BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT TESTIMONY

OF

GRANT L. DAVIES

WESTAR ENERGY

DOCKET NO. ______________

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Grant L. Davies, Suite 600, 6935 Wisconsin Avenue, Chevy Chase, Maryland 20815.

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

A. Davies Consulting, Inc. (DCI), as President.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL QUALIFICATIONS AND PROFESSIONAL EXPERIENCE.

A. In 1969, I received a B.Sc. degree with honors in Biochemistry and Psychology from Concordia University and in 1971 received an M.B.A. in finance and economics from McGill University. From 1971 until 1986, I was employed by Touche Ross & Co. (now Deloitte & Touche), attaining partnership in 1979. From 1979 until

1986, I was a management consulting partner for Touche Ross and from 1982-1986 had responsibility for Touche Ross' global telecommunications practice. I joined Robert H. Schaffer & Associates as a partner in 1986. In 1991, I formed DCI. Since 1980, I have provided consulting services to electric utilities. Additional information regarding my professional experience is detailed in Exhibit ___ (GLD-1).

II. PURPOSE

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

A. My testimony discusses the status and use of Performance Based Ratemaking (PBR) in other jurisdictions. I support the PBR approach incorporated in Westar's Reliability-Based Sharing Proposal submitted in this proceeding. I also discuss the appropriate method for normalizing reliability-based performance measures. Additionally, my testimony reviews an assessment of the integrity of Westar's power delivery system infrastructure undertaken by DCI.

III. REVIEW OF PBR

Q. WHAT DO YOU MEAN BY PBR?

A. Since the PBR concept was introduced in the 1980's, definitions and applications of PBR have varied widely among state regulatory commissions. There is no single, accepted definition of PBR. Nor has PBR been consistently applied within single jurisdictions. For purposes of my testimony, I have defined PBR as any program in which a utility can receive an incentive or a penalty if it achieves or misses a particular service performance target or set of performance targets for both service quality and earnings. Although reflective of the broader movement among state commissions to adopt PBR, my recommendations in this proceeding relate specifically to Westar.

Q. PLEASE DESCRIBE YOUR REVIEW OF PBR IN OTHER JURISDICTIONS.

A. Under my direction, DCI surveyed state commissions from all 50 states plus the District of Columbia. Our initial survey was by telephone and was supplemented by follow-up calls and in-person visits with certain commissions. Exhibit ____ (GLD-2). We received responses from 29 state commissions. To supplement those responses, we conducted comprehensive interviews with 18 utilities operating in 39 states regarding the application of PBR in their respective jurisdictions. Exhibit ____ (GLD-3). In combination, the commission and utility responses provided information on the application of service quality measures and PBR within all 50 States and the District of Columbia.

Q. HOW MANY STATE COMMISSIONS HAVE SOME FORM OF PBR MECHANISM?

A. Exhibit ____ (GLD-4) identifies differing PBR programs and summarizes the types employed by various jurisdictions. Our survey found that 26 jurisdictions have adopted some type of service quality standard for PBR or target setting. Of those jurisdictions, 15 employ a PBR. Of the 15, five jurisdictions provide that a utility may earn a reward or pay a penalty based on the utility's performance *vis-á-vis* applicable benchmarks. Of these five jurisdictions, two have adopted a return on equity PBR mechanism that also incorporates service quality measures. The 13 states that employ PBR, but do not use a return on equity PBR mechanism, generally establish monetary penalties that must be paid either to the public utility commissions or, as refunds, to customers. In the majority of these states, when a utility performs better than the service quality benchmark, the utility does not receive any incentive for exceeding the target. However, in a number of states where no incentive payments are made, the utility is allowed to "bank" its better-than-standard performance to offset years where performance is below the benchmark or when it would have to make a monetary payment.

Q. CAN YOU SUMMARIZE THE CURRENT APPLICATION OF SERVICE QUALITY MEASURES BY STATE REGULATORY COMMISSIONS?

A. Exhibit ____ (GLD-5) is a map depicting the results of our survey. It shows that of the 50 states plus the District of Columbia, 38 jurisdictions use service quality measures for reporting, target setting or PBR. Thirteen states have no requirements. States, such as Kansas, were included in the "target setting" category if our survey found that the commission had established a performance target for at least one jurisdictional utility.

Q. BEYOND THE SURVEY RESULTS, DO YOU SEE ANY TREND TOWARD INCREASED USE OF PBR?

A. Yes. A number of states have active dockets or legislation where PBR is under consideration. For example, the Delaware Public Service Commission has opened a docket to consider implementing a PBR program that incorporates electric service reliability and quality benchmarks with a system of penalties and rewards. DPSC, In the Matter of Rules, Standards and Indices to Ensure Reliable Electrical Service by Electric Distribution Companies, Docket No. 50 (2000). The New Jersey Board of Public Utilities has proposed legislation that would require the Board of Public Utilities to implement service quality measures with a penalty and rewards system. I'm also aware that service quality reporting and PBR programs are being explored by commissions in the District of Columbia and Montana.

Q. CAN YOU SUMMARIZE THE CURRENT APPLICATIONS OF PBR THAT INCORPORATE EARNINGS AS THE PERFORMANCE TARGET?

A. There are a number of states that have adopted PBR approaches that incorporate earnings as the performance target. Under this approach, rates of return can be adjusted for such items as inflation and productivity.

Q. DO ANY OF THE STATES WITH PBR MECHANISMS IN PLACE HAVE PBR'S WHICH COMBINE SERVICE QUALITY PERFORMANCE WITH EARNINGS PERFORMANCE?

A. Yes. Mississippi and North Dakota incorporate service quality and earnings performance in their PBR mechanisms.

Q. WHAT UTILITIES ARE SUBJECT TO THE MISSISSIPPI PBR?

A. Entergy Mississippi and Mississippi Power.

Q. PLEASE DESCRIBE HOW THE MISSISSIPPI POWER PBR OPERATES

A. The Mississippi Public Service Commission has adopted a PBR approach that allows Mississippi Power to increase (decrease) its return on investment based on three service quality metrics. The metrics adopted are:

1. Customer Price – Determined by comparing Mississippi Power's average price per kWh to the

average price charged by Southeast Electrical Exchange Utilities.

2. Customer Satisfaction – Determined from the results of an independent semi-annual customer survey.

3. Customer Reliability – Determined by measuring reliability performance over a 36-month period.

The three performance metrics are combined to establish a company performance rating. This performance rating is used to adjust the upper and lower limits of a 'deadband' around Mississippi Power's allowed return on investment. The 'deadband' is ± 50 basis points. The projected return is compared to the company performance rating adjusted return. If Mississippi Power's projected return is above (or below) the deadband of the company performance rating adjusted return, the revenue can be increased (or decreased) to reflect performance. The increase (decrease) is adjusted to reflect superior and exceptional performance.

Q. WHAT UTILITIES ARE SUBJECT TO THE NORTH DAKOTA PBR?

A. Otter Tail Power and Xcel Energy.

Q. PLEASE DESCRIBE HOW THE NORTH DAKOTA PBR FOR OTTER TAIL OPERATES.

A. The North Dakota Commission has adopted a PBR methodology that allows Otter Tail Power to adjust its allowed rate of return based on the results of four performance areas. The four areas are reliability, customer satisfaction, customer price, and employee safety. The reliability metrics used are System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). The customer satisfaction metrics employed are the results of an annual Relationship Survey and the results of a semi-annual Transactional Survey. The customer price metrics used are a competitive price comparison and a comparison of the annual change in price. The employee safety metric employed is the OSHA Incident Rate for utilities with fewer than 1000 employees.

Each of the seven metrics is worth ± 25 basis points for a maximum total of 175 basis points. Each of the metrics is used to adjust the upper and lower limits of a deadband around the Otter Tail allowed return on equity (ROE). The deadband is ± 100 basis points. For example, if Otter Tail's ROE was 12%, the deadband would be 11%-13%. If Otter Tail performed above the reward threshold on all seven metrics, the upper band would move up to 14.75% (13% + 1.75%). The lower band would remain the same (11%). Therefore, Otter Tail's allowed ROE would move up to the midpoint between 11% and 14.75%, or 12.88%, and the new deadband would be 11.88% to 13.88%.

Q. HAVE YOU REVIEWED WESTAR'S RELIABILITY-BASED SHARING PROPOSAL?

A. Yes.

Q. IS WESTAR'S RELIABILITY-BASED SHARING PROPOSAL SIMILAR TO THE METHOD USED IN NORTH DAKOTA?

A. Yes. One significant exception, however, is that Westar's proposal does not allow for a surcharge to customers if earnings fall short of a minimum target.

IV. NORMALIZATION OF SAIFI AND SAIDI

Q. MR. FITZPATRICK HAS PROPOSED THAT SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI) AND SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI) BE INCLUDED AS SERVICE QUALITY MEASURES IN WESTAR'S RELIABILITY-BASED SHARING PROPOSAL. ARE THESE MEASURES AFFECTED BY MAJOR EVENTS BEYOND THE CONTROL OF A UTILITY?

A. Yes. SAIFI and SAIDI are affected by major events – generally weather-related – that a utility cannot control. SAIFI and SAIDI can be calculated including and excluding the effect of major events. I am proposing that the SAIFI and SAIDI performance targets be determined after exclusion of the effect of major events, i.e., that they be normalized.

Q. IS THERE AN INDUSTRY ACCEPTED STANDARD FOR DETERMINING WHICH MAJOR EVENTS SHOULD BE EXCLUDED?

A. Yes. After lengthy study and a consensus building process that involved academics, regulatory commissions and utilities, the Institute of Electrical and Electronic Engineers (IEEE) promulgated IEEE 1366 in 2003. IEEE 1366 2003 established a consistent standard for determining major event exclusion.

Q. FOR PURPOSES OF YOUR PROPOSED SAIFI AND SAIDI PERFORMANCE TARGETS, ARE YOU RECOMMENDING THAT IEEE 1366 2003 BE USED TO CALCULATE SAIFI AND SAIDI?

A. Yes. I recommend the adoption of IEEE 1366 2003 to determine which events should be excluded from the major event adjusted reliability measures (SAIFI and SAIDI). Currently, state commissions employ different approaches, but generally major event exclusions are based on the percentage of customers out of power, the duration of an event, or both. For example, this Commission currently excludes sustained interruptions to more than 10% of a utility's customers within a 24-hour period. In the process noted above, IEEE through a comprehensive process determined that exclusions based on percentage of customers or duration of an event resulted in SAIFI and SAIDI measures that did not reflect the variability that can occur in reliability measures as a result of weather. The Delaware Public Service Commission agreed with IEEE and has adopted IEEE 1366 2003 for utilities under its jurisdiction.

I recommend the adoption of IEEE 1366 2003 for Westar because, as the IEEE Committee that crafted 1366 noted, it provides a more consistent approach (than exclusion methods based on percentage of customers or hours of outage) for determining which major events should be excluded from the calculation of reliability measures. It also provides a more objective determination as to which events should be excluded and a more accurate view of system design.

V. ASSESSMENT OF WESTAR'S POWER DELIVERY INFRASTRUCTURE

Q. EARLIER YOU NOTED THAT ONE OF THE PURPOSES OF YOUR TESTIMONY WAS TO DISCUSS DCI'S ASSESSMENT OF WESTAR'S POWER DELIVERY SYSTEM INFRASTRUCTURE. PLEASE REVIEW THIS ASSESSMENT.

A. Similar to many utilities in the United States, a portion of Westar's power delivery system infrastructure has reached, or will soon reach, the end of its useful life. Prudent utility managers have begun to assess the business and regulatory implications this issue will have on their ability to continue to deliver electric power over the next 10 to 15 years. Westar management believes it is important for its regulators and customers to understand that expenditures over and above historic levels will have to be made over the next 5 to 10 years to replace aging power delivery infrastructure.

Q. CAN YOU SHARE ADDITIONAL INSIGHTS AS TO WHY UTILITIES ARE INVESTIGATING THEIR AGING INFRASTRUCTURE?

A. Yes. The August 2003 blackout experienced in the Northeast and Canada focused the attention of federal and state legislators and regulators on the electric power transmission and distribution grid. The age and status of the infrastructure was one of the areas reviewed.

> Even prior to the August blackout, the U.S. Department of Energy (DOE) was raising concerns. In a 2003 report, DOE stated: "America's electric system, 'the supreme engineering achievement of the 20th century', is aging, inefficient, and congested, and incapable of meeting the future energy needs of the Information Economy without operational changes and substantial capital investment over the next several decades.

"Department of Energy Grid 2030" – A National Vision for Electricity's Second 100 Years, p. iii, July 2003.

Other senior federal officials have also raised concerns about the implications the aging electricity infrastructure has for other elements of the economy. For example, Chairman Alan Greenspan of the Federal Reserve Board has said, "If the electricity infrastructure of this country is inadequate or in some way excessively costly, it will undermine economic growth, and is therefore a major issue that must be addressed." Testimony of Alan Greenspan, U.S. Senate Budget Committee Hearings, January 26, 2001.

Q. CAN YOU PROVIDE ADDITIONAL BACKGROUND ON ACTIONS OTHER UTILITIES OR REGULATORY COMMISSIONS HAVE TAKEN REGARDING AGING INFRASTRUCTURE?

A. Yes. A number of utilities and utility commissions have reviewed issues related to aging infrastructure. For example, in 2002, the Iowa Utilities Board opened an inquiry into the aging transmission and distribution infrastructure of utilities operating in Iowa. Iowa Department of Commerce, Utilities Board, "Order Initiating Inquiry," Docket No. NOI-02-2 (2002). This inquiry is still active.

In 2003, Connecticut Light and Power raised the issue of aging infrastructure in its rate application and proposed a four-year program of incremental investments to address aging infrastructure. The Connecticut Department of Public Utility Control stated in its December 2003 decision:

> CL&P has asked for significant increases to modernize its aging infrastructure and to train personnel to ensure the future reliability of its electric delivery system. The Department believes that revenues must be adequate to build and maintain a modern electric system to meet the growing demands and expectations of customers. At the same time, the Department must remain vigilant in its mission to ensure that rates remain just and reasonable. In this Decision the Department has allowed much of the capital improvements and personnel additions requested by the Company.

Connecticut Department of Public Utility Control, "Application of the Connecticut Light and Power Company to Amend its Rate Schedules," Decision, Docket No. 03-07-02 (2003).

Q. CAN YOU SUMMARIZE THE GOAL OF THE ASSESSMENT OF WESTAR'S POWER DELIVERY SYSTEM INFRASTRUCTURE?

A. The goal of the project was to identify key power delivery assets that, due to their condition or performance, may present long-term system integrity or reliability issues that should be addressed through retirement, replacement, or extensive maintenance over the next 5 to 10 years.

Q. CAN YOU SUMMARIZE THE METHODOLOGY USED TO CARRY OUT THE ASSESSMENT?

A. DCI undertook field inspections, reviewed Westar's business strategy, and reviewed various reports and databases. Using these data and DCI's experience, we identified and prioritized potential infrastructure projects. Exhibit ___ (GLD-6) contains a detailed listing of the steps employed to assess Westar's Power Delivery System.

Q. PLEASE SUMMARIZE THE RESULTS OF THE ASSESSMENT.

A. As noted in Mr. Henry's testimony, Westar has since the mid-1990's been investing in improving its reliability. Westar's expenditures initially focused on transmission assets, because transmission outages typically affect a large number of customers.

In addition, funds were expended to reduce vegetation caused outages. As reflected in the reliability data sponsored by Mr. Henry, these expenditures and the on-going day-to-day management of Westar's power delivery operations resulted in improved performance.

Westar's historic reliability improvement investments, however, have not reversed the trend of aging infrastructure. DCI's system integrity review looked beyond the "normal" level of investment required to maintain current reliability levels. Based on the assessment, and if Westar had the resources to fund all programs, the total 10-year incremental expenditures required to implement all of the recommendations would be approximately $127 million in operating and maintenance expenses and $206 million in capital projects above 2003 expenditure levels.

Q. GIVEN THE SIZE OF POTENTIAL EXPENDITURES, WAS ANY EFFORT MADE TO PRIORITIZE?

A. Yes.

Q. WHAT WERE THE RESULTS OF THE PRIORITIZATION?

A. Based on the Westar prioritization and independent prioritization data, we believe that expenditures of approximately $20 million on average per year above the 2003 expenditure levels over the next ten years will be necessary for Westar to meet and sustain its reliability goals. We anticipate that higher expenditure levels would be required in the early years.

Q. THANK YOU.

EDUCATIONAL QUALIFICATIONS AND EXPERIENCE

Grant Davies received his CPA (Canada) in 1973 and a Certified Management Consultant (CMC) designation in 1980. Mr. Davies has been engaged as a consultant by electric utilities since 1980. The primary focus of his electric utility work has been electric delivery systems, including strategic planning, reliability strategies and performance assessment, regulatory reviews, performance-based rate making reviews, and testimony. He has been a frequent speaker at the Edison Electric Institute (EEI) Transmission and Distribution Committee on asset management, reliability and performance management topics. Currently he is the engagement partner responsible for an EEI study of reliability and performance based rate making. He is also the project lead on a joint Canadian Electric Association and Canadian Public Utility Tribunal conference on reliability strategies and reliability investments.

Representative electric utility clients include: Ameren, American Electric Power, Commonwealth Edison, Conectiv, Duke Power, Duquesne Light, Florida Power and Light, Kansas City Power and Light, Manitoba Hydro, Nova Scotia Power, Ontario Hydro, PPL Energy, PECO, PEPCO, RG&E, United Illuminating, Westar Energy, and Xcel.

Mr. Davies has appeared before, or supported clients before, the following regulatory commissions on electric (and combined gas and electric) utility related matters: Alberta Public Utilities Board, British Columbia Board of Public Utilities, Delaware Public Service Commission, District of Columbia

Public Service Commission, Federal Energy Regulatory Commission, Florida Public Service Commission, Kentucky Public Utilities Commission, Maryland Public Service Commission, National Energy Board (Canada), New Jersey Board of Public Utilities, Nova Scotia Public Utilities Board, and the South Carolina Public Service Commission.

Commission Phone Interview

Date:

State:

Commission:

Person:

Position:

General Directions:

Introduce yourself and indicate you would like to speak to the person who can provide information about the State reliability requirements for Utilities within the State.

When you are transferred, introduce yourself again, indicate what you are looking for and verify that you have the correct person. Ask if they have time to answer a few questions and then proceed to the following:

For purposes of this survey I am defining Performance Based Rates as: "Any Utility in the state who can receive an incentive, penalty or earnings adjustment based on performance or service target." [If the earnings are based on cost of service, but they have penalties or rewards based on performance, we will define that as cost of service Performance-Based Rate Making.]

Questions:

1a. Does any Utility in your State have Performance Based Rates (PBR)?

_____Yes

_____No

1b. If no, does any Utility in your State have PBR Ratemaking (earnings based on cost of service) with rewards or penalties based on quality of service targets?

_____Yes

_____No

1c. If no, does any Utility in your State have reporting only for reliability metrics?

_____Yes

_____No

1d. If no, are you aware of any customer service metric reporting requirement in your State?

_____Yes

_____No

If no, thank them and terminate call.

2a. If answer is yes to 1a, what reliability metrics are measured? (List all)

2b. Can you provide the performance target for each metric? (If yes, list all. If no, proceed to question 2d.)

2c. Can you provide the top and bottom performing thresholds for each metric? (If yes, list for all metrics. If no, proceed to question 2d.)

2d. Can you provide the maximum penalty or reward the Utility can receive? (If yes, list for all metrics. If no, proceed to question 2e.)

2e. What is the reporting frequency?

2f. Have penalties or rewards ever been paid?

_____Yes

_____No

2g. Are major events (storms, etc.) included or excluded in targets?

_____Included

_____Excluded

3a. If answer is yes to 1b, what reliability metrics are measured? (List all)

3b. Can you provide the performance target for each metric? (If yes, list all. If no, proceed to question 3d.)

3c. Can you provide the top and bottom performing thresholds for each metric? (If yes, list for all metrics. If no, proceed to question 3d.)

3d. Can you provide the maximum penalty or reward the Utility can receive? (If yes, list for all metrics. If no, proceed to question 3e.)

3e. What is the reporting frequency?

3f. Have penalties or rewards ever been paid?

_____Yes

_____No

3g. Are major events (storms, etc.) included or excluded in targets?

_____Included

_____Excluded

4a. If the answer is yes to 1c, what reliability metrics are reported? (List all)

4b. What is the reporting frequency? (List all)

4c. Are major events included or excluded in targets?

_____Included

_____Excluded

5. If the answer is yes to 1d, what customer service metrics are the Utility required to report? (List all)

6a. Do you have vegetation requirements?

_____Yes

_____No

6b. If yes, do you know what the trim cycle is? (List) If no, go to the next question.

7. How do you define worst performance feeder?

<u>Closing</u>:

Thank you for your assistance with this survey. May we contact you if we have some follow-up questions?

Name:
Company:

Phone #:
E-mail:

EEI Utility Survey

1. Do you have:
   a. Performance Based Ratemaking tied to quality of service standards?
      1. ___ Yes
      2. ___ No
   b. Quality of Service Standards tied to reporting requirements?
      1. ___ Yes
      2. ___ No

2. If you have Reliability, which of the following do you have?
   a. Reliability Standard
      ___ 1. SAIFI
      ___ 2. SAIDI
      ___ 3. CAIDI
      ___ 4. MAIFI
      ___ 5. CEMI (Customers Experiencing Momentary Interruption)
      ___ 6. CELID (Customers Experiencing Longest Interruption Duration)
   b. Vegetation Standards
      1. Do you have a required trim cycle?
         a. ___ Yes (# of Yrs. _____)
         b. ___ No
      2. Do you trim by:
         a. ___ Region? or by
         b. ___ Feeder?
   c. Forced Outage Rate (FOR) – for transmission
      1. ___ Yes
      2. ___ No
   d. Others – Please list

      ____

      ____

3. If you have Customer Service standards, which of the following do you have:
   a. ___ Number of customer complaints ?
   b. ___ Customer Satisfaction Standard?
   c. ___ Service Connection (New Service)?
   d. ___ Dropped Calls (either wait time or busy signal)?
   e. ___ Call waiting (average speed to answer)?
   f. ___Late for appointments?

g. ___Estimated Meter reads?
h. Others – please list

____

4. For those standards that apply:
   a. What is your benchmark/performance for each standard?

	Standard	Target	Deadband
1			
2			
3			
4			
5			

   b. How were standards established?
   ____
   c. How and how often are the standards revised?______________________
   d. Do you use the same performance standard for the entire company or do you modify by region?
      1. ___ Same for entire Company
      2. ___ Modify by Region
   e. Are penalties and rewards tied to your performance
      1. ___ Yes
      2. ___ No
   f. What are the thresholds bands (e.g., 1 std dev, 2 std. dev.)____________
   g. How are penalties/rewards calculated?____________________________
   h. What is the maximum penalty/reward that you can accumulate?_________
   i. If you have rewards, are they used only as offsets to penalties or can you actually gather a reward at the end of the period?
      1. ___Offsets only
      2. ___Reward

   j. Have you had to pay penalties or collect rewards?
      1. Paid Penalties
         a. ___Yes
         b. ___ No
      2. Collected Rewards
         a. ___ Yes
         b. ___ No
   k. How frequently do you have to report your performance?

1. ___ Annual Report
2. ___ Other Period

5. Are major storms exempt from the reliability standard?
   a. ___Yes
   b. ___No
   c. What definition do you use for Major Events?
   ____
   ____

6. What is the definition of a momentary outage that you use?
   a. ___Less than 1 min.
   b. ___Less than 5 min.
   c. ___Other, please define ____________________

7. Poor Performing Circuits
   a. Are you required to identify and report poor performing circuits?
      1. ___ Yes
      2. ___ No
   b. If yes to a. above, how many circuits are you required to identify?
      1. Five worst circuits _______
      2. Ten worst circuits ________
      3. Other, please define ____________________
   c. If you do not improve feeder operations in the following year is there a penalty involved?
      1. ___ Yes
      2. ___ No
   d. If yes, what is the penalty?__________________
   ____

8. Service restoration standards
   a. Do you have a requirement that service must be restored within a set period of time?
      1. Yes _______
      2. No _______
      3. If yes, what is that time period
      ____
      4. How was the time period selected?__________________________
   b. Is there a reward/penalty associated with the standard?
      1. Reward
         a. ___ Yes
         b. ___ No

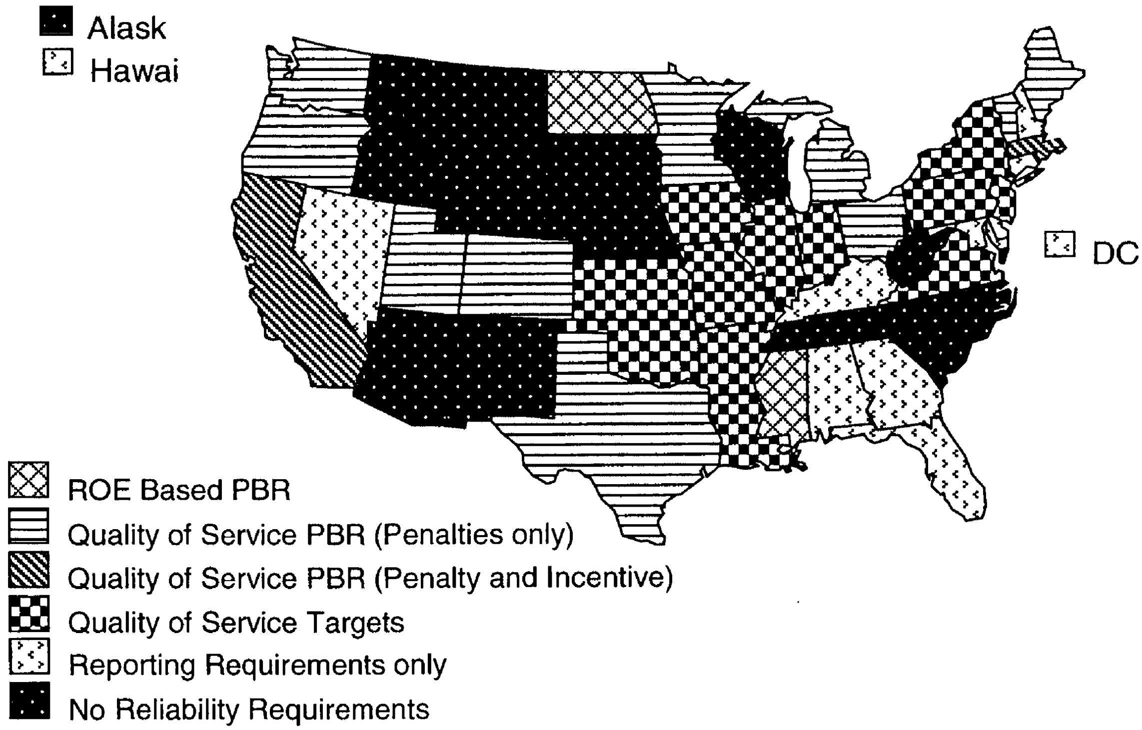
2. Penalty
   a. ___ Yes
   b. ___ No

If yes, how is the reward/penalty calculated?

SUMMARY OF STATE JURISDICTIONS' APPROACHES TO SERVICE QUALITY

Type of Mechanism	No.	States
Return on equity based PBR	2	Mississippi, North Dakota
Quality of service PBR – penalties and rewards	3	California, Massachusetts, Rhode Island
Quality of service PBR penalties only	10	Colorado, Maine, Michigan, Minnesota, Ohio, Oregon, Texas, Utah, Vermont, Washington
Quality of service - targets	11	Arkansas, Illinois, Indiana, Iowa, Kansas, Louisiana, New Jersey, New York, Oklahoma, Pennsylvania, Virginia
Quality of service – reporting	12	Alabama, Connecticut, Delaware, DC, Florida, Georgia, Hawaii, Kentucky, Maryland, Missouri, New Hampshire, Nevada
No reporting requirement	13	Alaska, Arizona, Idaho, Montana, Nebraska, New Mexico, North Carolina, South Carolina, South Dakota, Tennessee, West Virginia, Wisconsin, Wyoming

SERVICE QUALITY MEASURES/PBR APPLICATION MAP



Source: DCI Interviews/survey with 29 state commissions and 18

SYSTEM INTEGRITY ASSESSMENT METHODOLOGY

The steps described below were completed over eight weeks, and summarize the methodology used.

1. The delivery system infrastructure was divided into three distinct groups:
   a. Distribution assets
   b. Substation assets
   c. Transmission assets.
2. A series of three meetings was conducted with managers and subject matter experts that were responsible for the performance of the delivery infrastructure assets in each grouping.
3. The first meeting was conducted with group leadership to explain the project goals, establish a project work plan, solicit support, establish timelines, schedule work sessions, and identify subject matter experts from Electric Distribution Engineering, Technical Operations Support, Transmission, and Distribution Field Operations to assist in conducting the assessment.
4. The second series of meeting were conducted with the representatives from each asset grouping to:
   a. review available databases related to the infrastructure assets,
   b. establish the accuracy and completeness of the databases,

c. identify major reliability issues based knowledge and experience with the assets

d. establish maintenance or replacement opportunities that could provide significant improvement in current asset reliability and future system performance

5. The group representatives were asked to conduct similar exercises with a broader cross section of subject matter experts and program managers on the various assets within each grouping.

6. Data was collected from the subject matter expert meetings and used to establish parameters for specific improvement initiatives, projects, and programs targeted at improving the long term performance of system components within each asset grouping.

7. A third meeting was held with subject matter experts and decision maker level representatives from each asset grouping for the purpose of developing detailed cost and performance improvements projections for the initiatives and programs developed in step 6.

8. The performance improvement initiatives, projects, and programs were loaded into a database (MS Excel) with the following details described:

   a. Improvement #

   b. Performance Issue Addressed

   c. Scope of work (quantity of items, etc)

d. Location of assets affected

e. Cost per unit of work

f. Annual cost of improvement item separated by O&M and Capital

g. Specific reliability issue addressed and expected improvement

h. Customer impact

i. Priority

9. The Reliability and Integrity Assessment Information Data Sheets for each asset grouping were then shared with Power Delivery leadership for additional review and input into the assessment process.

10. Within each asset grouping, the initiatives, projects, and programs were summarized and place in a Reliability and Integrity Assessment Summary that projected the 10 year cost of the identified improvement items.

11. Westar's Power Delivery management team met together and prioritized the summarized list of improvement items. The first prioritization exercise involved each manager being asked to prioritize projects based on their view of its relative value. There were approximately 48 improvement items to be considered for the prioritization. The second prioritization exercise was developed using a common value model where each improvement item was

scored based on its contribution to reliability improvement, safety, improving customer service, meeting regulatory requirements, and improving system integrity. The ranking of the projects from both exercises was then provided to senior management.

12. A projection of ten-year funding requirements for the prioritized list of projects was created on a quartile basis and provided to senior management for review. Using PA Consulting Benchmark data for 2003, a comparison of Westar proposed spending vs. average utility spending was conducted.

13. A model was then created to project the potential five-year reliability benefits based on the funding level selected for the system improvements identified and presented to senior management with several performance improvement options.