management programs. EPAct also amended PURPA to add three new rate-design-related provisions for the State Commissions to consider or study:[5] (1) net metering for any customer with on-site generation that requests it; (2) offering of rates that vary by time period (e.g., standard time-of-day rates, critical peak pricing and real-time pricing) and reflect variations in the utility's costs of generating or purchasing wholesale power by period; and (3) provision of smart metering to customers requesting time-varying rates.

PURPA was also amended by the Energy Independence and Security Act of 2007 ("EISA 2007"). This legislation added a seventeenth rate design standard designed to promote energy efficiency investments:[6]

> (A) IN GENERAL—The rates allowed to be charged by any electric utility shall—
>
> (i) align utility incentives with the delivery of cost-effective energy efficiency; and
>
> (ii) promote energy efficiency investments.
>
> (B) POLICY OPTIONS—In complying with subparagraph (A), each State regulatory authority and each nonregulated utility shall consider—
>
> (i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
>
> (ii) providing utility incentives for the successful management of energy efficiency programs;
>
> (iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
>
> (iv) adopting rate designs that encourage energy efficiency for each customer class;
>
> (v) allowing timely recovery of energy efficiency-related costs; and
>
> (vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with

[4] The Domenici-Barton Energy Policy Act of 2005 (EPAct 2005).

[5] Title XII, Subtitle E.

[6] Section 532(a) of EISA.

making home energy efficiency improvements, and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

Section 1307 of EISA 2007 also added standards on Consideration of Smart Grid Investments and Smart Grid Information. The latter calls for daily and hourly information to be provided to electricity purchasers, to the extent practicable, including: time-based electricity prices in the wholesale electricity market, time-based electricity retail prices or rates that are available to the purchasers, and the customer's energy consumption (in kWh), with pricing information provided on a day-ahead basis to the extent available.

Taken together, these amendments to PURPA illustrate the growing national efforts to improve energy efficiency and increase demand management, and the recognition that efficient rate design (that reflects marginal costs and market prices) is a key demand management and energy efficiency tool.

Q. How did the Commission respond to the 2005 and 2007 PURPA amendments related to rate design?

A. The Commission had already adopted a net metering requirement and took no further action on that standard. The Commission decided to propose rules requiring each electric utility under its jurisdiction to offer large commercial and industrial customers time-varying rates (possibly including time-of-use, critical peak and real-time pricing as well as credits for pre-established load reduction programs) and advanced metering and communications.[7] The Commission has not yet considered the new EISA 2007 standards.

Q. What are the implications of the PURPA amendments and the Commission's response with respect to the use of marginal cost to set rates?

A. Net metering essentially pays customers for their energy exports to the utility's grid at the variable portion of the retail price. Whether this pricing mechanism provides generating customers with an efficient price signal for their energy exports and whether the mechanism constitutes a subsidy from other customers depends upon the structure of the retail tariff. For example, if the retail rate has a declining block with the tail-block price

[7] NDPSC Order in Case No. PU-06-290.

set below the utility's marginal cost of generation, the generating customer whose consumption ends in the tail block is compensated at less than the value of its exports to the utility, essentially providing a subsidy to other customers. If the retail rate recovers costs that do not vary with usage in the per kWh charges, so that credit for energy exports exceeds marginal cost, the generating customers is paid an inefficiently high price for energy deliveries and other customers are subsidizing the customer-generator. Using marginal costs in designing the retail rates used in net metering helps solve these problems.

The time-varying prices contemplated by the PURPA amendments and the Commission's order are designed to give efficient price signals to consumers regarding the timing of their consumption and the value of load shifting, peak load reductions, and participation in interruptible programs. In order for these price signals to encourage efficient behavior, they must be based as much as possible on marginal costs.

Q. How has growing national concern about energy efficiency and greenhouse gas ("GHG") emissions increased the importance of reflecting marginal costs in rates?

A. Most energy analysts expect the US to enact some form of GHG legislation – either a cap and trade program or carbon tax aimed at significantly reducing the country's GHG emissions – in the next few years. Meeting these targets will require significant changes in the way energy is produced and used. The GHG programs themselves will increase the marginal cost (and market prices) of electricity. Electric rates based on marginal cost will be an increasingly important tool for protecting utilities from the financial losses that could occur if they are pricing below marginal cost and sales are higher than expected. Using marginal cost will also be critical to encourage consumers to choose the most efficient appliances and energy types.

Q. How has the growth of competitive wholesale regional electricity and gas markets changed the regulatory environment with regard to use of marginal costs in rates?

A. In the days when State Commissions were considering the original PURPA cost-of-service standard, there were several competing approaches to estimating marginal costs, and often arguments about whether a short-run or long-run approach to marginal

generation costs was appropriate for use in rates. With the development of competitive regional electricity markets, and competitive retail electricity markets in some jurisdictions, there is general agreement among cost analysts that the marginal cost of generation is the market clearing price. In regions with competitive wholesale markets, most utilities that offer real-time pricing ("RTP") and critical peak pricing ("CPP") as part of their demand management efforts use market prices (or estimates of market prices) to set the generation portion of the RTP and CPP prices. Time-of-Day prices in such jurisdictions typically reflect the patterns of market prices as well. Jurisdictions with retail competition typically set (after initial transition periods) generation prices for default service based on market prices (either spot prices or prices of contracts resulting from competitive auctions). In short, the generation component of these rates is derived from market prices because the market price is the marginal cost for those utilities. The Minnesota Public Utility Commission recently accepted OTP rates that, like the rates proposed in this proceeding, were based on a marginal cost study that used market prices as the basis for the generation component.

The development of competitive wholesale natural gas markets means that consumers deciding whether to use gas or electricity for a particular function are making that decision based on gas prices that reflect (marginal cost) market prices. The commodity portion of a consumer's gas bill is a pass-through of a competitively determined market price. As a result, it is no longer argued or credible to suggest that marginal cost pricing of electricity might lead to increased distortions in energy consumption decisions because gas prices do not reflect the marginal cost of gas.

Q. Can the benefits of marginal cost pricing be preserved while setting rates to produce a revenue target based in part on embedded costs?

A. Yes. OTP's proposed rate designs in this case use standard methods to close the marginal/embedded cost revenue gap. These methods include: setting fixed charges below marginal cost, eliminating or reducing declining block rates, and maintaining the marginal cost relationships between pricing periods and between energy and demand charges.

Q. In 1981 the Commission was concerned that the utility and regulatory staff might not have the training and experience to use marginal costs in rate design. Is this still an issue?

A. No. The standard rate training programs for regulatory and utility personnel have included sessions on marginal cost estimating and use of marginal costs in rate design for many years. OTP has engaged consultants to help develop marginal cost studies for years, and has developed in-house experience to support those studies and use the results in rate design.

Q. Has the Commission had occasion to review a rate based on marginal costs?

A. Yes, there have been two recent opportunities. OTP's marginal cost study was used in the design of the Company's voluntary time-of-use rate for large commercial customers that the Commission allowed to take effect as the result of a settlement in 2007.[8]

Also, Xcel Energy witness Zins testified in its recent rate case, Case No. PU-07-776:

> Q. MR. ZINS, HAS MARGINAL COST INFORMATION BEEN USED IN THE COMPANY'S CCOSS *AND/OR* IN THE COMPANY'S PROPOSED RATE DESIGN IN THIS CASE?
>
> A. Yes, there are two significant refinements in the Company's CCOSS that reflect the application of marginal costing concepts. The two refinements are the "stratification" of fixed production costs and the application of the Company's "E8760" energy cost allocator. (p. 14: lines 9-16)...
>
> Q. HOW HAS THE COMPANY USED MARGINAL COSTS DIRECTLY IN DESIGNING ITS RATES?
>
> A. The most significant direct application of marginal costs in the design of the proposed rates can be seen in the design of the proposed time of day (TOD) rate and the high load factor energy charge credit, both of which Mr. Huso discusses in his testimony. The Company relied on an analysis of the system hourly marginal energy costs in designing both of these rate design features. For purposes of background information, it is also useful to understand that the Company has historically always used marginal cost information as a primary guide in developing interruptible rate programs and in evaluating their cost effectiveness. The Company has also used marginal cost information in establishing purchase power rates offered to customers who are also small power producers. (p. 14, line 18 to p 15, line 3)

[8] NDPSC Order in Case PU-07-3.

Advocacy Staff is supporting the adoption of Xcel Energy's proposed rate design and E8760 energy cost allocator.

Q. In 1981 the Commission was also concerned that use of marginal cost pricing would not meet the tests of simplicity and familiarity to consumers. Should this still be an issue?

A. No. Consumers today face a variety of electricity service options in North Dakota. For example, residential customers have a choice of seven different rates or rate combinations, many of which have quite complex structures. These residential rates currently have features such as minimum bills that include the first 50 kWh, multiple declining energy blocks, seasonally-differentiated demand charges with 12-month ratchets, seasonally-differentiated and blocked energy charges, and various degrees of utility load control. Commercial customers face rate structures and service options that are even more complex. For example, the standard general service rate includes a monthly minimum (that varies for urban and rural customers), three declining energy blocks, plus a fourth block that applies to energy use in excess of 200 kWh per kW of billing demand. The standard large commercial rate (which varies by voltage level of service) has three declining energy blocks, the last of which applies to all kWh in excess of 360 kWh per billing kW, and two declining blocks for demand. Billing demand is computed based on a formula that uses the customer's peak demand in the billing period and the customer's billing demand in the preceding 11 months. In short, the Commission has approved rate structures that are more complex than the marginal cost-based structures OTP is proposing in this case.

Furthermore, consumers do not need to understand the complexities of the *cost studies* that underlie their rates. Instead, to make efficient consumption decisions, they need to understand how their bill will change if they use more or less energy, or (in the case of TOU rates) shift load from peak to off-peak periods.

VI. MARGINAL COST APPROACH AND RESULTS

Q. What were the basic approaches that you and your team used to estimate OTP's marginal costs of providing electricity service?

A. Our goal was to ensure that the marginal costing methods accurately reflect OTP's participation in the regional electricity market, as well as the Company's planning and operating activities. For marginal costs of energy and generation capacity, we used a forecast of regional market prices of energy and capacity. For transmission, we used the financial marginal costs inherent in the MISO rules for wholesale transmission rates. For distribution substations and trunk feeders, we relied upon OTP's recent and forecast growth-related capital expenditures and the load growth that is driving those investments. For local distribution facilities we based our estimates on the cost of typical equipment configurations for customers of various types and sizes. Our marginal customer costs are based on the cost of typical meters and service drops and recent levels of customer-related expenses. The summary sheets from our study are located in Exhibit ___(HSP-1), Schedule 1.

Q. Please explain in more detail how you developed estimates of marginal energy costs.

A. OTP provided a commercial forecast of monthly energy prices (by MISO-defined peak and off-peak periods) at the Minnesota hub. We used two years of historical day-ahead prices at that hub to shape the monthly forecast into an hourly forecast. We adjusted these hourly prices for cash working capital and marginal energy losses to produce a marginal energy cost at each voltage level of service. This is a standard approach that I typically use.

Q. Please explain in more detail how you developed estimates of marginal generation capacity costs.

A. According to MISO rules, OTP must maintain sufficient (owned or purchased) accredited capacity to provide a specific reserve margin over monthly peak loads. OTP provided a forecast of seasonal capacity prices, and indicated that although the MISO requirement is a monthly requirement, capacity needed in a given month must generally be purchased for the entire season. Using five years of historic hourly OTP loads, we estimated the relative probability that a given hour is likely to be the seasonal peak hour, and multiplied these probabilities by the forecast seasonal market price (adjusted upward by 15 percent[9]

[9] OTP is a member of MAPP and MISO uses MAPP's standard for its members who are also members of MAPP.

to account for the MISO reserve margin rule) to produce estimated hourly generation capacity costs. These market price estimates were also adjusted by a cash working capital component and marginal losses.

Q. Please explain in more detail how you developed estimates of marginal transmission costs.

A. According to MISO rules, transmission owners' transmission revenue requirements are recovered through two types of zonal charges: the Network Integration Transmission Service ("NITS") rate and the Network Upgrade Charge ("NUC"). The monthly NITS and NUC charges are applied on the basis of a load-serving entity's monthly peak demand. Working with OTP staff, we developed forecasts of the NITS and NUC charges. Consistent with the way these rates are applied, we time-differentiated these equal monthly rates using estimates of the relative probability of a given hour's being the monthly peak hour, using five years of historic hourly OTP loads. These costs were adjusted for cash working capital and marginal losses.

Q. Please explain in more detail how you developed estimates of marginal distribution substation and trunk feeder costs.

A. Working with OTP staff, we identified growth-related distribution substation and trunk feeder projects in the period 2005-2008. We converted this investment to 2009 dollars and divided by an estimate of non-coincident substation load growth over the same period. We annualized this typical investment per kW of load growth using an economic carrying charge and added estimates of O&M, overheads, and working capital requirements to produce an annual marginal cost. Using a statistical analysis of five years of load patterns on a sample of substations, we estimated the relative probability of a given hour's being the peak hour on distribution substations. We used these probabilities to time-differentiate the annual cost, and adjusted them for marginal demand losses.

Q. Please explain in more detail how you developed estimates of local distribution facilities marginal costs.

A. OTP provided estimates of the installed costs of local facilities (secondary lines, transformers, and the local portion of primary taps) for various customer types, sizes and

characteristics. OTP provided similar information on local facilities and lighting facilities for categories of area and street lights. We converted these investments into a cost per design kW by dividing by transformer capacity. These marginal investment values were annualized as described above for distribution substations.

Q. Please explain in more detail how you developed estimates of meter and service drop marginal costs.

A. OTP provided estimates of the installed costs of meter (and associate equipment) and service drops for various customer categories. These marginal investment values were annualized as described above for distribution substations.

Q. Please explain in more detail how you developed estimates of marginal customer-related expenses.

A. We analyzed five years of historical levels of customer-related expenses and excluded accounts that are either not marginal (e.g., marketing expenses), or not applicable in North Dakota (the costs of the Conservation Improvement Project (CIP) in Minnesota). We also excluded costs that are recovered in separate charges and, therefore, should not be included in marginal customer costs that will be used to set customer charges (e.g., cost of equipment provided to load control customers and costs of connection/reconnection). Working with OTP staff, we identified expenses that are incurred equally for all customers and those that are incurred for specific sub-sets of customers. Using the resulting weighting factors, we developed estimates of marginal customer-related expenses by class.

Q. How did you develop seasonal and diurnal costing/pricing periods?

A. The development of marginal energy, generation capacity, transmission and distribution substation/trunk feeder marginal costs resulted in hourly cost estimates for a typical weekday, Saturday and Sunday in each month. We summed these hourly costs across cost components and used the resulting total hourly marginal costs in a statistical model to identify periods that (1) group hours with similar costs, (2) are consistent with the number of periods that OTP believes is administratively feasible (two seasons and three diurnal periods), (3) give special attention to the coldest months within the broad

"winter" season, (4) and are reasonably simple and easy for consumers to remember. We concluded that the periods proposed by OTP in its recent Minnesota rate case, and approved by the Minnesota Commission, meet these criteria.

Q. Are these the same periods currently in use in North Dakota?

A. No. A variety of different pricing period definitions are incorporated in current North Dakota rates. For example, the Residential Demand Control Rate defines Winter as November – April and Summer as May – October. The new LGS TOD rate defines Winter as October – May and Summer as June – September. This latter seasonal definition is consistent with the seasons OTP is proposing in the case. There are also a variety of definitions of peak or critical hours. Several of the load control rates allow for control in up to 14 (unspecified) hours per day. The fixed time of delivery rates allow for control from 7 a.m. to 11 p.m. (16 hours per day). The diurnal periods in the LGS TOD rate include peak, shoulder and off-peak periods and vary by weekday, Saturday and Sunday. The periods used in designing OTP's proposed rates are based on up-to-date information and reflect the time patterns of hourly marginal costs we expect OTP to face in the next few years.

Q. How did you use these costing/pricing periods?

A. We summed the hourly costs (or averaged them, in the case of marginal energy costs) across periods. These marginal costs by period were the inputs for OTP's analysis of class marginal cost revenues and the starting point for OTP's proposed rate designs.

VII. IMPLICATIONS OF MARGINAL COST RESULTS FOR OTP'S RATE DESIGN

Q. What are the general implications of the marginal cost study results for OTP's rate design?

A. The marginal cost results suggest several changes that would improve the efficiency of OTP's North Dakota rates:

- Seasonality – Because it operates in MISO, OTP's summer marginal costs are higher than its winter marginal costs. Only the Dual Fuel, Residential Demand Control and Large General Service Time-of-Day (LGS TOD) rates currently have seasonally-

differentiated charges. Because seasonal differentials require no additional metering, incorporation of seasonal differentials in all rates[10] is a readily achievable and economically important step.

- Declining Blocks – Many of OTP's rates include declining energy blocks, and several also include declining demand blocks, with tail block prices that are well below marginal cost. These rate structures send a signal that OTP is rewarding customers for using more. Elimination of declining blocks would produce more efficient, equitable and less complex rate structures.

- Very Low Energy Charges –The Dual Fuel and Fixed Time of Delivery energy charges are not adjusted for the cost of energy and are significantly below marginal cost. These below-cost prices send inefficient price signals and create cross-subsidies. The energy prices in these rates should be increased significantly.

- Minimum Charges – The current minimum charges are generally well below marginal customer and facilities costs and fixed charges are below the corresponding marginal costs. Defining the minimum charge as the sum of more cost-reflective customer and facilities charges would reduce cross-subsidies within the rates.

- Residential Demand Control – The seasonal demand charges in the Residential Demand Control Rate are higher in the winter than in summer, reflecting OTP's pre-MISO cost relationship. These should be updated to reflect OTP's current seasonal pattern of capacity costs.

VIII. LIKELY EFFICIENCY IMPROVEMENTS FROM OTP'S PROPOSED RATE DESIGNS

Q. Are OTP's proposed rate structures likely to produce efficiency improvements?

A. Yes. I have analyzed the relationships among current charges, marginal costs and proposed charges (included in OTP Witness Prazak's direct testimony). OTP has recognized in its proposed rate designs the marginal cost implications described in the previous section. With a few minor exceptions, the important price signals for marginal kWh and kW use are closer to marginal cost in the proposed rates than in the current rates. As customers respond to the new prices, they are likely to make electricity consumption decisions that are more efficient.

[10] Except for lighting and siren rates.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application by Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in North Dakota	))))	Case No. PU-08-____

AFFIDAVIT OF DR. HETHIE S. PARMESANO

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Hethie S. Parmesano
Dr. Hethie S. Parmesano

Subscribed and sworn to before me,
this 24th day of October, 2008.

Patricia A. Alaniz
NOTARY PUBLIC

PATRICIA A. ALANIZ
Commission # 1622373
Notary Public -- California
Los Angeles County
My Comm. Expires Dec 13, 2009

OTTER TAIL POWER COMPANY
2009 MARGINAL CAPACITY (G+T+D) AND ENERGY COST
BY VOLTAGE LEVEL & COSTING PERIOD

		June - September			October - May		
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	**Secondary**						
	Monthly Capacity Costs (2009 Dollars per kW)	$9.73	$2.69	$0.04	$3.77	$0.88	$0.38
	Seasonal	$12.45			$5.03		
	Annual	$7.51					
	Energy Costs (2009 Cents per kWh)	13.276	10.176	6.061	11.914	9.690	6.840
	Seasonal	8.843			8.929		
	Annual	8.900					
	Sum of Marginal Energy and Capacity Costs (2009 Cents per kWh)						
	Seasonal	10.545			9.619		
	Annual	9.929					
(2)	**Primary**						
	Monthly Capacity Costs (2009 Dollars per kW)	$9.66	$2.66	$0.04	$3.74	$0.88	$0.38
	Seasonal	$12.36			$5.00		
	Annual	$7.45					
	Energy Costs (2009 Cents per kWh)	13.219	10.134	6.041	11.856	9.645	6.810
	Seasonal	8.809			8.887		
	Annual	8.861					
	Sum of Marginal Energy and Capacity Costs (2009 Cents per kWh)						
	Seasonal	10.498			9.573		
	Annual	9.882					
(3)	**Transmission**						
	Monthly Capacity Costs (2009 Dollars per kW)	$8.22	$1.79	$0.03	$3.39	$0.76	$0.09
	Seasonal	$10.04			$4.25		
	Annual	$6.18					
	Energy Costs (2009 Cents per kWh)	12.868	9.881	5.921	11.505	9.369	6.629
	Seasonal	8.599			8.637		
	Annual	8.624					
	Sum of Marginal Energy and Capacity Costs (2009 Cents per kWh)						
	Seasonal	9.971			9.220		
	Annual	9.471					

OTTER TAIL POWER COMPANY
SUMMARY OF MONTHLY MARGINAL FACILITIES-RELATED COSTS PER KW OF DESIGN DEMAND AND PER CUSTOMER

	Customer Class	Monthly Facility Cost per kW of Design Demand ($/kW) (1)	Estimate of Typical Design Demand by Customer kW (2)	Monthly Facility Cost per Customer ($/customer/mo.) (1)*(2) (3)
	Residential			
(1)	Urban	$1.37	8	$11.38
(2)	Rural	2.17	21	44.92
(3)	Apartment, Gas	1.39	9	12.65
(4)	Apartment, Electric	0.85	5	3.85
(5)	**Farm**	2.67	21	55.38
	Small Commercial			
(6)	Stand-Alone customer, overhead	0.64	50	32.10
(7)	Stand-Alone customer 3ph, overhead	0.82	75	61.57
(8)	Shared-customer 3ph, overhead	0.87	75	65.50
(9)	Stand-Alone customer, underground	1.06	50	52.91
(10)	Shared-customer 3ph, underground	1.50	75	112.47
	Large Commercial (Secondary Only)			
(11)	101-150kVa, 3ph	0.94	150	140.36
(12)	151-300kVa, 3ph	0.65	300	193.74
(13)	301-500kVa, 3ph	0.52	500	259.01
(14)	>501 kVa, 3ph	0.40	2,600	1,042.26
(15)	**Very Large Commercial (Secondary TOU)**			
	3000 kVa (LGS)	0.40	3,000	1,208.29
	Large Commercial (Primary)			
(16)	3000 kVa (LGS)	0.27	3,000	819.34
(17)	5000 kVa (LGS TOU)	0.29	5,000	1,459.13

OTTER TAIL POWER COMPANY
SUMMARY OF MONTHLY MARGINAL FACILITIES-RELATED COSTS PER COMPONENT

	Customer Class	Monthly Facility Cost per Component
		(1)
	Lighting	
(1)	Area Light 1 HPS 9 (no pole), underground	11.60
(2)	Area Light 1 HPS 9 (no pole), overhead	10.74
(3)	Street Light - (no light, no pole), underground	7.69
(4)	Street Light - (no light, no pole), overhead	6.84

OTTER TAIL POWER COMPANY
SUMMARY OF MONTHLY MARGINAL CUSTOMER-RELATED COSTS
BY CUSTOMER CLASS

			Monthly Marginal Customer Cost per Customer (2009$ /mo.)
	Residential		
R-01	Residential		$10.11
R-03	Residential Controlled Demand		16.77
R-91	Residential Water Heat Controlled		7.07
I-02	Residential Controlled Dual Fuel		7.80
I-03	Residential Controlled Deferred Load		10.82
I-04	Residential Fixed Time Of Delivery		10.82
M-42	Street Lighting		3.67
	Flood Lighting		3.67
	Sign Lighting		3.67
	Energy-Only Street & Area Lighting - Metered		4.26
	Energy-Only Street & Area Lighting - Non-Metered		3.67
	Athletic Field Lighting- South Dakota Only		7.02
	Commercial and Industrial		
G-01	General Service < 20 kW		17.51
G-01	General Service >= 20 kW		26.50
G-02	General Service (Control Demand)		36.39
F-61	Farm Service		12.34
C-02	Large Commercial Service		
		Secondary	254.44
		Primary	303.69
C-03	Large General Service (Real Time Pricing)		
		Secondary	351.89
		Primary	400.99
C-04	Large General Service (Off Peak Rider)		
		Secondary	351.89
		Primary	400.99
C-09	Large General Service (Time Of Use)		
		Secondary	351.89
		Primary	400.99
R-91	Commercial Water Heat Controlled		6.33
I-01	Large Commercial Controlled Dual Fuel		34.17
I-02	Small Commercial Controlled Dual Fuel		14.35
I-03	Small Commercial Controlled Deferred Load		17.23
I-04	Small Commercial Fixed Time Of Delivery		17.23
I-06	Bulk Interruptible		405.87
M-03	Irrigation Service		23.56
M-04	Commercial Time Of Use		259.06
	Street Lighting		3.67
	Flood Lighting		3.67
	Sign & Area Lighting		3.67
	Energy-Only Street & Area Lighting - Metered		4.26
	Energy-Only Street & Area Lighting - Non-Metered		3.67
	Miscellaneous		
	Streetlighting		3.67
	Other Public Authority		25.21

HETHIE PARMESANO
Senior Vice President

Dr. Hethie Parmesano is an expert on electricity, gas, and water industry costing, pricing, sector structure, and regulation. In recent years she has been involved with projects dealing with regulation, restructuring, and privatization of state-owned utilities in a variety of different settings, including the U.K., Spain, Saudi Arabia, India, Ireland, Japan, Kenya, Greece, El Salvador, Argentina, Barbados, Brazil, Cambodia, and Mexico. Dr. Parmesano also has extensive experience with costing, pricing, and restructuring issues in the U.S. and Canadian utility industries. Her work both in the U.S. and abroad has involved issues such as regulating distribution companies, metering and settlement for customers with retail access, transmission pricing, rate structure for Provider-of-Last-Resort service, backup rates for distributed generation, real-time pricing and other innovative pricing options, and efficient pricing of bundled service. She teaches seminars on costing and pricing topics, directs a NERA-sponsored industry group called the Marginal Cost Working Group, and has testified widely on utility matters before regulatory agencies.

Education

Cornell University
Ph.D., Economics, 1973
M.A., Economics, 1971
Honors: received a National Science Foundation Traineeship
Major Areas: economic development, international economics, and economic theory

Colby College
B.A., *cum laude*, Economics, 1968

Professional Experience

NERA Economic Consulting

1980- Senior Vice President, Vice President, Senior Consultant, Senior Economic Analyst

Dr. Parmesano has been involved in numerous economic studies for electric, gas, and water utilities. She has specialized in issues related to marginal cost pricing, regulatory and electricity industry reform, strategic planning and resource planning. She has been involved in electric industry restructuring efforts in the U.S., Canada, U.K., Ireland, Greece, Kenya, Mexico, Argentina, Brazil, Spain, El

Salvador, Cambodia, Japan, and India. She has testified in regulatory proceedings in Arizona, California, Colorado, Florida, Idaho, Illinois, Indiana, Iowa, Maine, Maryland, Massachusetts, Minnesota, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Texas, Utah, and Alberta and Nova Scotia, Canada. Her responsibilities include teaching a series of seminars on marginal costing for the staffs of electric utilities and regulatory commissions.

Los Angeles Department of Water and Power (LADWP)

1977-1980 Staff Economist
Participated in a variety of rate studies and other economic analyses. Responsibilities included testimony at LADWP's PURPA hearings on electric rates, membership in the California Marginal Cost Pricing Task Force, and participation in environmental impact studies of proposed LADWP actions and projects.

Los Angeles City Planning Department

1973-1977 Economic Analyst
Participated in employment and demographic forecasting as well as economic impact analyses of city plans. Was also on the faculty at California State Polytechnic University at Pomona, teaching graduate courses in urban research techniques and computer applications in planning.

Languages

English – Excellent
Spanish – (reading) Good
French – (reading) Good

Project Experience

Otter Tail Power Company, Fergus Falls, MN 2007-08. Prepare a report on the appropriateness of phasing out or eliminating declining block rates; update marginal cost study; recommend marginal cost-based rate design for major customer classes; provide expert testimony in rate case in support of proposed marginal cost-based rates.

Otter Tail Power Company, Fergus Falls, MN 2006. Developed a revenue-neutral, marginal-cost-based, time-of-day rate for large general service electric customers. Assignment included extensive analysis of alternative pricing periods.

Alberta Electric System Operator, Canada 2006. Conducted a review of AESO's transmission cost-of-service study and stakeholder comments.

Newfoundland Power, Canada 2006. Prepared a study of NP's marginal distribution and customer costs, and computed marginal cost revenues (all elements) by rate class.

Fair Trading Commission of Barbados, Barbados 2006. Conducted marginal and embedded cost studies of Barbados Light & Power Co., Ltd; reviewed and commented on the utility's regulatory accounting policies, system planning and load forecasting practices; advised the Commission on rate base and rate of return policies; assessed the appropriateness and feasibility of time-of-use rates in Barbados; and provided training to Commission staff.

Newfoundland & Labrador Hydro, Canada 2006. Directed a marginal cost study of NLH's generation and transmission systems, and implications of the marginal cost results for rate design.

Xcel Energy, Minneapolis, MN 2005. Prepared a marginal cost study for filing in Xcel Energy's rate case in Minnesota.

Midwestern Electric Utility, Midwestern US, 2004-05. Directed a study of the utility's marginal costs of electric distribution service.

Otter Tail Power Company, Fergus Falls, MN 2004-05. Directed a study of the distribution costs avoided as a result of demand-side management, and the design and size of credits for distribution costs avoided as a result of distributed generation.

Nicor Gas, Naperville, IL 2004-05. Directed a marginal cost of gas study and advised the utility on a marginal cost-based gas delivery rate structure. Filed testimony in Nicor Gas' rate case on these issues.

Manitoba Hydro, Winnipeg, Manitoba Canada 2004-05. Directed a study of the appropriateness of time-of-use and inverted block electricity rate structures for Manitoba.

NSTAR Electric, Westwood, MA 2004. Testified for NSTAR on issues related to standby rates for customers with generation.

Manitoba Hydro, Winnipeg, Manitoba Canada 2004. Directed a study of appropriate methods for classification and allocation of generation and transmission costs in an embedded cost-of-service study for a hydro-dominated utility with significant wholesale transactions.

Commission for Energy Regulation of Ireland, Dublin, Ireland, 2001, 2002, 2004-05. Engaged by the Commission for Electricity Regulation (CER) to assist in the evaluation of the electricity supply tariff submission of the retail energy supplier. Role was to (1) help determine tariff objectives and constraints; (2) develop cost-based illustrative tariffs that would meet those objectives as much as possible, along with transition measures that could be used to move tariffs toward a more optimal set; (3) compare the company's submission to the illustrative tariffs; and (4) make recommendations to CER. Currently directing a major study of electricity transmission, distribution, and supply tariff structures, which involves conducting a marginal cost study and screening alternative structures.

Los Angeles Department of Water and Power (LADWP), Los Angeles, CA, 2003-present. Leading a group providing assistance to Los Angeles' municipal utility in the areas of marginal

and embedded costing, tariff design, tariff development process, and support in tariff-related litigation.

Portland General Electric Company (PGE), Portland, OR 2003-04. Assisted PGE in settlement negotiations regarding partial requirements service to distributed generation.

Electricity Regulatory Board of Kenya, Nairobi, Kenya, 2001-03. Led a NERA team charged with helping the ERB develop a new electricity tariff policy consistent with fair and effective regulation as well as with the country's goals of economic development, private capital attraction, and poverty elimination. NERA's work included recommended policies on revenue requirement determination, revenue allocation, tariff design, transition mechanisms, connection charge policy, transmission pricing, purchased power agreements, and retail competition. The NERA team also prepared models for use in tariff review by the ERB staff and provided training to the ERB and other stakeholders.

Mid-western US utility, 2001. Engaged to conduct a qualitative review of the company's electricity tariffs as the first phase of a three-phase project to restructure tariffs. NERA found that the current tariffs were not well-designed to deal with the cost and operating changes resulting from the newly-formed ISO, that the company's load control programs were not designed for the purposes for which they are currently being used, and that complex traditional tariff structures could be eliminated with greater use of time-of-use pricing structures.

Mid-western US Public Power District, 2001. Helped a mid-western public power district update its wholesale rate structure to better reflect marginal production costs, NERA prepared estimated of marginal generation capacity costs, developed a set of optimal demand charges based on marginal cost, and determined whether the new production demand charges being proposed were moving toward those optimal levels.

Direct Service Industries, Portland, Oregon, 2001. Assisted the DSIs in their intervention in the rate case of the Bonneville Power Administration, arguing that implementing rates for all consumer groups based on marginal cost prices at the margin (tiered rates) was a superior solution to the problem of high-priced marginal resources than using average pricing for all.

Public Power Corporation of Greece (PPC), Athens, Greece, 2001. Participated with other NERA economists in development of a draft Distribution Tariff Code, covering all aspects of distribution tariff setting and line extension policies. The project included preparation of estimates of the marginal costs of electricity distribution in Greece, the distribution company's revenue requirement, and sample marginal cost-based tariffs that produce that revenue requirement.

Rochester Gas & Electric Corporation (RG&E), Rochester, New York, 2001-2003. Led group that prepared studies of the marginal costs of gas and electric service for RG&E. Provided testimony on these studies and efficient tariffs developed from them, including a price floor for economic development contracts, and backup rates for distributed generation.

New York State Electric & Gas Corporation (NYSEG), Binghamton, NY, 2000-2003. Assisted NYSEG in the development of updated methods for computing marginal costs of electricity service. The assignments included use of marginal costs in setting economic development rates.

Large Southern US Electric Utility, 2001. Led a group of economists in the development of a retail pricing strategy for an investor-owned utility. The strategy will help the company prepare for coming retail access and implementation of an RTO.

Brazilian Electricity Regulatory Agency (ANEEL), Brasilia, Brasil, 2000. Directed a NERA team assisting the regulatory commission in developing policies and procedures for setting and revising electricity tariffs for the newly privatized distribution companies in the country.

Secretaria de Energia, Mexico City, Mexico, 1999-2000. Was part of a NERA team advising the Mexican government on electric industry restructuring. Directed the Tariffs Task Force for this project.

Andhra Pradesh Electricity Regulatory Commission, Hyderabad, India, 1999-2000. Directed a NERA team providing tariff-related assistance to the newly formed regulatory commission in the state of Andhra Pradesh. Responsibilities included staff training, development of a tariff philosophy, drafting of tariff filing guidelines and associated commission procedures, and on-site assistance to the commission during its review of the first tariff filed by the transmission and distribution licensee. Led team that developed costing and tariff design models for use by the commission and its staff.

US Power Exchange, 1999. Led group that developed an unbundled cost of service study for a US power exchange. The project included identifying the activities associated with each service provided, determining which of the costs of each activity were fixed and which variable, identifying cost drivers for each type of cost, and recommending methods for allocating common costs to minimize pricing distortions.

Ontario Hydro Services Company, Toronto, Ontario, 1999. Provided assistance to OHSC in the development of transmission rates, including cost-of-service allocations, evaluation of alternative rate designs, and participation in the stakeholder process.

Salt River Project (SRP), Phoenix, Arizona, 1998. At the request of the Board of Directors of the Salt River Project (SRP), reviewed SRP Management's proposed bundled and unbundled electric price plans and provided recommendations to the Board. The focus of the review was on (1) the proposed class allocations; (2) the proposed price plans; (3) the cost studies on which they are based; and (4) the relationship between the bundled and unbundled prices.

Rochester Gas & Electric Corporation (RG&E), Rochester, New York, 1997. Directed a NERA team that undertook the cost studies and rate design analysis for pricing new services that RG&E will be offering to electricity retailing companies when retail open access is offered. These services include special metering, non-standard billing, and administration of balancing and settlement.

Government of Argentina, Argentina, 1997. Advised the Government of Argentina on ways to improve the operation of the electricity sector, with special emphasis on expansion of retail access, metering and settlement mechanisms, distribution tariffs, retail open access, demand-side management, distortions caused by taxes and subsidies, and quality standards and penalties for distribution concessionaires. This effort was a part of the first formal review -- undertaken by NERA -- of the structure and functions of the Argentine electricity sector since its radical reform in 1992.

Orissa Electricity Regulatory Commission, Orissa, India, 1994-1999. Participated on the NERA team responsible for the design and implementation of Orissa Electricity Regulatory Commission, the first independent state regulatory commission in India. The Commission was created as a key part of the overall reform and restructuring of the Orissa electric state power sector. Responsibilities included: organizational design; development of rules and procedures for tariff approval; participation in drafting of enabling legislation; design of regulations and license; design and implementation of on-site regulatory training; on-site consulting on marginal cost analysis; and rate design.

Banco Brascan, Natal, Brazil, 1997. Was part of a NERA team assisting Banco Brascan to develop a proposed tariff system, efficiency program, and regulatory mechanism to be detailed in the concession contract for the privatization of COSERN, an electric distribution company in northeast Brazil. Work included analysis of the tariff structure, regulatory policies, and socio-political factors likely to affect revenues of the new firm.

Potential Investors in Electricity Distribution, El Salvador, 1997. Participated in a presentation to introduce potential investors to the El Salvadoran electricity sector. The presentation explained the reform program and regulatory structure and discussed areas of concern for investors in privatized distribution companies.

Iberdrola, Spain, 1997. Participated on a NERA team advising Iberdrola, a vertically-integrated electric utility in Spain, during the restructuring of the country’s electric industry. Provided advice on tariff structure, the cost basis for prices, mechanisms for recovery of strandable costs, and regulatory mechanisms. Work included providing training sessions to Iberdrola staff members.

Manitoba Hydro, Winnipeg, Manitoba, 1997. Led group that prepared a marginal cost study and report on the appropriateness of marginal cost-based electric rates for Manitoba.

New York State Electric & Gas Corporation (NYSEG), Binghamton, New York, 1997. Helped NYSEG develop its retail rate structure applicable when the utility’s retail customers are eligible for retail open access. Work included testimony before the New York State Public Service Commission.

Nova Scotia Power Incorporated, Halifax, Nova Scotia, 1995. Testified before the Nova Scotia Utility and Review Board regarding proposals to restructure rates to improve the utility’s competitive position.

Haryana Power Sector, Haryana, India, 1994-1995. Was a member of the NERA team preparing a major restructuring study of the Haryana State Electricity Board. The study examined all aspects of the power sector and recommended that the Haryana State Electricity Board be broken up into separate generation, transmission, and distribution entities. The project output included a detailed plan for implementing the restructuring proposal.

Los Angeles Department of Water and Power (LADWP), Los Angeles, California, 1991-92. Served as principal advisor to the Los Angeles Department of Water and Power in connection with a major restructuring of water rates. Work involved participating with the Mayor's Blue Ribbon Committee on Water Rate Structure. Attended virtually every meeting of the full committee and its subcommittees, offering advice on costing and rate design. One major task was to determine whether the rate structures being contemplated by the Committee were likely to cause financial difficulties for the Department. Also prepared a study of the marginal costs of the Los Angeles water system, a modification of which was ultimately used by the Committee to develop its inverted block rate proposal to the Mayor.

Publications

"Major Electricity Customer Pricing Options: The Case of Saudi Arabia," *The Electricity Journal*, January 2008

"Rate Design Is the No. 1 Energy Efficiency Tool," *The Electricity Journal*, July 2007.

"Portable Entitlements: Unlikely to Resolve Transition Dilemma," Letter to the Editor, *The Electricity Journal*, November 2004.

"The Thaw: The End of the Ice Age For American Utility Rate Cases -- Are you Ready?" *The Electricity Journal*, July 2004

"Standby Rates Issue is More Nuanced Than Authors Let on," Letter to the Editor, *The Electricity Journal*, November 2003, pp. 3-4.

"Standby Service to Distributed Generation Projects: The Wrong Tool for Subsidies" *The Electricity Journal*, October 2003.

"Making Every Electricity Consumer a Market Participant (Putting Demand Back in the Equation)," *The Electricity Journal*, April 2003.

"Use Tax Policy, Not Cross-Subsidies, to Aid the Poor," Letter to the Editor, *The Electricity Journal*, July 2002.

"An Introduction to Financial Transmission Rights," with Hamish Fraser and Karen Lyons, *The Electricity Journal*, December, 2000.

"Residential Electricity Tariffs: Getting the Structure Right," with Veronica Lambrechts, presented at online conference Energy Resource 2000, May 15-29, 2000.

"Letter to the Editor: Argument for Embedded Costs Has Basic Flaws," with Amy McCarthy, *The Electricity Journal* , March 1999.

"The Effects of the 1990 Clean Air Act on System Dispatch and Marginal Costs," with Bruce Ambrose and John Wile, *The Electricity Journal*, November 1993.

"The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey," NERA Working Paper, February 1992.

"Discount Electric Rates: Who Should Bear the 'Cost'?," with Carrie J. Hightman, NERA Working Paper, June 1991.

"Avoided Cost Payments to Qualifying Facilities: Debate Goes On," *Public Utilities Fortnightly*, September 17, 1987.

Impact of Rate Structure on Demand-Side Management Programs - Phase I Report, EPRI EM 4791, September 1986.

"Comments on John Wender's Article On Class Revenue Requirements," *Electric Potential*, Vol. 1, No. 2, November December 1985.

"The Evolution in U.S. Electric Utility Design," with Catherine S. Martin, *Annual Energy Review*, 1983.

"Pricing the Electrical Output of Cogeneration and Small Power Projects," *NERA Topics*, October 1983.

Testimony

Direct, Rebuttal and Surrebuttal testimony regarding rate design on behalf of Otter Tail Power Company. Before the Minnesota Public Utility Commission, MPUC Docket No. E-017/GR-07/1178, Oct. 2007 – Mar. 2008.

Prefiled direct testimony regarding proposed time-of-day rate for large general service customers on behalf of Otter Tail Power Company. Before the State of North Dakota Public Service Commission, Docket No. PU-07-03, June 2007.

Expert Report and associated oral testimony regarding alleged overcharging of governmental electric customers by the Los Angeles Department of Water and Power. Los Angeles County, Los Angeles Unified School District, Los Angeles County Metropolitan Transportation Authority, and Los Angeles Community College District ex rel. Barakat Consulting Incorporated and Samir F. Barakat, Plaintiffs v. Los Angeles Department of Water and Power and Does 1-50, Defendants. Superior court of the State of California for the County of Los Angeles, No. SCVSS100 293. August 2006 – January 2007.

Direct testimony regarding natural gas distribution marginal costs and rate design on behalf of Nicor Gas before the Illinois Commerce Commission. Filed November 2004.

Rebuttal testimony regarding standby rates on behalf of NSTAR before the Massachusetts Department of Telecommunications and Energy. Case DTE 03-121, April 2004.

Direct testimony regarding marginal gas and electricity costs on behalf of Rochester Gas & Electric Corporation before the New York Public Service Commission. RG&E was proposing to increase the degree to which its tariff structures reflect marginal costs. Case No. 02-E-0198, February 15, 2001.

Direct testimony regarding the supplemental proposal of the Bonneville Power Administration on behalf of the Direct Service Industries. The Companies on whose behalf this testimony is filed were proposing that BPA adopt a tiered rate structure, with the second tier price set at market price, as a substitute for BPA's proposal to charge a rolled-in average of the cost of energy. Case No. WP-02-E-DS/AL-02, March 2001.

Direct and supplemental testimony before the Public Utilities Commission of Ohio on behalf of Dayton Power & Light Company regarding shopping credits for consumers who choose another supplier of generation services and a forecast of switching rates by consumer category. Case No. 99-1687-EL-ETP, March and May 2000.

Rebuttal testimony before the Illinois Commerce Commission on behalf of Illinois Power Company related to the advisability of unbundling revenue cycle services; the appropriate basis for credits for these services, if unbundled; and the role of marginal costs in a world of retail access, February 10, 1999.

Rebuttal and Surrebuttal testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company regarding Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design, June 26, 1998 and August 31, 1998.

Testimony before the Salt River Project Board of Directors regarding SRP Management's Proposed Electric Price and Service Plan Changes Effective December 31, 1998, October 1, 1998.

Rebuttal testimony before the Public Utility Commission of New Mexico in the Matter of the Commission's Investigation of the Rates for Electric Service of Public Service Company of New Mexico, Case No. 2761, May 6, 1998, regarding electric rate unbundling.

Direct testimony before the Public Utility Commission of New Mexico in the Matter of the Petition of the City of Albuquerque to institute a retail pilot load aggregation program and its request for related approvals, Case No. 2782, April 16, 1998, regarding stranded cost recovery and other aspects of a pilot retail access program.

Testimony before the Public Utility Commission of New Mexico on behalf of Public Service Company of New Mexico, Case No. 2761 to explain the institutional conditions necessary for any reasonable unbundling of PNM's retail electricity rates, November 3, 1997.

Affidavit filed with the New Mexico Supreme Court in *Public Service Company of New Mexico vs. the New Mexico Public Utility Commission,* Case No. 2761 in support of PNM's request for a writ of mandamus, and request for stay regarding the NMPUC's order that PNM prepare unbundled electricity rates, October 8, 1997.

Direct and Responsive Testimony before the New York Public Service Commission on behalf of New York State Electric & Gas Corporation as part of NYSEG's rate/restructuring filing in compliance with Public Service Commission Opinion and Order 96-12 regarding rate design for retail access, September 27, 1996 and April 21, 1997.

Testimony before the Oregon Public Utility Commission on behalf of Portland General Electric Company - Case UM 827 on methods for estimating the marginal costs of electric utilities, April 7, 1997.

Rebuttal Testimony before the California Public Utilities Commission on behalf of Southern California Gas Company in the Biennial Cost Allocation Proceedings regarding two specific marginal cost issues—inclusion of replacement costs for existing equipment in marginal cost estimates and use of the "new customer only" approach to customer costs, August 8, 1996.

Direct Testimony before the Nova Scotia Utility and Review Board on behalf of Nova Scotia Power Incorporated in the matter of the Public Utilities Act, R.S.N.S. 1989, C. 380, as amended and in the matter of an Application of Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations; regarding rate restructuring to improve the utility's competitive position, December 11, 1995.

Rebuttal Testimony before the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company in Cause No. 40125, regarding an experimental real-time pricing tariff for large industrial customers, February 28, 1995.

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission, Docket Nos. 94-0134 and 94-0223 on behalf of Illinois Power Company, August 1994 regarding Illinois Power's proposal for a tariff that would allow contracts to prevent residential, commercial, and industrial electric customers from choosing an uneconomic municipal by-pass option.

Direct and Rebuttal Testimony before the Public Utility Commission of Texas, Docket No. 12957-TST-17-0 on behalf of Houston Lighting & Power Company, July 1994 regarding Houston Lighting & Power's proposal for a tariff to permit negotiated contracts with electric customers who have uneconomic bypass options.

Testimony and Comments before the Public Service Commission of Nevada, Docket No. 93-11045 on behalf of Nevada Power Company, June 2, 1994 and June 23, 1994 regarding

competition, standby rates and environmental externalities in marginal energy costs. (Testimony and Comments were filed, but case settled before hearings.)

Prefiled Rebuttal Testimony before the State of Maine Public Utilities Commission, Docket No. 92-315 on behalf of Central Maine Power Company, August 18, 1993 regarding resource planning, rate structures, and avoided cost investigation.

Prefiled Rebuttal Testimony before the Indiana Utility Regulatory Commission in Cause No. 39623 on behalf of Northern Indiana Public Service Company, May 1993, regarding approval of an electric service contract with Omni Forge, Inc.

Direct Testimony before the Public Utilities Commission of Ohio on behalf of the Dayton Power and Light Company, Case No. 92-594-EL-FOR, February 5, 1993 regarding avoided cost study and appropriateness of estimates used in evaluating DSM programs. (Testimony was filed but case settled before hearings.)

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket No. 91-0335, February 25 and March 30, 1992 regarding marginal costing and marginal cost-based rates.

Direct Testimony before the Public Utilities Commission of Ohio on behalf of Cincinnati Gas and Electric Company, Case No. 91-372-EL-UNC, August 27, 1991 regarding avoided cost pricing.

Direct Testimony before the Public Service Commission of Maryland on behalf of Baltimore Gas and Electric Company, Case No. 8241, Phase II, July 19, 1991 regarding avoided cost pricing.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, Docket No. 89-0276, December 27, 1989 and January 29, 1990 regarding revenue treatment of the differential between regular and economic development rates.

Expert testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket 90-0006, December 8, 1989 regarding marginal cost rate design.

Testimony before the New Mexico Public Service Commission, on behalf of Public Service Company of New Mexico, NMPSC Case 2262, November 1, 1989 and December 8, 1989 regarding marginal costs and incentive energy rates.

Testimony before the State of Maine Public Utilities Commission, on behalf of Central Maine Power Company, Docket No. 89-68, July 31, 1989 regarding marginal costs.

Expert testimony before the State of Maine Public Utilities Commission, regarding Central Maine Power Company's Application for Fuel Cost Adjustment and Establish¬ment of Short-Term Energy-Only Rate for Small Power Producers Less Than 1 MW, on behalf of Central

Maine Power Company, Docket No. 89-80, April 14, 1989 regarding energy and capacity components of fuel clause.

Testimony before the Alberta Public Utilities Board and Energy Resource Conservation Board, on behalf of TransAlta Utilities Corporation, Docket No. RE870621, October 1987 regarding independent power producer payments.

Testimony before the Public Service Commission of Utah, on behalf of Utah Power & Light Company, Docket No. 87-035-12, August 17, 1987 regarding marginal costs.

Expert testimony before the Public Service Commission of Nevada, on behalf of Nevada Power Company, Docket No. 86-1201, February 5, 1987, regarding avoided costs.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, in *A. E. Staley Manufacturing Co. v. Illinois Power Company*, Docket No. 86-0038, September 12, 1986 and November 25, 1986 regarding standby rates.

Expert testimony before the Indiana Public Service Commission, on behalf of Northern Indiana Public Service Company, in Cause No. 38045, June 16, 1986 regarding potential for cogeneration and small power production.

Expert testimony before the Indiana Public Service Commission, on behalf of Northern Indiana Public Service Company, in Cause No. 37863, April 1986 regarding capacity credit formula for qualifying facilities (QF).

Expert testimony before the Maine Public Utilities Commission, on behalf of Central Maine Power Company, in Central Maine Power Company Cost of Service and Rate Design, Docket No. 86-2, February 14, 1986 regarding marginal costs.

Expert testimony on behalf of the Los Angeles Department of Water and Power et al., in the Bonneville Power Administration's 1985 Wholesale Rate Case, November 1984 regarding nonfirm rate design.

Expert testimony before the Superior Court of the State of California for the County of Los Angeles, on behalf of Los Angeles Department of Water and Power, in *California Manufacturers' Association, et al. vs. City of Los Angeles*, March 1984 regarding marginal cost-based rate restructuring.

Expert testimony on behalf of the Public Service Company of New Mexico, in Docket 1835, before the New Mexico Public Service Commission, February 1984 regarding marginal costs.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1983 Wholesale Rate Case, June 1983 regarding nonfirm rate design.

Testimony before the Florida Public Service Commission, on behalf of Metropolitan Dade County, in Docket No. 820406 EU, April and May 1983 regarding QF payments.

Testimony before the Texas Public Utility Commission, on behalf of Houston Lighting and Power Company, in Docket No. 4712, December 1982 regarding avoided costs.

Expert testimony before the Idaho Public Utilities Commission, on behalf of Idaho Power Company, in Case Nos. U 1006 197 and U 1006 200, October 1982 regarding QF payments.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1982 Wholesale Rate Case, May 1982 regarding ratemaking objectives.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1981 Wholesale Rate Case, February 1982 regarding nonfirm rate design.

Testimony before the Maine Public Utilities Commission, on behalf of Central Maine Power, in Docket No. 80 66, January 1982 regarding marginal cost-based rates.

Expert testimony before the Corporation Commission of the State of Oklahoma on behalf of the Commission, in Cause No. 27208, November 1981 regarding QF payments.

Expert testimony before the Minnesota Public Service Commission on behalf of the State of Minnesota Department of Public Service, in Docket No. E017/6R 81 315, November 1981 regarding marginal costs.

Expert testimony before the Public Service Commission of Utah on behalf of Utah Power & Light Company, in Case No. 80 999 09, March 1981 regarding marginal costs.

Expert testimony before the Colorado Public Utilities Commission on behalf of the City of Aspen, Pitkin County and Windstar Foundation, in Case No. 5970, November 1980 regarding cogeneration.

Testimony before the Idaho Public Utilities Commission on behalf of Utah Power & Light Company, in Case Nos. U 1009 107 and P 300 18, August 1980 regarding marginal cost-based rates.

Expert testimony before the Iowa State Commerce Commission on behalf of the Commission, in Docket No. RMU 80 1, July 1980 regarding marginal cost-based rates.

Expert testimony before the Board of Directors, on behalf of the Board of Directors in the 1980 Salt River Project Electric Rate Case regarding revenue requirement.

Expert testimony before the LADWP Board of Commissioners in LADWP's PURPA hearings, 1980 regarding appropriateness for LADWP's of adoption of PURPA standards.

Consulting Reports

"Declining Block Rate Elimination Plan, " September 2007, prepared for Otter Tail Power Company.

"Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design," July 2006, prepared for Newfoundland and Labrador Hydro.

"Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission," May 2006, prepared for Newfoundland and Labrador Hydro.

"Classification and Allocation Methods for Generation and Transmission in Cost-of-Service Studies," February 2004, prepared for Manitoba Hydro.

"Survey of Electric Utility Embedded Cost Methods for Generation and Transmission in North America," December 2003, prepared for Manitoba Hydro.

"Electric Utility Use of Marginal Costs: US Case Studies," July 2003, prepared for JANUS (Tokyo, Japan).

"Review of Comments on NERC Tariff Methodology," January 18, 2001, prepared for National Energy Regulatory Commission of Ukraine.

"DP&L Report on Shopping Incentives," December 1999, prepared for Dayton Power & Light Company.

"An Introduction to System Benefits Charges," May 11, 1998, prepared for The Salt River Project.

"Analysis of the Reform of the Argentine Power Sector: Final Report," January 1998, prepared for the Ministerio de Economía y Obras Servicios Públicos, Secretaría de Energía y Puertos of Argentina.

"Development of RG&E's Fees for New Services," February 19, 1998, prepared for Rochester Gas & Electric Corporation.

"Using Capacity Contracts and Energy Savings To Estimate Marginal Generation Capacity Costs -- Contracts: They're Not Just for Lawyers Anymore," October 27, 1997 prepared for the Marginal Cost Working Group.

"Rate Design for Retail Access," October 1, 1996 prepared for the Marginal Cost Working Group.

"Preliminary Evaluation of the Electricity Tariffs of Peninsular Spain," September 16, 1996 prepared for Iberdrola.

"Use of LRIC by the Telecommunication Industry," April 16, 1996 prepared for the Marginal Cost Working Group.

"The Time-Differentiated Marginal Costs of the Orissa State Electricity Board Constituent Companies," February 1996.

"Implications of Retail Wheeling for the State of [Midwestern state]," Confidential, July 1995.

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"Restructuring Study for the Haryana (India) Power Sector Restructuring Project," January 1995 prepared for Haryana State Electricity Board.

"Linking Integrated Resource Planning and Rate Design: Comments on the Tellus Institute's Report for NARUC," October 1994 prepared for the Marginal Cost Working Group.

"The Time-Differentiated Marginal Costs of the Los Angeles Department of Water and Power," November 30, 1993.

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"The Time-Differentiated Marginal Costs of the City of Anaheim Public Utilities Department, Electric Services," December 11, 1992.

"The Marginal Costs of the Los Angeles Department of Water and Power Water System," May 27, 1992.

"The Time-Differentiated Marginal Costs of New York State Electric and Gas Corporation," Revised March 9, 1992.

"The Time-Differentiated Marginal Costs of Public Service Gas and Electric Company," November 22, 1991.

"A&G and General Plant Loaders: Are They Marginal?" April 1991.

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"Cut-Off Points in the Differential Revenue Requirements Avoided Cost Method," April 1989.

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"An Evaluation of the Feasibility of a Common Costing Methodology," Central Maine Power Company, October 28, 1987.

"Report on An Audit of the Resource Planning Activities of the Department of Water and Power of the City of Los Angeles," December 24, 1986.

"Standby Rates for Cogenerators and Small Power Producers," Illinois Power Company, November 15, 1985.

"Avoided Cost Payments for Off System Qualifying Facilities," San Diego Gas and Electric Company, September 17, 1985.

"A Methodology for Comparative Risk Analysis: Introducing Competition into Avoided Cost Pricing," City of Houston Public Service Department, June 1984.

"Cogeneration in the United States," prepared for Kansai Electric Power Company, Inc., September 1983.

"An Analysis of the Time Differentiated Marginal Costs of Rochester Gas and Electric Corporation," December 1982.

"An Analysis of Electric Utility Tariffs and Contracts for Cogenerators and Small Power Producers," September 1982.

"An Analysis of the Time Differentiated Marginal Costs of Central Illinois Light Company," June 1982.

"An Updated Analysis of the Time Differentiated Marginal Costs of Central Illinois Light Company," prepared for Central Illinois Light Company, December 1981.

"An Updated Analysis of the Time Differentiated Marginal Costs of Otter Tail Power Company," prepared for the Minnesota Department of Public Service, November 1981.

"An Analysis of the Costs Avoided by Oklahoma Gas and Electric Company When Energy and Capacity are Supplied by Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, September 1981.

"Summary of Concerns Expressed by Oklahoma Utilities Pertaining to Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, September 1981.

"Summary of Concerns Expressed by Potential Cogenerators and Small Power Producers in Oklahoma," prepared for the Oklahoma Corporation Commission, August 1981.

"Measuring Avoided Costs for Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, June 1981.

"An Analysis of the Time Differentiated Marginal Costs of Central Maine Power Company," prepared for Central Maine Power Company, April 1981.

"Salt River Project Review of Proposed 1981 Rate Increase," prepared for the Board of Directors of the Salt River Project Agricultural Improvement and Power District, December 1980.

"An Analysis of the Time Differentiated Marginal Costs of Utah Power & Light Company," prepared for the Utah Power & Light Company, October 1980.

"An Analysis of the Time Differentiated Marginal Costs of Hawaiian Electric Company," prepared for Hawaiian Electric Company, October 1980.

"An Analysis of the Time Differentiated Marginal Costs of Idaho Power Company," prepared for Idaho Power Company, September 1980.

Presentations and Speeches

"Inter-Class Clashes Over Rising Revenue Requirements: Economic Issues," presented at Utilities Rate Case Issues and Strategies Conference, Las Vegas, NV, February 8, 2008.

"Rate Design in the Campaign for Energy Efficiency," presented at Utility Rate Case Issues and Strategies Conference, Las Vegas, NV, February 22, 2007.

"Making Every Electricity Consumer a Market Participant (Putting Demand Back in the Equation)," a presentation to the California Municipal Rates Group, Sacramento, CA, June 2003.

"Line Extension Policies in the Restructured US Electric Industry," a presentation to the Marginal Cost Working Group (MCWG), Myrtle Beach, SC, April 2001.

"Residential Electricity Tariffs: Getting the Structure Right," a presentation to the Marginal Cost Working Group (MCWG), Santa Fe, NM, October 4-6, 2000.

"Line Extension Policies – Due for a Change?" a presentation to the Marginal Cost Working Group (MCWG), Las Vegas, NV, April 3-5, 2000.

"Antitrust Concerns in Retail Access: Learning the Lingo," a presentation to the Marginal Cost Working Group (MCWG), Cambridge, MA, April 27-29, 1998.

"The Role of Securitization of Stranded Costs in a Future Competitive Electric Industry," a presentation to the Conference on Securitization of Electric Utility Stranded Costs, San Francisco, California, October 6, 1997.

"Electric Rate Structure," a presentation to the University of Florida International Training Program on Utility Regulation and Strategy, Florida, January 21, 1997.

"Is Your Contract or Rate Profitable? How Can You Tell?" a presentation to the California Municipal Rates Group, West Hollywood, California, June 25, 1996.

"Alternative Approaches for Area-Specific Marginal Transmission and Distribution Cost Estimation," a presentation to the 1994 EPRI Innovative Pricing Conference, Tampa, Florida, February 11, 1994.

"Marginal Costs: Academic Exercise or Crucial Factor in Electric Utility Decision-Making?" a presentation to the 1993 Annual Meeting of the Canadian Electrical Association, Halifax, Nova Scotia, May 18, 1993.

"Water Rates - Costing for the 90's," a presentation to the California Municipal Rates Group, San Pedro, California, February 16, 1993.

"Implementing a Dynamic Marginal Cost Study at the City of Anaheim," before the American Public Power Association, New Orleans, Louisiana, September 29, 1992.

"Estimating Hourly Marginal Costs," before the California Municipal Rates group, Anaheim, California, January 11, 1990.

"Ratesetting Using Marginal Cost at LADWP," before the California Municipal Rates Group, Winter Meeting, Anaheim, California, January 11, 1990.

Sept08