APPENDIX

A

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy
Docket No.: G002/M-16-0891 Information Request No. 36
Response To: Office of Attorney General
Requestor: Joseph Dammel
Date Received: January 24, 2017

Question:

Reference: Petition, page 2

The Company states that, with respect to its prior GUIC efforts, "These efforts culminate in safer and more reliable gas service for customers and reduce the likelihood of catastrophic incidents in the metro."

- Provide a definition of "catastrophic incidents" as well as a description of catastrophic incidents that have occurred on Xcel's system in the past 10 years, including the date, cause of incident, and type (material, age, size) of the pipe.
- Describe how the metrics proposed in the Jan. 13 filing measure both the safety and the reliability of the system.

Response:

The Pipeline Hazardous Materials Safety Administration (PHMSA), which is the federal entity that regulates operators of natural gas systems, has two classifications and definitions of incidents:

- Serious Incidents are those that include a fatality or injury requiring in-patient hospitalization.
- Significant Incidents are those including any of the following conditions:
  1. Fatality or injury requiring in-patient hospitalization;
  2. $50,000 or more in total costs, measured in 1984 dollars;
  3. Highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more;
  4. Liquid releases resulting in an unintentional fire or explosion.

The Company is also concerned about other impacts to our local communities such as customer, employee, and asset safety, reliability, financial risk, and customer credibility.

Integrity management programs such as the Transmission and Distribution Integrity Management Programs (TIMP and DIMP) are specifically designed to identify risks to the system and systematically mitigate the risk before they result in significant or "catastrophic" failures.

The Company experienced a significant event on February 1, 2010. The event was reported to PHMSA as required by 49 CFR Parts 191, 195. The cause of this incident was a natural gas line that was installed through a sewer line and then breached by a sewer contractor's cutting tool. As a result, natural gas was released into the sewer and migrated into the home, resulting in gas ignition and injury to a contractor, and a fire that destroyed a customer's home. The Company has no other PHMSA reportable incidents (meeting the criteria shown above) in the last 10 years.

The measurements proposed by the Company reflect a method to measure relative risk in terms of the likelihood (or probability) and the consequence. Although the metrics proposed do not have a direct numerical alignment with safety and reliability, they do have a correlation with the likelihood and consequences factors of risk. For example, relative risk scores that are higher mean that the likelihood or consequence of a serious or significant incident is greater than those with lower risk scores.

Preparer:	Katie Hellfritz
Title:	Senior Director
Department:	Gas Governance
Telephone:	303-571-3162
Date:	February 3, 2017

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	G002/M-16-0891	Information Request No.	38
Response To:	Office of Attorney General		
Requestor:	Joseph Dammel		
Date Received:	January 24, 2017		

<u>Question:</u>

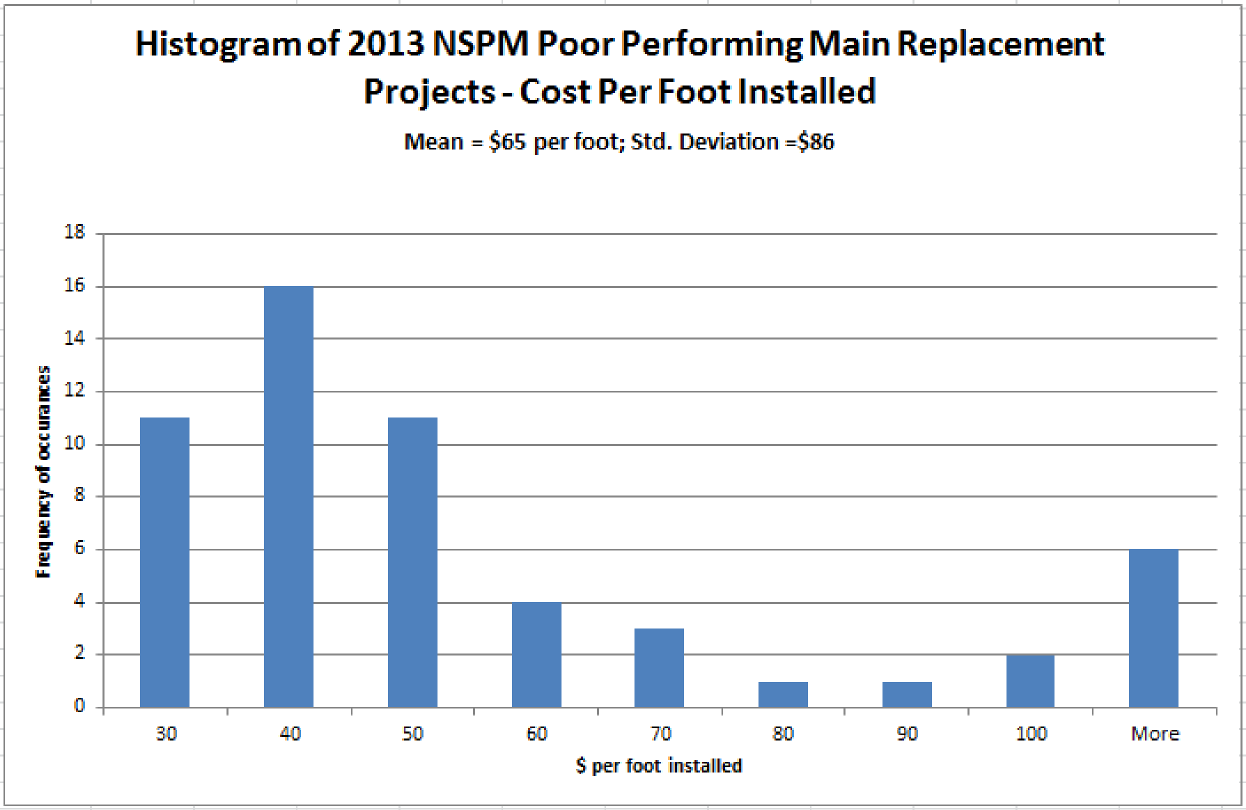
Reference: Supplemental Petition, Table 3, page 5

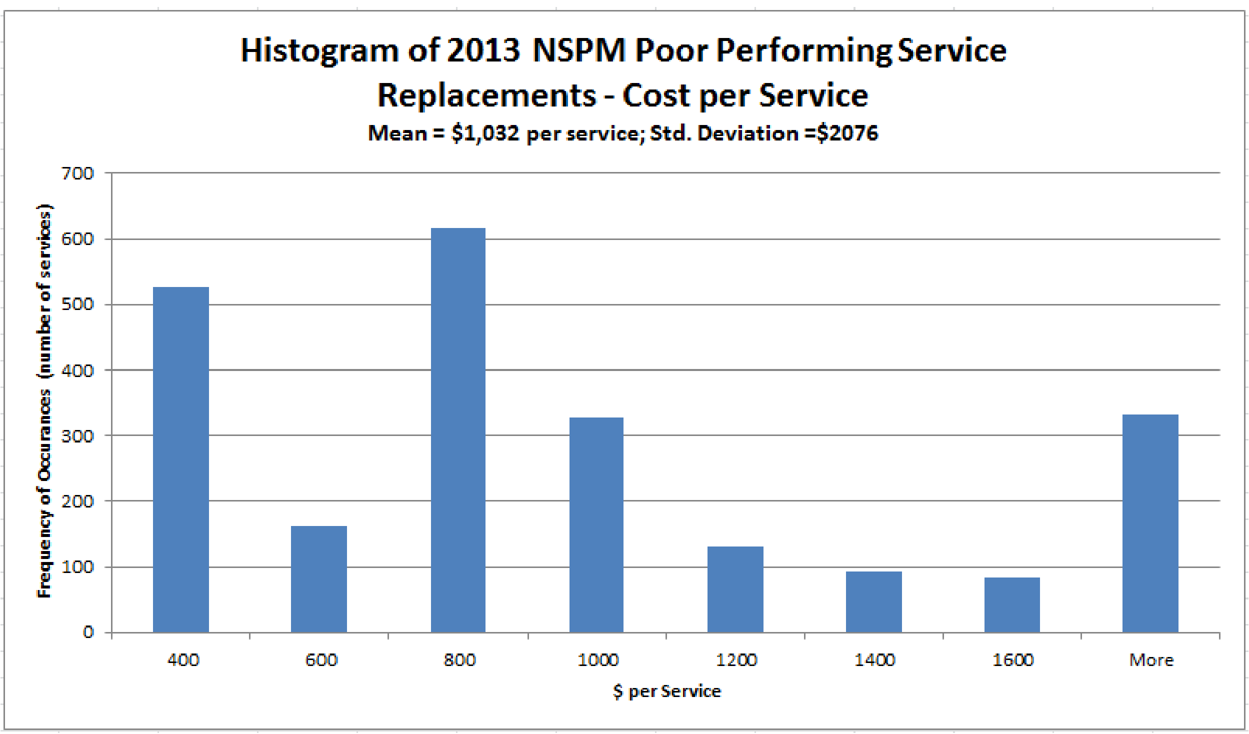
Provide the actual results for all proposed metrics for 2013, 2014, 2015, and 2016.

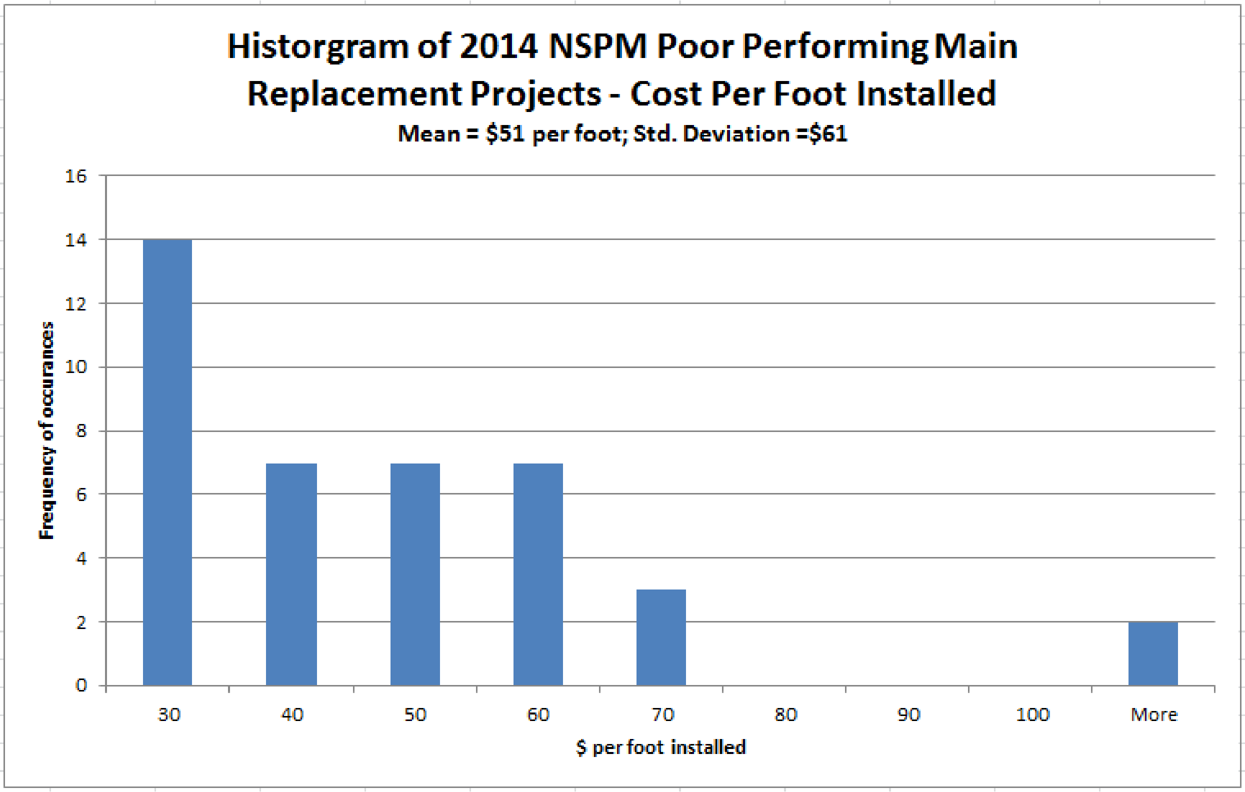
<u>Response:</u>

Figure 2 of the Supplemental Petition (page 6) provides results from years 2011 through 2014 for the coated steel leak rate by vintage. Data necessary to update Figure 2 for 2015 and 2016 is not currently available. The reason the data is not yet available is that the Company must complete a process of assigning each leak repair to the associated pipe in its Graphic Information System (GIS) in order to determine the installation date of the pipe for which the leak was repaired. This work is in progress but not estimated to be available until August 2017.

Figure 3 and 4 of the Supplemental Petition (pages 7-8) provide unit cost results for 2015 for Poor Performing Main and Service Replacements. Data for 2016 is not yet available. Data for 2013 and 2014 is provided below. Note that the service data for 2013 and 2014 is based on cost for each individual service, since grouping by larger project was not possible for this past work.


Histogram of 2013 NSPM Poor Performing Main Replacement Projects - Cost Per Foot Installed
Mean = $65 per foot; Std. Deviation =$86
Frequency of occurances
18
16
14
12
10
8
6
4
2
0
30
40
50
60
70
80
90
100
More
$ per foot installed


Histogram of 2013 NSPM Poor Performing Service Replacements - Cost per Service
Mean = $1,032 per service; Std. Deviation =$2076
Frequency of Occurances (number of services)
700
600
500
400
300
200
100
0
400
600
800
1000
1200
1400
1600
More
$ per Service


Historgram of 2014 NSPM Poor Performing Main Replacement Projects - Cost Per Foot Installed
Mean = $51 per foot; Std. Deviation =$61
Frequency of occurances
0
2
4
6
8
10
12
14
16
30
40
50
60
70
80
90
100
More
$ per foot installed

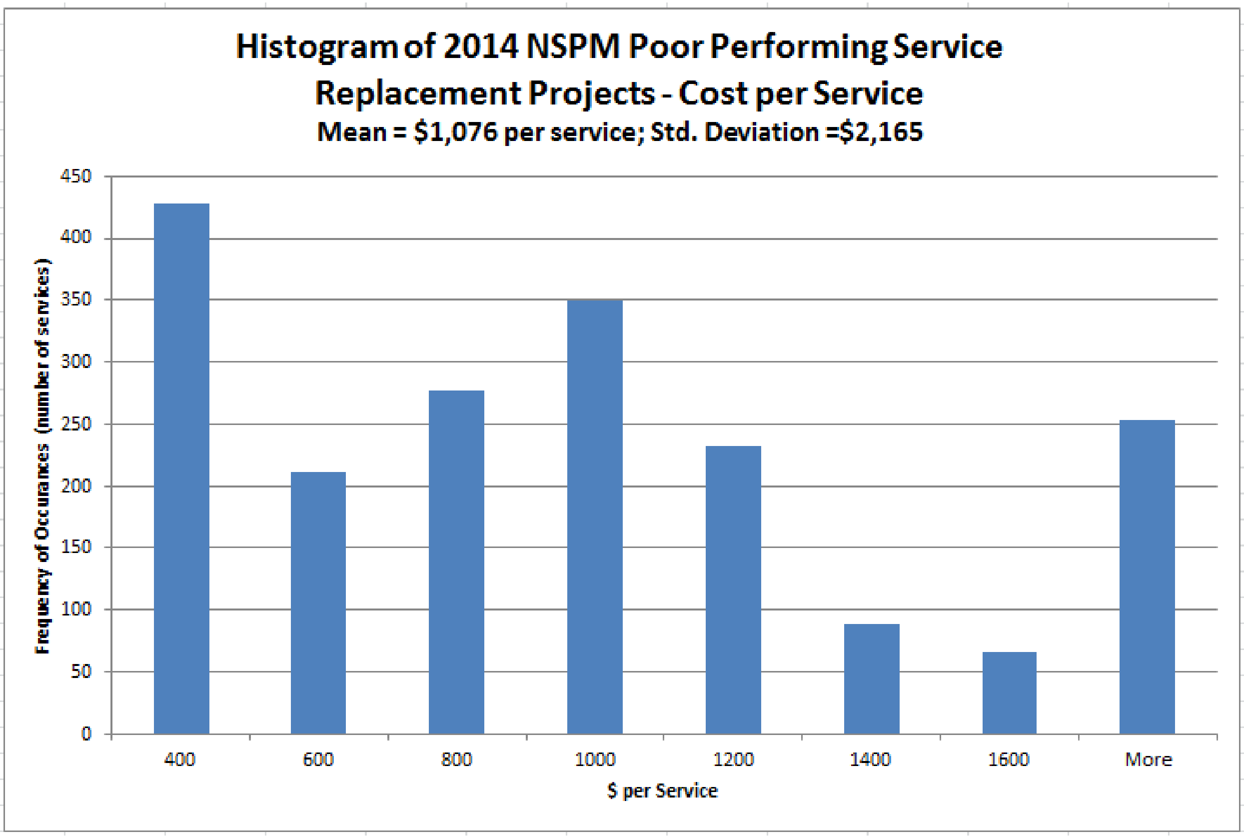

Histogram of 2014 NSPM Poor Performing Service Replacement Projects - Cost per Service
Mean = $1,076 per service; Std. Deviation =$2,165
Frequency of Occurances (number of services)
0
50
100
150
200
250
300
350
400
450
400
600
800
1000
1200
1400
1600
More
$ per Service

Figure 5 of the Supplemental Petition (page 9) provides the number of TIMP anomalies repaired for 2010 through 2015. 2016 data is currently being prepared for the Company's 2016 Annual Report to the Pipeline and Hazardous Materials Administration (PHMSA) but is not currently available. This 2016 data should be available by March 15, 2017.

Actual vs. Estimated Cost Variance Explanations for TIMP projects are proposed for 2017 and have not been generated for previous TIMP projects and are thus not available.

Preparer: Eric G. Kirkpatrick
Title: Director
Department: Gas Engineering
Telephone: 303-571-3223
Date: February 3, 2017

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	G002/M-16-0891	Information Request No.	41
Response To:	Office of Attorney General		
Requestor:	Joseph Dammel		
Date Received:	January 24, 2017		

Question:

Reference: Supplemental Petition, page 6

The Company states that, "As a measure of effectiveness we expect that the leak rates for the pre-1970 coated steel pipe will continue to decrease over time as problematic pipe is replaced."

- Explain the calculation of leaks per mile and include a live Excel spreadsheet to support Figure 2, including the number of miles surveyed each year and a running tally of miles of vintage coated steel remaining in the system.
- Is the Company replacing all pre-1970 coated steel pipe in its system and, if so, when does it expect to complete this work?
- Does the Company replace only pre-1970 coated steel pipe? Or does it also replace post-1970 coated steel pipe as well? Describe why this date is significant.
- Is the "Post-1970" leak rate for coated steel considered the "target" leak rate for "Pre-1970" coated steel and did the 2013 results, where all three categories appear to be relatively close, affect the scope of replacement in 2014 and beyond?
- Given the three-year leak survey cycle, can 2014 be compared relative to 2011? In other words, are the same stretches of pipe surveyed every three years? Describe the three-year cycle in more detail, including the applicable federal or state regulations that require the specific schedule.

If the Company is measuring leaks-per-mile of, for example, pre-1970 coated steel, why would removal and replacement of that particular vintage/material result in a reduction of leaks? If the Company started out with 100 miles of vintage coated steel and found 10 leaks (0.1 leaks/mile), then why, if it replaced 20 miles of vintage coated steel, wouldn't it expect to find the same leak rate (8 leaks / 80 miles of vintage coated steel remaining)?

Response:

- The plot shown in Figure 2 is included in Attachment A to this response. Included in Attachment A, provided in live Excel spreadsheet format, is the number of underground, non-excavation damage leaks on coated steel pipe as well as a running total of the number of miles of coated steel pipe remaining in the system. The number of miles of coated steel pipe surveyed each year is not available. The calculation of leaks per mile utilized in Figure 2 is based on the number of underground leaks not associated with excavation damage in a given year divided by the mileage of coated steel mains and services remaining in the system that given year.
- The current scope of the Company's program does not include all pre-1970 coated steel pipe. As described in the Petition's Attachment C2(a) Page 2, the Company utilizes commercial risk assessment software to identify high or medium risk steel pipeline projects for renewal. It is important to note that all materials degrade over time, and these assets will continue to degrade as well. The Company will continue to monitor the leak rates associated with the pre-1970 coated steel pipe and will complete renewals as high and medium risk pipe is identified.
- As described in Petition Attachment C2(a) Page 2, the Company utilizes commercial risk assessment software to identify high or medium risk steel pipe projects for renewal. The identified projects may be either pre or post 1970s vintage based on the risk associated with the project. In 1970, Code of Federal Regulations, Part 192 was enacted. This regulation provided minimum federal safety standards for the design, construction, operation, and maintenance of gas pipeline infrastructure. The Company expects that many of the high and medium risk projects identified for replacement will be of the pre-1970s vintage installed prior to the federal regulations, primarily because they were not installed or maintained with these minimum standards over the asset life.
- The "target" for coated steel mains and services is that leak rates for the pre-1970s coated steel will decrease to similar levels as other modern materials (plastic and steel) in the system. Additionally, the Company expects that the leak rates for the three categories identified in Figure 2 would trend downward over time. Although the leak rates for all three categories shown in Figure 2 did appear to be relatively close in 2013 this did not impact the scope of replacement in 2014 and beyond.
- The Code of Federal Regulations, Part 192, Subpart M requires operators to conduct periodic leakage surveys of Distribution Pipeline Systems. Generally, the Company conducts leak survey over the same stretches of pipe every three years. However, the Company does shift leak survey of stretches of pipe to different years to maximize efficiency and align with other Company work in the vicinity. In addition to the periodic leak survey process, leaks are also identified by other means (customer call, etc.) that are not related to the three year cycle. As such, some variation of leak rates from year to year is expected.

- Current information indicates that high leak rates on the pre-1970 coated steel pipe can be largely attributed to threaded fittings and mechanical couplings. These problematic fittings were utilized primarily between 1950 and 1960. However, the Company expects that isolated cases may be identified outside of this range. As a result, project risk and associated leak rates are not uniform across all pre-1970 coated steel mains and services. As described in Petition Attachment C2(a) Page 2, the Company utilizes commercial risk assessment software to identify high or medium risk steel pipe projects for replacement. As the pre-1970s pipe with the highest risk and highest leak rates is replaced it is expected that the overall leak rates for pre-1970s coated steel pipe will decrease.

Preparer:	Ray Gardner
Title:	Director
Department:	Integrity Management Programs
Telephone:	303-571-3904
Date:	February 3, 2017

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	G002/M-16-0891	Information Request No.	43
Response To:	Office of Attorney General		
Requestor:	Joseph Dammel		
Date Received:	January 24, 2017		

Question:

Reference: Supplemental Petition, Figures 3 and 4

Does the Company propose to remove any projects that cost in excess of one standard deviation of the average cost? Explain how the Company chose one standard deviation as the cutoff for requiring further explanation.

Response:

The Company does not propose to remove projects that cost in excess of one standard deviation of the average cost. As described in Section B of the Supplemental Petition (pages 7 and 8), the Company proposes to provide a detailed explanation of why those project costs exceeded one standard deviation.

The Company chose one standard deviation because it is a common means of determining statistical significance.

Preparer: Eric Kirkpatrick
Title: Director
Department: Gas Engineering
Telephone: 303-571-3223
Date: February 3, 2017

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	G002/M-16-0891	Information Request No.	45
Response To:	Office of Attorney General		
Requestor:	Joseph Dammel		
Date Received:	January 24, 2017		

Question:

Reference: Petition, page 30

The Company states that a portion of the $800,000 in the Distribution Valves and Pipeline Data project is slated to go to "replace existing distribution system isolation valves which have outlived their useful lifespan." In the absence of TIMP/DIMP, would the Company have replaced these outdated system isolation valves?

Response:

Prior to the DIMP rules established in 49 CFR Part 192, Subpart P, the Company performed asset renewals. However, under the requirements of 49 CFR Part 192, Subpart P (DIMP), the Company is required to assess and improve the safety, reliability, and integrity of our natural gas infrastructure pursuant to those regulatory requirements. The pace and magnitude of the renewal and other mitigation efforts under DIMP and TIMP have outstripped similar efforts that were undertaken prior to these regulatory requirements.

Preparer:	Eric G. Kirkpatrick
Title:	Director, Gas Engineering
Department:	Gas Engineering
Telephone:	303-571-3223
Date:	February 3, 2017

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	G002/M-16-0891	Information Request No.	46
Response To:	Office of Attorney General		
Requestor:	Joseph Dammel		
Date Received:	January 24, 2017		

Question:

Reference: Supplemental Petition, Attachment A, page 23

The "Oversight" slide in the attached material states that the Rider Review Committee ensures that there are no betterments included in GUIC-recoverable projects. Provide any and all instances since the GUIC rider program began where the Rider Review Committee reviewed a project or a portion of a project, determined that it was a betterment, and removed the project. Provide any and all policies regarding identification of and removal of a betterment.

Response:

There has been one instance where a portion of project costs for a DIMP pipeline replacement were identified and removed from the GUIC through the oversight process described below.

The oversight process begins with the Director of Gas Engineering submitting an "Engineering Assessment of Capacity Enhancement to GUIC Project" to the Gas Capacity Planning Manager. This document provides information on the proposed project and includes key engineering facts and analysis. To the extent the proposed project includes upsizing pipe, the assessment provides evidence that the upsize is the most appropriate project solution to the pipe replacement need.

The Gas Capacity Planning Manager reviews the assessment and develops a report summarizing the project drivers, alternatives, incremental costs, highlighting the pipeline capacity in relation to peak demand. The Manager will then circulate this report to the Director of Gas System Strategy & Business Operations for review along with recommendations of support or non-support. If approved by the Director, the project proceeds as a GUIC project.

The incremental material cost of installing a larger pipe diameter than what would be otherwise required for TIMP or DIMP purposes determines the level of review required. Consistent with Rider Review Committee guidelines, any project where this incremental cost exceeds $500,000 requires review and approval from the Senior Vice President of Gas and the Regional Vice President of Rates and Regulatory Affairs. If the incremental cost of the upsized pipe is below $500,000, approval is limited to the Director of Gas Engineering, Director of Gas System Strategy & Business Operations, and Manager of Gas Capacity Planning.

If approved, the Gas Strategy & Business Operations group will provide the approved project's respective Work Order number and percent of incremental pipe material upsize cost to total project cost to the Revenue Requirements group in the Financial Operations Department. The Work Order is added to the Power Plan capital expenditure report in the group's rate model that is utilized to calculate the revenue requirement and subsequently included in the Company's next rate request. The incremental percentage identified in the engineering report is applied to the total project's actual monthly capital expenditures within the rate model. This ensures incremental upsizing costs not driven by integrity management programs are not recovered through the GUIC Rider.

As stated, only one project has triggered this advanced oversight process: the Sartell Bridge Replacement Crossing Project. This project is part of the DIMP Programmatic Replacement Program. A 4-inch pipe with exposed corroding is the sole supply for the community of Sartell. The Company is replacing the current 4-inch pipe with an 8-inch pipe because of the expected growth in the community. As a result of the oversight program, the Company does not seek recovery for the incremental difference between the 4- and 8- inch pipes through the GUIC Rider mechanism.

Please reference the following Attachments related to this project:

Attachment A:	The Engineering Assessment of Capacity Enhancement to GUIC Project
Attachment B:	Gas Capacity Planning's 1-Page Project Summary

Preparer: Austin Kerns
Title: Manager
Department: Gas System Strategy & Business Operations
Telephone: 303-571-7666
Date: February 3, 2017

Engineering Assessment of Capacity Enhancement to GUIC Project:
SARTELL BRIDGE CROSSING REPLACEMENT PROJECT

Old Sartell Bridge is one of only a handful of Truss bridges that span across the Mississippi River. With changes in Minnesota State law in 1914 requiring the Truss design bridges to be phased out, the bridge was no longer capable of keeping up with the increased traffic demand and in the 1950s due to structural weaknesses the bridge was closed to trucks to prolong its useful life. The Bridge was converted for pedestrian use in 1984 and subsequently closed to all traffic and pedestrian use. NSP currently has a 4 inch steel pipeline attached to the bridge. This is currently the only gas supply to the town of Sartell.

There is visible corrosion on the 4'' STL Main and the pipeline is also subject to outside force damage should the bridge fail or erosion at the banks of the river cause damage.

Installing a new pipeline on the bridge is not possible due to the remaining risk of outside force damage and the fact that the City of Sartell would eventually like to demolish the bridge.

The proposed project involves directionally boring beneath the Mississippi river approximately 2500' north of the old Sartell pedestrian bridge.

- Retiring 400' of 4" steel main along the intersection of W Sartell St and Riverside Ave N.
- Retiring 700' of 6" steel main along the intersection of E Sartell St and 1st Ave NE.
- Retiring approximately 700' of 4'' steel main beneath the old Sartell Pedestrian Bridge.
- The project also involves installing approximately 1300' of 8" steel main by directionally boring beneath Mississippi river approximately 2500' north of old Sartell pedestrian bridge

- Installing approximately 700' of 6" plastic main along the intersection of 1st St N and 4th St N.
- Installing approximately 1000' of 6" plastic main along N Benton Dr. in order to connect to the new river crossing.
- Installing a 6’’ Valves along N Benton Dr. and the 8’’ steel main crossing
- Installing an 6’’ Valve along the intersection of 4th St N and 1st Ave N

In conjunction with this GUIC problematic main replacement project it is proposed to install an 8 inch diameter crossing of the river in order to accommodate future load growth. The table below shows the capacity of the existing system as well as the capacity reinforcement alternatives considered.

	Non-interruptible Capacity At Design Day Temperatures	**At 1% Growth Rate**
Existing 4'' STL Main on Sartell Bridge	167 MCFH	Meets Non-interruptible load requirement through 2017
Current 100% Coincidence peak Core Demand	163 MCFH	
Crossing with 6 inch pipeline in new alignment	190 MCFH	Meets Non-interruptible load requirement through 2025
Crossing with 8 inch pipeline in new alignment	240 MCFH	Meets Non-interruptible load requirement through 2031

The overall cost estimate for the project with the 8 inch river crossing is $775,000. The estimated cost differential for increasing the pipe size from 4 inch to 8 inch is $218,000. This incremental $218,000 for future capacity may not be accrued to the GUIC rider.

Approved: Eric Kirkpatrick, Director Gas Engineering
Date:

Approved: Joni Zich, Director Business Operations & System Strategy Planning
Date:

4" (8") Sartell Bridge Crossing Replacement Project

Updated: 5/20/2016

Project Drivers

- Existing 4" steel main crossing hangs on a bridge. Traffic was removed from the bridge in the 1950's and it was converted to a pedestrian bridge. With continued degradation of the bridge it was closed entirely in 1984.
- The current crossing can no longer be maintained or inspected and is showing signs of corrosion as well as loading stress at bridge abutments.
- Embankments adjacent to the bridge abutments are not stable and are showing signs of soil shifting which could result in a catastrophic failure to the existing faciltiy.
- This crossing is the only feed into the City of Sartell and the feed has no remaining capacity for future growth.
- The City of Sartell has requested that facilities be removed from the bridge to allow for demolition.
- Opportunity for cost sharing between kind-for-kind replacement and pipeline upsize

Project Alternatives

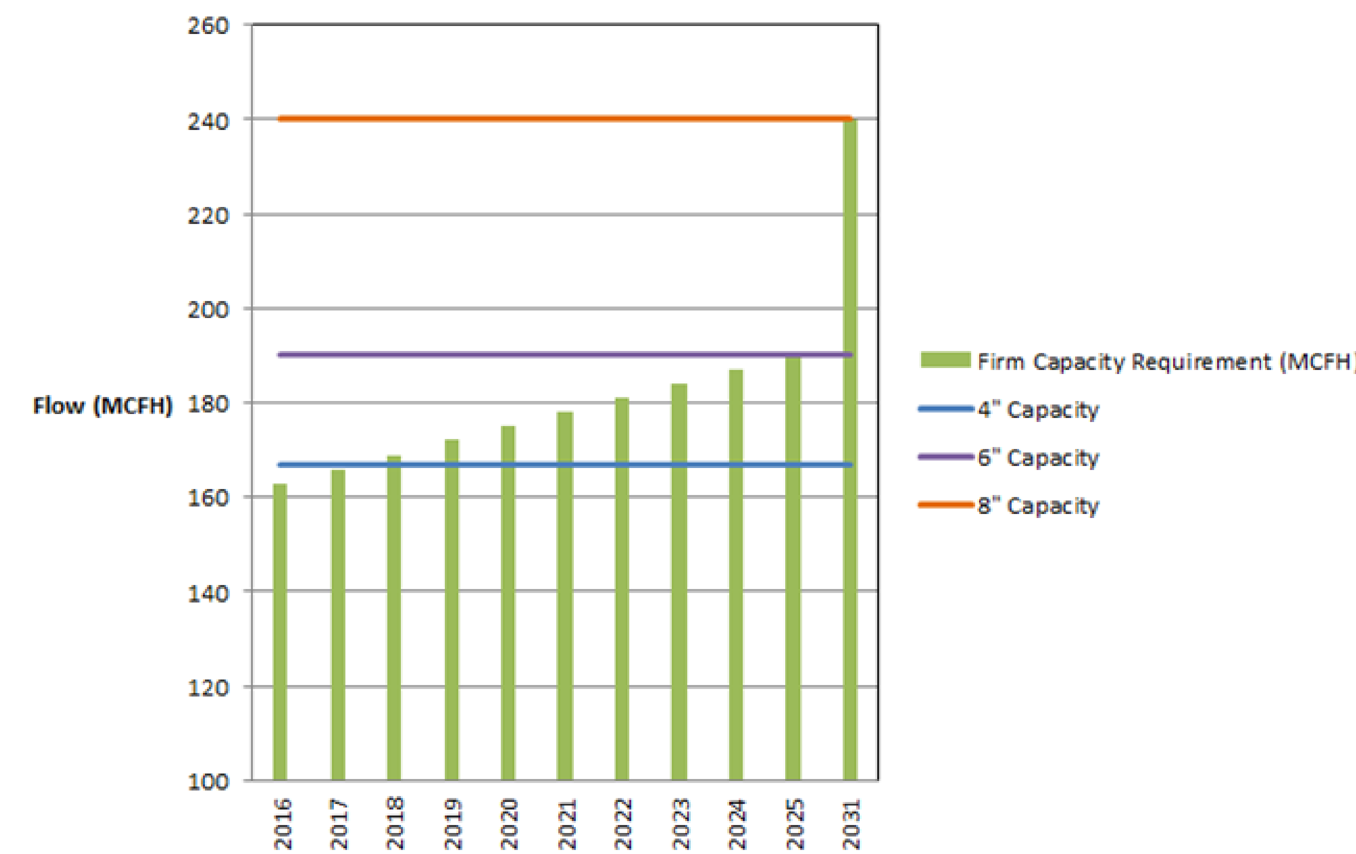
- The existing main cannot be replaced on the bridge as the bridge is unstable and is scheduled for demolition.
- System is a one-way feed.
- Replacing with similar piping through directional drilling would require reinforcement of the system in the near future.

Incremental Cost & Allocation

- Approximate incremental cost for project upsize from 4" steel main to 8" MDPE main is approximately $218,000.
- The incremental project allocation will be 28.1% ($218,000) of the total $775,000 project cost. This portion would be funded from general capital.
- The GUIC funded project allocation will be 71.9% ($557,000) of the total $775,000 project cost.

	Main Size	Estimated Cost	Allocation
GUIC	4"	$ 557,000	71.9%
Non-GUIC	8"	$ 218,000	28.1%
	Total:	**$ 775,000**	**100%**

Pipeline Capacity vs. Peak Demand



☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy

Docket No.:	G002/M-16-0891	Information Request No.	47
Response To:	Office of Attorney General		
Requestor:	Joseph Dammel		
Date Received:	January 24, 2017		

Question:

Reference: Supplemental Petition, page 2

Provide the final version of the AGA SOS (including any cover letter or explanatory material from the Company and/or the AGA) and all responses to date. Supplement as new responses are received.

Response:

The Company has submitted proposed survey questions to the American Gas Association, but the SOS is not yet in final form. Once the SOS is finalized and circulated, the AGA allows its members 2-3 weeks to respond to the survey and another 2-3 weeks to compile the results of the survey. This process could take 6-8 weeks before the Company receives the survey results. Once available, we will supplement this response with the final-version SOS and response information.

Preparer:	Joni Zich
Title:	Director, System Strategy & Business Operations
Department:	System Strategy & Business Operations
Telephone:	651-229-5564
Date:	February 3, 2017

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy
Docket No.: G002/M-16-0891 Information Request No. 97
Response To: Office of Attorney General
Requestor: Joseph Dammel
Date Received: January 27, 2017

Question:

Reference: Petition, p. 32.

Provide the actual and estimated GUIC factors on a total and customer class basis for the calendar years 2015–2022. Show the GUIC factor that the Company expects to be in effect on December 31 of that year; for example, the 2016 factor would be the factor in effect on December 31, 2016. In addition, provide the actual and expected bill impact by month and calendar year for 2015–2022 for each customer class. Provide this data in live Excel spreadsheet format, with all links and formulae intact, and describe any assumptions or alternative scenarios in narrative form.

Response:

Tables 1 and 2 below show the requested actual and estimated GUIC factors and annual bill impacts by class. This information is based on the Company's forecast of GUIC activities through 2021 as shown in our Petition filed on November 1, 2016 in this docket. GUIC factors and bill impacts are not available for 2022 at this time because the Company has not modeled a 2022 GUIC forecast. Attachment A to this response, provided in live Excel spreadsheet format, shows the bill impact by month.

Table 1: GUIC Factors as of December 31 each year

($/therm)

	2015 actual	2016 actual	2017 forecast	2018 forecast	2019 forecast	2020 forecast	2021 forecast
Residential	0.033941	0.010922	0.041689	0.046822	0.057790	0.054335	0.065487
Commercial Firm	0.019357	0.006110	0.023070	0.025513	0.031022	0.028737	0.034348
Dmd Billed	0.012021	0.005274	0.017177	0.019226	0.023675	0.022149	0.026561
Interruptible	0.008369	0.003860	0.012162	0.013720	0.017050	0.016024	0.019246
Transportation	0.002445	0.001570	0.004639	0.005717	0.007457	0.007246	0.008490
Average	0.018289	0.003758	0.042454	0.048271	0.060341	0.057178	0.068218

Table 2: GUIC Typical Annual Bill Impact per Customer

	2015	2016	2017	2018	2019	2020	2021
Residential	$22	$21	$23	$37	$44	$46	$49
Commercial Firm	$87	$78	$88	$143	$168	$177	$189
Dmd Billed	$2,206	$1,887	$2,577	$3,684	$4,404	$4,528	$4,993
Interruptible	$1,795	$1,831	$2,524	$3,644	$4,507	$4,764	$5,424
Transportation	$30,221	$28,780	$32,593	$42,709	$50,404	$48,613	$57,058

This response required making numerous assumptions. Below is a list of some assumptions, but is not an exhaustive or complete list.

1. Forecasted revenue requirements are actual revenue requirements approved for each year.
2. Cost of capital and allowed ROE are the same as filed.
3. Sales by customer class match actual sales for each year.
4. No new GUIC eligible capital projects are included in future forecasts.
~~5.~~ GUIC projects are approved as forecasted each year.
6. Capital costs for each project occur exactly as budgeted.
7. O&M for TIMP and DIMP occur exactly as forecasted for each year.
8. Timely regulatory approval and recovery for each year (otherwise carryover would flow into outer years changing factors).
9. Assumes State tax rates, corporate Federal tax rates, and MACRS tables stay unchanged over the time period.

Preparer:	Lisa Peterson	James Aurand
Title:	Regulatory Analysis Manager	Senior Rate Analyst
Department:	Regulatory Affairs	Revenue Requirements North
Telephone:	(612) 330-7681	(612) 337-2076
Date:	February 9, 2017	

GUIC $ per therm	2015 actual	2016 actual	2017 forecast	2018 forecast	2019 forecast	2020 forecast	2021 forecast
Residential	0.033941	0.010922	0.041689	0.046822	0.057790	0.054335	0.065487
Commercial Firm	0.019357	0.006110	0.023070	0.025513	0.031022	0.028737	0.034348
Comm Dmd Billed	0.012021	0.005274	0.017177	0.019226	0.023675	0.022149	0.026561
Interruptible	0.008369	0.003860	0.012162	0.013720	0.017050	0.016024	0.019246
Transportation	0.002445	0.001570	0.004639	0.005717	0.007457	0.007246	0.008490
Average	0.018289	0.003758	0.042454	0.048271	0.060341	0.057178	0.068218

Annual Bill Impact	2015	2016	2017	2018	2019	2020	2021
Residential	$22	$21	$23	$37	$44	$46	$49
Commercial Firm	$87	$78	$88	$143	$168	$177	$189
Comm Dmd Billed	$2,206	$1,887	$2,577	$3,684	$4,404	$4,528	$4,993
Interruptible	$1,795	$1,831	$2,524	$3,644	$4,507	$4,764	$5,424
Transportation	$30,221	$28,780	$32,593	$42,709	$50,404	$48,613	$57,058

		Revenues ($)					Customers		
		Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed
Feb-15	Actual	2,402,326	731,509	43,601	104,056	20,795	412,589	34,286	133
Mar-15	Actual	1,413,159	456,911	41,155	109,076	70,367	412,997	34,311	133
Apr-15	Actual	770,864	222,777	23,469	69,471	54,884	413,096	34,312	133
May-15	Actual	357,701	147,253	21,024	42,348	34,782	412,970	34,256	133
Jun-15	Actual	220,063	71,319	18,191	50,809	49,044	412,573	34,230	133
Jul-15	Actual	218,197	79,772	19,855	32,348	61,040	412,167	34,197	132
Aug-15	Actual	220,457	83,368	17,989	39,003	52,265	412,253	34,188	132
Sep-15	Actual	266,057	100,014	19,481	44,007	55,825	412,639	34,217	133
Oct-15	Actual	545,728	199,239	25,364	69,713	40,848	413,975	34,283	135
Nov-15	Actual	1,069,547	358,273	32,251	90,634	51,374	414,582	34,331	135
Dec-15	Actual	1,636,824	526,898	32,269	82,100	70,197	415,103	34,400	136
Jan-16	Actual	2,251,312	696,699	39,731	113,378	62,539	415,591	34,486	135
Feb-16	Actual	1,836,632	576,548	42,637	138,303	48,507	416,075	34,518	135
Mar-16	Actual	1,249,064	383,330	33,197	106,275	72,915	416,260	34,551	137
Apr-16	Actual	844,236	250,184	22,011	41,008	63,940	416,431	34,542	137
May-16	Actual	337,619	137,256	22,156	53,222	56,031	416,533	34,508	136
Jun-16	Actual	248,620	71,688	17,011	37,147	57,428	416,262	34,474	135
Jul-16	Actual	212,129	74,178	15,739	43,668	76,459	415,931	34,417	135
Aug-16	Actual	214,992	76,374	18,127	48,899	87,451	416,303	34,424	135
Sep-16	Actual	77,586	23,869	6,103	21,502	39,673	416,478	34,427	135
Oct-16	Forecast	204,512	66,484	11,089	28,709	28,503	417,368	34,432	136
Nov-16	Forecast	418,515	130,395	13,951	38,679	18,946	418,208	34,564	136
Dec-16	Forecast	648,380	205,671	14,259	47,439	28,288	418,825	34,710	136
Jan-17	Forecast	746,726	226,026	17,392	49,189	21,038	419,419	34,788	136
Feb-17	Forecast	626,930	189,642	18,690	43,789	14,005	419,680	34,763	136
Mar-17	Forecast	497,947	163,184	14,652	42,135	23,609	419,928	34,794	136
Apr-17	Forecast	1,068,176	311,701	31,968	105,903	55,967	419,839	34,820	136

		Revenues ($)					Customers		
		Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed
May-17	Forecast	588,056	225,104	31,712	76,086	66,378	419,568	34,842	136
Jun-17	Forecast	336,637	96,249	26,034	67,726	79,120	419,157	34,800	136
Jul-17	Forecast	270,148	90,728	28,556	72,154	110,427	418,754	34,772	136
Aug-17	Forecast	272,977	96,241	25,589	68,762	81,899	418,855	34,731	136
Sep-17	Forecast	353,759	122,871	27,769	71,821	57,667	419,043	34,701	136
Oct-17	Forecast	782,237	255,851	36,065	90,093	70,694	420,034	34,768	136
Nov-17	Forecast	1,600,743	501,803	45,456	124,079	54,062	420,844	34,896	136
Dec-17	Forecast	2,479,825	791,475	46,599	151,850	82,176	421,427	35,044	136
Jan-18	Forecast	2,844,711	864,732	56,594	151,634	60,502	422,031	35,114	136
Feb-18	Forecast	2,388,300	725,528	60,920	137,334	42,132	422,303	35,075	136
Mar-18	Forecast	1,896,999	624,302	47,869	133,861	72,068	422,559	35,097	136
Apr-18	Forecast	1,197,345	349,272	35,716	115,647	77,454	422,478	35,115	136
May-18	Forecast	659,215	252,222	35,531	84,952	80,395	422,214	35,131	136
Jun-18	Forecast	377,395	107,868	29,225	78,409	95,086	421,806	35,080	136
Jul-18	Forecast	302,820	101,664	31,931	78,833	149,717	421,407	35,047	136
Aug-18	Forecast	305,995	107,842	28,669	77,534	96,926	421,511	35,000	136
Sep-18	Forecast	396,555	137,678	31,170	84,093	87,815	421,700	34,963	136
Oct-18	Forecast	876,892	286,684	40,333	99,214	49,604	422,692	35,022	136
Nov-18	Forecast	1,794,409	562,282	50,917	137,582	57,951	423,503	35,146	136
Dec-18	Forecast	2,779,738	886,851	52,207	169,630	69,959	424,087	35,281	136
Jan-19	Forecast	3,184,715	968,500	63,410	169,888	60,073	424,691	35,339	136
Feb-19	Forecast	2,673,706	812,587	68,231	153,500	41,426	424,963	35,293	136
Mar-19	Forecast	2,123,764	699,212	53,733	152,570	66,877	425,217	35,307	136
Apr-19	Forecast	1,473,045	430,103	43,909	140,808	93,743	425,135	35,318	136
May-19	Forecast	811,064	310,573	43,783	105,537	91,821	424,870	35,326	136
Jun-19	Forecast	464,357	132,855	36,095	100,750	112,966	424,461	35,272	136
Jul-19	Forecast	372,553	125,191	39,285	95,765	178,777	424,061	35,236	136

		Revenues ($)					Customers		
		Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed
Aug-19	Forecast	376,464	132,799	35,389	97,628	142,247	424,164	35,186	136
Sep-19	Forecast	487,887	169,537	38,329	100,196	100,674	424,353	35,148	136
Oct-19	Forecast	1,078,881	353,023	49,711	122,715	64,701	425,344	35,206	136
Nov-19	Forecast	2,207,708	692,401	62,895	173,717	76,018	426,155	35,328	136
Dec-19	Forecast	3,419,850	1,092,060	64,124	204,178	79,565	426,738	35,466	136
Jan-20	Forecast	3,929,579	1,193,867	78,458	214,169	78,357	427,341	35,525	136
Feb-20	Forecast	3,298,988	1,001,668	84,019	189,795	54,210	427,613	35,479	136
Mar-20	Forecast	2,620,529	861,904	65,975	181,814	76,737	427,867	35,493	136
Apr-20	Forecast	1,384,538	403,913	41,236	133,802	73,466	427,784	35,504	136
May-20	Forecast	762,392	291,632	41,089	100,975	85,606	427,518	35,513	136
Jun-20	Forecast	436,522	124,800	33,657	89,081	102,897	427,109	35,457	136
Jul-20	Forecast	350,174	117,567	36,914	95,542	161,749	426,709	35,418	136
Aug-20	Forecast	353,855	124,712	33,077	89,367	127,254	426,811	35,367	136
Sep-20	Forecast	458,595	159,206	35,835	92,704	93,337	426,998	35,326	136
Oct-20	Forecast	1,014,136	331,513	46,708	120,694	62,870	427,988	35,382	136
Nov-20	Forecast	2,075,182	650,223	58,774	159,364	73,449	428,797	35,501	136
Dec-20	Forecast	3,214,423	1,025,511	60,104	191,617	79,560	429,378	35,633	136
Jan-21	Forecast	3,665,794	1,114,791	73,325	197,457	76,140	429,979	35,688	136
Feb-21	Forecast	3,077,471	935,316	78,758	177,800	52,505	430,248	35,637	136
Mar-21	Forecast	2,444,662	804,805	61,771	169,125	88,005	430,499	35,649	136
Apr-21	Forecast	1,655,632	486,642	49,646	163,277	79,487	430,412	35,658	136
May-21	Forecast	911,746	351,329	49,213	117,648	115,907	430,143	35,664	136
Jun-21	Forecast	522,075	150,402	40,405	106,639	130,169	429,729	35,606	136
Jul-21	Forecast	418,746	141,646	44,302	114,140	176,602	429,323	35,565	136
Aug-21	Forecast	423,153	150,255	39,711	108,487	150,850	429,420	35,510	136
Sep-21	Forecast	548,416	191,805	43,093	113,988	117,565	429,602	35,469	136
Oct-21	Forecast	1,212,804	399,395	55,960	140,687	77,120	430,586	35,524	136

		Revenues ($)					Customers		
		Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed
Nov-21	Forecast	2,481,661	783,381	70,550	190,394	86,443	431,389	35,644	136
Dec-21	Forecast	3,843,876	1,235,492	72,368	232,444	104,477	431,963	35,776	136

		Bill Impact ($/Customer)				
Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport
419	18	$5.82	$21.34	$327.83	$248.34	$1,155.28
418	18	$3.42	$13.32	$309.44	$260.95	$3,909.29
419	18	$1.87	$6.49	$176.46	$165.80	$3,049.11
419	18	$0.87	$4.30	$158.07	$101.07	$1,932.33
418	18	$0.53	$2.08	$136.78	$121.55	$2,724.67
418	19	$0.53	$2.33	$150.42	$77.39	$3,212.63
397	19	$0.53	$2.44	$136.28	$98.25	$2,750.79
397	19	$0.64	$2.92	$146.47	$110.85	$2,938.16
397	19	$1.32	$5.81	$187.88	$175.60	$2,149.89
397	19	$2.58	$10.44	$238.89	$228.30	$2,703.89
397	19	$3.94	$15.32	$237.27	$206.80	$3,694.59
398	20	$5.42	$20.20	$294.30	$284.87	$3,126.97
396	22	$4.41	$16.70	$315.83	$349.25	$2,204.88
393	22	$3.00	$11.09	$242.32	$270.42	$3,314.33
392	22	$2.03	$7.24	$160.66	$104.61	$2,906.36
388	23	$0.81	$3.98	$162.91	$137.17	$2,436.12
387	23	$0.60	$2.08	$126.01	$95.99	$2,496.87
386	23	$0.51	$2.16	$116.59	$113.13	$3,324.29
386	23	$0.52	$2.22	$134.27	$126.68	$3,802.23
384	23	$0.19	$0.69	$45.21	$56.00	$1,724.90
393	22	$0.49	$1.93	$81.54	$73.05	$1,295.60
391	22	$1.00	$3.77	$102.58	$98.92	$861.19
391	22	$1.55	$5.93	$104.84	$121.33	$1,285.84
388	22	$1.78	$6.50	$127.89	$126.78	$956.29
388	22	$1.49	$5.46	$137.43	$112.86	$636.61
387	22	$1.19	$4.69	$107.74	$108.88	$1,073.12
387	22	$2.54	$8.95	$235.06	$273.65	$2,543.96

Bill Impact ($/Customer)

Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport
385	22	$1.40	$6.46	$233.18	$197.63	$3,017.20
392	22	$0.80	$2.77	$191.43	$172.77	$3,596.38
392	22	$0.65	$2.61	$209.97	$184.07	$5,019.41
378	22	$0.65	$2.77	$188.15	$181.91	$3,722.67
377	22	$0.84	$3.54	$204.18	$190.51	$2,621.23
376	22	$1.86	$7.36	$265.18	$239.61	$3,213.38
375	22	$3.80	$14.38	$334.23	$330.88	$2,457.36
375	22	$5.88	$22.59	$342.64	$404.93	$3,735.28
373	22	$6.74	$24.63	$416.13	$406.52	$2,750.09
373	22	$5.66	$20.69	$447.94	$368.19	$1,915.11
372	22	$4.49	$17.79	$351.98	$359.84	$3,275.82
371	22	$2.83	$9.95	$262.61	$311.72	$3,520.63
369	22	$1.56	$7.18	$261.25	$230.22	$3,654.30
380	22	$0.89	$3.07	$214.89	$206.34	$4,322.09
380	22	$0.72	$2.90	$234.78	$207.45	$6,805.30
368	22	$0.73	$3.08	$210.80	$210.69	$4,405.73
368	22	$0.94	$3.94	$229.19	$228.51	$3,991.59
366	22	$2.07	$8.19	$296.56	$271.08	$2,254.72
365	22	$4.24	$16.00	$374.39	$376.94	$2,634.12
364	22	$6.55	$25.14	$383.87	$466.02	$3,179.95
363	22	$7.50	$27.41	$466.25	$468.01	$2,730.60
362	22	$6.29	$23.02	$501.70	$424.03	$1,883.00
362	22	$4.99	$19.80	$395.10	$421.46	$3,039.86
361	22	$3.46	$12.18	$322.86	$390.05	$4,261.03
360	22	$1.91	$8.79	$321.93	$293.16	$4,173.67
368	22	$1.09	$3.77	$265.41	$273.78	$5,134.81
368	22	$0.88	$3.55	$288.86	$260.23	$8,126.22

Bill Impact ($/Customer)

Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport
356	22	$0.89	$3.77	$260.21	$274.24	$6,465.75
355	22	$1.15	$4.82	$281.83	$282.24	$4,576.10
354	22	$2.54	$10.03	$365.52	$346.65	$2,940.95
352	22	$5.18	$19.60	$462.46	$493.52	$3,455.38
352	22	$8.01	$30.79	$471.50	$580.05	$3,616.57
351	22	$9.20	$33.61	$576.90	$610.17	$3,561.67
351	22	$7.71	$28.23	$617.79	$540.73	$2,464.11
350	22	$6.12	$24.28	$485.11	$519.47	$3,488.03
350	22	$3.24	$11.38	$303.21	$382.29	$3,339.35
348	22	$1.78	$8.21	$302.12	$290.16	$3,891.19
357	22	$1.02	$3.52	$247.48	$249.53	$4,677.16
357	22	$0.82	$3.32	$271.43	$267.62	$7,352.22
346	22	$0.83	$3.53	$243.22	$258.29	$5,784.29
345	22	$1.07	$4.51	$263.50	$268.71	$4,242.58
344	22	$2.37	$9.37	$343.44	$350.85	$2,857.73
342	22	$4.84	$18.32	$432.16	$465.98	$3,338.61
342	22	$7.49	$28.78	$441.94	$560.28	$3,616.38
341	22	$8.53	$31.24	$539.16	$579.05	$3,460.89
341	22	$7.15	$26.25	$579.11	$521.41	$2,386.61
340	22	$5.68	$22.58	$454.20	$497.43	$4,000.21
340	22	$3.85	$13.65	$365.05	$480.23	$3,613.06
338	22	$2.12	$9.85	$361.86	$348.07	$5,268.48
346	22	$1.21	$4.22	$297.10	$308.20	$5,916.79
346	22	$0.98	$3.98	$325.75	$329.88	$8,027.36
335	22	$0.99	$4.23	$291.99	$323.84	$6,856.83
335	22	$1.28	$5.41	$316.86	$340.26	$5,343.85
333	22	$2.82	$11.24	$411.47	$422.48	$3,505.44

		Bill Impact ($/Customer)				
Interruptible	Transport	Residential	Commercial Firm	Commercial Demand Billed	Interruptible	Transport
332	22	$5.75	$21.98	$518.75	$573.48	$3,929.22
332	22	$8.90	$34.53	$532.12	$700.13	$4,748.97

☐ **Not Public Document – Not For Public Disclosure**
☐ **Public Document – Not Public (Or Privileged) Data Has Been Excised**
☒ **Public Document**

Xcel Energy
Docket No.: G002/M-16-0891 Information Request No. 98
Response To: Office of Attorney General
Requestor: Joseph Dammel
Date Received: January 27, 2017

Question:

Reference: Historical Replacement Rate

Provide the historical replacement rate, by pipe material in miles per year, from 2000 to 2016. Include a running inventory of miles of pipe, by material, remaining at the end of each year.

Response:

Historical replacement rates of Gas Distribution main by pipe material in miles per year are shown below from 2000 to 2016. Replacement rate information provided is based on "retired" gas distribution main as identified in the Company's Geographic Information System (GIS). This data includes pipe that has been retired as a result of activities such as pipe renewal, line relocations, abandonments, etc.

Pipe Type	Cast Iron	Bare Steel	Coated Steel	Plastic	Other/Unknown	Total (miles/yr)
2000	13.1	1.4	31.8	30.7	10.0	87.0
2001	0.2	0.1	5.5	3.6	0.4	9.8
2002	8.5	0.6	46.1	33.6	12.2	101.0
2003	3.2	2.9	20.1	26.0	1.7	53.9
2004	2.3	1.1	12.2	17.5	0.0	33.1
2005	1.8	1.6	9.8	18.3	1.8	33.3
2006	2.7	3.3	17.0	35.3	1.0	59.3
2007	2.7	1.9	14.3	74.2	0.4	93.5
2008	1.9	5.0	18.0	70.1	0.1	95.1
2009	4.2	1.6	19.4	25.8	0.5	51.5
2010	6.1	1.0	19.1	25.5	1.3	53.0
2011	6.2	1.6	14.1	16.1	1.2	39.2
2012	7.0	6.0	15.5	19.0	0.0	47.5
2013	0.0	2.2	18.9	19.5	0.0	40.6
2014	0.0	0.3	23.5	20.9	0.0	44.7
2015	0.0	0.0	32.3	48.9	0.1	81.3
2016	0.0	0.0	25.2	43.8	0.0	69.0

A running inventory of miles of distribution main, by Department of Transportation (DOT) material type, is shown below from 2000 to 2015. Inventory data for 2016 is not currently available but will be available in early March as part of the 2016 DOT annual report.

Pipe Type	Cast Iron	Bare Steel	Coated Steel	Plastic	Other/Unknown
2000	33	70	1294	6253	0
2001	26	70	1291	6358	0
2002	24	61	1275	6488	0
2003	24	52	1275	6578	0
2004	25	52	1284	6786	0
2005	22	50	1264	7030	0
2006	21	49	1236	7193	0
2007	20	49	1235	7267	0
2008	21	49	1231	7325	0
2009	15	49	1217	7375	0
2010	14	48	1198	7438	0
2011	7	22	1009	7772	0
2012	0	6	1010	7848	0
2013	0	2	1005	7907	4
2014	0	0	988	8092	5
2015	0	1	969	8125	62

Preparer: Ray Gardner
Title: Director
Department: Integrity Management Programs
Telephone: 303-571-3904

Date: February 16, 2017

OAG No. 100

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for Great Plains Natural Gas Co.	**MPUC Docket No.**	G004/M-16-357

By:	Joseph Dammel	**Date of Request:**	February 8, 2017
Telephone:	(651) 757-1061	**Due Date:**	February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

On January 13, 2017, in its Gas Utility Infrastructure Cost ("GUIC") rider docket, 16-891, Xcel Energy proposed several "GUIC Metrics" that it was ordered to develop in the previous GUIC rider docket, 15-808.

The proposed metrics are as follows:

- DIMP: leak rate by vintage and pipe material (leaks/mile);
- DIMP: eligible main replacement unit cost ($/foot)
- DIMP: eligible service main replacement unit cost ($/service)
- TIMP: gas transmission anomalies repaired
- TIMP: actual vs. estimated cost variance explanations for capital projects

More details regarding these metrics can be found in Xcel's Jan. 13, 2017 filing.

Provide results using these metrics for your company's TIMP/DIMP or otherwise GUIC-eligible projects for the years 2012 to 2016. Explain why these metrics are applicable (or not) to your company.

Great Plains' Objection: Great Plains objects to the Information Request on the basis that the Request seeks information that is related to Xcel's Gas Utility Infrastructure Cost rider filing in another docket and is not relevant to the Commission's review and evaluation of Great Plains' Annual Gas Service Quality Report for 2015. Great Plains was neither directed by the Commission to develop GUIC Metrics nor does the scope of its Annual Gas Service Quality Report include or address such metrics. Great Plains further objects to the Request on the basis that the Request infers knowledge of a requirement imposed on another utility and responding to the Request would be unduly burdensome and outside the scope of the matters to be addressed in Docket No. G004/M-16-357.

Response By: **Brian Meloy, Stinson Leonard Street**
Title: **Partner**
Department: **Counsel for Great Plains**
Telephone **612-335-1451**

OAG No. 101

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for Great Plains Natural Gas Co.	**MPUC Docket No.**	G004/M-16-357

By:	Joseph Dammel	**Date of Request:**	February 8, 2017
Telephone:	(651) 757-1061	**Due Date:**	February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

Provide answers to the following questions as it relates to your company's TIMP/DIMP or otherwise GUIC-eligible projects.

- Does your company have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates?
  - If yes, please describe your company's cost recovery mechanism including the docket number(s) and enabling statute or regulation/rule.
- Has your company developed performance metrics to evaluate the effectiveness of your TIMP and DIMP investments? If so, please describe.
- What process did you use to develop the metrics?
- Do the metrics change over time based on the type of investments being made?
- How do metric results inform TIMP/DIMP investment decisions made by the company, if at all, and to what extent have metrics been incorporate into your company's decision-making process?
- Are there any financial incentives or penalties that are triggered by outcomes of the performance metrics? If so, please describe.
- Have you experienced any cost savings, such as O&M costs, associated with TIMP and/or DIMP investments and are you required to account for those savings in your cost recovery rider?
- Have you generated any learnings from your metrics?

Great Plains' Objection: Great Plains objects to the Information Request on the basis that the Request seeks information that is related to Xcel's Gas Utility Infrastructure Cost rider filing in another docket and is not relevant to the Commission's review and evaluation of Great Plains' Annual Gas Service Quality Report for 2015. Great Plains was neither directed by the Commission to develop GUIC Metrics nor does the scope of its Annual Gas Service Quality Report include or address such metrics. Great Plains further objects to the Request on the basis that the Request infers knowledge of a requirement imposed on another utility and responding to

Response By: **Brian Meloy, Stinson Leonard Street**
Title: **Partner**
Department: **Counsel for Great Plains**
Telephone **612-335-1451**

the Request would be unduly burdensome and outside the scope of the matters to be addressed in Docket No. G004/M-16-357.

Response By: **<u>Brian Meloy, Stinson Leonard Street</u>**
Title: **<u>Partner</u>**
Department: **<u>Counsel for Great Plains</u>**
Telephone **<u>612-335-1451</u>**

OAG No. 100

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for Minnesota Energy Resources Corporation	**MPUC Docket No.** G011/M-16-371
By: Joseph Dammel **Telephone:** (651) 757-1061	**Date of Request:** February 8, 2017 **Due Date:** February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

On January 13, 2017, in its Gas Utility Infrastructure Cost ("GUIC") rider docket, 16-891, Xcel Energy proposed several "GUIC Metrics" that it was ordered to develop in the previous GUIC rider docket, 15-808.

The proposed metrics are as follows:

- DIMP: leak rate by vintage and pipe material (leaks/mile);
- DIMP: eligible main replacement unit cost ($/foot)
- DIMP: eligible service main replacement unit cost ($/service)
- TIMP: gas transmission anomalies repaired
- TIMP: actual vs. estimated cost variance explanations for capital projects

More details regarding these metrics can be found in Xcel's Jan. 13, 2017 filing.

Provide results using these metrics for your company's TIMP/DIMP or otherwise GUIC-eligible projects for the years 2012 to 2016. Explain why these metrics are applicable (or not) to your company.

MERC Response:

The above metrics are not applicable to MERC and such analysis is not available because MERC does not maintain such data by main segment. Additionally, as noted in response to OAG Information Request No. 101, MERC does not currently have a cost recovery mechanism to recover TIMP/DIMP or other GUIC-eligible costs outside of base rates.

As such, the development of generic GUIC metrics for the natural gas utilities will be difficult and of little use. For example, MERC's distribution system is different from Xcel Energy's system and the materials installed, the date of installations, and the replacement programs to date are dissimilar. Regarding the transmission anomalies, MERC has less than 25 miles of transmission and no transmission in high consequence areas.

Response by Amber S. Lee
Title Regulatory and Legislative Affairs Manager
Department Minnesota Energy Resources
Telephone (651) 322-8965

OAG No. 101

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for Minnesota Energy Resources Corporation		**MPUC Docket No.**	G011/M-16-371
By:	Joseph Dammel	**Date of Request:**	February 8, 2017
Telephone:	(651) 757-1061	**Due Date:**	February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

Provide answers to the following questions as it relates to your company's TIMP/DIMP or otherwise GUIC-eligible projects.

- Does your company have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates?
  - If yes, please describe your company's cost recovery mechanism including the docket number(s) and enabling statute or regulation/rule.

MERC Response:

No, MERC does not have a cost recovery-mechanism to recover TIMP and/or DIMP costs outside of base rates.

- Has your company developed performance metrics to evaluate the effectiveness of your TIMP and DIMP investments? If so, please describe.

MERC Response:

No, MERC has not developed performance metrics to evaluate the effectiveness of DIMP and/or TIMP investments. MERC does not manage its integrity program to measure the effectiveness of these investments. Rather, MERC manages its system integrity program to measure and reduce risk.

- What process did you use to develop the metrics?

MERC Response:

Not applicable.

- Do the metrics change over time based on the type of investments being made?

Response by Amber S. Lee
Title Regulatory and Legislative Affairs Manager
Department Minnesota Energy Resources
Telephone (651) 322-8965

<u>MERC Response</u>:

Not applicable.

- How do metric results inform TIMP/DIMP investment decisions made by the company, if at all, and to what extent have metrics been incorporate into your company's decision-making process?

<u>MERC Response</u>:

Not applicable.

- Are there any financial incentives or penalties that are triggered by outcomes of the performance metrics? If so, please describe.

<u>MERC Response</u>:

Not applicable.

- Have you experienced any cost savings, such as O&M costs, associated with TIMP and/or DIMP investments and are you required to account for those savings in your cost recovery rider?

<u>MERC Response</u>:

Not applicable.

- Have you generated any learnings from your metrics?

<u>MERC Response</u>:

<u>Not applicable.</u>

Response by <u>Amber S. Lee</u>
Title <u>Regulatory and Legislative Affairs Manager</u>
Department <u>Minnesota Energy Resources</u>
Telephone <u>(651) 322-8965</u>

OAG No. 100

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for CenterPoint Energy Resources Corporation	**MPUC Docket No.** G-008/M-16-377
By: Joseph Dammel	**Date of Request:** February 8, 2017
Telephone: (651) 757-1061	**Due Date:** February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

On January 13, 2017, in its Gas Utility Infrastructure Cost ("GUIC") rider docket, 16-891, Xcel Energy proposed several "GUIC Metrics" that it was ordered to develop in the previous GUIC rider docket, 15-808.

The proposed metrics are as follows:

- DIMP: leak rate by vintage and pipe material (leaks/mile);
- DIMP: eligible main replacement unit cost ($/foot)
- DIMP: eligible service main replacement unit cost ($/service)
- TIMP: gas transmission anomalies repaired
- TIMP: actual vs. estimated cost variance explanations for capital projects

More details regarding these metrics can be found in Xcel's Jan. 13, 2017 filing.

Provide results using these metrics for your company's TIMP/DIMP or otherwise GUIC-eligible projects for the years 2012 to 2016. Explain why these metrics are applicable (or not) to your company.

Response:

CenterPoint Energy ("Company") objects to this request as vague, overbroad, unduly burdensome, not relevant to the issues before the Minnesota Public Utilities Commission ("Commission") and beyond the scope of this docket. As explained in the Company's April 29, 2016 Annual Service Quality Report for 2015 ("Report"), the Report was filed in compliance with the reporting requirements in the Commission's Order dated August 26, 2010 in Docket No. G-999/CI-09-409. The Company also explained that the Report includes additional information, in compliance with the Commission's Orders on March 15, 2010 in Docket No. G-008/M-09-1190, March 6, 2012 in Docket No. G-008/M-10-378, and November 25, 2015 in Docket No. G-008/M-15-414. The Company has not requested a GUIC rider and has not participated in the Xcel Energy docket referenced in this Information Request.

OAG No. 101

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for CenterPoint Energy Resources Corporation

MPUC Docket No. G-008/M-16-377

By: Joseph Dammel
Telephone: (651) 757-1061

Date of Request: February 8, 2017
Due Date: February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

Provide answers to the following questions as it relates to your company's TIMP/DIMP or otherwise GUIC-eligible projects.

- Does your company have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates?
    - If yes, please describe your company's cost recovery mechanism including the docket number(s) and enabling statute or regulation/rule.
- Has your company developed performance metrics to evaluate the effectiveness of your TIMP and DIMP investments? If so, please describe.
- What process did you use to develop the metrics?
- Do the metrics change over time based on the type of investments being made?
- How do metric results inform TIMP/DIMP investment decisions made by the company, if at all, and to what extent have metrics been incorporate into your company's decision-making process?
- Are there any financial incentives or penalties that are triggered by outcomes of the performance metrics? If so, please describe.
- Have you experienced any cost savings, such as O&M costs, associated with TIMP and/or DIMP investments and are you required to account for those savings in your cost recovery rider?
- Have you generated any learnings from your metrics?

Response:

See Response to OAG Information Request 100. Subject to and without waiving this objection, the Company responds that it does not have a specific cost recovery mechanism, beyond base rate recovery, through which it recovers investments or expenses related to its integrity management programs.

OAG No. 100

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for Greater Minnesota Gas, Inc.		**MPUC Docket No.**	G022/M-16-383
By:	Joseph Dammel	**Date of Request:**	February 8, 2017
Telephone:	(651) 757-1061	**Due Date:**	February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

On January 13, 2017, in its Gas Utility Infrastructure Cost ("GUIC") rider docket, 16-891, Xcel Energy proposed several "GUIC Metrics" that it was ordered to develop in the previous GUIC rider docket, 15-808.

The proposed metrics are as follows:

- DIMP: leak rate by vintage and pipe material (leaks/mile);
- DIMP: eligible main replacement unit cost ($/foot)
- DIMP: eligible service main replacement unit cost ($/service)
- TIMP: gas transmission anomalies repaired
- TIMP: actual vs. estimated cost variance explanations for capital projects

More details regarding these metrics can be found in Xcel's Jan. 13, 2017 filing.

Provide results using these metrics for your company's TIMP/DIMP or otherwise GUIC-eligible projects for the years 2012 to 2016. Explain why these metrics are applicable (or not) to your company.

GMG RESPONSE:

GMG reviewed the referenced Xcel Energy proposal and the GUIC Metrics contained therein. While GMG recognizes that some natural gas systems in Minnesota contain substantial amounts of vintage material, thus giving rise to GUIC recovery programs, GMG's system is still in its relative infancy and is comprised primarily of plastic pipe. As such, GMG has not encountered a need for instituting either a replacement program or a GUIC recovery program. With specific regard to the proposed metrics, GMG provides the following information:

Response by Kristine Anderson
Title Corporate Attorney
Department Legal
Telephone 507-665-8657

- ***DIMP: leak rate –*** *Less than 0.15% of GMG's system is considered "vintage" in that it pre-dates 1970 and GMG has not experienced any leaks in the vintage system area. Hence, there is no leak rate to report.*
- ***DIMP: eligible main replacement cost –*** *Not applicable. GMG's DIMP risk evaluation has not identified any elevated threats that require or are likely to require remediation in the foreseeable future; ergo, GMG has not instituted a replacement program.*
- ***DIMP: eligible service main replacement cost –*** *Not applicable. GMG's DIMP risk evaluation has not identified any elevated threats that require or are likely to require remediation in the foreseeable future; ergo, GMG has not instituted a replacement program.*
- ***TIMP: anomalies repaired –*** *GMG has not identified any anomalies that required repair.*
- ***TIMP: cost variance explanation –*** *Not applicable. GMG has not undertaken any TIMP-related capital projects.*

With regard to the broader question of applicability of the metrics to GMG, the metrics do not generally apply. GMG concurs that leaks per mile is, theoretically, a valuable metric for some purposes. However, GMG respectfully posits that such an inquiry related to the appropriateness of GUIC recovery should exclude leaks resulting from both first and third party damage and should focus exclusively on leaks resulting from problems with system integrity, faulty materials, etc. With regard to the metrics examining DIMP replacement cost per foot, GMG submits that it is virtually impossible to compare cost per foot across systems and that it is not appropriate to use a standard cost per foot calculation. Cost is dependent on size and type of pipe, location of pipe, a gas company's accounting method for cost allocation, etc. Those are not necessarily uniform from project to project, much less from company to company. Likewise, TIMP analysis will vary based on similar variables.

GMG believes that metrics that allow companies to quantify risk and evaluate program effectiveness can be very beneficial tools. That said, each company is in the best position to develop metrics that are appropriate for its own system to measure improvement and to evaluate the appropriateness of its GUIC expenditures. GMG does not believe that universal metrics are an appropriate tool to provide meaningful analysis of GUIC expenditures and recovery because of the dramatic differences among the various company systems.

Response by **Kristine Anderson**
Title **Corporate Attorney**
Department **Legal**
Telephone **507-665-8657**

OAG No. 101

State Of Minnesota
Office Of The Attorney General
Utility Information Request

In the Matter of 2015 – 2016 Annual Service Quality Reports for Greater Minnesota Gas, Inc.	**MPUC Docket No.** G022/M-16-383
By: Joseph Dammel	**Date of Request:** February 8, 2017
Telephone: (651) 757-1061	**Due Date:** February 21, 2017

Re: Xcel Energy's Jan. 13, 2017 Supplemental Petition in Docket No. 16-891

Provide answers to the following questions as it relates to your company's TIMP/DIMP or otherwise GUIC-eligible projects.

- Does your company have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates?
  - If yes, please describe your company's cost recovery mechanism including the docket number(s) and enabling statute or regulation/rule.
- Has your company developed performance metrics to evaluate the effectiveness of your TIMP and DIMP investments? If so, please describe.
- What process did you use to develop the metrics?
- Do the metrics change over time based on the type of investments being made?
- How do metric results inform TIMP/DIMP investment decisions made by the company, if at all, and to what extent have metrics been incorporate into your company's decision-making process?
- Are there any financial incentives or penalties that are triggered by outcomes of the performance metrics? If so, please describe.
- Have you experienced any cost savings, such as O&M costs, associated with TIMP and/or DIMP investments and are you required to account for those savings in your cost recovery rider?
- Have you generated any learnings from your metrics?

GMG RESPONSE:

As discussed in GMG's response to Information Request No. 100, GMG does not yet have a need for a TIMP/DIMP investment program and does not have GUIC recovery eligible projects. Consequently, GMG provides the following information with regard to each specific component of the question:

Response by Kristine Anderson
Title Corporate Attorney
Department Legal
Telephone 507-665-8657

- ***Cost Recovery Mechanism*** - *GMG does not have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates because GMG's risk models have not identified a need for remediation in the foreseeable future given the system's modernity, both in terms of age and materials.*
- ***Investment Effectiveness Metrics*** - *GMG has not made TIMP and/or DIMP investments, so there are necessarily no performance metrics to evaluate the effectiveness of such investments. However, GMG's integrity management program risk assessment would ultimately reflect the effectiveness of any such future investments.*
- ***Metric Development Process –*** *GMG has not developed investment effectiveness metrics because it does not yet need an investment program. GMG uses the industry-standard SHRIMP tool, provided for small utilities by the APGA Security and Integrity Foundation with support from PHMSA and state pipeline safety regulators, for its integrity management program. SHRIMP is designed for natural gas operators to customize integrity management programs for the specific needs of their respective systems rather than employing a one-size-fits-all model.*
- ***Metric Evolution Over Time –*** *Since GMG has not made any investments and has no metrics, they have not changed over time. Nonetheless, GMG anticipates that metrics to evaluate investment effectiveness would likely evolve based on the type of investments being made and relevant variables in order to provide meaningful analysis, both within a company and across companies.*
- ***Impact of Metric Results on Company Decisions*** - *No TIMP/DIMP investments have been made by GMG at this time; ergo, there are no applicable metric results to impact them. The metrics employed in GMG's integrity management risk assessment impact company decisions regarding the need to allocate resources; and, GMG anticipates that its integrity management program metrics will similarly produce information that will inform GMG's future investment decisions.*
- ***Financial Incentives and Penalties –*** *Not applicable, given GMG's current system status as discussed throughout these Information Request responses.*
- ***Cost Savings Experienced –*** *Not applicable, given that GMG does not have TIMP/DIMP investments or a cost recovery rider.*
- ***Generated Learnings –*** *Since GMG has not made TIMP/DIMP investments and does not have a GUIC recovery rider, it does not employ metrics to evaluate them and has not acquired any information in that regard. Nonetheless, GMG's integrity management program does employ metrics that allow GMG to quantify risk levels to its system and periodically assess its current and future needs regarding integrity management protocols and potential investment.*

Response by Kristine Anderson
Title Corporate Attorney
Department Legal
Telephone 507-665-8657

APPENDIX

B

Gas Distribution Cast/Wrought Iron Pipelines

Date run: 2/8/2017

Data Source: US DOT Pipeline and Hazardous Materials Safety Administration
Portal - Data as of **2/8/2017**

Notes:

- Sort any column by hovering over the column header, then selecting sort order.

Year: 2015

State		Main Miles	% of Total Main Miles	Service Count	% of Total Service Count
NEW JERSEY	NJ	4,586	13.2%	0	0.0%
NEW YORK	NY	3,960	8.1%	6,375	0.2%
MASSACHUSETTS	MA	3,315	15.4%	1,492	0.1%
PENNSYLVANIA	PA	2,901	6.0%	78	0.0%
MICHIGAN	MI	2,812	4.9%	15	0.0%
ILLINOIS	IL	1,431	2.3%	65	0.0%
CONNECTICUT	CT	1,349	16.9%	37	0.0%
MARYLAND	MD	1,318	8.9%	31	0.0%
ALABAMA	AL	1,076	3.5%	219	0.0%
MISSOURI	MO	916	3.3%	0	0.0%
RHODE ISLAND	RI	769	24.0%	137	0.1%
TEXAS	TX	657	0.6%	0	0.0%
DISTRICT OF COLUMBIA	DC	412	34.0%	0	0.0%
NEBRASKA	NE	388	3.0%	0	0.0%
LOUISIANA	LA	354	1.3%	962	0.1%
OHIO	OH	315	0.5%	10	0.0%
VIRGINIA	VA	263	1.2%	77	0.0%
INDIANA	IN	209	0.5%	0	0.0%
FLORIDA	FL	168	0.6%	0	0.0%
NEW HAMPSHIRE	NH	113	5.9%	22	0.0%
DELAWARE	DE	76	2.5%	0	0.0%
CALIFORNIA	CA	60	0.1%	0	0.0%
KANSAS	KA	58	0.3%	0	0.0%
KENTUCKY	KY	56	0.3%	454	0.1%
ARKANSAS	AR	50	0.2%	0	0.0%
MAINE	ME	45	3.8%	30	0.1%
MISSISSIPPI	MS	44	0.3%	1	0.0%
TENNESSEE	TN	39	0.1%	0	0.0%
WEST VIRGINIA	WV	14	0.1%	23	0.0%
MINNESOTA	MN	10	0.0%	0	0.0%
GEORGIA	GA	5	0.0%	0	0.0%
COLORADO	CO	0	0.0%	0	0.0%
IOWA	IA	0	0.0%	0	0.0%

Gas Distribution Bare Steel Pipelines

Date run: 2/8/2017

Data Source: US DOT Pipeline and Hazardous Materials Safety Administration
Portal - Data as of **2/8/2017**

Notes:

- Sort any column by hovering over the column header, then selecting sort order.

Year: 2015

State	Abbrev	Main Miles Bare Steel	% of Total Main Miles	Service Count	% of Total Service Count
OHIO	OH	7,672.29	13.3%	147,170	4.2%
PENNSYLVANIA	PA	7,208.44	15.0%	274,084	9.6%
NEW YORK	NY	6,138.13	12.6%	291,466	9.1%
TEXAS	TX	5,851.42	5.5%	121,212	2.5%
CALIFORNIA	CA	3,797.00	3.6%	16,720	0.2%
KANSAS	KS	3,256.42	14.5%	101,526	10.6%
WEST VIRGINIA	WV	2,860.14	26.4%	78,206	18.4%
MASSACHUSETTS	MA	1,566.40	7.3%	172,621	13.2%
NEW JERSEY	NJ	1,333.00	3.8%	216,648	9.2%
MICHIGAN	MI	1,251.65	2.2%	45,475	1.4%
ARKANSAS	AR	1,245.11	6.2%	22,020	3.2%
OKLAHOMA	OK	1,187.28	4.5%	45,819	3.5%
MISSOURI	MO	1,089.35	4.0%	10,502	0.7%
FLORIDA	FL	804.90	2.9%	30,144	3.5%
KENTUCKY	KY	694.92	3.7%	22,359	2.6%
INDIANA	IN	651.79	1.6%	48,797	2.4%
LOUISIANA	LA	615.79	2.3%	25,180	2.2%
ALABAMA	AL	567.70	1.8%	149,858	13.8%
ARIZONA	AZ	538.67	2.2%	10,639	0.8%
NEBRASKA	NE	501.02	3.9%	4,123	0.7%
VIRGINIA	VA	496.73	2.3%	13,064	1.0%
MISSISSIPPI	MS	464.98	2.8%	832	0.1%
MINNESOTA	MN	345.15	1.1%	1,886	0.1%
ILLINOIS	IL	276.07	0.4%	23,660	0.6%
RHODE ISLAND	RI	266.00	8.3%	37,992	19.5%
MARYLAND	MD	258.66	1.7%	83,971	8.2%
COLORADO	CO	183.09	0.5%	16,995	1.1%
IOWA	IA	172.49	1.0%	6,942	0.7%
CONNECTICUT	CT	155.99	2.0%	50,816	11.5%
HAWAII	HA	101.80	16.7%	6,764	19.6%
NEW MEXICO	NM	84.95	0.6%	10,257	1.6%
GEORGIA	GA	52.28	0.1%	10,599	0.5%
TENNESSEE	TN	43.77	0.1%	1,676	0.1%
SOUTH DAKOTA	SD	27.69	0.5%	1,828	0.8%
DISTRICT OF COLUMBIA	DC	24.96	2.1%	7,039	5.7%
WYOMING	WY	24.93	0.5%	3,028	1.6%
NEW HAMPSHIRE	NY	16.58	0.9%	6,309	6.9%
DELAWARE	DE	11.83	0.4%	692	0.4%
NORTH DAKOTA	ND	8.30	0.2%	75	0.0%
MONTANA	MT	8.12	0.1%	101	0.0%
ALASKA	AK	7.99	0.2%	0	0.0%
SOUTH CAROLINA	SC	6.00	0.0%	386	0.1%
OREGON	OR	3.02	0.0%	35	0.0%
WASHINGTON	WA	3.00	0.0%	86	0.0%
MAINE	ME	0.72	0.1%	138	0.4%
NEVADA	NV	0.00	0.0%	1	0.0%
WISCONSIN	WI	0.00	0.0%	2	0.0%

Gas Distribution Cast/Wrought Iron Main Miles and Service Count Operator Trend

Date run: 2/1/2017

Data Source: US DOT Pipeline and Hazardous Materials Safety Administration
Portal - Data as of **2/1/2017**

Notes:

- Sort any column by hovering over the column header, then selecting sort order.

State: MINNESOTA

Operator ID	Operator Name	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
12350	CENTERPOINT ENERGY RESOURCES CORP., DBA CENTERPOINT ENERGY MINNESOTA GAS	89.1	84.1	82.0	75.0	69.0	66.0	58.0	43.0	29.4	16.2	9.6
31636	NORTHERN STATES POWER CO OF MINNESOTA	22.0	21.0	20.0	19.0	15.0	14.0	7.0				
	Grand Total	**111.1**	**105.1**	**102.0**	**94.0**	**84.0**	**80.0**	**65.0**	**43.0**	**29.4**	**16.2**	**9.6**

Gas Distribution Bare Steel Main Miles and Service Count Operator Trend

Date run: 2/1/2017

Data Source: US DOT Pipeline and Hazardous Materials Safety Administration
Portal - Data as of **2/1/2017**

Notes:

- Sort any column by hovering over the column header, then selecting sort order.

State: MINNESOTA

	Calendar Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Operator ID	**Operator Name**											
918	AUSTIN UTILITIES	9.00	8.00	7.00	7.00	6.00	5.33	4.83	3.71	3.52	2.00	1.80
6690	GREAT PLAINS NATURAL GAS CO				0.05	0.05	0.07	0.05	0.02	0.01	0.01	0.01
7250	HIBBING PUBLIC UTILITIES COMM						26.65					
12350	CENTERPOINT ENERGY RESOURCES CORP., DBA CENTERPOINT ENERGY MINNESOTA GAS	626.54	540.56	561.00	541.00	523.00	450.00	474.00	459.00	425.14	392.01	342.64
13400	NEW ULM PUBLIC UTILITIES COMMISSION	0.00										
15359	BLACK HILLS ENERGY	36.00										
31292	NORTHWEST GAS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
31636	NORTHERN STATES POWER CO OF MINNESOTA	50.00	49.00	49.00	49.00	49.00	48.00	22.00	6.00	1.56	0.01	0.70
32198	MINNESOTA ENERGY RESOURCES CORPORATION		36.00	33.00	33.00	30.00	26.44	22.89	11.02	8.30	5.62	
Grand Total		**721.55**	**633.57**	**650.01**	**630.06**	**608.06**	**556.49**	**523.78**	**479.76**	**438.53**	**399.66**	**345.15**

OPERATOR_NAME	MMILES_STEEL_UNP_BARE	MMILES_STEEL_UNP_CC	MMILES_STEEL_CP_BARE	MMILES_STEEL_CP_COATED	MMILES_PLASTIC	MMILES_CI	MMILES_C	MMILES_TOTAL	NUM_SRVS_STEEL_UNP_BARE	NUM_SRVS_STEEL_UNP_COATEI	NUM_SRVS_STEEL_CP_BARE	NUM_SRVS_STEEL_CP_COATEC	NUM_SRVS
MINNESOTA ENERGY RESOURCES CORPOR/	0	0	0	1499.29	3329.49	0	0	4828.78	0	0	0	42907	177352
NORTHERN STATES POWER CO OF MINNE!	**0.7**	**184.6**	**0**	**784.5**	**8124.9**	**0**	**62.3**	**9157**	**42**	**3857**	**0**	**6026**	**384425**
GREATER MINNESOTA GAS INC.	0	0	0	12.708	750.608	0	0	763.316	0	0	0	2	6746
GREAT PLAINS NATURAL GAS CO	0	0	0.005	118.953	339.985	0	0	458.943	0	0	34	3807	19326
CENTERPOINT ENERGY RESOURCES CORP.,	326.472	16.886	16.17	3659.913	9648.495	9.606	0	13677.542	1253	225	0	52029	690714

Gas Distribution Leaks by Cause

Time run: 2/13/2017 5:40:29 PM

SMART Data as of **2/12/2017 5:00:38 PM**

Portal Data as of **2/13/2017 3:13:46 AM**

Geo Region: ALL Geo State: ALL

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Leak Cause											
Corrosion	139,236	133,751	127,810	128,421	147,484	140,522	132,415	133,133	122,812	124,940	122,144
Natural Force	27,177	27,889	24,268	26,957	27,418	27,294	28,847	27,552	29,701	33,603	32,673
Equipment	41,692	46,402	52,653	53,326	90,098	79,278	91,306	106,432	118,884	131,437	152,171
Material or Weld	53,215	49,877	47,930	49,645	72,863	54,497	46,799	42,427	43,633	45,768	53,740
Excavation	118,843	116,138	106,374	92,435	75,724	73,796	71,909	73,382	70,255	73,773	78,002
Operations	7,536	10,173	12,426	14,747	14,523	10,035	10,341	8,360	9,169	11,699	14,600
Other Outside Force Damage	10,560	11,701	16,012	11,328	10,850	9,675	17,130	12,525	13,800	13,886	14,123
Other Cause	117,967	106,318	98,462	110,204	114,016	90,858	82,792	88,105	75,038	73,316	69,257

Gas Distribution Leaks by Cause

Time run: 2/13/2017 5:46:35 PM

SMART Data as of **2/12/2017 5:00:38 PM**

Portal Data as of **2/13/2017 3:13:46 AM**

Geo Region: EASTERN Geo State: NEW JERSEY

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Leak Cause											
Corrosion	7,842	7,703	6,257	8,308	7,002	6,901	7,480	6,718	6,095	6,572	6,189
Natural Force	3,164	3,421	3,757	3,019	3,593	3,605	4,460	4,172	4,975	6,591	5,009
Equipment	383	1,091	323	378	332	374	1,577	2,038	1,854	2,550	2,860
Material or Weld	815	719	409	632	636	610	846	598	751	856	894
Excavation	2,533	2,629	2,391	1,869	1,531	1,621	1,493	1,498	1,748	1,755	1,738
Operations	202	466	315	336	334	342	478	389	470	879	711
Other Outside Force Damage	353	346	291	285	345	372	362	295	347	406	275
Other Cause	1,978	2,275	1,531	1,518	1,412	1,736	1,368	1,362	1,272	1,662	1,721

Gas Distribution Leaks by Cause

Time run: 2/13/2017 5:47:50 PM

SMART Data as of **2/12/2017 5:00:38 PM**

Portal Data as of **2/13/2017 3:13:46 AM**

Geo Region: EASTERN Geo State: MASSACHUSETTS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Leak Cause											
Corrosion	6,379	6,574	6,164	6,469	7,898	6,660	5,816	4,873	4,341	4,880	4,892
Natural Force	4,889	3,193	2,936	2,681	2,881	840	866	559	1,144	1,168	1,366
Equipment	207	246	256	264	295	1,377	1,674	1,207	1,594	2,837	2,604
Material or Weld	828	668	825	1,052	1,057	501	317	324	619	1,474	1,312
Excavation	1,442	1,118	938	882	717	1,080	950	936	1,000	1,012	1,030
Operations	49	90	67	95	55	37	21	18	46	67	60
Other Outside Force Damage	81	231	245	119	127	34	25	54	81	27	52
Other Cause	4,132	4,238	4,738	4,984	6,197	6,156	6,421	5,267	6,162	5,649	5,588

Gas Distribution Leaks by Cause

Time run: 2/13/2017 5:44:29 PM

SMART Data as of **2/12/2017 5:00:38 PM**

Portal Data as of **2/13/2017 3:13:46 AM**

Geo Region: ALL Geo State: MINNESOTA

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Leak Cause											
Corrosion	489	600	610	633	704	794	852	764	446	588	580
Natural Force	627	624	663	603	487	577	711	445	434	415	376
Equipment	2,105	2,642	3,326	2,957	10,310	7,486	7,069	6,500	6,634	7,118	6,315
Material or Weld	528	514	768	726	833	1,012	988	767	530	606	563
Excavation	1,763	2,060	1,801	1,431	1,255	1,234	1,392	1,393	1,139	1,348	1,427
Operations	37	25	65	36	45	89	142	145	176	125	225
Other Outside Force Damage	117	219	132	101	109	220	290	241	244	202	191
Other Cause	733	440	481	506	447	295	191	333	274	258	278

APPENDIX

C

From:	Dammel, Joseph
To:	"Liberkowski, Amy A"
Cc:	Peterson, Lisa R; Martinka, Mary A; Barlow, Ryan; Nelson, Ron
Subject:	RE: GUIC Metrics/request for feedback
Date:	Wednesday, December 14, 2016 11:35:35 AM
Attachments:	image001.png image002.png

Hi Amy,

Thanks for the update and apologies for the delay in response. Regarding time to review the proposed metrics, I think the more time we have to review, the better. I can't say whether two weeks would be sufficient time to review or not. Perhaps the best course of action would be to review the supplemental filing when it is made and make a decision about the time necessary to provide comments upon review. I don't want to be in the position of causing an unnecessary delay in the overall timeline or, conversely, prejudging the amount of time we will need to review and comment before we see the supplement.

We are also open to providing feedback on an AGA survey, as we stated in the meeting. Based on our comments from last year and on our initial impressions from the presentation at the meeting, the proposed metrics may be a good first step, but we would like to learn more about metrics being implemented across the country to identify best practices.

In addition, our comments from last year stressed the need to create metrics that can be used by regulators to determine an optimal level of risk in the system so as to determine the appropriate amount of risk that is removed each year by GUIC projects. Given the size and the ongoing nature of the investments, we believe that regulators need some way to identify where, on the spectrum between business as usual and zero risk/perfect safety, an appropriate level of investment lies, and what types of risk reducing projects are most appropriate to cost-effectively achieve this goal.

I hope this helps your group understand the general concerns we have regarding this docket and the type of metrics we seek to ensure that the public interest is being best-served. I will be out the rest of the week (I picked a great time to move), but am happy to pick up this conversation in the coming weeks.

Thanks again,

Joe

Joseph A. Dammel
Assistant Attorney General
Residential Utilities and Antitrust Division

Office of the Minnesota Attorney General
Suite 1400
445 Minnesota Street
St. Paul, MN 55101-2131

651-757-1061 (phone)
651-296-9663 (fax)
joseph.dammel@ag.state.mn.us
www.ag.state.mn.us

From: Liberkowski, Amy A [mailto:amy.a.liberkowski@xcelenergy.com]
Sent: Friday, December 02, 2016 4:41 PM
To: Dorothy.Morrissey@state.mn.us; kate.oconnell@state.mn.us; Barlow, Ryan; Dammel, Joseph; Krishnan, Ganesh (PUC); Brill, Bob (PUC)
Cc: Peterson, Lisa R; Martinka, Mary A
Subject: GUIC Metrics/request for feedback

Hello everyone,

Thank you for participating in the discussion of Xcel Energy's proposed GUIC performance metrics on Nov 16th. At the meeting, we committed to soliciting feedback through email and providing several pieces of information, which are listed below.

1. **National Leak trend for plastic pipe** – Jon Wolfgram of MNOPS mentioned in the stakeholder meeting that the industry supported our trend of a slight increase in leak rates on new plastic pipe. Pages 4-5 of the Plastic Pipe Databank Committee's "Plastic Piping Data Collection Initiative Status Report" issued on March 24, 2016 summarizes the recent elevation in failures and leaks on plastic pipe. See full report link embedded in the following: https://www.apga.org/blogs/john-erickson/2016/05/26/plastic-pipe-database-committee-releases-report-on-plastic-pipe-performance

2. **Histograms for 2015 Poor Performing Main & Service Replacements** (slides 33 and 34 of the Nov 16th presentation):
cid:image002.png@01D241B2.EEF678C0

cid:image006.png@01D241B2.EEF678C0

3. **<u>TIMP Metrics reported to PHMSA</u>** (PHMSA website: http://phmsa.dot.gov/pipeline/library/data-stats)

PHMSA code §192.17 requires transmission pipeline operators to submit an annual report no later than March 15th. PHMSA code §192.945 defines reportable performance measures:

§192.945 What methods must an operator use to measure program effectiveness?

(a) *General*. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see §192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §191.17 of this subchapter.

<u>Overall Performance Measures</u>

(1) number of miles of pipeline inspected
(2) number of immediate repairs completed
(3) number of scheduled repairs completed
(4) number of leaks, failures, and incidents (classified by cause)

<u>ASME/ANSI B31.8S, Appendix A Performance Measures</u>

External corrosion

- Number of hydrostatic test failures caused by external corrosion
- Number of repair actions taken due to in-line inspection results
- Number of repair actions taken due to direct assessment results

- Number of external corrosion leaks

Internal corrosion
- Number of hydrostatic test failures caused by internal corrosion
- Number of repair actions taken due to in-line inspection results
- Number of repair actions taken due to direct assessment results
- Number of internal corrosion leaks

Stress corrosion cracking
- Number of in-service leaks or failures due to SCC
- Number of repair replacements due to SCC
- Number of hydrostatic test failures due to SCC

Manufacturing
- Number of hydrostatic test failures caused by manufacturing defects
- Number of leaks due to manufacturing defects

Construction
- Number of leaks or failures due to construction defects
- Number of girth welds/couplings reinforced/removed
- Number of wrinkle bends removed
- Number of wrinkle bends inspected
- Number of fabrication welds repaired/removed

Equipment
- Number of regulator valve failures
- Number of relief valve failures
- Number of gasket or O-ring failures
- Number of leaks due to equipment failures

Third-party damage
- Number of leaks or failures caused by third-party damage
- Number of leaks or failures caused by previously damaged pipe
- Number of leaks or failures caused by vandalism
- Number of repairs implemented as a result of third-party damage prior to a leak or failure

Incorrect operations
- Number of leaks or failures caused by incorrect operations
- Number of audits/reviews conducted
- Number of findings per audit/review, classified by severity
- Number of changes to procedures due to audits/reviews

Weather related and outside force
- Number of leaks that are weather related or due to outside force
- Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

4. **DIMP Metrics reported to PHMSA**

21 metrics specified in §192.1007(e) (seperate metrics for the multiple leak causes and multiple material types)

§192.1007(e): *Measure performance, monitor results, and evaluate effectiveness.*

(1) Develop and monitor performance measures from an established baseline to evaluate

the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) of this subchapter (or total number of leaks if all leaks are repaired when found), categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material; and

(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat

5. **Draft AGA survey on performance metrics** – We will pass along draft survey questions in the next couple weeks. Just a heads up though, the survey process is conducted by the AGA, and it can take a few months for them to issue and get results back from the survey.

I've attached the presentation from our meeting which includes the proposed metrics we covered and look forward to your feedback. As discussed, we are hoping to incorporate feedback and file the proposed metrics as a supplement to our current GUIC petition. Does a couple weeks give everyone they time they need to review and provide comments? This shouldn't interfere with the review of the rest of the petition, so let me know if additional time would be helpful.

Thanks,

Amy Liberkowski
612-330-6613

APPENDIX

D

AGA SOS
Performance Metrics

Background: Northern States Power Company, a Minnesota Company (NSPM) d/b/a Xcel Energy has a Gas Utility Infrastructure Cost (GUIC) rider to recover Transmission and Distribution Integrity Management Program (TIMP and DIMP) costs. NSPM seeks information through the AGA SOS process to determine what performance metrics other companies have implemented to track the efficiency or appropriateness of TIMP and DIMP expenditures.

1. Company Name ____
2. Does your Company have a cost recovery mechanism to recover TIMP and/or DIMP costs outside of base rates?
   ____Yes
   ____ No
   If yes, please describe your Company's cost recovery mechanism including the docket number(s) and enabling statute or regulation/rule.
   ____
   ____
   ____
   ____
3. Has your Company developed performance metrics to evaluate the effectiveness of your TIMP and DIMP investments? If so, please describe.
   ____
   ____
   ____
   ____
4. What process did you use to develop the metrics?
   ____
   ____
   ____
   ____

Deleted: the

5. Do the metrics change over time based on the type of investments being made?

____
____
____
____

6. How do metric results inform TIMP/DIMP investment decisions made by the Company, if at all, and to what extent have metrics been incorporated into your Company's decision-making process?

____
____
____
____

Formatted: Indent: Left: 0.5", No bullets or numbering

7. Are there any financial incentives or penalties that are triggered by outcomes of the performance metrics? If so, please describe.

____
____
____
____

Formatted: Indent: Left: 0.5", No bullets or numbering

8. Have you experienced any cost savings, such as O&M costs, associated with DIMP and/or TIMP investments and are you required to account for those savings in your cost recovery rider?

____
____
____
____

Formatted: Indent: Left: 0.5", No bullets or numbering

9. Have you generated any learnings from your metrics?

____
____
____
____

10. Should NSPM have further questions surrounding your responses to the SOS, please provide a contact at your Company to answer these questions

Name: ____________________________
Phone Number: ____________________
Email Address: ______________________

APPENDIX

E

How Performance Measures Can Improve Regulation

Ken Costello, Principal

The National Regulatory Research Institute

June 2010

10–09

Acknowledgments

The author wishes to thank his colleagues at NRRI, Ms. Evgenia Shumilkina and Mr. Scott Hempling; Commissioner Ric Campbell of the Public Service Commission of Utah; Dr. Mark Lowry of Pacific Economics Group Research; Professor Karl McDermott of the University of Illinois Springfield; Mr. Joseph W. Rogers of the Massachusetts Attorney General's Office; and Dr. Michael Schmidt of the Kansas Corporation Commission for their comments on an earlier draft of this paper. The author is responsible for any remaining errors in the document.

Online Access

The reader can find this paper on the Web at http://www.nrri.org/pubs/multiutility/NRRI_utility_performance_measures_jun10-09.pdf.

Executive Summary

Regulation's central purpose is to induce high-quality performance from our utilities. To achieve that objective, regulators must measure and evaluate utility actions.

Performance depends on how well management uses the available resources. Also affecting performance are factors outside management's control.

Uses of Performance Measures

The challenge for regulators is to determine what constitutes a well-performing utility. What do they consider acceptable performance? These are questions that regulators need to address if they are to exploit fully the information contained in performance measures for regulatory actions such as prudence determination and rate setting. The measurement of performance trends in the absence of a standard, for example, might limit regulatory action to further review, not to a determination of cost recovery.

The National Regulatory Research Institute (NRRI) is writing a series of papers on performance. This particular paper helps regulators to form a context, rationale, and a general framework for initiating a strategy to measure and evaluate the performance of utilities in their states. It begins with a discussion on major questions that regulators should address before applying performance measures. The paper also provides guidance to regulators on how to better gauge utility performance in non-cost functional areas such as reliability and other dimensions of service quality. Such evaluation allows regulators to satisfy the objective of consumer protection.

This paper provides regulators with the following information:

1. The rationale for why regulators should measure and evaluate utility performance;

2. Guidance on how regulators can best apply performance measures in various areas of utility operations;

3. General interpretations of utility performance and alternative regulatory responses;

4. Different performance measures that regulators can use;

5. The uses and limitations of different performance measures and performance-measurement techniques;

6. The different regulatory venues for the application of performance measures, both within and outside a rate case; and

7. A general framework and sequence of steps that regulators can take to initiate performance measurement and evaluation tasks.

An Illustration of a Regulatory-Review Process

Figure ES-1 illustrates one way in which regulators can review a utility's performance and take appropriate action. The diagram shows four major things:

1. ***Regulation itself affects utility management behavior.*** Together with factors that fall outside the control of a utility, management behavior determines a utility's performance. Regulatory rules, policies and practices directly and indirectly affect utility performance. Utility performance, in turn, can influence regulatory actions. Poor utility performance, for example, might induce regulators to provide utilities with stronger incentives and disincentives or to establish standards for future performance.

2. ***Regulators should initially assess the utility's performance by comparing actual performance with a pre-specified standard.*** Any substantial deviation can reflect exceptionally good or bad performance. The utility would then have the opportunity to respond to the evidence of bad performance, with subsequent evaluation by the regulator.

3. ***Based on its review, the regulator can then take a particular action.*** The action may affect cost recovery by the utility, lead to a more detailed investigation such as a retrospective management audit or induce the regulator to institute a mechanism that would reward or penalize the utility for exceptional performance. The regulator can take other actions or no action in response to its assessment. One such action might include rewarding the utility for above-average performance that the regulator judged to reflect exceptional management behavior.

4. ***Performance measures can help regulators determine "just and reasonable rates."*** The objective of the proposed regulatory approach is to enhance the ability of state commissions to make informed decisions. Accountability requires regulatory assurance that utility costs incorporated in rates reflect prudent, efficient, effective and customer-responsive management behavior. Accountability also demands that regulators recognize the financial interests of utilities; namely, to permit prudent and efficient utilities a reasonable opportunity to earn a fair rate of return and attract capital to serve the long-term interest of their customers. Performance measures can provide regulators with a tool to achieve these outcomes.

Organization of the Paper

This paper contains six parts. Part I defines "performance." Part II gives reasons for why regulators should measure utility performance. Part III identifies the challenges that regulators face in interpreting performance measures for various applications. In Part IV, the paper provides an overview of the different techniques for performance measurement. Part V discusses specific applications of performance measurement in different regulatory venues, including rate cases, the development of incentive mechanisms and periodic oversight. The final part lists six steps for executing a regulatory "performance" initiative.

Figure ES-1. A Regulatory Process for Reviewing and Responding to a Utility's Performance

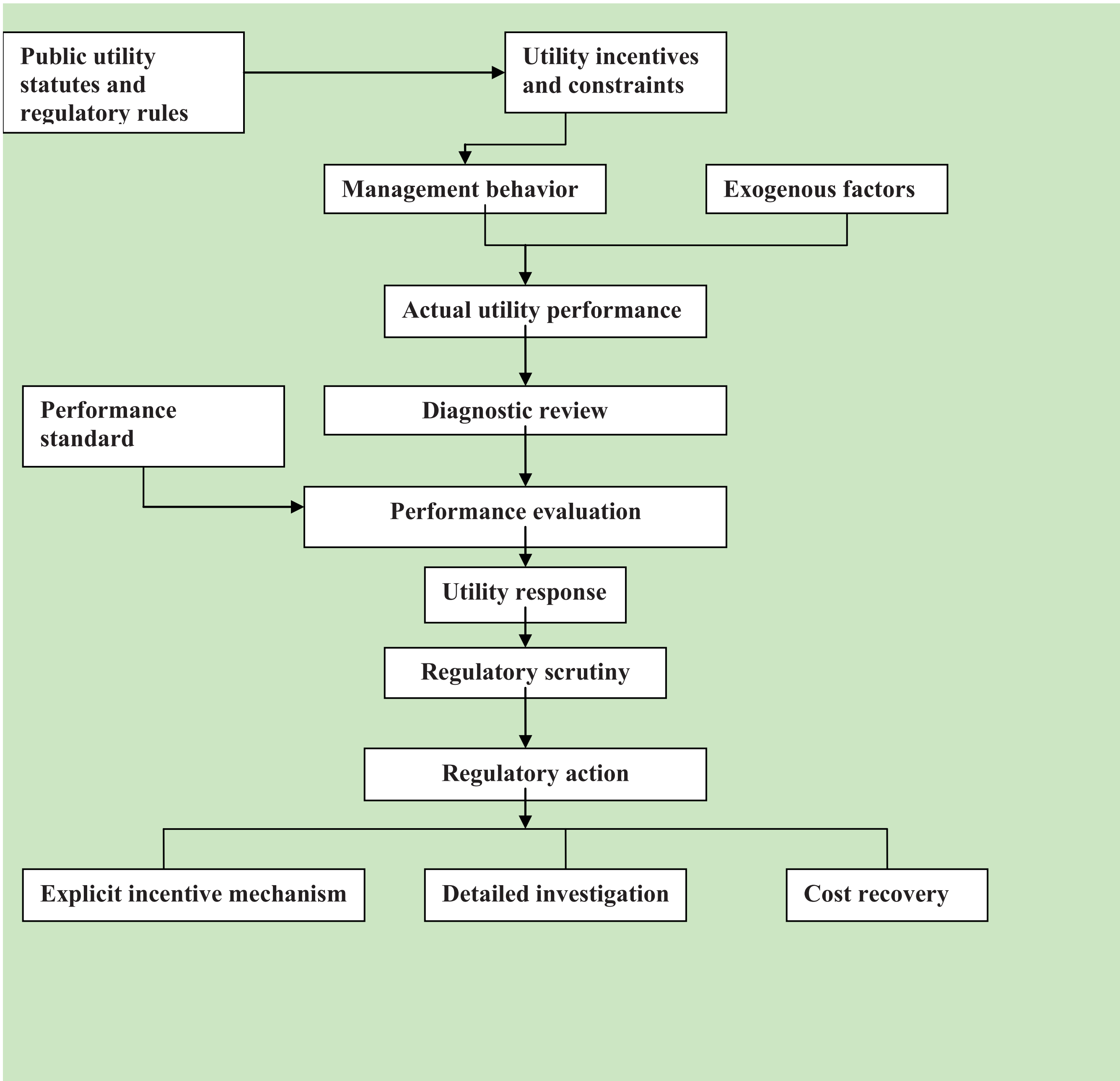


Table of Contents

I. What Do We Mean by "Performance"?.. 3

A. Multi-dimensional nature of performance 3

B. Performance standards 3

II. Why Should Regulators Measure Utility Performance? 5

A. Performance problems under regulation 5

B. Regulators have an information disadvantage 5

III. The Challenge Facing Regulators in Measuring and Evaluating Utility Performance 7

A. Factors affecting utility performance 7

B. Sports metaphors 8

C. Regulatory considerations for applying performance measures 8

D. How might regulators interpret and use the results?.................................11

IV. An Overview of Different Techniques for Measuring Performance 14

A. Attributes of good performance measures 14

B. Econometric methods, indexing, and data envelopment analysis.............15

C. Additional ways to measure utility performance 16

1. Management audits 16

2. Accounting ratios for individual functional areas..........................16

3. Uses and limitations of performance measurement 17

V. Applications of Performance Measures in Different Regulatory Venues 19

A. General uses of performance measures and examples 19

1. Illustration of service quality 19

2. Illustration of energy-efficiency activities 20

3. Prudence review 20

4. Evaluation of a regulatory action 20

B. Specific applications 21

1. Regulatory incentive mechanisms 21

2. Periodic monitoring of utility performance outside a rate case 22

3. Comparison of a utility's actual performance with a benchmark, both in rate cases and other regulatory forums 23

4. Evaluation of the reasonableness of "cost-of-service" components, adjustment of the rate of return on equity (ROE), and use of total factor productivity 24

5. Preliminary review of a utility's performance to determine further action 25

6. Examination of the reasons for performance differences across utilities 26

7. Publicity of a utility's performance on a periodic basis 26

VI. A Six-Step Approach for a "Performance" Initiative 27

A. Identify the uses of performances measures 27

B. Select utility functional areas for regulatory review 27

C. Calculate the performance measures 27

D. Compare a utility's performance with a predetermined benchmark 27

E. Assess a utility's performance 27

F. Take action..27

Appendix A: Price Differentials across Utilities: The Challenge of Detecting Causes... 29

Appendix B: Real Unit Cost Indices 32

Appendix C: An Illustration of the Use of Performance Measures in a Cost-Sharing Incentive Mechanism.. 34

Appendix D: The Relationship between Total Factor Productivity and Average Cost... 37

How Performance Measures Can Improve Regulation

Regulation's central purpose is to induce high-quality performance from our utilities. To achieve this objective, regulators must measure and evaluate utility actions, then inject the evaluation's results into regulatory decisions. Measurement can cause better regulatory incentives and improved utility performance. Improved performance, in turn, can lead to lower rates over time, higher quality of service, fewer rate cases, and avoidance of excessive utility costs. Performance measurement can detect subpar utility management that could lead to further investigation, cost disallowances, or a change in regulatory incentives. It can also help regulators determine whether utilities are satisfying stated objectives or targets. Performance measurement can also help regulators reward utilities for superior performance that benefits customers through lower rates or higher quality of service.

Compared to their foreign counterparts (especially European countries),[1] U.S. regulators have relied less on performance measures as a benchmarking tool to set rates and evaluate utility performance. In most U.S. applications, benchmarking has focused on operation and maintenance expenses rather than total cost performance.

In the absence of quantifiable performance measures, it becomes difficult for regulators to know if utilities are falling short of, meeting, or surpassing predetermined objectives or targets. Performance measures can empower regulators to grade utilities, mindful of the limitations of the particular measures for appropriate regulatory actions. Performance measurement can accompany special incentive mechanisms, management audits and other detailed investigations, and specific actions on cost recovery.

This paper addresses several questions. First, it provides reasons for why state public utility commissions (or "regulators") would want to measure utility performance. Next, it identifies the challenge that regulators face in interpreting performance measures for various applications. The paper then provides an overview of the different techniques for performance measurement. A previous NRRI paper detailed some of these techniques. Finally, it identifies specific applications of performance measurement in different regulatory venues, including rate cases, the development of incentive mechanisms, and periodic oversight.

This paper helps regulators by providing them with the following information:

1. The rationale for why regulator should measure and evaluate utility performance;

---

[1] *See*, for example, Cambridge Economic Policy Associates, *Background to Work on Assessing Efficiency for the 2005 Distribution Price Control Review*, prepared for Ofgem, September 2003; Per Agrell and Peter Bogetoft, *Benchmarking for Regulation*, Final Report, prepared for the Norwegian Water Resources and Energy Directorate, July 2003; and Jeff D. Makholm, *Benchmarking, Rate Cases and Regulatory Commitment*, prepared for the Australian Competition and Consumer Commission, November 15, 1999.

2. Caveats on how regulators can best apply performance measures in various areas of utility operations;

3. General categories of utility performance and alternative regulatory responses;

4. Different performance measures that regulators can use;

5. The uses and limitations of different performance measures and performance-measurement techniques;

6. The different regulatory venues for the application of performance measures, both within and outside a rate case; and

7. A general framework and sequence of steps that regulators can take to initiate performance measurement and evaluation tasks.

I. What Do We Mean by "Performance"?

A. Multi-dimensional nature of performance

"Performance" refers to the outcomes of one or more utility actions resulting from management decisions. These actions affect the various dimensions of a utility's operations and services, including cost performance, reliability, and service quality, all of which affect consumer welfare. Performance is the "proof of the pudding," determining how a utility's actions affect its customers and the public.

This paper focuses on quantifying with objective information (e.g., actual numerical "performance" outcomes based on accounting data) how well a single utility or a group of utilities address these multiple dimensions. Performance measures rely on historical data or on estimates derived from economic models and statistical techniques. The latter metrics contain an element of error in measuring actual performance that regulators need to interpret carefully.

B. Performance standards

Regulators can consider performance from different perspectives. One perspective is efficiency. From an engineering perspective, efficiency takes on a strictly physical form. The ratio of person-hours of labor to kilowatt-hours of output is an example. This perspective disregards costs and assumes that a lower input-to-output ratio is desirable. This perspective, by itself, is limiting: A utility can increase its labor productivity by simply reducing its employees and substituting inputs such as capital or outsourcing; these alternatives, however, might be expensive enough to increase the utility's overall costs.

From an economic standpoint, efficiency reflects management behavior in minimizing costs over the long term. Management, for example, can affect a utility's cost performance by: (1) adjusting inputs to reflect the relative input prices, (2) exerting the optimal amounts of managerial effort to control costs, (3) constraining costly managerial expenditures (e.g., on expensive art and furniture) and other sources of waste (i.e., X-inefficiency), and (4) adopting new innovations and technologies when cost-beneficial.

Another way to consider performance is by means of comparison. If the regulator's standard for power plant equivalent availability[2] is 80 percent and the utility performs at 70 percent, the efficiency ratio is 0.875 (70/80). Efficiency is a relative term whose measurement requires a benchmark or standard of performance. The standard might be the average performance of other utilities or the maximum efficiency that the regulator feels the utility under review can achieve.

The evaluation of utility performance often relates to "prudence." One widely applied definition of prudence is decisions consistent with what a "reasonable person" would do, based

[2] Equivalent availability is a measure of power plant reliability.

on information available to the utility at the time of those decisions. The prudence standard focuses on actions, not outcomes.[3] One criticism of the prudence standard is that a utility can satisfy it without performing at an above-average level. It establishes a threshold of minimum acceptable performance; it does not distinguish acceptable performance from exceptional performance. Grading and evaluation are done dichotomously: the utility's behavior is either acceptable or unacceptable; there are no intermediary levels of utility-management behavior.[4]

While performance evaluations often focus on cost, management also affects the non-cost aspect of utility performance. The effects of outages and service interruptions to customers depend on the response of utilities in restoring service and in isolating these incidents to selected areas to minimize the overall effect on customers. Utility performance also reflects the responsiveness of utility personnel to customer complaints and overall service quality.

---

[3] For a detailed discussion of "prudence," including the many ways in which state and federal commissions and courts apply the term, *see* Hempling, *The Fundamentals of Electricity Law* (2006), available from NRRI.

[4] According to this interpretation, a prudent decision resembles a utility receiving a "passing" grade when it performs between C to A; a C grade connotes mediocre utility performance for which the utility recovers all of its costs but it could have reduced its costs with more effort and competence; if a utility improves its grade from C to B, it exerts more effort but it might gain nothing in the long term under conventional ROR regulation; the incentive is akin to college students taking a course on a pass/fail basis.

II. Why Should Regulators Measure Utility Performance?

A. Performance problems under regulation

Regulation has an obligation to induce high-quality utility performance, whether it is customer service, physical operation of the utility system, service reliability, cost controls, or the adoption of new technologies. The economics literature shows that public utilities left unregulated, or regulated ineffectively, would perform suboptimally. They would set prices too high, price discriminate among customers, provide inferior-quality service, deploy a nonoptimal mix of inputs, and expend too little effort to control costs and innovate.[5]

Further, economic theory predicts that regulated utilities subject to rate of return regulation would perform at less than the highest possible allocative or productive efficiency.[6] Traditional regulation tends to give utilities weak incentives to minimize their costs. To the extent a utility can pass on to customers additional costs and also pass on any cost savings it achieves, it has diluted any economic incentive to perform efficiently. Since rate-of-return regulation, by itself, will not produce the desired performance, some form of performance standards, including measurement, evaluation, and consequences, becomes more essential.

B. Regulators have an information disadvantage

In traditional regulation, the regulator is at a disadvantage relative to the utility in interpreting the utility's performance. Do the actual costs reflect competent utility management, or do they include wasteful costs that the utility could have avoided? The utility generally would defend these costs as reflecting their best effort under the circumstances. Some utilities would, therefore, be inclined to provide misleading information on their managerial efforts and cost opportunities. They may portray themselves as high-cost providers because of an unfavorable business environment. Under existing incentives, utilities may act rationally by exerting less-

---

[5] *See*, for example, Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review* 52 (December 1962): 1052-69; Harvey Leibenstein, "Allocative Efficiency vs. 'X-Efficiency,'" *American Economic Review* 56 (June 1966): 392-412; and Paul L. Joskow and Nancy L. Rose, "The Effects of Economic Regulation," in *Handbook of Industrial Organization, Volume II*, Richard Schmalensee and Robert D. Willig, eds., 1449-1506 (New York: Elsevier Science Publishers, Inc., 1989).

[6] What analysts call the Averch-Johnson (A-J) effect says that a utility would use excessive capital input relative to other inputs such as labor, fuel, and materials. This outcome occurs when a utility faces a binding rate-of-return constraint on its rate base and its allowed rate of return exceeds its actual cost of capital. X-inefficiency occurs when the utility wastes resources by operating above its cost frontier. Unlike the A-J effect, this source of inefficiency would tend to reduce the utility's profits, at least in the short run because of regulatory lag. The underlying cause of both inefficiencies is the lack of strong incentives for a utility to minimize costs.

than-desirable managerial effort to reduce costs. After all, the opportunity cost for managers to spend more time and effort at their job is lost leisure time and more discomfort. The regulator might deem extant incentives as inadequate for motivating exceptional utility performance. Performance measures and their various applications by regulators can help lessen the information asymmetry that they inherently face in their oversight of utilities.

If regulators had good information about how utilities should perform, they could readily set performance standards that the utility would have to meet or suffer the consequences. In the real world, however, the regulator faces the problem of less-than-perfect information on the efforts of utility management and on the utility's cost opportunities. Cost-saving opportunities differ across utilities, depending on the inherent features of their production technology, exogenous input costs, and other factors that cause costs to vary by location because of their attributes. Utilities serving rural areas, for example, tend to have higher average costs than urban utilities.

The regulator observes outcome (e.g., power plant reliability) but does not have a utility's expertise in assessing how management produced that outcome. Since regulators lack the required information to identify optimal performance, they have to resort to alternative actions, such as special incentives or judgment of a utility's performance based on the information provided to them by the utility and other sources.

III. The Challenge Facing Regulators in Measuring and Evaluating Utility Performance

The appropriate use of performance measures requires careful interpretation of what they represent. Some measures reflect a utility's short-term performance, mostly factors beyond utility management control. Other measures estimate performance in some functional area that is subject to statistical error.

A. Factors affecting utility performance

Utility performance depends on three general factors:

1. The resources used,

2. Management skills, which determine what resources a utility should use and how it should combine them to produce some "output," and

3. Market and business conditions over which the utility has little control.

Utility performance derives from two distinct factors: *internal efficiencies and external conditions.* The first factor encompasses resources used, and the management skills that determine how to combine and deploy those resources. The second factor accounts for market and business conditions over which an individual utility has little or no control. Events over which a utility has no control, such as abnormal weather or economic conditions, however, should not exonerate the utility for how it responds to these incidents. If a storm causes a utility to interrupt service, it should reestablish service with the shortest possible delay consistent with general safety and the public welfare; nor do external events eliminate the utility's responsibility to anticipate and cost-effectively mitigate the effects of those events.

The appropriate uses of performance measures depend on their ability to separate out the effects of external and internal factors on performance. As an illustration, the cost of providing electricity is a function of the level of labor, fuel, and capital; their costs; consumer demographics; size of different customers and their electricity usage over different periods of time; and geographical characteristics of the utility's service territory. Two distinct management teams in charge of operating the same utility would likely produce different outcomes. The one team may better economize on the use of labor; for different reasons it might elicit higher productivity from the employees than the other management team. It might also operate its power plants more efficiently, and adapt more optimally to changes in input prices. Overall, even though both management teams face the same outside factors and have access to the same resources, one team is more proficient, at least in controlling costs. We can then conclude that one management team is superior to the other team, at least in terms of cost efficiency.

Appendix A illustrates the challenges to regulators in interpreting differences in one broad performance measure across utilities, namely, retail price. Analysts face difficulty in isolating the effect of management behavior on the differences, even when they apply the most sophisticated techniques.

B. Sports metaphors

One analogy involves two golfers who play on the same golf courses week after week. If one golfer has an average scope of 70 stokes per round and the other golfer averages 73 strokes per round, we can conclude that the first golfer is better. If both of these golfers play on different courses, however, the golfer who averages 70 strokes per round may not be the better golfer if he plays on easy courses while the other golfers plays on more difficult courses (e.g., courses with volatile weather, high rough, fast greens, and longer holes). The golfer who shoots lower scores might average 75 strokes per round if he played on the courses of the other golfer. It is assumed here that the two golfers use the same or similar equipment (e.g., clubs, balls, shoes), so score differentials result from either differences in the golfers' skills or the difficulty of the golf courses on which they play, or both.

The same difficulty arises when trying to evaluate the managers of different baseball teams, each with players of dissimilar abilities. Can we say that the teams with the best records have the best managers, or should we have to consider whether those teams just have better players? How can we control for the differences in players' ability in evaluating the managers? Are there other factors that we would need to consider before ranking the managers? What criteria do we use to evaluate the managers? Is it controlling for other all factors, to the extent possible, and then measuring the separate effect of the managers on increasing their team's wins?

C. Regulatory considerations for applying performance measures

Performance measures quantify the effect of both management behavior and outside factors on "outcome." Utility management makes decisions on what actions to take—for example, build a new power plant, procure natural gas under long-term contracts, hedge fuel costs, or purchase gas. The outcomes and their effects on consumers and society as a whole, however, depend to some degree on factors over which the utility has little or no control.

When not applied properly by regulators, performance measures can lead to wrong decisions and perverse outcomes. Regulators should understand the limitations of performance measures to avoid these problems and to use those measures most constructively.

The following list identifies several elements of performance measures and the methods of measurement that regulators need to understand before applying them in different venues.

1. *The first decision is to select the functional areas for measuring utility performance.* Major criteria for selection are: (a) the effect of a functional area on a utility's total cost or on consumer value from reliable and high-quality utility service, (b) the ease of measurement, (c) the effort required to interpret a performance measure, and (d) the influence of utility management in affecting performance. The ultimate goal is to

maximize the net benefits from society's perspective, which involves comparing the benefits from improved regulation with the costs of measuring and evaluating performance. Examples of performance measures that meet at least some of these criteria are power plant equivalent availability, operation and maintenance (O&M) expenditures, and service reliability levels. All of the measures are quantifiable, are important in terms of affecting consumer well-being, and are subject to utility-management discretion.

2. *Improved performance in one area can reduce performance in another.* An increase in power plant performance can reduce a utility's total factor productivity (TFP)[7] or increase its total costs. A reduction in maintenance and other costs, as a second example, may jeopardize the utility's service quality. These outcomes call for a utility-wide cost-benefit test. When focused on a single component of utility operations—in our example, power plant performance—regulatory actions can create perverse incentives: The utility would tend to devote excessive resources to the targeted area, in the process jeopardizing performance in other areas. An emphasis on cost reductions can cause service quality to suffer by reducing reliability and customer service. As another example, a focus on improving power-plant capacity factors or equivalent availability could cause a utility to overspend on O&M and pass these costs onto its customers. These additional costs, conceivably, could more than offset the benefits to customers from increased power-plant performance.[8] As a last caution, in recent years regulators have become involved in addressing non-traditional objectives such as the promotion of energy efficiency, renewable energy resources, and affordable energy.[9] In achieving these objectives, regulators might have to compromise on the traditional objective of providing reliable utility service at a reasonable price.

---

[7] Total factor productivity measures a utility's total quantity divided by total inputs. It reflects the firm's efficiency in combining inputs (e.g., labor materials, fuel, and capital) to produce and deliver utility services (e.g., kilowatt-hours, peak demand). With positive productivity growth, the utility is increasing output by more than inputs, which translates into a decline of real cost per unit of output. Productivity growth means improved efficiency in the use of society's resources.

[8] The implication for regulators is that they might want the utility to report not only on its power plant performance but also on related functions such as O&M. The regulator could then see whether the utility's O&M costs substantially increase concurrently with improved power-plant performance. The regulator could require the utility to report on the O&M costs of comparable power plants owned by other utilities.

[9] *See* Ken Costello, *How To Determine the Effectiveness of Energy Assistance, and Why It's Important*, NRRI 09-17, December 2009, found at http://www.nrri.org/pubs/gas/NRRI_energy_assistance_dec09-17.pdf.

3. *Improved performance in one area can increase performance in another.* In a complementary relationship, better performance in one area can directly lead to improved performance in one or more other areas. As an example, an increase in power-plant equivalent availability can reduce a utility's fuel costs. A complementary relationship between two or more areas of utility operations heightens the importance of performance improvement in those areas.

4. *The previous two items indicate an interrelationship between different performance areas of a utility that regulators should take into account.* For regulators, this association means that the cost-benefit effect of performance improvement in a single area has a spillover effect on other areas that requires consideration. When the association is negative, a seemingly attractive action to reduce purchased gas expenses, for example, might result in additional costs from hiring consultants and more in-house labor. The net effect might be to increase the utility's overall costs, although purchased gas costs would decline as intended. The implication for regulators is that to focus on improved performance in a single area can produce a counterproductive outcome in the form of higher rates to consumers without any corresponding increase in the value of service.

5. *Performance depends upon different factors, as mentioned above, some under a utility's control, others exogenous to a utility.* The challenge for regulators is to separate the effects of management from the effects of factors beyond a utility's control. Without separation, the proper applications of performance measures become greatly restricted. Specifically, it is unreasonable for regulators to then apply performance measures mechanically or as the sole source of information for evaluating a utility's performance.

6. *Performance measures are either estimates or actual accounting numbers.* Total factor productivity is an estimate of a utility's overall performance in using labor, capital, materials, and other inputs to produce and deliver a service. It is an estimate because it assumes certain production behavior by the utility and requires data that represent estimates rather than actual unadjusted accounting numbers (e.g., capital services). These performance measures require the use of statistical and econometric techniques that make certain, and sometimes restrictive, assumptions. Other performance measures derive directly from reported data for example, labor productivity, unit cost for customer service, and total operation and maintenance expense per customer.

7. *Varying degrees of difficulty exist in measuring performance.* The more sophisticated approaches, while in theory better suited for broader applications, are susceptible to measurement and data errors. These approaches include econometric and total factor productivity techniques. They require regulatory staff to have a good understanding of statistical techniques and other quantitative methods. If staff members don't have this understanding, the regulator would then have to rely on outside consultants, which can cost a non-minimal amount of money.

8. *Regulators can use either* ex post *or* ex ante *measures of performance, or both in a particular application.* Regulators can apply the former measure for prudence reviews or to compare a utility's actual performance with the expected outcome. In these applications, regulators can actually use both kinds of performance measures, with the e*x ante* measure acting as a prospective standard for benchmarking a utility's performance. Assume that the regulator sets a customer service standard for a utility. After observing the utility's actual performance, the regulator can compare this performance with the standard to help judge whether the utility acted prudently.

9. *Trade-offs can exist between short-term and long-term performance.* Additional capital expenditures have the effect of temporarily reducing a utility's total factor productivity while increasing long-term productivity. Tree trimming is a good example in which spending more today would likely lead to lower costs in the future because of fewer outages and lower maintenance costs. This kind of investment over time benefits both the utility and its customers. Higher O&M costs in general incurred today can lead to better utility performance in the long run.

10. *Benchmarking can use as a reference, "average," "exceptional," or "standard" performance.* In evaluating or measuring a utility's performance, the analyst often needs to specify a "reference" or "baseline" performance. Average performance can represent the "mean" performance for a sample of comparable utilities. Some regulators might interpret average performance as the costs incurred by an efficient utility. To other regulators, average performance might reflect subpar performance if they deem the "mean" utilities to be performing poorly, say, because of weak regulatory incentives. Exceptional performance might include the performance of the first quartile of utilities or, more stringently, those utilities lying on or close to the efficiency frontier measured by statistical or non-statistical approaches. Regulators can designate "standard performance" as a target for a utility to achieve or surpass. The standard itself can reflect the average performance of a sample of utilities or the performance of the top comparable utilities.

    Regulators should consider whether they should view "standard" performance as a moving target, rather than as a static concept that remains constant over time. As technology improves and the utility adopts better management practices, regulators would expect the utility to improve its performance over time. Regulators might also press utilities to move in the direction of "frontier" performance in which they would adopt "best practice" technologies and management practices.

D. How might regulators interpret and use the results?

Regulators can interpret a utility's performance differently. Their interpretation affects what action they take with regard to cost recovery, prudence reviews, and a follow-up investigation. The different interpretations include:

1. The utility is performing prudently;

2. The utility is performing prudently but its performance can improve;

3. The utility is performing worse than peer utilities;

4. The utility is performing better than peer utilities; and

5. The utility is performing unsatisfactorily.

Each interpretation has different implications for regulatory action. The regulator would first need to have information before it can interpret utility performance. A performance metric would seem essential: The regulator would need to compute the utility's historical performance, the performance of a group of utilities, or a predetermined performance standard based on cost, engineering, and other information. In comparing performance across utilities, the regulator would have to select a peer group whose characteristics are similar to the utility under review. As an alternative, the utility could select a wider group of utilities and control for differences in characteristics through statistical techniques and other quantitative methods.

For each of the above five interpretations of utility performance, a different regulatory response would seem appropriate. The *first interpretation* can result in no incremental regulatory action. The regulator might perceive utility performance as satisfactory in reflecting prudent utility behavior; that is, the utility's performance coincides with acceptable management behavior.

In the *second interpretation*, the regulator perceives utility performance as acceptable but believes that it can improve. "Prudence" here refers to utility management behavior that meets some minimum threshold but is not necessarily "above average." The regulator might want to establish, for example, special incentives that would elicit "above average" performance or set a target that the utility would have to achieve by a specified future date. The regulator should first decide whether better performance for a specific area of operation is warranted (e.g., cost-beneficial) from the perspective of consumers and the general public. An improvement in system reliability, for example, can produce smaller benefits to consumers than the additional costs they will have to pay.

The *third interpretation* can result in a penalty for the utility or further regulatory action that would attempt to identify why the utility under review is performing below its peers. A comparison of a utility's performance with other utilities involves "benchmarking." Benchmarking means setting a standard that is a point of comparison or reference for performance appraisal. If, for example, the benchmark cost per customer is $X and a utility has a cost per customer of $1.2X, the utility is performing below the average level of its peers. The analyst can conduct a statistical test to determine whether the utility's cost is significantly different than the mean cost for the peer group. The test would calculate a confidence interval that would indicate the accuracy of benchmarking and allow for hypothesis testing of cost performance. Use of this information depends on what regulators judge it to represent. If the numbers adjust for those cost factors beyond a utility's control, then regulators might conclude that any residual is attributable to utility-management behavior. In this instance, the regulator might be more inclined to penalize the utility or investigate further why the utility's performance falls below its peers.

The *fourth interpretation*, in which the utility is performing above its peers, can result in the regulator rewarding the utility for its performance. It can give the utility a higher allowed rate of return or at least signal to the utility that it won't be penalized for its performance. Analogous to the third interpretation, before rewarding the utility the regulator should further investigate to judge whether the utility's above-average performance is the product of exceptional management behavior or simply favorable conditions.

The *fifth interpretation* of performance can cause the regulator to penalize the utility or take some other response that intends to improve the utility's performance in the future. The regulator might require a management audit of the utility or set future targets for the utility to meet or else face penalties. In taking any action that directly affects a utility's financial condition, the regulator should have good evidence that the utility's poor performance reflects bad or imprudent management behavior. In other words, the regulator should clearly understand why the utility's performance is subpar before taking any action that affects the utility's financial condition.

Good regulatory decisions require a combination of quantifiable information and judgment. Performance metrics in conjunction with other information can empower regulators to take consequential actions. The action might involve cost and other adjustments in a rate case, a detailed investigation of the utility triggered by preliminary evidence of subpar utility performance, or penalties or rewards for exceptional performance.

IV. An Overview of Different Techniques for Measuring Performance

A. Attributes of good performance measures

Performance measures should be objective, quantifiable, and verifiable. One interpretation of these qualities is that good measures represent metrics with numerical values based on public data and sound analytical techniques that anyone can replicate. Benchmarking—that is, a comparison of a utility's performance with some reference such as its past performance or the average performance of similar utilities—requires quantitative performance measures; otherwise, regulators would find it difficult to determine whether a utility has performed satisfactorily. Some measures are estimates derived from advanced mathematical and statistical techniques. Replication and proper interpretation of these measures requires a high level of skills. Other measures derived from actual accounting numbers are easier to calculate and replicate.

When establishing benchmarks, regulators should use performance measures that, as much as possible, reflect utility management behavior. One benchmark for regulators to consider is the performance of an "average utility." If the regulator established a tighter or looser standard, a utility could face unfair penalties or enjoy windfall gains[10] because of exogenous factors. Assume, for example, that the benchmark represents the performance of the most efficient utility and the regulator penalizes the utility for performing below this level. A utility can argue correctly that this outcome is incompatible with competitive markets where firms receive low returns when they perform below average, not if they perform less well than the highest performing firm; in competitive markets, firms receive above-normal returns when they perform above average.[11] When performance measures do not separate management behavior from other factors, a utility, on the other hand, could profit or assume a top ranking even if only because of the favorable environment under which it operates.

[10] A "windfall gain" means that the utility's profits increase without any benefits to customers.

[11] Some regulatory experts have argued that the primary objective of regulation should be to replicate the outcome of effective competition in achieving marginal-cost pricing and minimum cost of production. If regulators were to follow the second objective, they would not distinguish between outcomes that were beyond the control of the utility and outcomes largely influenced by management behavior. A competitive firm, for example, could have a good outcome even with bad management judgment if it has good fortune (e.g., good weather for a farmer). Conversely, it could have a bad outcome even if it performed superbly.

B. Econometric methods, indexing, and data envelopment analysis

A March 2010 NRRI paper identified various approaches for measuring utility performance.[12] The approaches include econometric methods, indexing, and data envelopment analysis (DEA).[13] They differ in data requirements, ease of measurement, interpretation, and other ways. Their uses by different regulatory bodies vary. U.S. regulators have more experiences with the econometric and indexing approaches than with DEA.

In this country, the application of econometric methods for performance measurement has mostly involved the estimation of statistical cost functions for operation and maintenance. Performance for an individual utility relates to the difference between actual costs and predicted costs.[14] This method defines standard performance or the benchmark as the average performance of utilities in the sample.[15] In contrast, frontier cost functions define the standard as the best performing utility. The difference between the two definitions of a benchmark for setting rates can have large financial consequences for a utility trying to recover its costs.

A number of utilities have applied the statistical cost approach, most often to demonstrate to their regulators that they have performed above average in the operational area under review. As far as the author knows, no state public utility commission has taken the initiative in applying econometric methods or DEA to monitor and evaluate the performance of energy utilities.[16]

---

[12] *See* Evgenia Shumilkina, *Utility Performance: How Can Commissions Evaluate It Using Indexing, Econometrics, and Date Envelopment Analysis?* NRRI 10-05, March 2010, at http://nrri.org/pubs/multiutility/NRRI_utility_performance_mar10-05.pdf.

[13] DEA is a method in which linear programming or other operations research methods calculate the efficient input-output relationships for individual utilities. A major shortcoming of this method, as well as other non-statistical ones, is that they are unable to separate the inefficiency effect from statistical noise or randomness because of poor quality data and data errors, omitted variables, and other problems. DEA defines the benchmark as the best performing utilities.

[14] *See*, for example, Pacific Economics Group, *The Cost Performance of Boston Gas*, January 28, 2003; and Pacific Economics Group, *Benchmarking the Operating Performance of Portland General Electric*, February 10, 2010.

[15] "Average performance" occurs when the predicted cost and the actual cost are equal. *See* the studies cited in footnote 14.

[16] The Ontario Energy Board uses the econometric method to assist in evaluating utility performance. *See*, for example, Pacific Economics Group, *Benchmarking the Costs of Ontario Power Distributors*, March 20, 2008.

C. Additional ways to measure utility performance

1. Management audits

A management audit is a systematic assessment of the tools, processes, and policies of utility management in resource usage, planning, and organizational activities. Management audits can: (1) assess the current effectiveness of management, (2) recommend improvements, and (3) establish "best practices" standards for future use. U.S. regulators often use management audits to evaluate a utility's performance. Overall, management audits can help both regulators and utilities understand current processes, evaluate those processes relative to "best practices," and recommend changes.

The major positive feature of management audits is their scrutiny of utility processes and the detailed information they provide to regulators. Management audits can investigate specific utility operational areas or the utility as a whole. On the negative side, management audits are expensive and rarely provide a quantitative benchmark for evaluating a utility's "output" performance. The most useful audits recommend improvements in management practices for a single component of a utility's operation, such as work-force management or maintenance of power plants. Because they are expensive, management audits are most appropriate when there is evidence of a specific problem. That evidence can derive from narrow-based performance measures relating to specific functional areas.

2. Accounting ratios for individual functional areas

Examples of accounting ratios are labor expense per dollar of revenue, administrative and general expense per customer, and operation and maintenance expense per customer. These ratios are easy to calculate: They require no sophisticated estimation technique such as econometrics and linear programming.

Regulators must use caution, however, in applying these measures for benchmarking and evaluating a utility's performance. Since ratios do not control or account for factors beyond a utility's control, they reflect more than utility management behavior; when not used appropriately, ratios can lead to counterproductive outcomes. Appendix B illustrates accounting ratios adjusted for inflation, labeling them "real unit cost indices."

Simple accounting ratios can assist regulators in "red flagging" operational concerns. They can also help regulators (a) identify historical trends—for example, the growth of labor costs per dollar of revenue over the past ten years; (b) determine today's baseline performance—for example, the mean performance of a group of utilities; and (c) quantify relative performance across utilities—for example, the labor costs per dollar of revenue of a utility compared with the mean for other utilities in the same state. Regulators should refrain from using these ratios by themselves to adjust a utility's rates, to determine cost recovery, or to make other decisions that directly affect the utility's financial condition. It would be unfair to the utility or its customers: penalizing a utility for subpar performance or rewarding it for exceptional performance, both explained by exogenous factors, would produce a zero-sum outcome; the regulators could deprive the utility of recovering prudent cost or the utility would enjoy a windfall gain with no apparent "performance" benefits to customers.

Accounting ratios could be useful in placing on the utility the "burden of going forward" to explain performance problems. Accounting ratios are a low-cost regulatory tool that has definite limitations but, when applied correctly, can improve the ability of regulators to evaluate a utility's performance.

The usefulness of these ratios depends on the selection of the peer group whose average performance represents the benchmark for evaluating the performance of a single utility. No perfect benchmark exists, because no peer group operates in an environment identical to the utility under review. The selection of similar utilities can result in more meaningful benchmarking. Differences in performance between utilities would then reflect more management behavior than exogenous factors.

3. Uses and limitations of performance measurement

Table 1 shows different performance measures and measurement techniques. In addition to their uses, it lists the limitations that regulators should keep in mind when applying them in specific situations. This paper previously discussed these uses and limitations. Part V.B discusses how regulators can apply performance measures in different venues.

Table 1. The Uses and Limitation of Different Performance Measures and Measurement Techniques

Performance measurement	**Use**	**Limitation**
Statistical method	• Estimation of average performance as the predicted cost controlling for a utility's exogenous conditions • Ranking of the performances of different utilities based on the deviation between a utility's actual performance and average performance • Estimation of the effect of individual factors on cost • Application of statistical tests for performance evaluation	• Predictions of average performance sensitive to different assumptions, model design, the data, and econometric errors • Requirement of substantial date • Demand for skills in sophisticated econometric and statistical techniques • Inclusion of only quantifiable factors
Accounting cost and non-cost ratios	• Provision of information that "red flags" or identifies potential problem areas at low cost • Provision of preliminary information for in-depth inquiry • Comparison of a utility's performance over time or with other utilities	• No separation of management effects and other factors on performance • Narrow-based measures that don't account for interdependencies between utility functions • No definite benchmark
Management audits	• Evaluation of current processes, policies, and management practices for specific functional areas • Recommendations on improvements or prudence of past actions • Establishment of "process" standards for future performance	• Expensive to conduct • No "outcome" metric or benchmark
Total factor productivity	• Quantification of the overall cost performance of a utility • Quantification of the effects of individual factors on performance • Comparison of a utility's performance over time or with other utilities	• Estimation of some required data • No separation of management effects and other factors on performance • No definite benchmark
Price	• Comparison of a utility's average cost with other utilities	• No separation of management effects and other factors on performance • No explicit benchmark

V. Applications of Performance Measures in Different Regulatory Venues

Performance measures offer regulators a tool that is useful for different purposes in different venues. This section will first identify three broad ways in which regulators can use performance measures. It will then discuss seven specific applications of performance measures.

Regulators first should recognize the shortcomings of the performance measures for benchmarking purposes. They need to exercise caution in interpreting and using the measures. It is not uncommon for rankings of utility performance to vary depending on the measurement and benchmarking methods used. A good approach is to use different benchmarking methods to compare and evaluate the results, rather than rely on a single method.

A. General uses of performance measures and examples

Regulators can judge a utility's actions in three general ways:[17]

1. Evaluate the information used by a utility prior to an action.

2. Observe and evaluate the utility's actual performance.

3. Retrospectively review the prudence of the utility in undertaking the action.

Regulators can use performance measures in each of these three ways. The first way requires evaluation prior to an action, while the second and third evaluate utility performance after the fact. One example is the regulator periodically reviewing a utility's construction performance in controlling cost and reaching scheduled milestones. Another example is a regulatory review of a utility's prospective and retrospective actions with regard to customer service.

1. Illustration of service quality

The regulator might want to assess in advance whether a utility's proposal to improve its service quality is cost-beneficial. It might judge, after the fact, whether the utility's actual service quality is satisfactory or requires additional review to determine whether the utility complied with the regulator's standard. The regulator might establish service quality targets to compare periodically with the utility's actual performance. The regulator might resort to an incentive mechanism that would reward a utility for surpassing a target and penalize it for performing below the target. Another option is for the regulator to penalize a utility for failing to meet pre-specified standards, but not reward it for superior performance. This option is premised

[17] *See*, for example, William E. Encinosa, III and David E. M. Sappington, "Toward a Benchmark for Optimal Prudency Policy," *Journal of Regulatory Economics* 7 (1995): 111-130.

on the belief that a utility should not earn a reward for fulfilling a primary obligation, such as providing high-quality service.[18]

2. Illustration of energy-efficiency activities

In evaluating a utility's proposed action, the regulator can review other utilities' actions, in addition to the outcome of those actions, to compare with what the utility under review is proposing. If the utility, for example, proposes to invest in energy efficiency, the regulator can compare its estimated costs with the actual costs incurred by other utilities for comparable investments. The regulator can also compare the utility's estimated benefits with the actual benefits for similar initiatives undertaken by other utilities. These comparisons can help the regulator gain access to information that is presumably more reliable and objective than the information it receives from the utility under review. They can, consequently, enhance the regulator's ability to make an informed decision.

After the utility undertakes an action, the outcomes become measurable. Once the utility implements its energy-efficiency initiatives, the regulator or some other party can measure the actual benefits. The regulator can use the measurement to compare with the utility's estimates to judge whether individual initiatives should continue, expand, or terminate. Measured performance by itself does not imply prudence or management competence; it can, however, "red flag" a potential problem that needs correction or indicate that the utility's performance is exceptionally bad, warranting further investigation.

3. Prudence review

Performance measures by themselves cannot determine whether a utility acted prudently. If regulators use them in this capacity, the utility becomes highly susceptible to a whimsical evaluation based on outcomes rather than the prudence of the decisions themselves. A regulator who penalizes a utility for hedging its natural gas purchases when the spot market price turns out to be lower than the hedged price is an example. Could the utility not have hedged, and would it have resulted in lower cost? Yes, no question—the utility had the option to purchase all of its gas at the spot price and would have benefited from doing so. But was the utility imprudent in deciding to hedge? We don't know unless we do a detailed inquiry as to: (a) what the utility knew at the time it made the decision, and (b) how it used that information to conclude that hedging was a reasonable alternative. The ratio of the hedged price to the actual price over several years—a form of performance indicator—could suggest a problem requiring review.

4. Evaluation of a regulatory action

Another possible application of performance measures is to determine whether a particular regulatory action or change in policy produced the intended improvement. After establishing a new incentive mechanism for gas procurement, for example, the regulator should

---

[18] For an excellent review of different regulatory options, *see* Pacific Economics Group, *Service Quality Regulation for Detroit Edison: A Critical Assessment*, March 2007.

want to know whether the mechanism improved the efficiency of a utility to purchase natural gas. A major challenge for the analyst is to attribute any improved performance to the incentive mechanism, *per se*, rather than to other factors: What would the utility's gas costs have been in the absence of the incentive mechanism?

Overall, performance measures can play an important, even if only a subordinate, role in the three general ways for regulators to evaluate a utility's performance. By themselves, the measures lack the capability to assess management performance. Performance measures, however, can supplement other information to assist regulators in assuring customers that utilities do not flow through excessive costs to their customers and underperform in other ways.

B. Specific applications

1. Regulatory incentive mechanisms

The core component of an incentive mechanism is the benchmark, which determines the specific costs and revenues applicable to the mechanism, the strength and nature of incentives, the relative likelihood of award or penalty, and the utility's exposure to risk as a result of the incentive mechanism. Appendix C describes one kind of incentive mechanism that highlights the importance of a benchmark in distributing the economic benefits between the utility's shareholders and consumers.

The rationale for an incentive mechanism is that it would motivate the utility to perform at a higher level than that at which the utility performed previously. It has this effect by decoupling revenues from a utility's actual costs when its performance falls in the "exceptional" category. Under one form of incentive mechanism, the utility earns no reward or receives no penalty if actual costs equal (or are within a tolerance band around) the benchmark, and the utility receives an incentive award if it beats the benchmark. In principle, then, the benchmark should measure performance that results from reasonable management behavior reflecting acceptable, but not superior, performance deserving of no award or penalty.[19] The benchmark could represent average or non-exceptional performance. As illustrated in Appendix C, the wrong benchmark can have counterproductive results: They can cause higher rates for customers and a windfall gain to the utility. Incentive mechanisms require performance measures to calculate the magnitude of utility rewards or penalties (e.g., a prespecified percentage of the difference between actual performance and the benchmark).

Performance measures applied to past utility actions can help regulators determine whether an incentive mechanism had actually improved performance. Such a determination, however, is extremely difficult to conduct. The regulator would need to determine how the utility would have performed in the absence of the incentive mechanism. If the utility's performance substantially or even marginally improved with the mechanism, the regulator might

---

[19] *See*, for example, Ken Costello and James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI Report 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

infer that the mechanism had a positive effect. But how much the mechanism improved performance depends on the collective effects of other factors that might have changed.

2. Periodic monitoring of utility performance outside a rate case

a. Performance for individual functional areas

Monitoring has four major purposes: (1) report and evaluate utility performance in one or more functional areas, (2) propose changes to regulatory policies and practices to improve utility performance, (3) determine utility compliance with rules, guidelines, and expectations, and (4) apply any mitigating actions when necessary. Performance measures offer regulators a tool in conjunction with other information to carry out monitoring activities. Regulators might want to quantify the performance of a utility in specific areas on an annual basis. If the measures suggest a potential problem, regulators might further investigate with more detailed information and analysis.

Periodic reviews can increase the regulator's understanding of a utility system, and its components, in addition to its actual performance. This understanding can assist regulators in determining whether to adjust rates or take other actions based on evidence of exceptional performance. Performance measures can help direct regulatory resources to those areas of utility operations that are most in need of improvement.

Regulators may establish performance targets to evaluate a utility's actual performance, at least in terms of deciding whether to pursue further inquiry. Monitoring of a utility's performance can lead to: (1) regulatory actions aimed at avoiding recurrence of past problems or (2) determining whether a utility has complied with a regulatory standard or obligation for a functional area of operation. Did the utility continue to have bad customer service that needed improvement? Did the utility meet the requirements established by the regulator for reliable service?

b. Utility-wide performance

Econometrics, *data envelopment analysis*, and *total factor productivity* are distinct approaches for measuring the overall cost performance of a utility. Although measuring a utility's cost performance in specific areas is important, it neglects the more substantial question of how these "component" performances add up to the utility's overall cost performance. After all, it is the utility's total cost that determines the rates it charges to different customers.

Appendix D shows how an improvement in total factor productivity reduces a utility's average costs and rates. By comparing a utility's past growth rate of total factor productivity with a peer group, the regulator is able to measure the effect of any differential on the utility's total cost. Assume that two utilities have different historical growth rates of TFP. This outcome should cause the utility with the higher growth rate to have a lower percentage change in cost over time, assuming other thing remaining the same. An increase in TFP is equivalent to a decline in the real dollar cost of the aggregate input per unit of output. (*See* Appendix D for the mathematical relationship between TFP and average costs.) The regulator might want to know the additional dollars expended by the utility with the lower historical TFP growth. TFP depends on several factors, including technical change, economies of scale, and the ability of utility management to combine inputs to maximize output (i.e., productive efficiency).[20] A comparison of TFP growth rates across utilities, therefore, reflects a mixture of internal efficiencies and external market conditions.

3. Comparison of a utility's actual performance with a benchmark, both in rate cases and other regulatory forums

The measurement of performance is the first step toward a preliminary evaluation of a utility's performance. The next step is to develop a standard, which can include selecting peer utilities and measuring their average performance. Regulators can then compare this average performance with the performance under review. A statistically significant difference can attract the regulator's attention and lead to further action.

Analysts have assigned different functions for benchmarking. They include:

1. Identify "best practices" in management processes and tools,

2. Monitor relative performance across utilities,

3. Identify areas of a utility's operations that require needed attention or further investigation,

4. Establish targets or standards for utility performance,

5. Mitigate the cost-plus nature of regulation, and

6. Place the focus on outcomes instead of inputs.

As one application, regulators can then use the "benchmarking" results, along with other information, to determine whether a utility should develop a plan to improve performance in a function the regulator deemed problematic. Regulators can apply this tool both within a rate case and in other regulatory venues.

[20] A major factor for the short-term movement of total factor productivity is output fluctuations as they affect a firm's capacity utilization.

4. Evaluation of the reasonableness of "cost-of-service" components, adjustment of the rate of return on equity (ROE), and use of total factor productivity

a. Rate-of-return regulation

Performance measures can assist regulators in a rate case. Regulators can adjust a utility's allowed rate of return on equity for past performances. They might reward a utility by adjusting upward the utility's rate of return by 50 basis points for surpassing performance targets established by the regulator. On the other side, a utility might receive a lower allowed ROE for poor customer service or other subpar performance.

A major task of regulators in rate cases is to determine whether a utility overstated its revenue requirements to justify a higher rate increase.[21] Assume that a regulator uses a future test year to determine new rates. The two broad factors affecting differences between historical and future costs are forecasted changes in productivity and input prices. The utility's forecasts of costs are, therefore, dependent on expectations of its future productivity growth and input-prices escalation. By understating the productivity gains, other things constant, the tendency is for the utility to overstate its future revenue requirements and, therefore, the rate adjustment required for earning a fair rate of return.[22] Regulators should ask: Do the cost forecasts incorporate a change in productivity that reflects good utility-management behavior and is comparable to the utility's historical performance? Regulators can use performance measures to determine whether future test-year costs for specific functional areas reflect an appropriate baseline for setting new rates. The regulator can observe historical values over a number of years to judge whether the change in specific costs from current values to forecasted values is consistent with historical changes. Changes in performance can supplement other information to determine reasonable costs for setting new rates.

Appendix B illustrates a cost measure for individual utility functions adjusted for inflation. Regulators can discern whether the implicit productivity change for a specific function as projected by the utility is in line with historical changes. Assume, for example, that the utility is projecting advertising costs per dollar revenue (in constant dollars) to increase by 10 percent per annum over the next two years. If historically over the past five years, the per-annum increase was only 2 percent, the regulator might rightly conclude that the utility is inflating advertising costs in its future test-year filing, unless the utility provides a good explanation for the higher growth rate in the future.

---

[21] If a regulator approves test-year costs that are excessive, other things being the same, the utility's actual rate of return would exceed its cost of capital and rates would be too high.

[22] A larger share of the cost savings from actual productivity gains over the effective period of new rates would then go to the utility. In adjusting rates, regulators implicitly determine the distribution of productivity benefits between the utility and its customers. Integral to good regulation, any rate adjustment should reflect a level of productivity, as well as input prices, that are compatible with "reasonable" performance by utility management.

b. Price-and-revenue cap regulation

In a number of foreign countries, regulators have used performance measures as a benchmark to set the parameters for a price-cap mechanism. They apply statistical benchmarking to help determine the base price[23] and the "stretch factor" component of the X-factor for an individual utility based on changes in the TFP for peer utilities.[24] One interpretation of the base rate is that it represents the cost of an efficient utility, rather than strictly the cost of the utility under review. Many of the price-cap plans include benchmarks for service quality. One concern is that under price caps a utility would be strongly motivated to control costs, even to the point of compromising service quality. A separate component using historical service-quality levels as a benchmark would penalize a utility for falling below those levels (or, below the lower bound of a pre-specified "band").[25]

c. Riders

Regulators can tie rate adjustments outside a formal rate case to a utility's performance. These adjustments occur within the confines of cost or formula-rate riders.[26] Annual adjustments of base rates can depend, for example, on the utility's performance in customer service relative to some predetermined standard. Performance is, therefore, a factor in the context of both what the regulator expects from the utility and what outcome the utility achieves.

5. Preliminary review of a utility's performance to determine further action

Performance measures can act as indicators of potential problem areas. They can help regulators assess the benefits expected from a management audit or other thorough investigation. This use of performance measures involves detecting areas of a utility's operation for which its

---

[23] In traditional regulation, the base rate would correspond to the actual costs of the utility under review. Under benchmarking the base rate would account for the efficiencies and costs of peer utilities. The reason is that setting the base rate on the basis of information only for the utility under review would invite gaming and perverse incentives,

[24] Under a price-cap mechanism, the maximum price that a utility can charge for period t equals the base price plus the accumulated changes since the base period, determined by the change in the selected price index (e.g., GDP Implicit Price Deflator) minus the X-factor, which commonly relates to a measure of total factor productivity. The "stretch factor" attempts to adjust the X-factor for differences in past TFP changes between utilities.

[25] Another benchmark can include the average service-quality level of a group of similar utilities.

[26] Under one definition of formula rates, rates are adjusted annually to reflect changes in a utility's costs and revenues relative to test-year levels. The goal is to assure that the utility's actual rate of return on equity (ROE) does not deviate far from what the regulator approved in the last rate case.

current performance compares unfavorably with other utilities, with the historical performance of the utility itself, or with the regulator's predetermined desired outcome. A utility with certain costs that are "outliers" should undergo more detailed review to determine the reasons for its exceptional performance.

One such detailed review that can uncover potential problem areas is a management audit, which this paper discussed in Part IV.C.1. An audit can evaluate past performance to determine cost recovery; or evaluate current management practices to recommend changes in these practices, such as work-force management and power-plant maintenance. These changes have the purpose of improving the utility's future performance.

Narrow-based performance measures can provide the initial information to justify a management audit. Management audits can help regulators better understand current utility processes and practices. They can lead to changed utility actions that are more in line with "best practices."

6. Examination of the reasons for performance differences across utilities

A statistical analysis can identify factors explaining why some utilities perform better in certain operational areas than other utilities. Why, for example, do some utilities have lower O&M expenses or higher equivalent availability for coal power plants? Regulators should want to know why some utilities under their jurisdiction are performing worse than other utilities. Effective regulation would include inquiries into these questions—how else can regulators know that the utilities under their jurisdiction are charging "just and reasonable" rates that reflect prudent and efficient utility management? This use of performance measures requires more than just calculating performance directly from accounting or other reported data; it also requires statistical analysis that measures the effects of individual factors on a utility's performance.

7. Publicity of a utility's performance on a periodic basis

The use of publicity to induce utility performance is uncommon in the U.S., but regulators in other countries have more frequently used these tactics, especially in instances in which a utility's performance was poor.[27] In Massachusetts, some utilities send in their customers' bills an annual report card on their performance. The regulator checks the accuracy of the report before the utility releases it to the public. The information includes a comparison of the utility's commitment to a targeted performance level with its actual performance. Performance areas for one utility, Western Massachusetts Electric Company, include: (a) the utility's response to customer calls, (b) average outages per customer, (c) the average number of minutes without power per customer, and (d) customer complaints per thousand customers.[28]

---

[27] *See*, for example, Sanford V. Berg, *Survey of Benchmarking Methodologies*, prepared for the World Bank, March 1, 2006.

[28] I thank Joseph Rogers for this information.

VI. A Six-Step Approach for a "Performance" Initiative

Regulators can undertake six sequential tasks for developing a "performance" initiative. These are:

A. Identify the uses of performances measures

What purposes would they serve in improving utility performance? Regulators need to know how they can best apply performance measures and not use them inappropriately. Part V.B discusses seven possible applications of performance measures.

B. Select utility functional areas for regulatory review

Part III.C lists four criteria for selection: (a) the effect of a functional area on a utility's total cost or consumer value from reliable and high-quality utility service, (b) the ease of measurement, (c) the effort needed to correlate performance measures with management behavior, and (d) the influence of utility management in affecting performance. It makes sense to select a functional area that has a substantial effect on a utility's costs or other dimensions of performance over which the utility has discretion.

C. Calculate the performance measures

Performance measures can derive directly from accounting or other statistics periodically compiled and reported by utilities; or utilities or regulatory staff can estimate performance measures using sophisticated analytical techniques. These techniques have the ability to separate the effects of management behavior from other factors in determining overall utility performance. Their applications require proficiency in statistics and other numerical methods.

D. Compare a utility's performance with a predetermined benchmark

The benchmark can be the performances of other utilities, the regulator's own standard, or the utility's own historical performance. A comparison can help determine whether a utility's performance is exceptionally good or bad or falls outside the range of "standard" performance.

E. Assess a utility's performance

The regulator can perform an internal review to further examine the performance statistics to identify possible explanations for exceptionally good or bad performance. The regulator might also want the utility to respond to performance metrics showing its performance to lag behind the performances of other utilities.

F. Take action

An action might include allowing a utility to recover costs for a particular function, conducting a more detailed review of the utility's behavior, or establishing stronger regulatory incentives for improved utility performance. With supplemental analysis, regulators can apply performance measures to disallow costs as well as penalize a utility in other ways. Symmetrical regulation would also reward a utility if its performance is exceptionally good—for example, if its performance exceeds the standard predetermined by the regulator because of outstanding management behavior.

Appendix A: Price Differentials across Utilities: The Challenge of Detecting Causes

Theoretical problem

Assume that regulators want to compare the prices charges by different utilities. They can use this information in various ways. First, they can see how the prices of utilities in their state rank with those in other states. Second, they might conduct a statistical analysis to identify reasons for price differences. They might, for example, want to know whether demand conditions and other factors beyond the control of a utility explain most of the differences. This analysis would require specifying and estimating a conceptual model such as:

$$P_{ci} = f\,(D_{ci}, C_{ci}, R \ldots Z),$$

where the price charged by utility i to customer class c relates to demand conditions (D_{ci}), costs (C_{ci}), regulatory practices (R), and other factors (Z). By estimating the relationships between price and the individual factors, regulators can assess the effect of each factor on price. They can then use this information to better understand why prices vary across utilities. Regulators can then interpret price differences that are unexplained by these factors as a residual. The residual can reflect model error in predicting price or variations in management competence, or a combination of both.

Some regulators might attempt to use price as a benchmark to penalize or reward a utility. Price is easy to measure and it compasses all of a utility's costs, avoiding the distortive incentives that could arise from using a partial measure of performance. But the problems associated with a "price" benchmark are potentially serious. Utilities might have different prices at a point in time because of the uneven treatment of certain costs (e.g., some states may allow construction work in progress in rate base while other states do not). One utility also could have higher growth in output, which because of economies of scale would cause its average costs to decrease relative to other utilities. Each of these factors could cause one utility to rank lower than other utilities even though management behavior was no factor.

An illustration: identifying price factors for a natural gas utility

One or more of the following general factors can explain the large differences in retail gas prices between natural gas utilities, both within a state and across states: (1) customer-demand characteristics (e.g., load factor, gas usage per customer, use of gas for space heating), (2) cost and supply conditions (e.g., proximity to gas fields, the number of pipelines serving the utility), and (3) management practices (e.g., hedging strategies, proficiency in cost control). A major component of gas prices to small retail customers is gas commodity costs. These costs, when added to pipeline costs and distribution margins, comprise the retail price charged to small customers. Thus, in examining price differences across utilities, an analysis should first disaggregate the differences by individual functions. For example, to what extent do higherpriced gas utilities have higher pipeline rates, distribution margins, and commodity gas costs?

One can imagine several factors accounting for price differentials across gas utilities. They include:

1. *Levels of storage available to each gas utility*: Those utilities without storage capability would tend to have higher costs, assuming other things held constant. Some gas utilities tend to have higher rates partially because of their lower storage capability relative to other gas utilities.

2. *Rate legacy*: Cost allocation methods and the ratios of rates to different customer classes may vary across utilities. For various reasons, the residential rates of some gas utilities may reflect cost-of-service principles less than those of other gas utilities. Also, different accounting treatment of storage costs and other cost components can affect rates.

3. *Cycling issue with purchased gas adjustment (PGA) clauses*: The adjustment period might not be uniform across utilities; adjustments, for example, might be monthly, quarterly, or annually, depending upon the gas utility. The periods for which a utility adjusts its purchased gas costs can, therefore, distort a snapshot comparison of prices across utilities.

4. *Gas procurement and hedging practices*: Transaction arrangements and hedging activities are important factors in affecting purchased gas costs. Viewed from across the country and within individual states, one observes a wide discrepancy in physical and financial hedging by utilities. This discrepancy means that when wholesale gas prices change, up or down, there would be a lesser rate effect on those utilities that have hedged more. Differences in management philosophy may explain why some gas utilities hedge more or less than other utilities.

5. *Distribution margins (i.e., the portion of retail rates left over after subtracting gas commodity and pipeline costs)*: Large differences exist across utilities; a major factor is the sales volumes or throughput per customer. Distribution margins are generally higher for rural utilities, for utilities in warmer climates, and for those utilities with recent capital expenditures recovered in rates. Prices in warm-weather states are generally higher because utilities have to recover their fixed costs over fewer sales, which drives up their average cost and prices.

6. *Pipeline rates:* Factors include the zonal area of a pipeline, as the Federal Energy Regulatory Commission (FERC) allows price differences between designated zones. The number of pipelines that move gas to a specific utility may affect rates (i.e., competitive conditions would tend to place a downward pressure on rates). The load factor of firm customers may also be important—for example, utilities with lower load factors would tend to have higher pipeline rates because of FERC's straight-fixed rate design.

7. *Different services offered under the base rate*: Some utilities may still provide maintenance and other services under base rates.

8. *Economies of scale*: Larger gas utilities may have lower average cost because of the economies from procuring gas and pipeline transportation at greater amounts.

9. *Economies of scope*: Some utilities like combination electric and gas utilities may perform more functions that offer synergies with other functions, which would lower costs.

One consulting firm, Pacific Economics Group (PEG), has conducted several studies that apply an econometric statistical cost model to explain differences in non-fuel O&M costs and other costs across energy utilities.[29] These studies show that the services provided, the scale of operations, the prices of inputs, and other business conditions explain some of the cost differences across utilities. Their studies have found, for example, that greater use of cast iron increases both maintenance and replacement costs. PEG also found that scope economies lower costs. They distinguish between the effects on cost from increased throughput per existing customer and from the addition of new customers. (The latter has a greater effect.) They also found that natural gas utilities serving urban areas have higher costs partially because of the greater difficulty of installing mains and service lines.

[29] *See*, for example, Pacific Economics Group, *The Cost Performance of Boston Gas*, January 28, 2003; Pacific Economics Group Research, *Benchmarking the Operating Performance of Portland General Electric*, February 10, 2010; and Mark Newton Lowry et al., "Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors," *The Energy Journal* 26, 3 (2005): 75-92.

Appendix B: Real Unit Cost Indices

The real unit cost index equals:

$$UC_k = E^r_k/Q_k\ ,$$

where UC_k is the unit cost in constant dollars for utility function k, E^r_k is total cost for function k deflated by a price index, and Q_k is the output measure for function k. The percentage change in real unit cost equals the difference between the percentage changes in total cost in real dollars and output. An increase in UC_k over time reflects a decline in productivity, since mathematically the relationship between real unit cost and productivity is reciprocal. If E^r_k equals total cost for a utility and output is the total kilowatt-hours or therms provided by a utility, then UC_k represents the inverse of the total factor productivity for the utility.

Assume we want to calculate the change in a utility's real unit cost for operation and maintenance during the period 2007-2009. We define output as total sales. We have the following statistics as reported by the utility:

	2007	2008	2009
Total O&M expenses (10^3 dollars)	\$223,063	\$242,789	\$266,519
Expense index	1.000	1.088	1.195
Price index	1.000	1.084	1.141
Sales (Gwh)	33,440	34,271	34,789
Sales index	1.000	1.025	1.040

The indices measure the values of O&M expense, price, or sales for a particular year relative to their values for the base year (2007). The expense index for 2008 (1.088), for example, equals the ratio of total O&M expenses in 2008 and 2007 (i.e., \$242,789/\$223,063); the sales index for 2009 (1.040) equals the ratio of sales in 2009 and 2007 (i.e., 34,789/33,440).

We can calculate the percentage change in real unit cost as

$$\ln (UC_{k,\,t}/UC_{k,\,t-1}) \cdot 100 = [\ln (E_{k,\,t}/E_{k.t-1}) - \ln (P_{k,\,t}/P_{k,\,t-1}) - \ln (Q_{k,\,t}/Q_{k,\,t-1}],$$

where k is the function under review, t and t-1 are time periods, and P is the price index used to convert expenses of different periods into constant dollars; UC and E, as defined above, are unit cost and total cost. Applying the numbers in the table, the growth rates for real unit cost percent during 2007-2008 and 2008-2009 are -2.1 percent and 2.7 percent, respectively.

A regulator can acquire this information for the utility under review as well as for other utilities with similar characteristics. Differences in growth rates can reveal whether the utility under review is an outlier or an average performer, as determined by the mean growth rate of the other utilities compared with the utility's growth rate. Regulators can calculate real unit cost indices with time series, cross-sectional, or panel data. With time series data, regulators can compare the performance of an individual utility over time with itself or a peer group of utilities. Cross-sectional data can compare a utility's performance with other utilities at specific points in time. Panel data can provide comparisons of performance both over time and at specific points in time.

Appendix C: An Illustration of the Use of Performance Measures in a Cost-Sharing Incentive Mechanism

Example of a cost-sharing mechanism

Assume that a regulator has approved an incentive mechanism for purchased gas. The mechanism has a cost-sharing arrangement, expressed as the following:

$$C_f = C_a + s\cdot(C_b - C_a), \text{ or}$$

$$C_a\cdot(1\text{-}s) + C_b\cdot s,$$

where C_f is the costs flowed through to consumers, C_a equals actual costs incurred by the utility, s is the sharing parameter, and C_b equals benchmark costs. A regulator might want to modify the above plan to include a "dead band." This provision would account for the likelihood that small deviations of a utility's performance from the benchmark do not reflect management behavior. These deviations may represent "white noise" explained by factors beyond utility-management control.

Applying the previous formula, assume that C_a equals \$100 million, C_b equals \$120 million and s is 0.2. Then, C_f equals \$100 million + 0.2(\$120 million - \$100 million) = \$104 million. The results seem positive: the utility earns \$4 million in rewards and consumers ostensibly receive benefits of \$16 million from lower gas purchasing costs, after adjusting for the utility reward. (The assumption is that actual costs would equal \$120 million without the incentive mechanism.) Consumers pay the *actual costs* plus the *reward* to the utility (when $C_b > C_a$) or the actual costs minus the penalty to the utility (when $C_b < C_a$).

Consumers benefit only when the reduction in actual costs exceeds the reward to the utility. So for consumers to benefit from an incentive mechanism, $(C_b - C_a)$ must be greater than $s\cdot(C_b - C_a)$. Thus, it seems, at least mathematically, that consumers always benefit when the utility beats the benchmark, since s is less than one. But this assumes that $(C_b - C_a)$ represents the real cost savings from the incentive mechanism. This presumption may distort reality if C_b, in fact, does not reflect what the utility's costs would have been in the absence of the incentive mechanism. (The subsection below, "The effects of a biased benchmark," examines this problem.)

When contemplating incentive mechanisms, regulators need to consider the tradeoff between: (1) creating strong incentives for superior performance and (2) achieving a balanced distribution of economic gains between the utility and its customers. Cost-sharing mechanisms such as the one presented above represent a compromise that provides better incentives for cost efficiency than cost-plus arrangements but mitigates the likelihood that utility customers would earn an unreasonably small share of the total economic gain from improved utility performance. Under a typical incentive mechanism, a utility receives additional revenues from improved performance. A relevant question for "equity" purposes is: What benefits do consumers receive when utility performance improves? Do these benefits at least cover the additional revenues that consumers have to pay? To say it differently, do the benefits of improved performance to consumers coincide with the additional revenues to the utility? Although in many instances the benefits to consumers may be non-quantifiable, regulators should have the ability to make an informed decision on whether the benefits to consumers from improved performance correspond to the additional revenues that a utility receives. The significance of consumer benefits falling short of additional revenues is that the utility receives a windfall gain at the expense of consumers.

The "benchmark" cost is clearly pivotal for dividing up the gains between the utility and consumers. One tough challenge for regulators is to set the correct benchmark. The wrong benchmark can derived from: (1) gamesmanship by utilities and consumer groups (e.g., biased cost revelation by the utility), and (2) incomplete information. The utility will argue for a benchmark that will make it easy to earn a reward and avoid a penalty; consumer groups will attempt to make it hard on the utility to earn a reward. The utility might reveal its cost opportunities to be lower than what they really are (e.g., the utility would argue that it has certain constraints in reducing costs when, in fact, it has no such constraints.) The regulator finds it difficult to know the "true benchmark:" What costs should the utility have under reasonable management? What costs would the utility incurred in the absence of an incentive mechanism? What are reasonable utility actions deserving of neither a reward nor a penalty?

A good benchmark also is also beyond the control of a utility. If the utility, through its actions, is able to affect the "benchmark" value, distortion can readily occur. A utility, for example, might be able to strategically manipulate the benchmark to improve its profits at the expense of consumers. The "benchmark" value should also change over time in response to changed market and other conditions.[30] In other words, it should adapt to changes in outside conditions. The intent of an incentive mechanism is to direct the incentives at only those activities over which the utility has some control.

The effects of a biased benchmark

The cost effect on consumers when a utility is able to manipulate the benchmark, and assuming no change in actual costs, is as follows: let $\Delta C_f = \Delta C_a \cdot (1\text{-}s) + \Delta C_b \cdot s$; with $\Delta C_a = 0$, $\Delta C_f = s \cdot \Delta C_b = \Delta$ R (rewards). The result is a zero-sum game, in which the additional reward to the utility is a dollar-for-dollar payment from consumers.

Assume that C_b equals the calculated benchmark and C_b* is the true ("unbiased") benchmark, with $C_b > C_b^*$. One defensible measure of the true benchmark is the cost that the

[30] *See*, for example, Ken Costello and James F. Wilson, *A Hard Look at Incentive Mechanisms for Natural Gas Procurement*, NRRI Report 06-15, November 2006, at http://www.nrri.org/pubs/gas/06-15.pdf.

utility would have incurred in the absence of the incentive mechanism. The utility receives a higher reward, equal to $s \cdot (C_b - C_b^*)$. What is the effect on consumers? It depends, but here we assume an alternative world without an incentive mechanism. The following calculates the effect on consumers (i.e. the change in the costs flowed through to consumers) from a benchmark cost that is set too high:

$$\Delta C_f = \Delta C_a + \text{Reward to the Utility}$$

$$\text{Let } C_b = C_b^* + ụ \text{ and } C_b^* = C_{a0}$$

$$\text{Then, } \Delta C_f = (C_{a1} - C_{a0}) + s \cdot (C_b^* + ụ - C_{a1})$$

$$\Delta C_f > 0, \text{ when } s \cdot (C_{a0} + ụ - C_{a1}) + (C_{a1} - C_{a0}) > 0, \text{ or}$$

$$\Delta C_f > 0, \text{ when } (1 - s) \cdot (C_{a0} - C_{a1}) < sụ$$

The actual benchmark (C_b) exceeds the true benchmark by ụ. The true or unbiased benchmark (C_b^*) equals the actual costs incurred in the absence of the incentive mechanism (C_{a0}). One term not yet defined is C_{a1}, which equals the actual cost with the incentive mechanism in place. The incentive mechanism should reduce the actual cost (i.e., $C_{a1} < C_{a0}$).

Taking a numerical example, assume that C_b^* (i.e.,C_{a0}) is \$50 million, C_b is \$54 million, s is 0.5, and C_{a1} is \$49 million. With no incentive mechanism, consumers pay \$50 million. With the incentive mechanism, consumers pay \$49 million (C_{a1}) + 0.5(\$54 million - \$49 million), which equal \$51.5 million. In this example, consumers become worse off even when the utility lowers its cost. The reason is that consumers pay an excessive reward to the utility because the benchmark cost was set too high. Performance assessment can help regulators set an appropriate benchmark that would mitigate the chances of a utility earning a disproportionate share of the economic gains from improved performance.

Appendix D: The Relationship between Total Factor Productivity and Average Cost

- Average cost = Total cost / Output level
- Average cost = (Price of inputs · Input level) / Output level
- Average cost = Price of inputs / (Output level / Input level)
- Average cost = Price of inputs / *Total factor productivity*

Assume that when the binding regulatory condition holds in which total cost (or the total revenue requirements) equals operating revenues, an increase in total factor productivity causes a decline in average cost, rates and revenue requirements. Growth in total factor productivity can originate from different sources—for example, technology improvements, economies of scale, higher output, less waste of internal resources, and more efficient mix of inputs. Some of these factors fall within the control of utility management, while others fall outside.

Assume a hypothetical firm that uses only one input whose price is $5 per unit and that its total factor productivity equals 2. The average cost of the utility is then $2.50; that is, for each unit of output the utility uses one-half input. Since one input costs $5, one-half input is $2.50. Assume that over time the input price increases by 5 percent and that total factor productivity increases by 2 percent. Average cost would then increase to 5(1.05)/2(1.02) or $2.57.

As a general condition, when input prices increase faster then total factor productivity, prices would tend to rise. Prices would tend to fall when total factor productivity rises faster than input prices.

Utility Performance Incentive Mechanisms

A Handbook for Regulators

Prepared for the Western Interstate Energy Board

March 9, 2015

AUTHORS

Melissa Whited
Tim Woolf
Alice Napoleon

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

Acknowledgments

This material is based upon work supported by the Department of Energy National Energy Technology Laboratory under Award Number(s) DE-OE0000422.

The authors thank the project management team for their extensive input and guidance in developing this report:

Steve Ellenbecker, Western Interstate Energy Board
Richard McAllister, Western Interstate Energy Board
Maury Galbraith, Western Interstate Energy Board
Ron Lehr, Western Grid Group
Andy Satchwell, Lawrence Berkeley National Laboratory
Carl Linvill, Regulatory Assistance Project

We are also grateful for the many comments and edits received from external reviewers including Mike Florio, Jeff Goltz, Rich Sedano, and Devra Wang.

The views presented in this report are those of the authors and do not necessarily represent those of the project management team or reviewers. All errors are our own.

CONTENTS

EXECUTIVE SUMMARY 1

1. INTRODUCTION 6

2. REGULATORY CONTEXT 9

3. PERFORMANCE METRICS 17
   - 3.1. Introduction 17
   - 3.2. Performance Dimensions That May Warrant Metrics 17
   - 3.3. Defining Metrics 19
   - 3.4. Design Principles 28
   - 3.5. Dashboards for Data Reporting 31

4. PERFORMANCE TARGETS 34
   - 4.1. Design Principles 34

5. FINANCIAL REWARDS AND PENALTIES 41
   - 5.1. Design Principles 41
   - 5.2. Rewards and Penalties in the Context of New Regulatory Models 48

6. IMPLEMENTATION 51
   - 6.1. Questions to Help Inform Regulatory Action 51
   - 6.2. Implementation Steps 52
   - 6.3. Pitfalls to Avoid 53
   - 6.4. Summary of Key Performance Incentive Mechanism Design Principles 57

BIBLIOGRAPHY 58

APPENDIX A – DETAILED CASE STUDIES 63
   - California 63
   - The UK RIIO Model 70
   - New York 81

Illinois.. 84
Hawaii . 89
Performance Incentives Related to Fuel Adjustment Clauses 94
FERC's Bonus ROE for Transmission Projects 95

APPENDIX B – DATA SOURCES AND AVAILABILITY 96

APPENDIX C – DASHBOARD EXAMPLES 103

List of Tables

Table 1. Key Principles and Recommendations 4
Table 2. Three Categories of Regulatory Systems 10
Table 3. Traditional Performance Areas 19
Table 4. Emerging Performance Areas 19
Table 5. Reliability Performance Metrics 21
Table 6. Employee Safety Performance Metrics 22
Table 7. Public Safety Performance Metrics 22
Table 8. Customer Satisfaction Performance Metrics 23
Table 9. Plant Performance Metrics 23
Table 10. Cost Performance Metrics 24
Table 11. System Efficiency Performance Metrics 25
Table 12. Customer Engagement Performance Metrics 26
Table 13. Network Support Services Metrics 27
Table 14. Environmental Goals Performance Metrics 27
Table 15. Hypothetical Presentation of Financial Incentives in Different Units 46
Table 16. Key Principles and Recommendations 57
Table 17. RIIO Environmental Impact Performance Incentive Mechanisms 73
Table 18. RIIO Customer Satisfaction and Social Obligations Performance Incentive Mechanisms 74
Table 19. RIIO Connections Performance Incentive Mechanisms 75
Table 20. RIIO Reliability and Availability Performance Incentive Mechanisms 77
Table 21. Selected Smart Grid Metrics in Illinois 85
Table 22. Metric Formulas and Data Sources 96
Table 23. Data Sources and Notes on Availability 101

List of Figures

Figure 1. Performance Incentive Mechanisms vs. Performance Metrics 7
Figure 2. Dimensions of Utility Performance That May Warrant Tracking or Incentives 18
Figure 3. MA DOER Interactive Dashboard on Distributed Generation Interconnection Time 33
Figure 4. Example Dashboard for Utility Outage Frequency 33
Figure 5. Hypothetical Linear Formula with Deadband 43
Figure 6. Quadratic Function Compared to a Linear Function 44
Figure 7. Hypothetical Step Function 45
Figure 8. Plausible ROE Range for UK Distribution Utilities 50
Figure 9. Illustrative Scorecard for Outputs 78
Figure 10. Plausible ROE Ranges for UK Distribution Utilities 79

Executive Summary

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms. Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources.

Whether performance incentive mechanisms are added onto traditional ratemaking practices, included as part of performance-based regulation (PBR) plans, or considered as a central element of new regulatory and utility business models, they can be used to help improve utility performance. As with all regulatory mechanisms, they should be designed thoughtfully and they should build off of lessons learned from past practices.

Advantages of Performance Incentives

Utility performance metrics and incentives can serve as a valuable tool for regulators for various reasons:

- They help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized, or well understood.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals. In the absence of performance metrics and incentives, utilities have little incentive or guidance for achieving policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

Potential Pitfalls of Performance Incentive Mechanisms

As with all regulatory mechanisms, the success of performance incentive mechanisms is very much dependent upon their design and implementation. Experience to date has shown that there are many potential pitfalls that regulators should be aware of:

> Disproportionate rewards (or penalties). Performance incentive mechanisms can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.
>
> Unintended consequences. Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.
>
> Regulatory burden. Performance incentive mechanisms can be costly, time-consuming, or a distraction from more important activities for all parties involved. If this burden becomes too great, it can undermine the value of performance incentive mechanisms.
>
> Uncertainty. Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. In addition, significant and frequent changes to performance incentive mechanisms create uncertainty for utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.
>
> Gaming and manipulation. Every performance incentive mechanism carries the risk that utilities will game the system or manipulate results.

In most cases, these pitfalls can be managed through sound design and implementation of performance metrics and incentives. They can also be mitigated by ongoing evaluation of and improvements to the incentive mechanisms. Chapter 6 presents a more detailed discussion of these pitfalls and recommendations for how to avoid them.

Performance Incentives Can Be Used in Any Regulatory Context

One of the advantages of performance metrics and incentives is that they can be used in any regulatory context. However, it is critical that performance metrics and incentives be specifically tailored to the existing (or anticipated) regulatory context in each state, to ensure that they adequately complement and balance the financial incentives provided by that regulatory context.

> In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance; to address areas

where regulators see opportunities for greater efficiencies or reduced costs; and to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.

In a state with performance-based regulation, performance metrics and incentives might be especially important to prevent the degradation of service as a result of pressures to reduce costs, and to complement the existing regulatory incentives, such as those provided by price (or revenue) caps, fixed periods between rate cases, and cost trackers.

In a state developing new regulatory and utility models, performance metrics and incentives might be especially important to re-direct utility management priorities toward desired performance outcomes, and shift the source of utility revenues away from capital investments and toward those desired outcomes.

In any state, performance metrics and incentives can be used to promote resources that are not supported or encouraged by the existing regulatory system, such as energy efficiency and renewable resources.

In any state, performance metrics and incentives can be used to provide guidance on how utilities can meet state regulatory policy goals, such as improving reliability and resiliency, empowering customers to reduce bills, or minimizing the cost of complying with the EPA Clean Power Plan.

In any state, performance metrics and incentives can be used to encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the existing regulatory system, such as distributed generation, grid modernization, storage technologies, or practices to support electric vehicles.

Key Principles and Recommendations

Based on our review of the literature and the lessons learned from various jurisdictions, we provide numerous recommendations and principles for designing effective performance metrics and incentive mechanisms. These are summarized in the table below.

Table 1. Key Principles and Recommendations

Regulatory Contexts (Chapter 2)	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics (Chapter 3)	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets (Chapter 4)	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties (Chapter 5)	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

Questions for Regulators

Regulators may wish to ask several questions to help inform their decisions on whether and how to proceed with performance metrics and incentives:

- How well does the existing regulatory framework support utility performance?
- How well does the existing regulatory framework support state energy goals?
- What are the policy options available to improve utility performance?
- Are industry, technology, customer, or market conditions expected to change?
- Does the commission wish to articulate specific, desired performance outcomes? If so, in what performance areas?
- Does the commission prefer to oversee utility expenses and investments after the fact (e.g., through rate cases and prudence reviews), or to guide performance outcomes before investments are made?

Implementation Steps

Once a determination has been made to implement performance metrics or incentive mechanisms, the following steps can be implemented. These can be implemented incrementally to allow for each step to inform the subsequent step, or they can be implemented all at once.

1. Articulate goals**.** The first step is to identify and articulate regulatory policy goals. These goals should help inform choices of performance areas, targets, and penalties.

2. Assess current incentives**.** Next it is critical to understand the financial incentives created by the current or anticipated regulatory context.

3. Identify performance areas that warrant performance metrics**.** Performance metrics may be warranted for traditional performance areas or new and emerging areas.

4. Establish performance metric reporting requirements**.** Review performance reports to monitor those areas identified above, to identify any performance areas that may require targets.

5. Establish performance targets, as needed**.** Establish targets to provide utilities with clear messages regarding the level of performance expected by regulators. Review results to determine whether any performance areas warrant rewards or penalties.

6. Establish penalties and rewards, as needed. Establish rewards or penalties to provide direct financial incentives for maintaining or improving performance.

7. Evaluate, improve, repeat. The effectiveness of the mechanisms should be monitored and evaluated on a regular basis to determine whether there is a need for improvement.

1. INTRODUCTION

Purpose and Overview

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms (sometimes abbreviated here as PIMs). Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources. The ultimate objective of performance metrics and incentives is to better align utility regulatory and financial incentives with the public interest.

In the following chapters, we identify many of the metrics and performance incentives that regulators have used to monitor and evaluate utility performance, as well as emerging metrics and incentives that are being discussed in jurisdictions facing new issues and challenges, such as integration of renewable and distributed energy resources.[1] We provide a set of principles and recommendations for regulators, based on our review of the large amount of literature on these topics and the lessons learned from the case studies that we reviewed. Our research is primarily focused on electric utilities, but we have included some metrics specific to natural gas utilities as well.

This handbook builds off of a Western Interstate Energy Board report titled *New Regulatory Models* (Aggarwal and Burgess 2014).[2] That report provides a number of examples of how performance standards have been used by regulators.

Industry Changes and Pressures

Traditional cost-of-service regulation was originally designed in an era of significantly increasing sales and decreasing marginal costs, where the primary decisions required by utilities were related to how much and what type of generation and transmission to build to meet growing customer demand, and where the main goal was to ensure just and reasonable rates. The conditions currently facing the utility industry have changed considerably, for instance:

- Retail sales are increasing at much lower levels than in the past, and some utilities are experiencing declining sales. Sales may drop even further as customers adopt more demand-side measures, especially energy efficiency, distributed generation, and storage technologies.

---

[1] In fact, even where utility commissions have not implemented specific utility standards, utilities already comply with a variety of industry standards set by organizations such as the Institute of Electrical and Electronics Engineers (IEEE), the Occupational Safety and Health Administration (OSHA), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), the Financial Accounting Standards Board, and the Environmental Protection Agency (EPA).

[2] The Phase I report is available here: http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf

On the other hand, electric vehicles and other forms of electrification could lead to increased sales.

- Many utilities are facing the need to replace aging infrastructure, which may require significant capital investments that will not necessarily lead to reduced costs or increased sales.
- Utilities have many more options to choose from, in terms of generation, transmission, and distribution technologies, as well as more ways to address customer needs through resources on the customer side of the meter (including energy efficiency, demand response, distributed generation, automated metering technologies, and customer-facing smart grid options).
- Regulators have established a variety of public policy goals beyond simply maintaining just and reasonable rates. These include goals related to consumer protection, promoting competitive markets, encouraging and implementing demand-side resources, encouraging and implementing renewable resources, improving responses to major outages, and meeting carbon and other environmental constraints.

Some states are finding that traditional cost-of-service regulation may not provide utilities with the financial incentives to respond effectively to all of these developments. In some cases, traditional regulatory practices may provide financial incentives that hinder utilities from addressing these challenges. Consequently, performance metrics and incentives may provide an opportunity to better align utility incentives with evolving regulatory goals and the public interest in general.

Performance Metrics and Incentive Mechanisms

In this report we focus on both performance incentive mechanisms that use financial rewards and penalties to encourage utilities to meet specific targets, as well as performance metrics for simply monitoring and reporting utility performance. The relationship between the steps to implement these regulatory tools is shown in Figure 1 below.

Figure 1. Performance Incentive Mechanisms vs. Performance Metrics

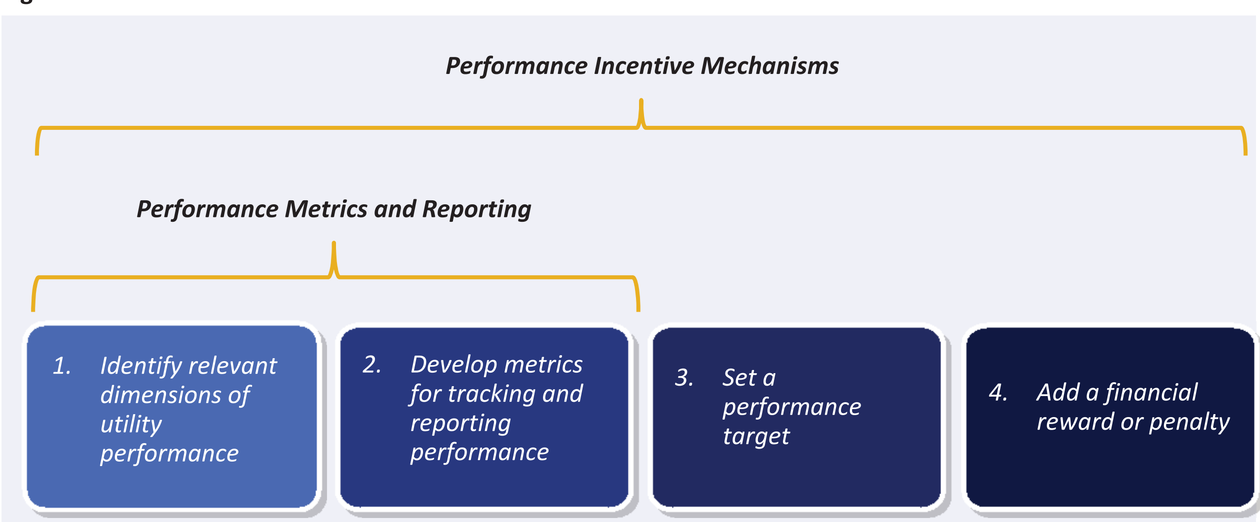


Figure 1 also highlights the various components involved in creating performance metrics and incentives.

These steps can be taken incrementally over time until the desired level of incentives is reached. First, performance metrics and reporting can be established to monitor utility performance. Second, specific performance targets can be set to provide a clear signal regarding the level of performance that is expected of a utility. Finally, financial rewards and penalties can be applied to increase the utility's motivation to achieve the performance targets. This incremental approach allows regulators and utilities to learn from each step before designing and implementing the next step. It also enables regulators to review utility performance without implementing financial rewards or penalties where such incentives are not necessary.

Alternatively, these four steps can be applied all at once, in the form of performance incentive mechanisms. This would be appropriate in those cases where regulators (a) have performance areas, metrics, and goals in mind, and (b) recognize the need for rewards and penalties.

Advantages of Performance Metrics and Incentive Mechanisms

Utility performance metrics and incentives can serve as a valuable tool for regulators for various reasons. For example:

- They help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized, or well understood.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals. In the absence of performance metrics and incentives, utilities have little incentive or guidance for achieving policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

2. REGULATORY CONTEXT

Evolving Regulatory Contexts

As Peter Bradford noted in the book *Regulatory Incentives for Demand-Side Management*: “All ratemaking is incentive ratemaking. It rewards some patterns of conduct and deters others” (Bradford 1992). In other words, every regulatory environment contains a variety of financial incentives that will affect utility performance. In designing performance metrics and incentive mechanisms, it is critical to first understand the incentives that existing under the existing regulatory environment.

There is currently a wide variety of regulatory systems across the United States, as each state has adopted different regulatory mechanisms over time to address its own needs. However, it is useful to discuss three categories of regulatory contexts for the purpose of describing how performance incentives might fit into each. These categories include: cost-of-service (COS) regulation, performance-based regulation (PBR), and new regulatory models. These regulatory contexts are summarized in Table 2 and discussed below.

It is important to emphasize that these three categories are simplistic, by design, relative to the many variations of regulatory elements in use today. Few states fall clearly into one category or another. The purpose of this table is simply to identify the key distinguishing features among these three frequently-discussed categories.

Table 2. Three Categories of Regulatory Systems

Regulatory Element	Cost of Service Regulation	Performance-Based Regulation	New Regulatory Models Proposed to Date
Basis for initial rates	Based on cost-of-service studies using a test year	Based on cost-of-service studies using a test year	Would likely be based on cost-of-service studies; may be influenced by utility business plans
Frequency of rate cases	Utilities apply for rate cases as needed or required, typically to recover large capital investments or revenue attrition	Pre-determined, fixed period of time (e.g., five years) to encourage efficient management and operations	Pre-determined, fixed period of time (e.g., eight years) to encourage efficient management and operations
Base rate adjustments between rate cases	Generally none	Price cap modified to account for factors such as inflation and productivity	Price cap may be modified to allow for inflation, productivity, or costs included in utility business plans
Cost trackers	Generally limited to costs beyond utility control	May include trackers for capital costs not easily accounted for in the price cap	Would likely include trackers for capital costs identified in utility business plans
Prudency reviews	Generally applied after the fact, where excessive costs become obvious	Applied after the fact, in cases where excessive costs become obvious	Applied after the fact; would likely be limited, based on utility business plans
Resource Planning	Option to include integrated resource planning	Option to include integrated resource planning	Strategic business plans would be used to inform cost trackers and adjustments between rate cases
Revenue regulation	Option to implement a decoupling mechanism	Option to include a revenue cap, instead of a price cap	Would likely include a revenue cap, instead of a price cap
Performance Incentive Mechanisms	Focus on areas of poor performance or opportunities for improvement	Focus on areas that may experience service degradation in response to pressure to reduce costs	Designed to create incentives to achieve a broad set of desired outcomes

Traditional Cost-Of-Service Regulation

Traditional cost-of-service regulation is characterized by the following elements:

1. Base rates are set in a rate case, typically based on known and measurable costs identified in a test year (historical, future, or a hybrid).

2. Frequency of rate cases, which typically occur at the request of the utility for the purpose of recovering major capital expenditures or addressing revenue attrition. Commissions generally have the authority to request that a utility file a rate case, but this rarely occurs in practice.

3. Base rates generally remain constant until the next rate case.

4. Cost trackers and rate riders may be applied to some costs that are partly or wholly beyond a utility's control.

5. A utility's allowed return on equity is set by the commission in a rate case, and this return is earned on all investments that are placed into the utility's rate base. Actual profits may deviate from the allowed return on equity, depending upon many factors both within and outside a utility's control.

6. Prudency reviews are used retrospectively (after the investment has occurred) to ensure costs are reasonable. Cost disallowances as a result of prudency reviews are rarely applied, and then only in cases of egregious mismanagement or cost overruns.

There are several significant, widely-recognized financial incentives underlying traditional cost-of-service regulation. The most significant incentives include the following:

Capital expenditures. When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect. In theory, prudency reviews can mitigate some of the incentive to maximize capital expenditures. However, in practice prudency reviews and disallowances are rare, burdensome, and are mostly applied to large capital expenditures.

Sales. Traditional cost-of-service regulation creates an incentive for a utility to maximize sales in order to increase profits. Whenever a utility's short-term marginal costs are lower than its average costs (i.e., the costs embedded in rates), then it can increase profits by increasing sales. This "throughput incentive" poses a significant financial disincentive to utilities with regard to energy efficiency and distributed generation. This incentive to increase sales, combined with the utility focus on capital expenditures, significantly undermines utility motivation to apply least-cost planning principles and to develop the most cost-effective balance of supply-side and demand-side resources. As a consequence, customers must cover significantly higher energy costs than necessary.

Regulatory lag. Regulatory lag refers to the period between rate cases when the utility is incurring costs, but rates have not yet been adjusted to recover these outlays. Some industry observers claim that regulatory lag provides utilities with incentives for efficient management and cost control, because utilities are able to benefit from any cost savings that they create between rate cases. On the other hand, regulatory lag can pose financial challenges for a utility, causing it to apply for rate cases more frequently. In general, the incentive created by regulatory lag depends upon whether the utility's average costs are decreasing or increasing relative to revenues (Costello 2014).

Risk. Under traditional cost-of-service regulation, utilities are generally permitted to recover all capital costs, with a profit. This certainty of cost recovery provides little incentive to reduce risks associated with major capital expenditures—expenditures that can involve considerable uncertainty and risk (Binz et al. 2012). Cost trackers and rate riders further eliminate risks to the utilities by shifting all of the risks associated with such costs to customers. For example, fuel adjustment charges can reduce incentives for the utility to optimize its generation portfolio to account for the risk of fuel cost increases.

Innovation. There is little incentive for utilities to adopt innovative practices, technologies, or resources under traditional cost-of-service regulation. Utilities have considerable certainty that regulators will allow them to recover costs of prudently incurred investments in conventional projects, but much less certainty about being allowed to recover costs associated with innovative practices and technologies with uncertain results.

Many states continue to rely upon some form of cost-of-service regulation, even in states that have restructured their electricity markets. Regulators in these states frequently employ a variety of tools to improve the alignment of regulatory incentives with the public interest, such as revenue decoupling, forward-looking costs on some items, and performance incentive mechanisms.

Performance incentive mechanisms under traditional cost-of-service regulation typically have been developed to improve service or reduce costs, for example, reliability, power plant performance, cost of renewable generation, or O&M costs. Some states have developed performance incentive mechanisms to support specific resource goals, such as increasing renewable energy generation, energy efficiency savings, and resource diversity.

Performance-Based Regulation

Performance-based regulation (PBR) was introduced in the US electric sector in the 1980s and became popular in the 1990s as an alternative to cost-of-service regulation, particularly in states that introduced retail competition (Sappington et al. 2001). One of the goals of PBR was to improve upon the financial incentives provided under traditional cost-of-service regulation, and to provide incentives more focused on operational efficiency and cost reduction.

Performance-based regulation is characterized by the following elements:

1. The time period between rate cases is fixed at the outset of each period, and is designed to be long enough to provide the utility with incentives to reduce operating costs and keep the operational savings between rate cases.

2. A price cap (or a revenue cap) is used to set prices for a fixed period of time.

3. Automatic adjustments to the price (or revenue) cap may be established to account for expected cost changes between rate cases. These frequently include automatic increases to account for inflation, coupled with automatic reductions to encourage productivity improvements. Many states adopted the "RPI – X" formula, where RPI is the retail price index and "X" is a productivity factor.

4. Trackers may be established to allow the utility to recover certain types of costs outside of the price (or revenue) cap, typically costs that are volatile and beyond a utility's control. Some states also allow trackers for major capital expenditures, because these costs are large and lumpy, and may therefore be difficult to accommodate in a fixed price (or revenue) cap.
5. Performance incentives are applied for key aspects of customer service, in order to ensure that utilities do not allow service to degrade in their pursuit of reduced costs and greater efficiencies.
6. Earnings sharing mechanisms are established to ensure that the utility's earned profits are neither excessive nor insufficient.

There are many different variations of PBR used in the United States today, incorporating different forms of the elements listed above.[3] The WIEB report *New Regulatory Models* referenced above provides several examples (Aggarwal and Burgess 2014). Also, there are many terms used to describe different combinations of these elements. The term "alternative ratemaking" is sometimes used synonymously with PBR. Some states use the term "multi-year rate plan" to refer to rates that are set for a fixed period of time, with automatic adjustments and cost trackers between rate cases. Such multi-year rate plans may or may not include performance incentives.

In theory, PBR is intended to provide more direct financial incentives for utilities to reduce costs, without heavy-handed, ongoing oversight from regulators. The key to this incentive is the fixed period between rate cases. If the utility succeeds in keeping its costs below its allowed revenues, it can keep the excess revenues. Capital investments made during the period should lead to reduced operations and maintenance costs, which would accrue to the utility until the next rate case.

In practice, there are many incentives embedded in PBR mechanisms, with various implications:

- The fixed period between rate cases should provide utilities with an incentive to reduce operating costs. However, the impact of this incentive depends upon the length of time between rate cases, where relatively shorter periods will result in more muted incentives.
- The productivity factor should provide an incentive to increase productivity. However, establishing the right productivity factor can be difficult, particularly when (a) there are few comparable peer utilities for comparison purposes; (b) utilities need to replace aging infrastructure; (c) utilities (or the industry) are in a period of rapid transition, in terms of markets, technologies, or operations; and (d) historical costs and practices are not a good indication of what future costs and practices will be.
- Placing certain types of costs into trackers eliminates the utility's incentive to optimize those costs and transfers the risks associated with those costs to ratepayers.
- If major capital expenditures are recovered through a fully reconciling cost tracker, utilities have little incentive to ensure that those costs are planned and managed as efficiently as possible. In such a case, it may be important to design a major capital cost tracker so as to provide such

[3] For a relatively recent survey, see Lowry, Makos, and Waschbusch 2013.

incentives, for example by establishing a mechanism that requires the utility to absorb a significant portion of any cost overruns.

- If major capital expenditures are not recovered through a cost tracker, it can become much more challenging to establish a price (or revenue) cap and a productivity index that provides cost control incentives while allowing the utility to adequately recover capital costs and protect consumers.[4]
- Performance incentives can be useful to prevent service degradation in light of pressures to reduce costs, or to improve performance in some areas. However, performance incentives must be designed carefully to achieve the desired results. The effective design of performance incentives is discussed throughout later chapters of this report.

In recent years, several PBR investigations have attempted to address some of the challenges associated with the incentives and implications listed above.[5] In addition, many of these issues have been investigated and addressed by Ofgem, the electricity and gas regulator in the United Kingdom, the first regulator to apply PBR to electricity utilities, and the creator of the model upon which many US PBR designs were based. After several decades of experience with PBR, Ofgem has significantly modified its PBR mechanism. The new mechanism being developed in the UK is referred to as RIIO (Revenues = Inputs + Incentives + Outcomes), and is discussed in some detail in Appendix A.

New Regulatory Models

In many states, electricity load growth has slowed significantly due to many factors, including increased use of distributed energy resources (DER) such as energy efficiency and distributed generation. At the same time, the electric industry is experiencing many forces that frequently increase costs, including: the need to replace aging infrastructure, increased transmission needs, requirements to reduce environmental impacts, and pressure to modernize the electric grid. Combined, these factors are simultaneously increasing the need for utility capital expenditures while reducing the revenue from sales growth they have historically relied upon. Traditional cost-of-service regulation and traditional PBR mechanisms may be ill-equipped to handle these challenges, and may not provide utilities with the incentives or the regulatory guidance needed to address them.

Some jurisdictions and stakeholders have begun to investigate new regulatory and utility business models to address the limitations of the current systems.[6] Several proposals in these contexts focus on

---

[4] See, for example, Direct Testimony of Tim Woolf before the Maine Public Utilities Commission in Docket No. 2013-168, *Central Maine Power Request for Approval of an Alternative Rate Plan (ARP 2014)*, December 12, 2013.

[5] See, for example, Maine Public Utilities Commission Docket No. 2013-168 and Hawaii Public Utilities Commission Docket No. 2013-0141.

[6] See, for example, the New York Public Service Commission Case Number 14-M-0101, *Reforming the Energy Vision*; Hawaii Public Utilities Commission, Decision and Order No. 32052, Exhibit A: *Commission's Inclinations on the Future of Hawaii's Electric Utilities,* and Hawaii Public Utilities Commission Docket 2013-0141; e21 Initiative 2014; GTM Research 2015; and Lehr 2013.

PBR mechanisms, with the overall goal of creating financial incentives that are based more on performance and less on recovery of costs.[7]

These proposals include several modifications to the way that PBR is currently applied in the United States. For example:

1. Expand the types of performance metrics applied to utilities to include emerging performance areas such as system efficiency, customer engagement, network support services, or environmental goals (see Section 3.2). This is intended to provide regulatory guidance and financial incentives regarding the variety of outcomes that are important for delivering quality service and meeting state energy policy goals.

2. Shift the financial incentive away from investments in rate base and towards achieving performance goals. This can be accomplished by reducing the portion of revenue requirements that a utility recovers from rate base, and comparably increasing the portion of revenue requirements that can be recovered from performance metrics.[8]

3. Establish longer periods between rate cases. This is intended to increase the magnitude of the financial incentive to increase productivity and reduce costs between rate cases.

4. Provide more up-front guidance from regulators and stakeholders with regard to future major capital expenditures. This is intended to provide utilities with greater flexibility and incentive to adopt innovative and emerging technologies and practices.

Many of these modifications are consistent with those that have been adopted recently in the UK RIIO model, suggesting that the lessons learned from the UK PBR experience may be relevant to the new regulatory and utility business models being considered in the United States. This is discussed in more detail in Appendix A.

Some states have already established performance metrics or incentive mechanisms to address emerging performance areas, such as customer retail choice, grid modernization, and distributed generation interconnections. Examples and further discussion of metrics and incentives to address these emerging areas are provided in Chapter 3.

Performance Metrics and Incentives Can Be Applied in Any Regulatory Context

One of the advantages of performance metrics and incentives is that they can be used in any regulatory context. However, it is critical that performance metrics and incentives be specifically tailored to the

---

[7] See, for example, Energy Industry Working Group 2014; Malkin and Centolella 2014; Blue Planet Foundation 2014; e21 Initiative 2014; Massachusetts Grid Modernization Steering Committee 2013.

[8] For example, under RIIO, the British distribution utilities face rewards and penalties of approximately five percent of their base distribution revenues (CEPA LLP 2013).

existing (or anticipated) regulatory context in each state, to ensure that they adequately complement and balance the financial incentives provided by that regulatory context.

> In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance, or areas where regulators see opportunities for greater efficiencies or reduced costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.

> In a state with performance-based regulation, performance metrics and incentives might be especially important to prevent the degradation of service as a result pressures to reduce costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as those provided by price (or revenue) caps, fixed periods between rate cases and cost trackers.

> In a state developing new regulatory and utility models, performance metrics and incentives might be especially important to re-direct utility management priorities toward desired performance outcomes, and shift the source of utility revenues away from capital investments and toward those desired outcomes. Performance metrics should be applied to the priority performance areas, and performance incentives should be designed to complement, offset, or mitigate existing financial incentives.

> In any state, performance metrics and incentives can be used to promote resources that are not supported or encouraged by the existing regulatory system, such as energy efficiency and renewable resources.

> In any state, performance metrics and incentives can be used to provide guidance on how utilities can meet state regulatory policy goals, such as improving reliability and resiliency, empowering customers to reduce bills, or minimizing the cost of complying with the EPA Clean Power Plan.

> In any state, performance metrics and incentives can be used to encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the existing regulatory system, such as distributed generation, grid modernization, storage technologies, or practices to support electric vehicles.

3. PERFORMANCE METRICS

3.1. Introduction

There are significant advantages of establishing performance metrics—even without administering financial incentives. Reporting utility performance facilitates regulatory oversight and encourages utilities to strive for better performance, as subpar performance is likely to result in negative public response and greater regulatory scrutiny. Implementing tracking and reporting metrics is straight-forward and low risk. It can be designed to present little administrative burden on either regulators or utilities, while providing valuable information.

3.2. Performance Dimensions That May Warrant Metrics

Performance incentive mechanisms have historically been used to help achieve traditional goals of reliable, safe, and low-cost utility service. Today, new incentives are being proposed to attain a whole new set of energy policy objectives, such as environmental quality, fuel diversity, fast-responding resources, and customer empowerment, to name a few.

For example, states throughout the West are facing stricter environmental standards for criteria air pollutants, water use, and carbon emissions, and many states are experiencing rapid growth in rooftop solar PV.[9] In response to these new regulations and the growth of distributed generation, utilities are investing billions of dollars in new renewable energy capacity[10] and transmission and distribution infrastructure (including smart grid technologies), and will need to procure significant amounts of resources to accommodate variations in net load (including demand response, advanced wind and solar control technologies, and storage).[11]

To ensure that utilities are operating efficiently and meeting energy policy goals, regulators may wish to track a variety of dimensions of utility performance, and possibly also implement financial rewards or penalties in areas where additional incentive is needed. The figure below highlights a variety of dimensions of utility performance that may warrant tracking and reporting or incentives. Performance dimensions generally fall into three categories: traditional goals, new business models, and environmental goals. Some aspects of utility performance have been important in more than one area;

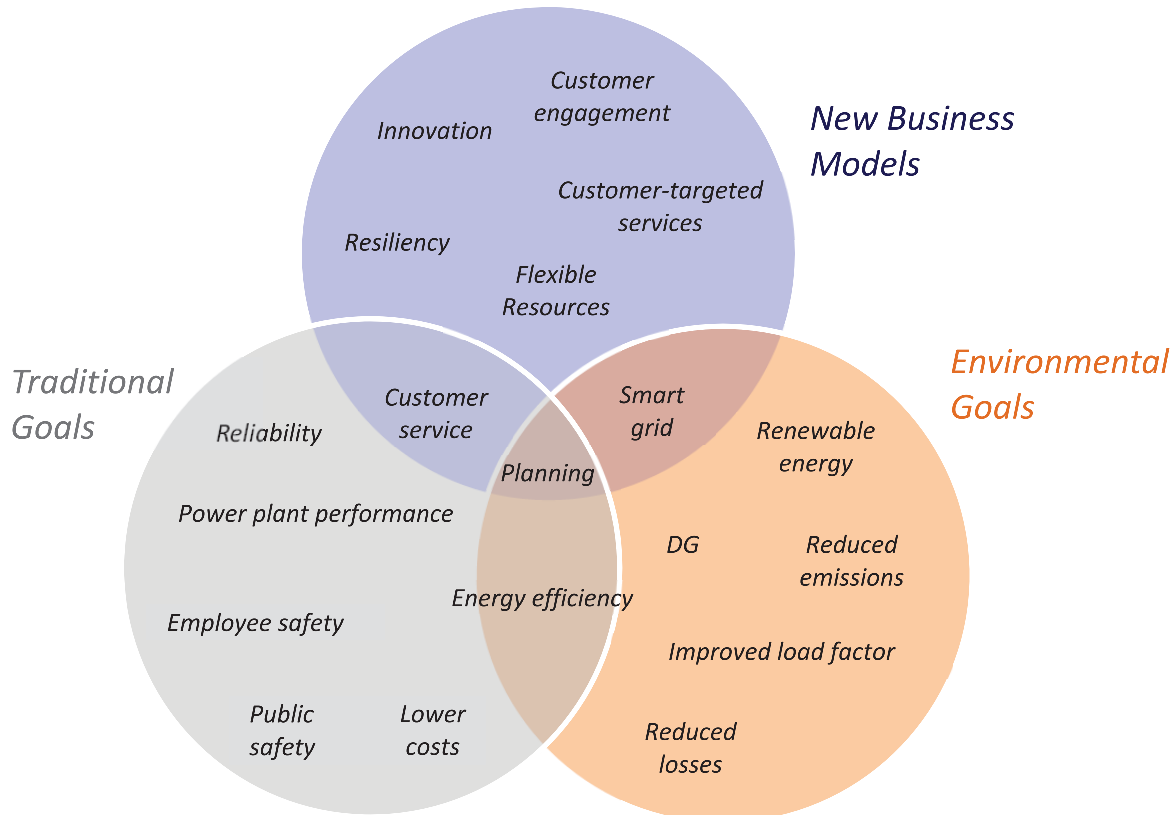
[9] Residential installations of PV are expanding at a rate of more than 50 percent year-over-year, with California, Arizona, and Colorado among the top states (SEIA/GTM Research 2013).

[10] The Western Electricity Coordinating Council (WECC) predicts that renewable resources in the West (excluding conventional hydro) will produce nearly 17 percent of the region's energy by 2022 (WECC Staff 2013).

[11] During certain times of the year, total system load net of solar and wind changes rapidly producing an effect known as the "duck curve." These very fast changes to net load (total load minus the output of variable resources) require fast-ramping resources to mitigate reliability impacts caused by the sudden appearance or departure of variable energy resources (Lazar 2014).

for example, successful implementation of cost-effective energy efficiency can reduce emissions associated with fossil generation (an environmental benefit) and defer or avoid new generation, capacity, transmission, and distribution resources, resulting in cost savings (a traditional focus of utility performance regulation). Planning has a critical role in informing regulatory outcomes across all three areas, and thus it takes a central location in the Venn diagram below.

Figure 2. Dimensions of Utility Performance That May Warrant Tracking or Incentives



Traditional Performance Areas

Several aspects of utility performance have a long history of being tracked and reported to state utility commissions, federal regulatory agencies, or otherwise made publicly available. These traditional performance areas are reliability, safety, customer satisfaction, power plant performance, and costs; as indicated in Table 3.

Metrics for monitoring these traditional performance areas are generally well developed, and the data readily available. Where standard metric definitions exist and have been adopted by utilities, regulators may wish to track and compare performance across utilities within a state or across the region. (However, peer group comparisons may not be appropriate for the determination of rewards and penalties without controlling for differences among utilities. This is discussed in greater detail in later sections.)

Table 3. Traditional Performance Areas

Performance Dimension	Purpose
Reliability	To indicate the extent to which service is reliable and interruptions are remedied quickly
Employee Safety	To ensure that employees are not subjected to excessive risks
Public Safety	To ensure that the public is not subjected to excessive risks
Customer Satisfaction	To ensure that the utility is providing adequate levels of customer service
Plant Performance	To indicate the performance of specific generation resources
Costs	To indicate the cost of supply side resources

Innovative and Emerging Performance Areas

In order to address evolving industry challenges, regulators are beginning to focus attention on new aspects of utility performance, including overall system efficiency such as system load factor, use per customer, etc.; customer engagement (including tools to empower customers to better manage their bills); network support services; environmental impacts; and clean energy goals. Examples of these emerging performance areas and metrics for tracking them are provided in Table 4.

Table 4. Emerging Performance Areas

Performance Dimension	Purpose
System Efficiency	To indicate the extent to which the utility system as a whole is being operated more efficiently
Customer Empowerment	To indicate the extent to which customers are participating in demand-side programs or installing demand-side resources
Network Support Services	To indicate the extent to which customers and third-party service providers have access to networks
Environmental Goals	To indicate the extent to which the utility and its customers are reducing environmental impacts, particularly related to climate change

3.3. Defining Metrics

Simply defined, a metric is a standard of measurement. In assessing utility performance, metrics play a central role in enabling regulators to determine how well a utility is performing in the areas of interest. Defining a metric typically involves the following:

- Specific data definitions
- A precise formula used to quantify each metric

- Data collection and analysis practices and techniques, including identification of the entity responsible for collecting and reporting the data
- Requirements for measurement and reporting
- Verification techniques and entity responsible for verifying data

For example, a common metric for measuring reliability is the sustained average interruption duration index, SAIDI. The data include the average number of utility customers and the number of sustained outages, and may or may not exclude outages from major storms. However, to employ this metric, the definition of both a "sustained outage" and "major storm" needs to be clarified, the frequency of measurement (e.g., annual or quarterly) defined, and a verification process established.

Table 5 through Table 10 contain metrics for traditional performance areas that regulators may find useful for measuring utility performance, including metrics for reliability, employee safety, public safety, customer satisfaction, plant performance, and costs. Table 11 through Table 14 contain metrics for emerging performance areas, including system efficiency, customer engagement, network support services, and environmental goals.

These tables are intended to cover a wide range of issues of importance to regulators, but do not exhaust the universe of metrics that regulators may wish to consider. Nor are these metrics necessarily the "best" means of measuring performance in a certain area. The first step in determining which metrics will best serve the needs of a particular state is to articulate the policy goals that the state wishes to achieve. Regulators should then design metrics that are capable of accurately and reliably measuring progress toward these goals. The metrics includes in the tables below (and their formulas) provide examples of existing or potential metrics that could be implemented, but may not necessarily suit a particular jurisdiction's needs.

Examples of Innovative Performance Metrics

As the electric industry transforms, new metrics are being proposed to measure how well utilities meet evolving customer needs. Many of these existing or proposed performance metrics are described in more detail in the appendix, including:

- *Peak load reductions (Illinois)*
- *Stakeholder engagement (Illinois, Hawaii)*
- *Customers accessing energy usage portals (Illinois)*
- *Effective resource planning (Hawaii)*
- *System load factor (Illinois)*
- *Line loss reductions (UK, Illinois)*
- *Distributed generation interconnections (UK, Illinois, Hawaii)*
- *Cost of renewable energy (California)*
- *Carbon intensity (Hawaii)*
- *Renewable energy curtailments (Hawaii)*

See Appendix A for detailed case studies describing some of these metrics and performance incentive mechanisms.

Table 5. Reliability Performance Metrics

Metric	Purpose	Metric Formula
System Average Interruption Duration Index (SAIDI)	Indicator of sustained interruptions experienced by customers	Total customer minutes of sustained interruptions / total number of customers
System Average Interruption Frequency Index (SAIFI)	Indication of how many interruptions are experienced by customers	Total number of customer interruptions / total number of customers
Customer Average Interruption Duration Index (CAIDI)	Indicator of the length of interruptions experienced by customers	Total minutes of sustained customer interruptions / total number of interruptions
Momentary Average Interruption Frequency Index (MAIFI)	Indicator of momentary interruptions experienced by customers	Total number of momentary customer interruptions per year / total number of customers
Power quality	Indicator of voltage changes, which can cause damage to end use equipment and frequency deviations	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker; CPS 1 and 2 that measure frequency excursions

Table 6. Employee Safety Performance Metrics

Metric	Purpose	Metric Formula
Total Case Rate (TCR)	Indicator of employee injuries, fatalities, and productivity losses due to work-related incidents	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000) / Employee hours worked[12]
Days Away, Restricted, and Transfer (DART) case rate	Indicator of employee injuries, restrictions, and productivity losses due to work-related incidents	(Number of work-related days away from work and job transfers or restrictions due to work accidents times 200,000) / Employee hours worked
Days Away From Work (DAFWII) case rate	Indicator of employee injuries and productivity losses due to work-related incidents	(Number of work-related days away from work due to work accidents times 200,000) / Employee hours worked

Table 7. Public Safety Performance Metrics

Metric	Purpose	Metric Formula
Incidents, injuries, and fatalities (electric)	Indicator of incidents, injuries, and fatalities associated contact with the electric system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity
Emergency response time (electric)	Indicator of speed of response to emergency situations involving the electric system	Percent of electric emergency responses within 60 minutes each year
Incidents, injuries, and fatalities (gas)	Indicator of incidents, injuries, and fatalities associated with the gas system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause
Emergency response time (gas)	Indicator of speed of response to emergency situations involving the gas system	Average minutes for gas emergency response
Leak repair performance (gas)	Indicator of speed of response to non-emergency situations involving the gas system	Average days for repair of minor and non-hazardous leaks

[12] 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). (U.S. BLS 2013)

Table 8. Customer Satisfaction Performance Metrics

Metric	Purpose	Metric Formula
Call center answer speed	Indicator of customer ease of contacting utility	Percentage of calls answered within 30 seconds
Transaction surveys	Indicator of how well the utility is meeting customer needs based on recent contact with utility	Percentage of customers satisfied with their recent transaction with the utility
Customer complaints	Indicator of how well the utility is meeting customer needs	Formal complaints to commission (per 1,000 customers) over a set period. May also track complaints resolved.
Order fulfillment	Indicator of response time to service requests and outages	Speed with which orders for service installation and termination, outage responses, and meter re-reading are fulfilled
Missed appointments	Indicator of how well the utility is meeting customer needs	Percentage of appointments not met for meter replacements, inspections, or any other appointments in which the customer is required to be on the premises
Avoided shutoffs and reconnections	Indicator of efficient provision of services to low income customers	Disconnects and reconnections avoided by customer percentage of income payment plans or other means
Residential customer satisfaction	Indicator of how well the utility is meeting the needs of residential customers	Electric Utility Residential Customer Satisfaction index, Gas Utility Residential Customer Satisfaction index
Business customer satisfaction	Indicator of how well the utility is meeting the needs of business customers	Electric Utility Business Customer Satisfaction index, Gas Utility Business Customer Satisfaction index

Table 9. Plant Performance Metrics

Metric	Purpose	Metric Formula
Fuel usage	Indication of the fuel consumption by specific generation resources	Quantity of fuel burned
Heat rate	Indication of the efficiency of specific generation resources	Average BTU per kWh net generation
Capacity factor	Indication of actual generation by a specific resource	Average energy generated for a period / energy that could be generated at full nameplate capacity

Table 10. Cost Performance Metrics

Metric	Purpose	Metric Formula
Capacity costs	Indicator of costs of peak consumption	Cost per kW of installed capacity
Total energy costs	Indicator of costs of all hours consumption	Expenses per net kWh
Fuel cost	Indicator of costs of fuel input	Average cost of fuel per kWh net gen and per Million BTU; total fuel costs
Effective resource planning*	Indicator of efficacy, breadth, and reasonableness of resource planning process	Numerous metrics regarding incorporation of stakeholder input, consideration of all relevant resources, use of appropriate assumptions and modeling tools, etc.
Cost-Effective Alternative Resources*	Indicator of system savings through use of cost-effective alternatives to traditional infrastructure	$/MW cost of alternative portfolio relative to the $/MW cost of traditional investment

**See Appendix A, New York and Hawaii case studies, for more information on these metrics.*

Table 11. System Efficiency Performance Metrics

Metric	Purpose	Metric Formula
Load factor	Indication of improvement in system and customer load factors over time	Sector average load / sector peak load
		Monthly system average load / monthly system peak load
Usage per customer	Indication of customers' energy consumption changes over time	Sector sales / sector number of customers
Aggregate Power Plant Efficiency	Indication of the efficiency and availability of supply-side generation resources in total	System average BTU per kWh net generation (heat rate)
		Equivalent Forced Outage Rate (EFOR) = Equivalent Forced Outage Hours / (Period Hours – Equivalent Scheduled Outage Hours)
		EFORd: variant of EFOR, measuring the probability that units will not meet generating requirements demand periods because of forced outages or derates
		Weighted equivalent availability factor: over a given operating period, the capacity-weighted average fraction of time in which a fleet of generating units is available without any outages and equipment or seasonal deratings
Flexible Resources	Indication of the capacity of supply side resources to quickly respond to changes in net load	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)
System losses (electric)	Indication of reductions in losses over time	Total electricity losses / MWh generation, excluding station use
System losses (gas)	Indication of reductions in gas losses over time	Total gas losses / total sales

Table 12. Customer Engagement Performance Metrics

Metric	Purpose	Metric Formula
Energy efficiency (EE)	Indication of participation, energy and demand savings, and cost effectiveness of EE programs	Percent of customers per year
		Annual and lifecycle energy savings
		Annual and lifecycle peak demand savings (MW)
		Program costs per MWh energy saved
Demand response (DR)	Indication of participation and actual deployment of DR resources	Percent of customers per year
		Number of customers enrolled
		MWh of DR provided over past year
		Potential and actual peak demand savings (MW)
Distributed generation (DG)	Indication of the technologies, capacity, and rate of DG installations, and whether net metering policies are supporting DG growth	Number of installations per year
		Net metering installed capacity (MW)
		Net metering MWh sold back to utility
		Net metering number of customers
		MW installed by type (PV, CHP, small wind, etc.)
Energy storage	Indication of the technologies, capacity, and rate of customer-sited storage installations and their availability to support the grid	Number of installations per year
		MW installed by type (thermal, chemical, etc.)
		Percent of customers with storage technologies enrolled in demand response programs
Electric vehicles (EVs)	Indication of customer adoption of EVs and their availability to support the grid	Number of additions per year
		Percent customers with EVs enrolled in DR programs
Information availability	Indicator of customers' ability to access their usage information	Number of customers able to access daily usage data via a web portal
		Percent of customers with access to hourly or sub-hourly usage data via web
Time-varying rates	Indication of saturation of time-varying rates	Number of customers on time-varying rates

Table 13. Network Support Services Metrics

Metric	Purpose	Metric Formula
Advanced metering capabilities	Indication of metering functionality	Number of customers with AMI and AMR
		Energy served through AMI
Interconnect-ion support	Indication of DG installation support	Average days for customer interconnection
		Customer satisfaction with interconnect process
Third-party access	Indication of network access by third-party vendors	Open and interoperable smart grid infrastructure that facilitates third-party devices
		Third-party vendor satisfaction with utility interaction
Provision of customer data	Indication of customer access to relevant data	Customers able to authorize third-party access electronically
		Percent of customers who have authorized third-party access
		Third-party data access at same granularity and speed as customers

Table 14. Environmental Goals Performance Metrics

Metric	Purpose	Metric Formula
SO_2 Emissions	High-level indicator of emissions	Tons
Average NOx Rate	High-level indicator of emissions	lbs/MMBtu
CO_2 emissions	High-level indicator of emissions	Tons CO_2
Carbon intensity	Indicator of carbon emissions that accounts for changes in customers	Tons CO_2 / customer
System carbon emission rate	Indicator of carbon emissions that accounts for volume of generation	Tons CO_2 / MWh sold
Clean Power Plan (CPP) emission rate	Indicator of compliance with EPA's CPP	lbs CO_2 from fossil generators / (Fossil Fuel Generation (MWh) + 5.8% Nuclear Generation (MWh) + Renewable Generation (MWh) + Cumulative Energy Efficiency (MWh))
Fossil carbon emission rate	Indicator of carbon emissions accounting for improved efficiency and dispatch of fossil resources	Tons CO_2 / MWh fossil generation
Fossil generation	Indication of reduction in fossil fuel use	Fossil MWh percent of total generation
Renewable generation	Indicator of development of renewable power	Renewable percent of total generation

3.4. Design Principles

The following design principles should be considered when establishing performance metrics. Metrics should be:

1. Tied to the policy goal
2. Clearly defined
3. Able to be quantified using reasonably available data
4. Sufficiently objective and free from external influences
5. Easily interpreted
6. Easily verified

These principles are discussed in more detail below.

Metrics Should be Tied to Policy Goals

To be useful, metrics should help stakeholders understand the degree to which policy goals are being achieved. Too often, metrics report data without conferring useful information. For example, if a policy goal is to improve the system load factor by reducing peak demand, it is not meaningful to simply report the number of customers enrolled in a demand response program, as this provides no information regarding whether these customers actually reduced demand, and by how much, during peak periods. To be useful, a metric should reflect whether or not the underlying policy goal is being met; e.g., whether peak demand has decreased over the prior year.

Metric Definitions Should be Unambiguous

How a metric is calculated should be defined in a way that leaves little ambiguity regarding precisely what data are included and excluded, the units of measurement, the frequency of measurement, and the methods used to analyze and report it. Failure to do so may impair meaningful comparisons of performance across years or utilities, while potentially increasing contention during proceedings (see Nevada case study in sidebar).

Where possible, metrics should be defined in a manner consistent with national or regional standards and definitions in order to facilitate comparisons across utilities. However, regulators should not be constrained by these definitions; similar metrics that report slightly different data may be more useful for determining whether utilities are achieving a policy goal. In such cases, data under both the standard definition and the jurisdiction-specific definition could be reported.

Careful attention to metric definitions is necessary to simplify data review, ensure that metrics will be reported consistently over time, and enable meaningful comparisons. The specificity required for data definitions should not be underestimated. For example, although there exists a common industry standard for measuring and reporting reliability performance, few utilities adhere to this standard.[13] Thus standard metrics such as System Average Interruption Duration Index (SAIDI) are actually often reported in different ways, with definitions of "major events" or the length of a "sustained interruption" varying across utilities and jurisdictions. In fact, sometimes these metrics are reported inconsistently even within a jurisdiction.[14]

Metrics Should be Able to be Quantified Using Reasonably Available Data

Data that are not readily available may be costly to collect. Making use of existing industry standards and generally available data can ease administrative burdens to regulators and utilities alike, and, where appropriate, can facilitate benchmarking utility performance against others. Fortunately, a large amount of data is already reported by utilities to the Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), the North American Electric Reliability Corporation (NERC), and other entities. Specific data sources for many of the metrics presented in Tables 4 and 5 are provided in Appendix B.

Fuel Diversity in Nevada

Per Nevada administrative code NAC 704.9484, the Public Utilities Commission can grant critical facility (CF) status for the purpose of protecting reliability; promoting resource diversity; developing renewable energy resources; fulfilling specific statutory mandates; or promoting retail price stability. Owners of CFs may be granted special ratemaking treatment (e.g., deferral of incremental O&M costs) or other incentives (return on equity adder for the facility, or including construction work in progress in rates).

The criteria used to evaluate whether a facility meets the criteria for CF status have not been explicitly defined, however. This has resulted in ambiguity for resource developers, contentious proceedings, and uncertainty regarding whether policy goals are being achieved.

By 2010, all approved requests for CF status involved construction of gas-fired generation resources, leading to concerns about over-reliance on gas. Clearly articulated goals, metrics, and targets could have helped to avoid this over-investment in a single resource and reduced the litigation associated with related proceedings.

For more information, see PUC order dated July 28, 2010 in Docket Nos. 10-02009. 10-03022. and 10-03023.

---

[13] The Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003 is intended to increase consistency among utility reliability reporting practices, but adoption of the standard is voluntary. Many utilities report reliability metrics (such as SAIDI and SAIFI) using somewhat different data definitions (Eto and LaCommare 2009).

[14] For example, the Maryland PSC staff noted that "the Maryland utilities have not been consistent with their treatment of planned outages when reporting reliability metrics to the Commission. The investor-owned utilities report reliability metrics excluding planned outages and the cooperatives report reliability metrics including planned outages" (MD PSC Staff 2011, 6).

Metrics Should Be Sufficiently Objective and Largely Free from Exogenous Influences

Regulators may wish to track many metrics in order to better understand what is happening in their state's electric system. However, not all of these metrics are good indicators of utility performance. To evaluate how utilities themselves are performing, and particularly to administer penalties or rewards, the metrics chosen should be sufficiently objective and free from exogenous influences. Otherwise, factors that the utility has no control over can influence the results, obscuring the role that utility management played in the outcome.

For example, average customer bills can be a tempting metric to use to evaluate utility efficiency. However, average bills are impacted by numerous factors, ranging from fossil fuel prices, costs of steel and other commodities, weather, and the economy. These exogenous factors prevent average bills from serving as a sufficiently objective metric.

Objectivity does not necessarily mean that all data must be purely quantitative or measured using physical units. For example, customer satisfaction surveys can be designed to be sufficiently objective through the use of specific, targeted survey questions (see sidebar). Surveys can be conducted in phases over time so that no single event (e.g., a storm related outage) has too strong of an influence on the results.

Customer Survey Results as an Objective Metric

A number of states require utilities to report customer satisfaction survey results. In Massachusetts, poor customer satisfaction survey scores may lead to substantial financial penalties. The application of penalties to survey results was recently opposed by many Massachusetts utilities, who argued that surveys are too subjective. However, the Massachusetts Department of Public Utilities reaffirmed that surveys can provide sufficiently objective information, if designed and administered well.

To enhance the quality of information collected in the surveys, the Massachusetts survey was modified from a more general question regarding customer satisfaction to very specific questions about whether customers' issues were resolved after the first contact with the utility, and how easy it was to conduct business with the utility. The specificity of these questions helps to control for the influence of other factors (such as electricity rates or media coverage) on customers' responses.

See DPU Order dated July 11, 2014, Investigation by the DPU on Its Own Motion Regarding the Department's Service Quality Guidelines, D.P.U. 12-120-B

Metrics Should Be Easily Interpreted

Metrics that are readily interpreted generally provide stakeholders with a better understanding of utility performance. To improve interpretability, metrics should exclude the effects of factors outside of the utility's control to the extent possible. For example, a metric that measures the time required to interconnect distributed generation could be limited to include only the time from when the application is deemed complete to the time when the application is approved. This definition would thereby exclude any delays due to customer inaction.

Another means of improving interpretability is to use per-unit metrics to facilitate comparison across time and across utilities. Examples include percentages (e.g., percentage line losses), per-kWh (e.g., average emissions per kWh of generation), and per-customer (e.g., O&M costs per customer). For example, if the objective is to increase utility efficiency by reducing costs, a metric based on O&M costs per customer may be more informative than total O&M costs, as the number of customers may change over time.

Metrics Should be Verifiable

Data validity and reliability is essential for ensuring that utility performance is being accurately measured. For this reason, external verification of performance data is often relied upon, and the metrics chosen should lend themselves to such verification.

Where commissions have implemented performance tracking and reporting, commission staff frequently review and verify data, but independent third-party evaluators are also used, particularly when financial rewards or penalties are at stake. Greater use of third-party evaluators may help to prevent performance incentive gaming, such as that which occurred in California in the 1990s-2000s (see sidebar).

The use of straight-forward data collection and analysis techniques should be used where possible, as it improves transparency, enabling regulators and other stakeholders to more easily determine the data's accuracy. This makes manipulation of data more difficult and reduces the costs of oversight, as there is less need to hire specialized consultants (Costello 2010). In contrast, metrics that require complex data collection or analysis techniques make review and interpretation more difficult while increasing costs.

Gaming of Performance Incentive Mechanisms in California

In the late 1990s and early 2000s, Southern California Edison operated under a PBR plan with performance incentive mechanisms for customer satisfaction (as measured through surveys) and employee health and safety. The problems with the customer survey were many, but the most serious instances arose when utility employees sometimes falsified customer contact information to screen out customer interactions that might result in negative customer satisfaction surveys.

The employee health and safety performance mechanism was similarly problematic. Not only did the incentive mechanism actually discourage workers from reporting injuries in order to avoid jeopardizing safety incentive compensation for their group, but some supervisors participated in or encouraged under-reporting of data. Methods used to disguise injuries and avoid internal reporting included: employee self-treatment; treatment by personal physicians rather than the company doctor; and timecard coding of lost time as sick days or vacation. See Appendix A for further details.

3.5. Dashboards for Data Reporting

To be useful, performance metric data must be presented in an easily accessible, up to date, and properly contextualized manner. Without context, such as comparison of current performance to historical trends or benchmarks, utility performance data convey little meaningful information to regulators and stakeholders. Similarly, when performance statistics are not aggregated in a central location, but are provided only in filings made in various dockets on different reporting cycles, it becomes difficult and time-consuming to develop a holistic view of utility performance across multiple dimensions.

Data dashboards provide a means of collecting utility performance information in a central location and presenting the data in a transparent and meaningful way. A designated website—hosted either by the utility or the commission—provides a useful forum for displaying performance information, ideally through both interactive graphs and downloadable data. Dashboards allow data to be compared across years and between utilities. If a performance target is set, the dashboards enable all users to quickly determine whether the utility is meeting or failing to achieve the targets. Data dashboards should complement, rather than be a substitute for, prudency reviews.

Dashboards should be:

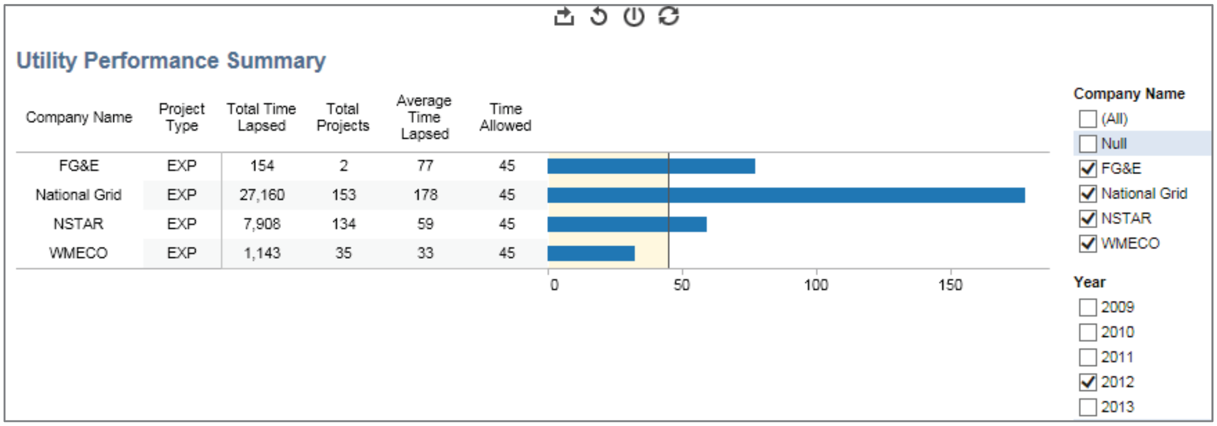
- **Accessible:** Performance data should be presented in a publicly-accessible manner, such as on a designated website, and should include a means for downloading the underlying data.
- **Contextualized:** Performance targets, historical performance data, peer performance, and explanations of any major events that impacted performance should be included in the data presentation.
- **Clear and concise:** Performance should be presented in graphs that are clear and easily interpreted. An explanation of how the metric is calculated should also be included. Highly technical terms should be adequately defined or avoided.
- **Comprehensive:** The dashboard website should provide data and graphs for all aspects of utility performance that the commission wishes to monitor.
- **Up to Date:** The data and graphs should be updated frequently. Many metrics may warrant quarterly updates, while others should be updated at least on an annual basis.

The Massachusetts Department of Energy Resources' (MA DOER) interactive graphs regarding interconnection of distributed generation provide an example of how such data can be effectively displayed and communicated to stakeholders. For example, Figure 3 shows a screen shot of one of the interactive graphs. The text accompanying the graph states:

> This chart helps you answer the question "On average how are utilities performing with regard to expedited projects that have not received a supplemental review?" Similar to the metric used in the DPU-approved Timeline Enforcement Mechanism (DPU 11-75-F), the average time lapsed is accounted for by dividing the total utility work time lapsed by the total number of projects by utility. Please note that only expedited projects without supplemental reviews, but with an "Interconnection Agreement Sent" date, are included. The other project types are not represented in this chart.

Users can select different combinations of utilities and data years, and are able to export the graph and download the underlying data. The vertical line in the graph demarcates the maximum interconnection time allowed and enables users to quickly determine whether a utility is meeting the target.

Figure 3. MA DOER Interactive Dashboard on Distributed Generation Interconnection Time

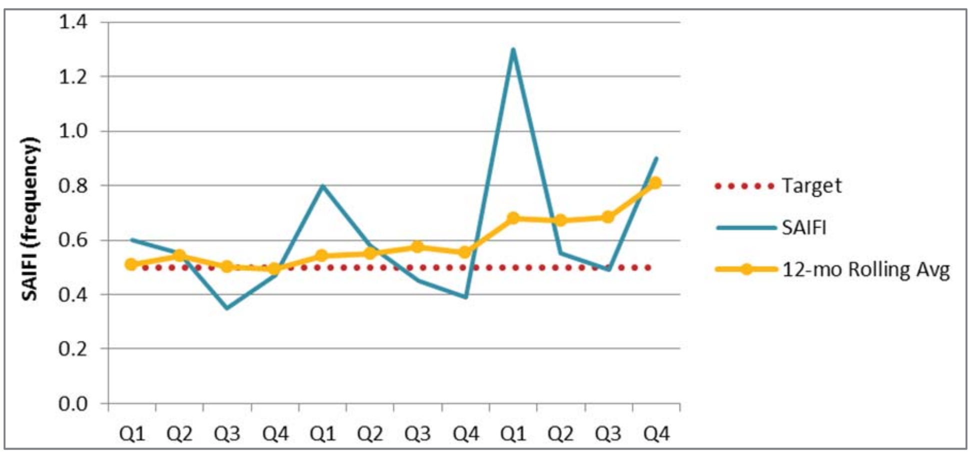


Company Name	Project Type	Total Time Lapsed	Total Projects	Average Time Lapsed	Time Allowed
FG&E	EXP	154	2	77	45
National Grid	EXP	27,160	153	178	45
NSTAR	EXP	7,908	134	59	45
WMECO	EXP	1,143	35	33	45

Source: Massachusetts Department of Energy Resources, Interconnection Utility Performance Summary Website. *https://sites.google.com/site/massdgic/home/interconnection/utility-performance-summary*[15]

Static graphs that display utility historical performance are also helpful. For example, the graph below presents hypothetical data for the frequency of utility outages, reported on a quarterly basis. Additional examples of data dashboards are provided in Appendix C.

Figure 4. Example Dashboard for Utility Outage Frequency



In sum, data dashboards can be an extremely useful tool for enabling regulators and other stakeholders to quickly review utility performance across a large number of performance areas.

[15] Note that although the interactive nature of the graphs is very helpful for comparing utility performance across years and utilities, the graphs appear to only display properly with Internet Explorer. In contrast, static graphs may have fewer technical issues.

4. PERFORMANCE TARGETS

A performance target defines the precise level of service or output that a utility is expected to achieve during a particular time period. Targets may be used simply to provide guidance for a utility, with neither penalty nor reward attached. Performance targets can also be used as the basis for providing a utility with a financial incentive to achieve desired outcomes.

4.1. Design Principles

The following design principles should be considered when setting performance targets:

1. Tie targets to regulatory policy goals
2. Balance costs and benefits
3. Set realistic targets
4. Incorporate stakeholder input
5. Use deadbands to mitigate uncertainty and variability
6. Use time intervals that allow for long-term, sustainable solutions
7. Allow targets to evolve

These principles are discussed more below.

Tie the Target to the Ultimate Policy Goal

Consider what level of performance is necessary to achieve policy goals, and state this explicitly. Doing so will help stakeholders evaluate whether performance targets are being set in a manner that moves toward achieving these policy goals and will help maintain momentum in that direction, while also allowing stakeholders to better determine when the underlying policy objective—as opposed to simply meeting the target—has been achieved.

Balance Costs and Benefits

Balance the costs to customers of achieving the target with the benefits to customers. Ratepayer surveys can help to identify ratepayers' priorities and how much they are willing to pay for higher levels of utility performance. For example, a 2010 survey of Ontarians found that 89 percent of residential customers were satisfied with current levels of electric reliability, and more than half of customers were not willing to pay more for increased reliability (Pollara 2010).

In theory, the optimal level of performance is obtained where the marginal benefits from improved performance are equal to the marginal costs of providing that increased level of performance. As explained by Baldwin and Cave,

> "as quality increases it becomes more expensive to raise it further; hence the marginal cost of quality improvement rises as quality rises. In contrast, as quality rises, the extra benefit consumers get from a further increase in quality declines. These two factors determine an optimal level of quality, where marginal benefit (to the customer) and marginal cost (to the utility company) are equal" (Baldwin and Cave 1999, 253).

Identifying the optimal level requires knowledge of both the utility's marginal cost curve, as well as customers' willingness to pay for different levels of reliability. Norwegian regulators have used surveys to construct a willingness to pay curve, and have internalized these values in the utility's decision-making process (see sidebar) (Growitsch et al. 2009). The Alberta Utilities Commission recently acknowledged the value of such customer willingness-to-pay surveys, but chose instead to rely on results from already-available customer satisfaction surveys to determine the acceptability of current levels of reliability for customers (Alberta Utilities Commission 2012).

In practice, especially for some performance areas, it may be difficult to quantify the marginal costs and benefits to determine the optimal performance target. In such cases, regulators may want to at least apply a qualitative assessment of what the costs and benefits to customers might be.

For example, if a commission were to establish a performance target related to the interconnection of distributed generation (in terms of average days for customer interconnection), it may be too burdensome to quantify all of the costs and benefits associated with reduced interconnection waiting time. Nevertheless, regulators, utilities, and others may be able to make a qualitative assessment of the value of increased distributed generation relative to the cost of reducing interconnection waiting time.

Balancing Reliability Costs and Benefits in Norway

Norway uses revenue cap regulation to provide a set amount of annual revenues to its electric utilities. Under this regulatory framework, utilities retain any savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, Norwegian regulators have internalized the costs of outages into the utility's profit-maximization function. This is done by adjusting utility revenues each year based on the costs of outages to customers.

If the utility reduces outages above a baseline level, it receives higher revenues the following year. In contrast, if outages increase, revenues are reduced. The amount of the increase or decrease in revenues is based on customers' willingness to pay for reliability, calculated separately by each customer sector. To maximize profits, the utility will increase expenditures up to the point where the marginal cost of increased reliability is equal to customers' willingness to pay (also referred to as the marginal benefit). The Norwegian utilities therefore face an incentive to provide the socially optimal level of reliability, where marginal costs are equal to marginal benefits.

Set a Realistic Target

The performance target should be realistically achievable by a well-managed utility. If utility performance is currently satisfactory, then the performance target could be set to simply maintain recent performance levels (assuming that future operating conditions will be similar to current conditions). If a higher level of performance is desired, a reasonable target can be developed based on (1) historical performance, (2) peer utility performance, (3) frontier methods such as data envelopment analysis, or (4) utility-specific studies.

1. Historical performance. Under the first method, a utility's previous performance over a set period of time—for example, the past ten years—is used to set the target. This method presumes that the data have been collected in the past and are readily available; that there has been little fundamental change in the key factors influencing utility performance; and that historical performance was satisfactory. Although historical data may be useful in setting initial performance targets, continuing to use historical data may be problematic due to the ratchet effect. The ratchet effect refers to the performance standard being raised if the utility performs well, making it harder for the utility to meet the standard in the next period, and diluting the incentive for the utility to improve performance in the current period (Comnes et al. 1995).

2. Peer utility performance. The second method uses peer groups to determine the performance target. If a peer group is used, effort should be made to account for the utility's unique circumstances that may impact the ability of the utility to reasonably achieve the target, or recent external factors that significantly impacted performance, such as a major storm.[16] This can be done through one of two ways: choosing a peer group that is similar to the utility in question, or using econometric techniques to control for certain variables.

   Direct comparison with peer utilities is referred to as "indexing." To identify the relevant group of peer utilities, econometric analysis can be performed to identify the most significant variables affecting utility performance, such as the geographic region and operating scale. Then utilities that are similar in these respects may serve as a suitable point of comparison. Another means of identifying a peer group is through cluster analysis, which groups utilities according to certain characteristics using statistical software (Shumilkina 2010).

   Where data on a variety of external factors that impact performance are available, econometric modeling can be used to control for these factors and provide an indication of "average" utility performance. However, the accuracy of the model is highly dependent upon inclusion of the correct variables and specification of the correct functional form (Shumilkina 2010). Failing to include data on a relevant variable can lead to omitted variable bias, yet collecting all of the relevant data (on utility characteristics, weather, age of investments, etc.) can be time consuming and prone to error.

3. Frontier methods. A third method of analysis is frontier analysis, a form of which is Data Envelopment Analysis (DEA). DEA measures technical efficiency of firms based on a sample of

[16] Although reliability reporting and performance targets generally exclude the impacts of major storms, the definition of "major storm" varies from state to state.

firms, their input use, and their outputs. The analysis identifies the most efficient firms and creates an efficiency frontier based on these firms' input usage per unit of output. Other firms are then assigned a score based on their efficiency relative to the efficiency frontier (Shumilkina 2010). Factors that are outside of a utility's control should be taken into account in the DEA analysis, but this is not easily done. This technique also suffers from a lack of internal validation, such as misspecification tests or goodness-of-fit statistics. Nevertheless, DEA analysis has been used by energy regulators to determine price and revenue requirements for utilities in Finland, Norway, the Netherlands, Germany, Austria, and Australia (Australian Competition & Consumer Division 2012).

4. Utility-specific studies. Finally, regulators can use utility-specific economic and engineering studies to set targets. For example, integrated resource plans may provide detailed cost and benefit information regarding certain resource investments under specific planning assumptions. Energy efficiency and demand response potential studies can identify the amount of investments that would be cost-effective for the utility to make. Production cost simulations have been used to model efficient dispatch, operation, and purchasing decisions, providing benchmarks against which utility performance can be measured.[17] These studies can help regulators identify and define specific resource investment targets and costs.

Regardless of the manner in which targets are set, regulators should minimize the ability of the utility to game target-setting. If there is an expectation that performance targets will be set at a future date based on historical data, the utility has an incentive to underperform until the target is set in order to establish a more lenient target. Econometric and frontier models can present challenges in terms of transparency, as these models are complex and require careful specification (Shumilkina 2010), which could lead to manipulation of the model to achieve the desired results.[18] Finally, basing targets on utility-specific studies that have been developed by the utility may create an incentive for the utility to overstate cost forecasts in order to deliver projects at costs that are below the target.

Incorporate Stakeholder Input

Allowing for meaningful stakeholder input during the process of setting targets is likely to result in targets that meet state regulatory goals, result in desired outcomes, and minimizes the potential for manipulating or gaming the targets. In addition, a meaningful stakeholder process can enable

---

[17] San Diego Gas & Electric (SDG&E) operated under a generation and dispatch performance-based ratemaking (PBR) incentive plan from 1993 to 1997, and earned rewards during all three years that the plan was in operation. Year 1 and Year 2 awards were reported in SDG&E's *Electric Generation and Dispatch PBR Mechanism Final Evaluation Report*, April 1998, submitted pursuant to D.97-07-064 in A.92-10-017, and Year 3 awards were adopted in D.98-12-004 as part of the adopted settlement agreement.

[18] Econometric modeling requires that the modeler make a number of decisions regarding functional form, whether certain data points represent true outliers that should be excluded, whether to choose a model based on parsimony or goodness-of-fit, etc. These choices may all impact the final result and should thus be carefully reviewed.

stakeholder buy-in, and enhance the legitimacy of targets. Stakeholder input also reduces the likelihood of contentious disagreements once performance incentives are implemented and rewards and penalties start to be applied.

Energy efficiency performance standards sometimes use this approach, with good results. Some states have established advisory councils or collaboratives to help oversee and provide input to the efficiency program design and implementation, including the design and implementation of efficiency performance standards (e.g., Connecticut, Massachusetts, and Rhode Island – see sidebar). The stakeholders in these councils and collaboratives provide a considerable amount of input and review to the energy efficiency programs, which enables them to determine whether a particular performance incentive savings target is reasonable, or will be too easy or difficult to achieve. The stakeholders represent a broad range of views, including utility representatives, consumer advocates, environmental advocates, state agencies, and efficiency experts, which increases the chance that efficiency targets will be balanced and reasonable.

Stakeholder Engagement for Efficiency Standards

Efficiency councils have been established in Connecticut, Massachusetts, and Rhode Island—three of the leading states providing cost-effective efficiency programs. There are several key factors that make these three councils especially effective, including:

- *A broad representation of stakeholder interests.*
- *Frequent, well-organized meeting and communication systems to allow full access to information and debate.*
- *Efficiency experts available to provide technical support, with sufficient funding.*
- *Meaningful oversight by regulators, including a process where stakeholders can bring issues for resolution.*

Additional information is available at:

Connecticut - http://www.energizect.com/about/eeboard

Massachusetts - http://ma-eeac.org/

Rhode Island - http://www.rieermc.ri.gov/

Use Deadbands to Account for Uncertainty and Variability

Deadbands create a neutral zone around a target level in which the utility does not receive a reward or penalty. Deadbands can help to account for uncertainty regarding the optimal performance level, as well as allow for some performance variance based on factors outside of the utility's control (see sidebar for an example from Hawaii).

How large should deadbands be set? Deadbands are frequently set at one standard deviation of historical performance, but may be larger or smaller based on sample size and the tolerance for error. That is, if a large amount of historical data is available, then one standard deviation is likely to capture most of the normal variation in utility performance. If the sample size is small, for example three observations, then one standard deviation may not be large enough to capture the normal variation in utility performance. In such cases, a confidence interval can be constructed using the sample data and the regulator's desired level of confidence that the interval will sufficiently represent the range of normal variation.[19]

Use Time Intervals That Allow for Long-Term, Sustainable Solutions

The timeframe for measuring performance can impact the compliance strategies that the utility implements. If performance is measured only over a short timeframe, such as over one year, the utility has an incentive to implement solutions that can be quickly implemented, but may only have short-term benefits. In some cases, these short-run solutions may in fact be contrary to long-term sustainability. For example, a utility may be encouraged to compromise safety in order to achieve short-term economic goals.

In contrast, solutions that are optimal for the long-term may result in slow but steady improvement. For example, implementing sound maintenance and operational practices will result in long-term safety and economic benefits, but may not achieve short-term capacity factor targets. Thus performance measurements over the longer-term, such as the use of three-year rolling averages, may better encourage the utility to adopt sound long-term practices (NRC 1991).

Deadbands for Heat Rate Targets to Account for Integration of Renewables

Many states allow utilities to recover fuel and purchased power costs through automatic pass-through mechanisms. To ensure that utilities retain an incentive to operate their power plants efficiently, some states have conditioned fuel cost recovery upon power plant performance factors. For example, Hawaii's Energy Cost Adjustment Clause (ECAC) contains a heat rate efficiency factor.

Although Hawaii's ECAC encourages maintaining the thermal efficiency of thermal generators, concerns were raised that the fixed sales target heat rate would penalize the utilities for introducing renewable energy, as lower capacity factors and higher ramping requirements can negatively impact thermal units' heat rates. In order to avoid the resulting disincentive for efficiency and renewable energy, a deadband of +/- 50 Btu/kWh sales was added to the heat rate target, and an agreement was reached to revisit the heat rate target upon the future addition of larger increments of renewable resources.

See HECO Final Revised Tariff Sheet Nos. 63-63E, filed on July 24, 2012, in Docket No. 2010-0080

Allow Targets to Evolve

In general, once a target is set, it should be adjusted only slowly and cautiously in order to provide utilities with the regulatory certainty required to make long-term investments. However, targets may need to evolve over time for two reasons. First, if performance needs to be improved, it may not be possible for the utility to immediately achieve the desired level of performance, as noted above. Some problems may take years to fully remedy, despite the utility undertaking immediate actions to remediate the situation. In such cases, the performance measurement time interval can be lengthened, or targets can be set to become more stringent over time, providing the utility with a glide path for achieving the ultimately desired level of performance.

[19] For more information on this approach, see Lowry et al. 2000.

Second, a target may need to evolve over time as technologies and policy goals evolve, or as the operating environment changes significantly. For example, smart grid investments may be able to dramatically improve outage duration rates. Therefore, if a utility makes significant investment in new smart grid technologies, then any reliability performance targets for that utility should be reviewed, and perhaps modified, to reflect the implications of the new technologies.[20]

[20] In addition, if the utility is using improved reliability as part of the justification for such smart grid investments, then the performance targets can be used to ensure that those benefits are actually achieved.

5. Financial Rewards and Penalties

5.1. Design Principles

Once performance targets have been defined, regulators can establish incentives to further induce the utility to accomplish the desired outcomes. Rewards and penalties are generally financial in nature, although other forms of incentives may be used.[21]

The following design principles should be considered when setting financial rewards and penalties:

1. Consider the value of symmetrical versus asymmetrical incentives
2. Ensure that any incentive formula is consistent with desired outcome
3. Ensure a reasonable magnitude for the incentive
4. Tie incentive formula to actions within the control of utilities
5. Allow incentives to evolve

Value of Symmetrical versus Asymmetrical Rewards and Penalties

Financial incentives are frequently designed to be symmetrical, in order to provide balance and to both discourage poor performance and encourage exemplary performance. Symmetrical incentives generally also mirror more closely how a utility would be compensated in a competitive environment. However, in some cases asymmetrical incentives may be more appropriate than symmetrical ones.

Penalty-only incentives may be appropriate when the outcome is either an essential requirement for the utility, or when performance above target outcomes provides little additional benefit to ratepayers. For example, customers might not be willing to pay for incremental improvements in reliability beyond the target level, particularly if customers would be required to pay for any reliability improvements through both rates (to recover utility expenses) and performance rewards. At the same time, utilities have a clear obligation to provide sufficient levels of reliability, therefore unsatisfactory performance might

Asymmetrical Incentives in Alberta

In a 2012 order, the Alberta Utilities Commission rejected providing utilities with a positive performance incentive for exceeding service quality, writing "…in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher price for a service quality level that they may not want or cannot afford" (Alberta Utilities Commission 2012, 194–195).

[21] For example, the UK allows expedited regulatory treatment of utility business plans for business plans that are well executed. This offers utilities the benefits of reduced regulatory burdens and risks. In addition, the UK uses "reputational" incentives, where utilities' success in reducing carbon emissions is compared and made publicly available.

warrant the applications of penalties. See the sidebar for an example of asymmetrical incentives in Alberta.

In other cases, it may be beneficial to administer incentives on a positive basis only. This is common for energy efficiency incentives where any megawatt-hour of energy saved through a cost-effective efficiency program results in a benefit to ratepayers. In addition, reward-only incentives tend to encourage utilities to be more innovative, and may result in more collaborative and less adversarial processes (NY PSC 2012).

Ensure Incentive Formula Is Consistent with Desired Outcome

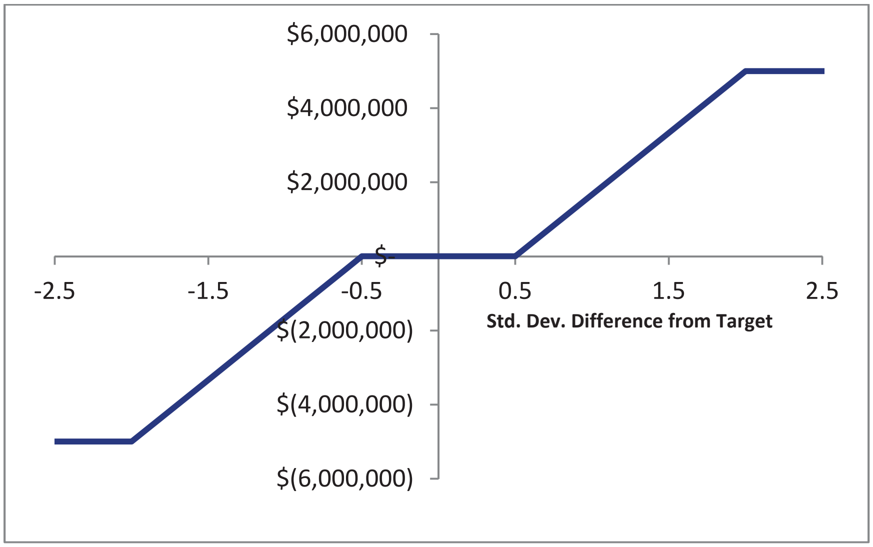
Incentive formulas can take numerous forms, including linear, quadratic, and step functions. It is important that the formula (and the shape and slope) of the incentive is consistent with the desired outcome and supports appropriate utility performance. The shape and slope of the formula determine how quickly the curves reach the maximum reward or penalty as performance deviates from the target (or the ends of the deadband). Below we present several possible incentive formulas and some of their benefits and drawbacks. Each graph shows how rewards or penalties (vertical axis) change as performance deviates from zero to two standard deviations from the target.

<u>Linear Function with Deadband</u>

Figure 5 depicts an incentive formula that has a deadband of 0.5 standard deviations, measuring how much performance varies from the average, on either side of the target. After 0.5 standard deviations, penalties and rewards increase in a linear fashion up to a maximum of $5 million. This formula is simple to understand and administer, and the deadband helps to control for normal fluctuations in performance due to factors that are outside the control of the utility.

A potential drawback is that a utility may be induced to perform at a level close to 0.5 standard deviations below the target, since such under-performance would not result in a penalty. The utility would especially have an incentive to operate close to -0.5 standard deviations from the target if the target is based on a rolling average of historical performance. This highlights the importance of monitoring utility behavior and making adjustments as necessary, such as narrowing the deadband over time, or delinking performance targets from historical performance.

Figure 5. Hypothetical Linear Formula with Deadband



Quadratic Function

A quadratic function (also referred to as a "parabolic function") can also be designed to provide increasing rewards or penalties as performance deviates from the target, but the rewards or penalties increase more slowly. Figure 6 presents a simple linear incentive function, as well as a quadratic incentive function with the same end points and central target.[22] As indicated, a quadratic formula acts similar to a deadband by providing little incentive near the central target. A quadratic function also results in an increasing slope as the performance deviates from the performance target.

Massachusetts has used a modified quadratic formula since 2001. In its order approving the formula, the Department of Public Utilities wrote: "While a linear formula may have the perceived advantage of simplicity, the Department considers a non-linear formula provides a stronger link between a utility's performance and the consequences of it failing to meet [service quality] measures" (MA DPU 2000, 25).

The formula for the quadratic function uses four inputs:

- Maximum reward or penalty (e.g., $5,000,000)
- Actual utility performance (e.g., a score of 1.75)
- A target (e.g., a score of 1.0)
- The standard deviation, σ (e.g., 0.5)

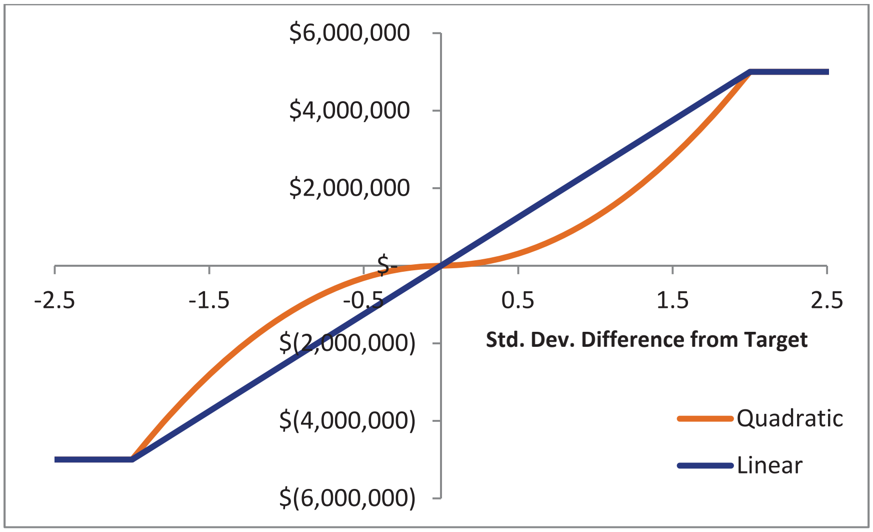
Penalties and rewards are maximized at two standard deviations from the target. A scalar of 0.25 is used to constrain the scores to values between 0 and 1, which is then multiplied by the maximum incentive.

[22] A linear function does not square the standard deviation difference from the target and uses a scalar of 0.5.
Reward or penalty = [(performance – target)/σ] x (0.5) x (maximum reward or penalty)

Reward or penalty = [(performance – target)/σ]^2 x (0.25) x (Maximum reward or penalty)

Using the example values from above: [(1.75 – 1.0)/0.5]^2 x (0.25) x $5,000,000 = $2,812,500

Figure 6. Quadratic Function Compared to a Linear Function

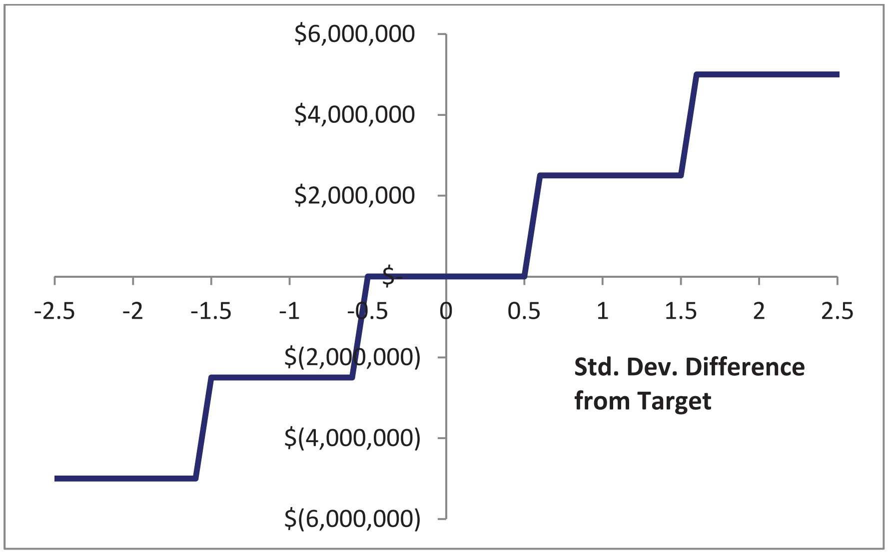


<u>Step Functions</u>

Step functions can be simple (e.g., two steps), or complex (multiple steps). Either way, the utility receives no incentive until it reaches a certain level of performance, at which there is a sharp change in the reward or penalty it receives. For example, in Figure 7 the utility receives no reward until it performs at 0.5 standard deviations above the target, at which point it receives a reward of $2.5 million. It continues to earn only $2.5 million until performance reaches 1.5 standard deviations above the target, at which point the reward increases to the maximum of $5 million.

Step functions are common and can be easy to administer, but they have several important drawbacks. When the amount of the penalty or reward can change dramatically with only a small change in performance (e.g., when performance increases from 0.49 standard deviations to 0.5 standard deviations from the target), the performance evaluation process can become very contentious. In addition, such sharp thresholds may induce a utility to engage in unsafe or unsound practices in order to avoid a large penalty or receive a large reward.

Figure 7. Hypothetical Step Function



Ensure a Reasonable Magnitude for the Incentive

When establishing the appropriate magnitude of financial incentives, regulators should generally seek to balance two competing objectives. Financial rewards and penalties should be large enough to capture utility management's attention and provide sufficient motivation to reach the desired outcome. On the other hand, rewards and penalties should not be disproportionate to the costs and benefits of the desired outcome. The reward should not unduly reward or penalize the utility, and rewards should not offset the benefits to ratepayers.

Performance incentive mechanisms should include a cap on the maximum penalty or reward, in order to ensure that the magnitude of the incentive will remain within a reasonable bound. Regulators should also consider the size of rewards and penalties within the context of the magnitude of existing incentives to ensure existing incentives and new incentives are properly balanced.

For utilities that are provided with multiple performance incentives, it is important to consider the potential impact on the total reward or penalty that might be applied. The total financial impact on a utility will depend on both the magnitude of the rewards and penalties and the likelihood of being assessed those rewards and penalties.

When establishing the magnitude of financial rewards and penalties, regulators may also need to consider the particular financial circumstances of the utility involved. This becomes especially important if the magnitude of the combined penalties and rewards are large enough to significantly impact the utility's financial position. Financial analysts and utility management typically pay special attention to the utility's financial position, thus it is important to recognize the financial implications of the penalties and rewards. This may involve several considerations:

- Financial analysts typically assess the risk associated with utilities, as well as the risk associated with regulatory systems and new regulatory measures. Therefore, it is important that the performance incentive mechanism and the potential financial impacts are clearly defined and transparent.

- Many utilities motivate managers and employees with incentive systems based upon stock options and prices. If the performance incentives have a significant effect on stock prices, then this provides additional, personal incentives to those employees to help meet performance goals.
- One thing that might help place the magnitude of rewards and penalties in perspective is to present them in financial terms, such as in terms of basis points on the return on equity, or in terms of equivalent cents per share on utility stock prices. Presentation of financial incentives is discussed briefly in the subsection below.

Further, rewards and penalties should always be proportionate to the importance of the performance goal to ratepayers. In general, incentive payments should not exceed the net benefits to ratepayers.

Presentation of Financial Incentives

Rewards and penalties can be expressed in several different equivalent units to help place their magnitude in context. For example, they can be presented as dollars, cents per share, basis points of return on equity (ROE), percent of non-fuel operating expenses, percent of base revenues, or percent of total earnings. The table below demonstrates how an incentive amount of $2.5 million could be presented in order to help stakeholders understand the magnitude of the incentive in relation to the utility's return on equity, operating expenses, cents per share, and percent of earnings. Total earnings can also be shown to provide context.

Table 15. Hypothetical Presentation of Financial Incentives in Different Units

Maximum Reward or Penalty	Equivalent Basis Points	Equivalent % of T&D Revenues	Equivalent cents/share	Percent of Pre-Tax Earnings	Total Pre-Tax Earnings
$2,500,000	25	0.9%	2.47	3.1%	$80,645,000

Presenting financial rewards and penalties in multiple units is useful during the process of setting the financial incentives. However, administration of the incentives is generally simplest when done as dollars, as other units can be administratively complex and result in perverse incentives. For example, positive incentives that are set in terms of ROE basis points could provide an incentive for a utility to increase rate base. See Appendix A for an example of the perverse impacts of an ROE adder for certain investments.

Tie Incentives to Actions and Outcomes within the Control of Utilities

Financial incentives should be based upon actions and outcomes that are within the control of the utility. First, if an action or outcome is beyond the control of the utility, then the performance incentive would have little to no effect on achieving the desired outcome, and therefore should not be applied at all. Second, it is unfair for customers to pay for utility rewards that are not a result of utility actions. Third, it is unfair to penalize utilities for outcomes that are beyond their control.

While this principle seems obvious and important, it can be difficult to hold to it in practice for some performance areas and metrics. Some events might be beyond a utility's control (e.g., the incidence and types of severe storms), but there may be things a utility can do to mitigate the implications of those events (e.g., by having effective emergency preparedness and emergency response programs).

Some elements of utility performance might be beyond a utility's control but may appear to be reasonable to include in an incentive formula. For example, some states have established "shared savings" incentives, where utilities are allowed to keep a small portion of the savings that they achieve as a result of improved power plant performance. This approach makes intuitive sense because customers can be expected to experience only net benefits as a result of the incentive, and ideally the majority of the net benefits. However, the magnitude of the savings from such incentives is often based on avoided fuel costs, which can fluctuate wildly for reasons completely beyond the control of the utility. As a result, utilities can experience undue windfalls or penalties. (See Appendix A for a discussion of the financial incentive for the Palo Verde nuclear power plant, which was based on avoided power costs. These avoided costs, and thus the financial incentive, skyrocketed during the California Energy Crisis in 2000).

In some instances it may be appropriate to provide financial incentives for actions that are only partly within a utility's control. For example:

- Regulators could provide all utilities in a multi-utility state with rewards if a statewide energy efficiency goal is met. A reward based on achievement of a statewide goal has two effects: (a) it encourages utilities to work together and share best practices; and (b) it provides an incentive for utilities to continue to pursue the statewide goal, even if they are clearly not going to meet their individual utility target.
- Regulators could provide utilities with rewards for supporting other initiatives regarding efficiency standards, building codes or commercialization of clean energy technologies. Utilities can have a significant influence on such statewide initiatives, even if they are partly or mostly beyond their control.
- Regulators could provide utilities with rewards for achieving certain energy policy, public interest, or societal goals that are partly beyond utility control, such as reducing the fuel burden on low-income customers or meeting economy-wide pollution targets.

Allow Incentives to Evolve

As with other aspects of performance incentive mechanisms, financial incentives may need to be adjusted over time. Financial incentives are sometimes adjusted when the magnitude of the incentive is found to be unreasonably large or small, or the basis for the financial incentive (e.g., avoided fuel costs) is found to be excessively volatile, resulting in excessive penalties or rewards.

Excessive penalties and rewards can sometimes be addressed easily, such as with a cap on rewards or penalties. In other cases a correction might require fundamental redesign of the incentive mechanism, including a full stakeholder process. While regulators should expect performance incentives to evolve over time in response to lessons learned in practice, it is also important to make any adjustments cautiously in order to preserve regulatory transparency and certainty to the greatest extent possible.

In order to avoid the possibility of overcompensation, it is advisable to begin with small financial incentives and adjust these gradually upward over time if needed. In some cases, a small financial incentive may be all that is needed in order to induce the utility to achieve the desired result, thus preserving the majority of benefits for ratepayers.

An incremental approach also allows utilities and regulators to gain experience with an incentive mechanism and manage any unforeseen consequences of the incentive without large impacts on ratepayers. As parties gain more confidence that the performance incentive mechanism does not suffer from any major flaws, the amount of compensation can be increased if needed.

5.2. Rewards and Penalties in the Context of New Regulatory Models

Several recent proposals for new regulatory models emphasize the goal of rewarding utilities for performance and desired outcomes. For example, a utility-stakeholder collaborative group in Minnesota writes:

> As its name suggests, a performance-based approach would tie a portion of a utility's revenue to achieving an agreed-upon set of performance metrics (e.g., measuring such things as energy efficiency, customer service, environmental sustainability, affordability, and competitiveness) so that utilities have a natural financial incentive to produce the outcomes customers want (e21 Initiative 2014, 3).

The RIIO model that is being developed and applied in the UK includes financial incentives that are roughly equal to 5 percent of utility revenues (see Appendix A). This is considered to be a relatively large portion of utility revenues to dedicate to financial incentives, and we are not aware of any states or countries that apply larger financial incentives.

Whether a set of performance incentives will result in "a natural financial incentive to produce the outcomes customers want" will clearly depend upon many factors, such as the type and scope of the outcomes targeted, the performance metrics, the targets chosen, the amount and type of financial incentives, and more. One of the key factors likely to determine how well the combination of incentives will lead to desired outcomes is the amount of money that is at stake. As described in Chapter 2, utilities already have many different financial incentives, some of which are aligned with customer interests, some of which are not. These existing financial incentives are very influential and exist in every regulatory context.

In thinking about new regulatory models, one key question that regulators should ask is: Will the set of new performance incentives be sufficient to modify, or at least balance against, the financial incentives of the existing regulatory model? Regulators should compare the magnitude of the proposed performance incentives with the magnitude of existing financial incentives. If new regulatory models are to result in a fundamental shift of incentives away from capital investments and toward performance outcomes, then the magnitude of the financial rewards and penalties will need to be significantly larger than the amounts used to date in the United States, and may need to be larger than under the RIIO model used in the UK, discussed below.

In addition, new regulatory models will need to reduce the incentive that utilities currently have to increase their rate base. This could be achieved by reducing, or eliminating, the amount of profit that a utility earns from rate base, and replacing that amount of profit with revenues from performance incentives.[23] Ultimately, the combined impact of modified equity recovery plus financial incentives should meet the standard criterion of allowing the utility to recover prudently incurred costs plus an opportunity to earn a reasonable return on equity. In this case the opportunity to earn a reasonable return on equity would be based primarily, or entirely, on utility performance relative to the performance incentives.

When designing new regulatory approaches for utilities to recover revenues, regulators must also be cognizant of the implications for utility financial positions. First, utilities must be able to maintain a reasonable financial position for a reasonable level of performance. Second, as noted above, managers and analysts need to be able to assess the risk associated with new regulatory mechanisms, and shifting the sources of revenues could easily change the risk profile of a utility's financial position.

It may also be important to consider the timing of revenue recovery. If the recovery of equity costs is partially replaced by the recovery of performance incentives, then the timing should be properly aligned. Currently utilities are allowed to recover equity and debt costs over the full book life of a capital asset. If the financial incentives are recovered over a shorter time period, then there might be a misalignment of when customers experience the benefit and when they are charged for it. On the other hand, performance incentives typically work best when the rewards and penalties are applied relatively close in time to the performance outcomes themselves.

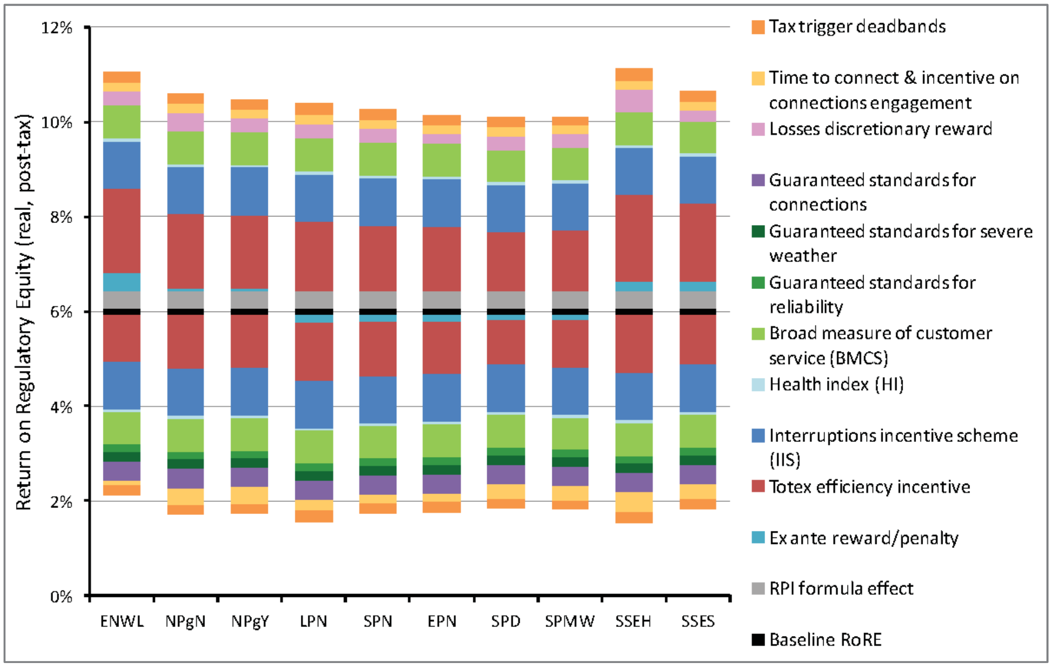
An Example: the RIIO Model

The UK's RIIO model bases a large amount of a utility's earnings on its performance. As detailed in Appendix A, potential rewards and penalties associated with environmental, customer satisfaction, social obligations, and connections performance incentive mechanisms equate to approximately 3 percent of utility annual base revenues. Reliability-related rewards and penalties carry with them the possibility of an additional 250 basis points in rewards or penalties. The results of Ofgem's modeling suggest that utilities' realized return on equity may fluctuate by approximately +/- 300 basis points due to these performance incentive mechanisms (Ofgem 2014b).

[23] Under RIIO, capital expenditures and operating expenditures are combined into one category: "total expenditures," or "totex." The utility then earns a return on a pre-determined portion of totex, regardless of whether the utility's capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus non-capital projects.

These performance incentive mechanisms are part of a revenue cap plan that provides for annual revenue increases at the rate of inflation and allows utilities to retain a large portion of any cost savings they achieve. Allowed revenues are set using a 6 percent return on equity, but actual earnings may vary significantly based on utility performance. According to Ofgem's modeling, the actual ROEs for "slow-track" utilities are likely to range from approximately 2 percent to more than 10 percent, as shown in the figure below (Ofgem 2014b).

Figure 8. Plausible ROE Range for UK Distribution Utilities



Source: Ofgem 2014b, page 46

This wide variability of potential utility returns is by design, as Ofgem determined early on that high-performing utilities should have the opportunity to earn an ROE of greater than 10 percent, while poorly performing utilities could earn an ROE of less than the cost of debt. Ofgem notes that the results shown in the figure above indicate that the package of risk and incentives has been "appropriately calibrated" (Ofgem 2014b, 46). The relatively large magnitude of incentives under RIIO not only helps to focus management attention on the attainment of the established targets, but may also help to provide the revenues necessary for innovating and implementing new technologies.

6. Implementation

6.1. Questions to Help Inform Regulatory Action

Regulators may wish to ask themselves, as well as relevant stakeholders, several questions that would help inform their decisions on whether and how to proceed with performance metrics and incentives. For example:

1. **How well does the existing regulatory framework support utility performance?**

   Are the utilities already achieving standard regulatory goals, such as providing low-cost, safe, reliable service? Are there specific areas of performance where utility performance has been questionable, or where customers have raised complaints? What activities or investments are currently the key profit centers for the utilities?

2. **How well does the existing regulatory framework support state energy goals?**

   What are the priority state energy policy goals, and how well do the utilities achieve them? These may include a variety of goals related to costs, reliability, clean energy resources, grid modernization, customer protections and more. Regulators should recognize that policy goals may evolve, and may require different incentives and regulatory models over time.

3. **What are the policy options available to improve utility performance?**

   As described in Chapter 2, there are many regulatory policies that will provide utility incentives and influence utility performance. Regulators may wish to modify or implement any of these other policy options in concert with, or in lieu of, performance metrics and incentives.

4. **Is the industry, market, or regulatory context expected to change?**

   If change is expected to occur, utilities may benefit from additional regulatory guidance regarding the preferred response, or may require additional incentives that were not necessary previously. There may also be emerging policy goals that the commission wishes to emphasize.

5. **Does the commission prefer to oversee investments, or to guide outcomes?**

   Traditional regulation typically allows regulators to oversee the utility investments and activities that are intended to achieve desired outcomes (e.g., during a rate case). In contrast, performance metrics and incentives allow regulators to provide more guidance on the desired outcomes, and less guidance on the means to achieve them.

6. **Does the commission wish to specify the outcomes in advance?**

   Traditional regulation typically allows regulators to oversee major capital investments and review expenses after the costs are incurred (typically during a subsequent rate case). As a result, there is little regulatory guidance provided before investments are made, at a time when alternative actions or investments can be considered. Integrated resource planning, where it is practiced, provides an exception to the common practice that regulation only takes place after the fact, after the money has been invested or spent. Performance metrics and incentives, on the other hand, provide greater regulatory guidance up front, and are therefore more likely to influence the outcomes.

The answers to these questions will help regulators determine what level of performance regulation is appropriate for their jurisdiction, and what type of performance metrics and incentives to implement.

6.2. Implementation Steps

Once a determination has been made to implement performance metrics or incentive mechanisms, the following steps can be implemented. These can be implemented incrementally, to allow for each step to inform the subsequent step, or they can be implemented several steps at a time, or all at once.

1. Articulate goals**.** The first step is to identify and articulate all the energy policy goals that are applicable to utility regulation, whether the goals are current or anticipated.

2. Assess current incentives**.** Next it is critical to assess and understand the financial incentives, including those in place within company management and provided by utility interactions with investor analysts, which are created by the current or anticipated regulatory, management, and financial context. Performance incentives should then be designed to modify, balance or supplement these existing incentives. (See Chapter 2.)

3. Identify performance areas that warrant performance metrics**.** These performance areas may include traditional performance areas or new and emerging performance areas, depending on the needs of the particular jurisdiction. (See Chapter 3.)

4. Establish performance metric reporting requirements**.** Use performance metrics to monitor those areas identified in Step 3. Review the results over time to identify any performance areas that may require targets. (See Chapter 3.)

5. Establish performance targets, as needed**.** Establish targets to provide utilities with a clear message regarding the level of performance expected by regulators. Review the results over time to determine whether any performance areas warrant rewards or penalties. (See Chapter 4.)

6. Establish penalties and rewards, as needed. Establish reward or penalties to provide a direct financial incentive for maintaining or improving performance. (See Chapter 5.)

7. Evaluate, improve, repeat. Creating effective performance incentive mechanisms is an iterative process. The effectiveness of the mechanisms should be monitored closely and evaluated to determine which aspects are working well, and which are not. Targets, financial incentives, and other components of the mechanisms may need to undergo several adjustments before they achieve their full potential. (See Section 6.4)

6.3. Pitfalls to Avoid

No performance incentive mechanisms can be said to be perfectly designed, but those that work well succeed in providing greater benefits than costs to all parties. Unfortunately, there are also many examples of performance incentive mechanisms that have not succeeded, for a variety of reasons. Below we address some common pitfalls that regulators should endeavor to avoid when designing performance incentive mechanisms.

Disproportionate Rewards (or Penalties)

Performance incentive mechanisms can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.

It is critical that regulators avoid the pitfall of over-rewarding utilities for performance. When utility rewards exceed the benefits to customers, particularly when they are first implemented, the entire concept of incentive mechanisms is undermined. Higher-than-expected rewards can also result in substantial backlash against performance incentive mechanisms that might have otherwise worked well.

Potential Solutions

One way to avoid this pitfall is for regulators to adopt an incremental approach: begin with small rewards and monitor and adjust over time. Another option is to establish caps on rewards (and penalties), to ensure that they stay within reasonable bounds.

Avoided Costs and Disproportionate Rewards

To encourage improved nuclear power plant performance, California implemented incentive payments for electricity produced by several of its nuclear reactors. In 1988, a settlement established the payment rate for electricity produced by Diablo Canyon, based on then-current avoided costs of fossil generation. This rate was to remain fixed, escalated only for inflation. By the mid-1990s, Diablo Canyon was earning more than $0.12/kWh, while Western Market wholesale power prices were approximately $0.03/kWh.

Later, a similar performance incentive mechanism was established for Palo Verde Nuclear Generating Station, but in this case the payment was set at the avoided cost of replacement power. Unfortunately, by the summer of 2000 the California energy crisis was in full swing, and the cost of replacement power had increased more than ten-fold. Again, the volatility of the markets had resulted in utility rewards much higher than intended. Both of these performance incentive mechanisms were subsequently modified, and further details can be found in Appendix A.

Another tool that can help prevent excessive compensation to utilities for some PIMs is shared savings. For example, when a utility implements a cost-saving measure, shared savings mechanisms pass on a portion of utility profits to ratepayers. Again, it is advisable to begin with a shared-savings mechanism that passes most profits to ratepayers, and reduce this proportion over time if needed in order to provide the utility with greater incentives.[24]

Unintended Consequences

Perhaps the most challenging aspect of designing performance incentive mechanisms is anticipating and avoiding unintended consequences. A common effect of establishing an incentive for one aspect of utility performance is to shift management's attention to the areas with incentives, to the detriment of areas that do not have incentives.

Unintended effects can also result from failing to recognize the linkages between various aspects of the utility's system. For example, providing an incentive for achieving high capacity factors at certain utility power plants could create several perverse incentives, such as encouraging the utility to: (1) increase sales, (2) operate units out of merit order, (3) engage in otherwise uneconomic off-system sales, or (4) defer needed maintenance outages.

<u>Potential Solutions</u>

Avoiding unintended consequences requires significant attention to the myriad incentives utilities face and the ways in which the performance target may influence other aspects of the utility's system. Strategies to minimize negative impacts include:

- Implement a diverse, balanced set of incentives to avoid concentrating management attention on only one area.
- Focus on performance areas that are relatively isolated from others, where possible. Energy efficiency is a good example of an area that may have relatively little impact on other aspects of utility performance.
- Explicitly assess up front how performance standards might influence other performance areas that do not have standards. Solicit input from multiple stakeholders and learn from experiences in other states.
- Allow for performance incentives to evolve over time to correct for unintended consequences.

Regulatory Burden

---

[24] Shared-savings mechanisms can also be structured to give a greater proportion of early savings to one of the parties (either shareholders or ratepayers), and a smaller proportion of later savings to that same party. A regressive sharing mechanism gives more of the early savings to shareholders, but less of the later savings. A progressive savings mechanism works in reverse by providing more of the early savings to ratepayers. An advantage of the progressive shared savings mechanisms is that it protects ratepayers against uncertainty, since if the performance target is miscalculated and set too low, ratepayers still retain a large portion of the savings. Progressive sharing mechanisms also create a stronger incentive for the utility to achieve high levels of savings. However, if the target is set where it is already difficult for the utility to meet and already delivers significant value to ratepayers, a regressive mechanism may be appropriate for equity reasons. For more discussion, see Testimony of William B. Marcus, PBR Economic Issues, JBS Energy, in California PUC Docket A. 98-01-014, July 3, 1998.

If performance incentive mechanisms are not designed well they can be too costly, too time-consuming, or too much of a distraction, for the utility, the regulators, and other stakeholders. Data reporting and verification can be resource intensive. Determining appropriate targets can be time-consuming and contentious, and disputes over penalties can be expected, particularly when large sums of money are at stake. These activities can divert limited resources away from more important issues, becoming an unnecessary distraction.

> ***Reducing Regulatory Burden in New York***
>
> *In 2012, the New York Public Service Commission issued an order that abolished the penalty portion of energy efficiency incentives. The Commission's experience was that the threat of penalties "created an adversarial approach to setting targets and budgets, undue aversion to risk, and short-term allocation of resources that may not serve the long-term interests of a balanced program." In addition, consideration of mitigating circumstances presented a substantial drain on staff and utility resources that could have been better spent on administering programs. See NY PSC 2012, 5-6.*

Potential Solutions

To avoid unnecessary regulatory burden, regulators should endeavor to streamline performance incentive mechanisms by using existing data and protocols where possible, and relying on simple mechanism designs. If a specific PIM is becoming a distraction, it may be because too much money is at stake. Ensuring that the reward or penalty is commensurate with the importance of the policy goal will help to ensure limited resources are appropriately allocated.

Uncertainty

Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. In addition, significant and frequent changes to incentives create uncertainty for the utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.

Potential Solutions

A critical step in reducing uncertainty is to carefully specify metric and target definitions, soliciting utility and stakeholder input where possible. If historical data are available, it can be instructive to use such data to provide examples of how the performance data will be assessed and rewarded or penalized in the future. As discussed in the case study in Chapter 3, such an approach may have helped Nevada utilities and stakeholders avoid much of the litigation and controversy regarding whether a certain type of facility would be designated as a "critical facility" eligible for enhanced return on equity.

The speed with which performance metrics and incentives are reported and applied can help reduce uncertainty. Information regarding the achievement of targets and the magnitude of incentives should be provided as quickly as possible, to minimize uncertainty and allow for mid-course corrections as soon as possible.

Regulatory certainty is equally important for ensuring that long-term utility investments are made efficiently, and incentives are not diluted. To this end, regulators should adjust targets and financial consequences only cautiously and gradually so as to reduce uncertainty and encourage utilities to make investments with long-term benefits.

Gaming and Manipulation

Every performance incentive mechanism carries the risk that utilities will game the system or manipulate results. "Gaming" refers to a utility taking some form of shortcut in achieving a target so that the target is reached, but not in a way that was intended. For example, if a performance incentive were set that rewarded a utility for increasing a power plant's capacity factor above a certain threshold, the utility might understandably respond by increasing its off-system sales from that power plant, even at an economic loss. Thus the utility would be able to meet or exceed the target capacity factor, but ratepayers would be worse off.

Manipulation of the results refers to the deliberate alteration or obscuring of unfavorable performance data, whether through use of dubious analysis methods, improper data collection techniques, or direct alteration of data. An example of this occurring in California is provided in Appendix A, as well as in a call-out box in Chapter 3.

Potential Solutions

The ability of utilities to game an incentive typically points to the need to refine how a metric is defined. In the example above, the metric could be redefined to exclude energy sold at a loss or energy from a unit that is operated out of merit order. This pitfall can be quickly remedied by ensuring that regulators carefully monitor how well performance incentive mechanisms are achieving their intended results, and step in quickly to make necessary adjustments, particularly where an incentive is clearly being gamed. In addition, the potential for gaming makes it all the more important that financial rewards and penalties are set conservatively in the beginning, and only increased once regulators and utilities gain experience with the performance incentive mechanism.

Manipulation can be more difficult to detect, particularly when data are collected and analyzed by the utility. To reduce the risk of manipulation, verification methods should be adopted and independent third parties used to collect, analyze, and verify data where practical. Complex data analysis techniques that are difficult to audit should generally be avoided, as they reduce transparency.

6.4. Summary of Key Performance Incentive Mechanism Design Principles

The table below provides a recap of the key principles for performance incentive mechanism design.

Table 16. Key Principles and Recommendations

Regulatory Contexts **(Chapter 2)**	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics **(Chapter 3)**	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets **(Chapter 4)**	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties **(Chapter 5)**	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

Bibliography

Aggarwal, Sonia, and Eddie Burgess. 2014. *New Regulatory Models*. Prepared for the State-Profincial Steering Committee and the Committee on Regional Electric Power Cooperation. http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf.

Alberta Utilities Commission. 2012. *Rate Regulation Initiative: Distribution Performance-Based Regulation*. Decision 2012-237. September 12.

American Forest & Paper Association, et al. 2011. *Joint Comments on Promoting Transmission Investment Through Pricing Reform*. FERC Docket No. RM11-26-000.

Australian Competition & Consumer Division. 2012. *Benchmarking Opex and Capex in Energy Networks*. Working Paper No. 6. http://www.accc.gov.au/system/files/Working%20paper%20no.%206%20%20-%20Benchmarking%20energy%20networks.pdf.

Baldwin, Robert, and Martin Cave. 1999. *Understanding Regulation: Theory, Strategy, and Practice*. Oxford University Press.

Biewald, Bruce, Tim Woolf, Peter Bradford, Paul Chernick, Susan Geller, and Jerrold Oppenheim. 1997. *Performance-Based Regulation in a Restructured Electric Industry*. Synapse Energy Economics, prepared for the National Association of Regulatory Utility Commissioners.

Binz, Ron, Richard Sedano, Denise Furey, and Dan Mullen. 2012. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know. How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection*. Ceres.

Blue Planet Foundation. 2014. *Blue Planet Foundation's Reply Statement of Position On Schedule B Issues, Declaration of Ronald J. Binz*. Hawaii Public Utilities Commission. Docket No. 2013-0141.

Bradford, Peter. 1992. "Foreword." In *Regulatory Incentives for Demand-Side Management*, edited by Steven Nadel, Michael Reid, and David Wolcott, ix – xi. Washington, DC: American Council for an Energy-Efficient Economy. http://www.aceee.org/sites/default/files/publications/ebook/regulatory-incentives-for-demand-side-management.pdf.

CEPA LLP. 2013. *RIIO-ED1: Review of the DNOs' Business Plans Annex 3: Incentives and Outputs*. A Report for Centrica. https://www.ofgem.gov.uk/ofgem-publications/82721/bgcepareport3incentivesresponseriioed1businessplans01.07.13.pdf.

ComEd. 2014. *Smart Grid Advanced Metering Annual Implementation Progress Report*. Commonwealth Edison Company.

Comnes, G.A., S. Stoft, N. Greene, and L.J. Hill. 1995. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource- Planning Issues*. LBL-37577 UC-1320. Lawrence Berkeley National Laboratory.

ConEd. 2015. *Petition for Rehearing and Clarification of Consolidated Edison Company of New York*. Consolidated Edison Company of New York, Inc. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={963D9EDC-0997-43D9-9796-C8496B26178B}.

Costello, Ken. 2010. *How Performance Measures Can Improve Regulation*. The National Regulatory Research Institute (NRRI).

———. 2014. *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*. 14-03. NRRI. http://www.nrri.org/documents/317330/8270bccc-7dcb-467b-a324-b4351310a841.

CPUC. 1988. *Decision 88-12-083, in Application of Pacific Gas & Electric Company for Authorization to Establish a Rate Adjustment Procedure for Its Diablo Canyon Nuclear Power Plant to Increase Its Electric Rates to Reflect the Costs of Owning, Operating, Maintaining, and Eventually Decommissioning Units 1 and 2 of the Plant and to Reduce Electric Rates Under Its Energy Cost Adjustment Clause and Annual Energy Rate to Reflect Decreased Fuel Expenses*. California Public Utilities Commission.

———. 1991. *Decision 91-03-032, Opinion Issued in R.90-02-008 and I.90-08-006*. California Public Utilities Commission.

———. 2001. *Decision 01-09-041, in Application of Southern California Edison for Authority to Make the Following Changes to Its Present Ratemaking for Its Share of Palo Verde Nuclear Generating Station Unit No. 1, 2, and 3: (i) Accelerate Recovery of the Company's Sunk Investment; (ii) Adopt Palo Verde Incremental Cost Incentive Pricing for Its Incremental Costs; and (iii) Receive Related and Substantive and Procedural Relief*. California Public Utilities Commission.

———. 2004. *Decision 04-07-022, Application of Southern California Edison Company For Authority To, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2003, And to Reflect That Increase in Rates.* California Public Utilities Commission. http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/38235.PDF.

———. 2008. *Decision 08-09-038, Decision Regarding Performance Based Ratemaking (PBR), Finding Violations of PBR Standards, Ordering Refunds, and Imposing a Fine*. California Public Utilities Commission.

———. 2010. *Decision 10-04-052, Decision Adopting a Solar Photovoltaic Program for Pacific Gas and Electric Company, Application 09-02-019*. California Public Utilities Commission.

———. 2014a. *Proposed Decision, Decision Setting Enforcement Rules for the Renewables Portfolio Standard Program, Implementing Assemby Bill 2187, and Denying Petitions for Modification of Decision 12-06-038, Rulemaking 11-05-005*. California Public Utilities Commission.

———. 2014b. *Decision 14-11-026, Decision Granting, in Part, Pacific Gas and Electric Company's Petition for Expedited Order Granting Modification of Decision 10-04-052 - Solar Photovoltaic Program, Application 09-02-019*. California Public Utilities Commission.

Daniels, Steve. 2013. "ICC Orders $72 Million Nicor Refund in Decade-Old Scandal." *Crain's Chicago Business*, June 5. http://www.chicagobusiness.com/article/20130605/NEWS11/130609908/icc-orders-72-million-nicor-refund-in-decade-old-scandal.

e21 Initiative. 2014. *Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota*.

ENA. 2014. "Distribution Charges Overview." *Energy Networks Association*. http://www.energynetworks.org/electricity/regulation/distribution-charging/distribution-charges-overview.html.

Energy Industry Working Group. 2014. *Creating a 21st Century Electricity System for New York State*. Position Paper.

Eto, Joseph, and Kristina Hamachi LaCommare. 2009. *A Quantitative Assessment of Utility Reporting Practices for Reporting Electric Power Distribution Events*. Lawrence Berkeley National Laboratory. http://emp.lbl.gov/sites/all/files/Utility%20Reporting%20Practices%20Electric%20Power-2009.pdf.

FERC. 2015. *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report.* U.S. Department of Energy Federal Energy Regulatory Commission. Accessed February 5. http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf.

Growitsch, Christian, Tooraj Jamasb, Christine Mueller, and Matthias Wissner. 2009. *Quality of Supply in Energy Regulation Measurement, Assessment, and Experience from Norway*. CWPE 0931 & EPRG 0920. University of Cambridge.

GTM Research. 2015. *Evolution of the Grid Edge: Pathways to Transformation*. A GTM Research Whitepaper.

HI PUC. 2014. *Decision and Order 31908 in Docket No. 2013-0141: Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited*. Hawaii Public Utilities Commission.

Jenkins, Cloda. 2011. *RIIO Economics: Examining the Economics Underlying Ofgem's New Regulatory Framework*. Florence School of Regulation.

Knittel, Christopher. 2002. "Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry." *The Review of Economics and Statistics* 84 (3).

Lazar, Jim. 2014. "Teaching the Duck to Fly." presented at the RAP Webinar, February 5. http://www.raponline.org/event/teaching-the-duck-to-fly.

Lehr, Ronald. 2013. *New Utility Business Models: Utility and Regulatory Models for the Modern Era*. http://americaspowerplan.com/wp-content/uploads/2013/10/APP-UTILITIES.pdf.

Lowry, Mark, Larry Kaufmann, Donald Wyhowski, and Katherine Dresher. 2000. *Statistical Benchmarking of Utility Service Quality*. Madison, WI: Pacific Economics Group.

Lowry, Mark, Matthew Makos, and Gretchen Waschbusch. 2013. *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*. Edison Electric Institute.

MA DPU. 2000. *Interim Order in D.T.E. 99-84, Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies*. Massachusetts Department of Public Utilities.

Malkin, David, and Paul Centolella. 2014. *Results-Based Regulation: A Modern Approach to Modernize the Grid*. GE Digital Energy and Analysis Group.

Massachusetts Grid Modernization Steering Committee. 2013. *Report to the Department of Public Utilities from the Steering Committee*. Massachusetts Electric Grid Modernization Stakeholder Working Group Process. DPU 12-76.

MD PSC Staff. 2011. *Staff Comments In Support of Proposed Service Quality and Reliability Standards Regulations*. Maryland Public Service Commission Staff.

New England Conference of Public Utility Commissioners v. Bangor Hydro-Electric Co. 2008.

NRC. 1991. *Possible Safety Impacts of Economic Performance Incentives: Final Policy Statement*. Nuclear Regulatory Commission. 56 FR 33945.

NY DPS Staff. 2014. *Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues*. New York Department of Public Service. Case 14-M-0101. August 22, 2014.

NY PSC. 2012. *Order Establishing Utility Financial Incentives*. Order Dated March 22, 2012. Case 07-M-0548, Proceeding on Motion of the Commission Regarding and Energy Efficiency Portfolio Standard. New York Public Service Commission.

———. 2014. *Order Establishing Brooklyn/Queens Demand Management Program*. Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program. New York Public Service Commission.

Ofgem. 2009. *Ofgem Annual Report 2008-2009*. Office of Gas and Electricity Markets. http://webarchive.nationalarchives.gov.uk/20130607131647/http://www.ofgem.gov.uk/About%20us/annlrprt/Documents1/annualreport09access.pdf.

———. 2010. *Handbook for Implementing the RIIO Model*. Office of Gas and Electricity Markets.

———. 2012a. *Strategy Consultation for the RIIO-ED1 Electricity Distribution Price Control: Outputs, Incentives and Innovation*. Supplementary Annex to RIIO-ED1 Overview Paper. Office of Gas and Electricity Markets.

———. 2012b. *Strategy Consultation for the RIIO-ED1 Electricity Distribution Price Control: Reliability and Safety*. Supplementary Annex to RIIO-ED1 Overview Paper. Office of Gas and Electricity Markets.

———. 2013a. *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control: Outputs, Incentives and Innovation*. Supplementary Annex to RIIO-ED1 Overview Paper. Office of Gas and Electricity Markets.

———. 2013b. *Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control: Reliability and Safety*. Supplementary Annex to RIIO-ED1 Overview Paper. Office of Gas and Electricity Markets.

———. 2014a. *Annual Report and Accounts 2013-14*. Office of Gas and Electricity Markets. https://www.ofgem.gov.uk/ofgem-publications/88450/annualreport2606201314.pdf.

———. 2014b. *RIIO-ED1: Final Determinations for the Slow-Track Electricity Distribution Companies*. Final Decision. Office of Gas and Electricity Markets.

PG&E. 2014. *Pacific Gas and Electric Company's (U 39 E) Petition for Expedited Order Granting Modification of Decision 10-04-052 (Photovoltaic Program) and Approval of a Proposed Schedule for the Third Photovoltaic Program Power Purchase Agreement Solicitation, Application 09-02-019*. Pacific Gas and Electric Company.

Pollara. 2010. "Electricity Outage and Reliability Study." Ontario Energy Board Presentation, September. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/OEB_Reliability%20Residential%20Survey_2010.pdf.

Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. 2001. "The State of Performance-Based Regulation in the U.S. Electric Utility Industry." *The Electricity Journal*, October.

SEIA/GTM Research. 2013. *U.S. Solar Market Insight Report, 2013 Q3*.

Shumilkina, Evgenia. 2010. *Utility Performance: How Can State Commissions Evaluate It Using Indexing, Econometrics, and Data Envelopment Analysis?*. 10-05. NRRI.

Smeloff, Edward, and Peter Asmus. 1997. *Reinventing Electric Utilities: Competition, Citizen Action, and Clean Power*. Washington, DC: Island Press.

Southern California Edison. 2006a. "Advice Letter 1991-E, Modification of Preliminary Statement, Part ZZ, Energy Resource Recovery Account (ERRA), Pursuant to Decision 04-07-022," April 21. https://www.sce.com/NR/sc3/tm2/pdf/1991-E.pdf.

———. 2006b. *SCE's Response to Information Requested in Ordering Paragraph 7 of I.06-06-014*. http://www3.sce.com/sscc/law/dis/dbattach5.nsf/0/F34B2B2468B89737882571A70054CD54/$FILE/2006-07-07+SCE+Response+To+OP+7.pdf.

U.S. BLS. 2013. "How to Compute a Firm's Incidence Rate for Safety Management." *U.S. Department of Labor Bureau of Labor Statistics*. November 7. http://www.bls.gov/iif/osheval.htm.

U.S. EIA. 2015a. *Annual Report of Natural and Supplemental Gas Supply and Disposition: Form EIA-176 Instructions*. U.S. Energy Information Administration. Accessed January 5. http://www.eia.gov/survey/.

———. 2015b. *Form EIA 923 Power Plant Operations Report Instructions*. U.S. Energy Information Administration. Accessed January 8. http://www.eia.gov/survey/.

———. 2014c. *Form EIA-861 Annual Electric Power Industry Report Instructions*. U.S. Energy Information Administration. Accessed November 18. http://www.eia.gov/survey/.

WECC Staff. 2013. *Interconnection-Wide Transmission Plan Summary*.

Appendix A – Detailed Case Studies

California

California has a long history of employing various performance incentive mechanisms, and much can be learned from the successes and failures of these experiments. Here we discuss a few of the performance incentive mechanisms that have been employed in California, focusing particularly on the lessons that have been learned along the way.

It is often easier to point out instances of when mechanisms have gone awry than where mechanisms have functioned well, due to the amount of attention garnered by the former. For this reason, much of the discussion below highlights the challenges that have been encountered along the way and strategies for avoiding similar difficulties in the future. This should not be taken to imply that performance incentive mechanisms always or often encounter these problems. Indeed, California's willingness to continue to experiment with performance incentive mechanisms indicates that regulators continue to believe that they are a useful regulatory tool.

Nuclear Power Plant Performance

<u>Diablo Canyon Nuclear Incentives</u>

The 1980s were characterized by numerous nuclear power plant cost overruns and generally low industry-wide nuclear plant capacity factors. Pacific Gas and Electric's (PG&E's) $5.5 billion Diablo Canyon power plant was one example of a power plant that exceeded its estimated construction budget by several billion dollars.

In 1988, the California Public Utilities Commission (CPUC) authorized a settlement regarding Diablo Canyon that was intended to protect ratepayers from the significant cost overruns of the plant, while encouraging the plant to operate efficiently. Instead of allowing PG&E to recover all of the costs of the plant automatically, the settlement based a large portion of the cost recovery on the amount of electricity that would be generated by Diablo Canyon. Energy from the plant was to be paid a set price per kilowatt-hour, and the utility would only recover all of its costs if the plant operated at a high capacity factor. Further, the utility and its shareholders assumed responsibility for all repairs and additional investments at Diablo Canyon (CPUC 1988).

The settlement shielded ratepayers from the risk that the plant would perform poorly or incur significant additional costs. However, there were three aspects of the performance incentive mechanism in the settlement that would ultimately work to the disadvantage of ratepayers:

- First, the target capacity factor above which PG&E would earn a profit was set based on industry averages, rather than based on the much higher-than-average capacity factor of Diablo Canyon at the time of the settlement.[25]
- Second, the financial reward to PG&E for generating electricity from the plant was set at a fixed price (escalated for inflation), rather than being flexible to account for changing market conditions. As a result, ratepayers continued to pay a set price per kWh of electricity from Diablo Canyon even when it would have been more economical to use energy from other sources (such as oil or gas) (CPUC 1988). Although the price set for electricity from Diablo Canyon appeared reasonable at the time, in later years Diablo Canyon power became significantly more expensive than power sold on the West Coast wholesale market.[26]
- The performance incentive mechanism contained no shared savings component or other safety valve that would have reduced the consequences of getting either of the above two elements wrong.

PG&E successfully operated the Diablo Canyon power plant, achieving capacity factors much higher than the industry average at the time of the settlement agreement, and producing profits for shareholders. In this way, the incentive mechanism can be said to have been successful in providing an incentive for the utility to operate the nuclear power plant efficiently, but the choice of a target capacity factor and locking in the power plant's energy price did not generate the intended benefits for ratepayers. The performance incentive mechanism ultimately proved to be unstable and was modified in later years and finally eliminated in 2002 through Decision 02-04-016.

A more tenable performance incentive mechanism might have also have (a) included a shared savings component, whereby ratepayers would receive a portion of any profits generated, or (b) tied the price paid for Diablo Canyon power to the avoided cost of power from fossil generators. These components would have distributed the risk more equitably between ratepayers and the utility.

<u>Palo Verde Nuclear Incentives</u>

In the 1990s, California adopted additional performance incentive mechanisms for other nuclear power plants, including the Palo Verde Nuclear Generating Station. The terms of this incentive mechanism were modified from those of Diablo Canyon: the utility would receive a reward for generation above a capacity factor of 80 percent, and the reward would be calculated based on the difference between Palo Verde's incremental variable cost and the cost of replacement power. In addition, the performance incentive mechanism initially included a provision for sharing of benefits between shareholders and ratepayers in later years, although this provision was eliminated before it took effect (CPUC 2001).

---

[25] The capacity factor from the date of commercial operation through June 30, 1988 was 67.7% for Unit 1 and 76.7% for Unit 2, as compared to an industry average of 58% for similar large nuclear power plants (CPUC 1988, 112, 114).

[26] In 1994, Diablo Canyon was earning more than 12 cents/kWh, while Western Market wholesale power prices were approximately 3 cents/kWh (Smeloff and Asmus 1997, 82).

Although this performance incentive mechanism incorporated greater protections for ratepayers than the PIM for Diablo Canyon, it ultimately also proved to be unstable. When the PIM was initially developed, the cost of replacement power was expected to be in the range of $0.03 to $0.05 per kilowatt-hour, but by summer 2000, these costs had escalated to more than ten times higher. For this reason, stakeholders lobbied for a limit on the incentive payments and the commission instituted a cap of $0.05 per kilowatt-hour (CPUC 2001).

The Palo Verde incentive mechanism was initially designed to expire at the end of 2001, at which point Palo Verde would be returned to cost-of-service ratemaking. Upon petition by SCE, the incentive mechanism was continued until SCE's next general rate case, effective May 22, 2003 (Southern California Edison 2006a).

Lessons Learned

California's experience with nuclear power incentives highlight just how difficult it can be to set a reasonable target and incentive payment. These difficulties can be mitigated by using shared savings mechanisms or instituting safety valves—such as Palo Verde's cap on the incentive payment.

Gaming and Manipulation of Performance Incentive Mechanisms

In 1990, the CPUC began an investigation into incentive-based ratemaking for gas utilities (R90-02-008 and I90-08-006), finding that a PBR plan with indexing could "provide substantial benefits in increased efficiency, innovation, ratepayer protection, risk allocation, and regulatory simplicity" (CPUC 1991, 1). Beginning in 1993, the CPUC approved gas procurement mechanisms for the gas utilities that replaced after-the-fact reviews of gas procurement with market-based gas price benchmarks.

Soon, the CPUC began to also approve PBR mechanisms for electric utilities. PBR was introduced as an alternative to cost-of-service regulation, which the Commission felt had become "too complex to allow us to regulate utilities effectively" (CPUC 2008, 2). The Commission hoped that PBR plans would help them find "new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations" (CPUC 2008, 3).

A PBR plan was adopted for Southern California Edison (SCE) though Decision (D.) 95-12-063 and modified by D.96-09-092. Three categories of service incentives were created: reliability, customer satisfaction, and health and safety.

SCE's Customer Satisfaction Incentive Mechanism terminated at the end of 2003, while some form of Employee Health & Safety Incentive Mechanism continued through 2005 (Southern California Edison 2006b). From 1997 to 2000, SCE received $48 million in rewards under the customer satisfaction and health and safety incentive mechanisms. Subsequently, SCE requested $20 million in customer satisfaction rewards for 2001 to 2003 and $15 million in health and safety rewards for 2001 and 2002. However, in a 2008 decision, the CPUC ordered SCE to refund these rewards and forgo the additional rewards requested, as well as pay a fine totaling $30 million. The problems leading to this decision are briefly described below, followed by remarks regarding how such results might be avoided in the future.

Customer Survey Problems

Under the Customer Satisfaction Incentive Mechanism, customer satisfaction was measured through the use of third-party administered surveys with rewards and penalties in four areas: field services, local business offices, telephone centers, and service planning. Each area received a score of 1 to 5+, where 1 was low. Scores were then averaged across the four service areas to obtain the overall average score (CPUC 2008).

The original target for the overall customer satisfaction score was set to 64% of scores being 5 or 5+, with a deadband of plus or minus 3%. Beyond the deadband, the utility received a reward or penalty of $2 million for each percentage point change in the average result, up to a maximum of $10 million per year. In addition, if any one area received a score of less than 56%, a penalty would be assessed. In D.02-04-055, the Commission increased the customer satisfaction target from 64% to 69%, based on the average of the then most recent nine years of survey results (CPUC 2008).

The problems with the customer survey began with the selection of customers for the survey pool. This exercise was left to the meter readers themselves, who were supposed to push a button on a handheld device they carried every time they had a meaningful interaction with a customer (whether it was positive, neutral, or negative). However, there was no practical means of ensuring that meter readers actually did record interactions that were both positive and negative. In addition, SCE employees sometimes falsified the contact information to screen out customer interactions that might result in negative customer satisfaction surveys (CPUC 2008).

Further, some SCE employees attempted to skew survey results favorably by requesting that customers give them a good score when surveyed, giving customers collateral materials (such as golf balls and ball point pens), or telling customers that a survey score of less than 5 would represent a failing score that might lead to disciplinary action against the utility employee (CPUC 2008).

Thus despite using a third party to administer the customer satisfaction survey, the performance incentive mechanism failed because the data collection process was exposed to data manipulation and gaming by utility employees. The issue only came to light when a whistle blower wrote an anonymous letter to an SCE senior vice president. Even then, the initial review of the allegations concluded that any survey problems were inadvertent. After another anonymous letter was received with more serious allegations (including that SCE managers and high-level directors were aware of the conduct), an independent investigation was launched that began uncovering the misconduct. Ultimately, the California Public Utilities Commission found that from 1997 through 2003, SCE “manipulated and skewed survey results, artificially inflated survey outcomes, and received PBR rewards” (CPUC 2008, 16).

Underreporting Employee Health and Safety Incidents

Employee health and safety was measured by the number of first aid incidents and lost time incidents, based on historical averages as reported to OSHA. Based on that data, the benchmark was set at 13.0 injuries and illnesses per 200,000 hours worked with a dead band of +/-0.3. In 2002, the target was reduced to 9.8 injuries and illnesses based on the most recent seven years of data, and in 2003 it was further reduced to 8.6 injuries and illnesses. Results above or below the dead band would result in rewards or penalties (CPUC 2008). Unfortunately, from the beginning this performance incentive mechanism was deeply flawed.

As with the customer surveys, the first problem with the Employee Health and Safety Incentive Mechanism was that data were not appropriately collected – both in the establishment of the performance target and for compliance reporting. To begin with, the utility did not establish a system to track all first aid incidents, leading to underreporting of the data used to establish the performance target, as well as the compliance data. Further, SCE maintained different standards for internal safety performance measures than for compliance with the performance incentive mechanism. The unsurprising result was that only a small fraction of first aid incidents were reported.

Second, the existence of the incentive mechanism actually discouraged employees from reporting injuries. The Commission found that particularly "when safety incentives are group-based (as they are in some business units), injured employees may want to avoid reporting their injuries and jeopardizing safety incentive compensation not just for themselves, but also for the rest of their group" (CPUC 2008, 60)

In addition, some supervisors participated in or encouraged under-reporting of data. "Among the methods used to disguise injuries and avoid internal reporting are: employee self-treatment; treatment by personal physicians rather than the company doctor; timecard coding of lost time as sick days or vacation; etc." (CPUC 2008, 60).

Lessons Learned

In both the customer satisfaction and health and safety incentive mechanisms, data collection was seriously flawed. These experiences highlight the need to validate data frequently and to employ independent third parties for data collection where possible. However, the disincentive for employees to self-report health and safety data may be too great to overcome. Because of the great importance of maintaining a safe work environment, some jurisdictions have elected to eliminate performance incentives for health and safety in order to avoid creating perverse incentives. This does not mean that such data cannot or should not be tracked, but financial rewards or penalties should be carefully considered.

Recent Experience with Performance Incentives in California

In the early 2000s, California abandoned performance-based ratemaking and returned to "a transparent regime of cost-based ratemaking" (CPUC 2004, 288). However, the Commission elected to continue to use performance incentive mechanisms, as

> "they provide a more responsive approach to deviations in service adequacy and quality than our other ratemaking mechanisms.… They can be carefully adapted to the cost-of-service regime and enhance our ability to regulate in the public interest, providing both financial incentives to guide utility activities and an early warning of longer-term trends

> that we can use to guide more intrusive regulatory interventions such as complaints and investigations. They represent a calibration, not a contradiction, of our cost-of-service principles" (CPUC 2004, 289).

Although the customer service and health and safety performance incentive mechanisms as described above have been discontinued, the California Public Utilities Commission has continued to experiment with performance incentive mechanisms where warranted. Under a cost-of-service regime, however, the CPUC requires that the need for such incentives be fully justified, stating:

> "We will consider whether the proposed performance incentives are necessary for achieving one or more of our regulatory objectives and are likely to be cost-effective; we do not believe that performance incentives should be adopted solely on the basis of their mere consistency with a particular objective. Since rates set through our conventional approach to ratemaking are intended to provide the funding required to meet the regulatory objectives of safe and reliable service, we must ask why the utility needs the possibility of additional ratepayer funding, or threat of reduced funding, to get the utility to do what it is already funded and expected to do. The burden is on the proponents of performance incentives to prove they are necessary, cost-effective, and otherwise reasonable" (CPUC 2004, 290).

Renewable Energy Procurement Costs

California has long had a Renewable Portfolio Standard (RPS), but certain provisions in the enforcement rules caused CPUC become concerned that construction delays and contract failures could jeopardize PG&E's compliance with the RPS (CPUC 2010). The RPS enforcement rules contained loopholes to deal with the cumbersome, short annual compliance period that was required by legislation, such as allowing retail sellers to incur a certain percentage of their annual procurement obligation as a deficit without explanation. As another example, the rules allowed "earmarking" of future contracted deliveries for the current compliance period, even if deliveries were not anticipated to commence in the current compliance period (CPUC 2014a).

In February 2009, PG&E filed a proposal—with no performance incentive component—to implement and recover costs of a photovoltaic (PV) program. In response to recommendations by other parties, the CPUC approved the program but adopted a price cap of $246 per MWh and a cost savings incentive mechanism "to better align PG&E's financial interests with those of ratepayers" (CPUC 2010, 31).

The program target called for installing 50 MW of utility-owned PV capacity per year for five years (for a total of 250 MW of utility owned generation). PG&E could also enter into power purchase agreements (PPAs) for up to 250 MW of PV. Under the cost savings incentive mechanism, PG&E shareholders were permitted to retain 10% of cost savings if actual average capital costs over the life of the PV Program fell below $3,920 per kW, representing PG&E's capital cost estimate with no contingency amount. Ratepayers were entitled to retain 90% of the cost savings below $3,920 per kW. Although the CPUC did not specify a penalty, capital costs above $4,312 per kW were subject to a reasonableness review.

Notably, PG&E opposed the cost cap and cost savings incentive mechanism, largely on the grounds that these elements exposed PG&E to uneven risks and rewards (CPUC 2010, 55–56).

In December 2012, PG&E requested to terminate its PV Program after the second PV PPA solicitation and to procure the remaining capacity using the Renewable Auction Mechanism (RAM) process adopted by the CPUC in D.10-12-048 instead. The CPUC rejected the request on procedural grounds. In February 2014, PG&E resubmitted its request, claiming that terminating the PV Program and using the RAM process to procure the remaining capacity would create significant administrative efficiencies, would reduce customer costs, and was appropriate given that the PV sector had significantly transformed since the PV Program was approved in 2010 (PG&E 2014). In November 2014, the CPUC granted PG&E's request to close the PV Program, noting that the CPUC's goals in establishing the program were substantially achieved and the availability of other procurement tools for smaller scale RPS-eligible products, making the PV program duplicative and administratively burdensome (CPUC 2014b, 14).

Lessons Learned

The experience with the PV Program cost savings incentive mechanism suggests that asymmetrical risk and reward mechanisms are likely to garner opposition by utilities. In this case, PG&E shareholders were permitted to retain only 10% of the cost savings below its capital cost estimate excluding contingency, and costs above the cost cap would be subject to regulatory review. On the other hand, ratepayers were entitled to retain 90% of the cost savings below $3920 per kW, and they were protected from the downside by a cost cap provision.

Another lesson from this experience involves consideration of administrative burden and redundancy. The potential rewards for the company were apparently not enough to outweigh the administrative burden of maintaining the PV Program. Given that the RAM process had matured since the inception of the PV Program, the latter became redundant.

The UK RIIO Model

When the British energy distribution and transmission utilities were privatized in 1990, a performance-based regulatory framework was adopted with a price control mechanism to regulate the utilities. This form of PBR was referred to as "RPI-X," as it allowed revenues to grow at the rate of the retail price index (RPI), less an X-factor which was designed to capture improvements in productivity, rewards and penalties, or other elements. The term of each PBR period was set at five years in order to incentivize efficiency improvements and cost reductions (the savings from which the utilities would retain until the end of the price control period). In order to prevent service quality degradation, the RPI-X plans also specified certain outputs that the utilities were required to deliver.

Over the past twenty-five years, this performance regulation framework has evolved to adapt to changing policy priorities and industry challenges. In 2008, the British Office of Gas and Electricity Markets ("Ofgem"), launched a fundamental review of the regulatory framework. Out of this review and stakeholder discussion was borne a revised form of PBR, one more comprehensive and performance-based than the RPI-X system. This new framework is referred to as "RIIO," an abbreviation for Revenue = Incentives + Innovation + Outputs.

RIIO seeks to improve upon the RPI-X model and respond to concerns that:

- The RPI-X framework focused the utilities on achieving cost savings, but not on delivering other outputs, such as improved quality of service.
- The five-year duration of the RPI-X price control period was not sufficient to encourage companies to focus on long-term trade-offs and effects of investments, innovation, and service quality.
- The RPI-X framework was not flexible enough to respond and adapt to step-changes in technology. Additional incentives were felt to be needed to stimulate innovation and adequately respond to sector-wide need to transition to a low-carbon energy industry (Jenkins 2011).

RIIO was designed to address these concerns by (a) shifting the focus from cost control to delivery of outputs through the use of performance incentives, (b) increasing the price control period to eight years, (c) increasing the focus on innovation through financial incentives and an innovative projects competition, and (d) increasing the emphasis on competition where possible. It is expected that these adjustments will encourage utilities to innovate to deliver cost savings and value for customers, as the utilities will retain most of the efficiency savings they generate for a longer period and they have the potential to earn rewards for over-delivering in certain performance areas.

Base revenues under RIIO are determined through utility business plans. These plans must be well-justified and designed to establish a long-term corporate strategy for delivering "value for money" to customers. In developing their business plans, the utilities are required to assess alternative options for delivering outputs, evaluate the long-term costs and benefits for each alternative, and incorporate stakeholder input. Once approved, the business plans form the basis for revenue adjustments over the next eight years, with annual true-ups to account for differences in actual versus projected sales. A sharing mechanism allows utilities and customers to share any savings or overages relative to the budget, with the majority of shared savings generally accruing to the utility (ENA 2014; Ofgem 2013a).[27]

In addition to the base revenues established through utility business plans, utilities may be rewarded or penalized based on their performance in delivering specific outputs. As discussed in detail in the following sections, these rewards and penalties can have a relatively large impact on each utility's realized return on equity, with impacts of up to approximately +/- 300 basis points (Ofgem 2014b).[28]

The electric distribution network price control period will begin on April 1, 2015 and last until March 31, 2023. At the time of writing, the electric utilities had submitted their business plans to Ofgem for review, and Ofgem had approved (with modification) all of the plans. One utility's plan was "fast tracked" and accepted in full, due to it being of sufficiently high standard. The fast-tracked utility also received a reward equal to 2.5 percent of "totex" (capital expenditures + operating expenditures). The other five utilities' plans were approved, but with allowed revenues of approximately 5 percent less than requested in their business plans (Ofgem 2014b).

RIIO Outputs

Outputs are a core element of the RIIO regulatory framework, falling in six categories:

1. Safe network services
2. Environmental impact
3. Customer satisfaction
4. Social obligations
5. Connections
6. Reliability and availability

Within each of these categories, "secondary deliverables" have been identified upon which utilities will be required to deliver. For example, one of the secondary deliverables under the environmental impact category is a utility's total CO_2 equivalent emissions.

A series of working groups was established in order to identify specific metrics and incentives for each of these deliverables. Ofgem also received input from the Consumer Challenge Group, a small group of

---

[27] The percent of savings that the utility can retain under the "efficiency incentive" ranges from 45 percent to 70 percent, depending on whether the utility is fast-tracked or not, and the degree to which the utility's forecasts align with Ofgem's models. This sharing rate is set as part of the Informational Quality Incentive (Ofgem 2013a).

[28] The financial impacts of the performance incentive mechanisms associated with specific outputs are in addition to total expenditure efficiency incentives, informational quality incentives, and rewards associated with compiling a high-quality business plan. These other incentives could have an additional impact of more than 100 basis points in either direction. See Figure 10 for the total impact of these factors.

consumer experts that work to ensure consumers' interests are fully considered. Targets for many metrics are set by the Ofgem with input from stakeholders, while for some metrics (such as asset health), utilities propose the targets themselves in their business plans. All targets proposed by utilities must be justified in terms of costs and benefits to customers and informed by stakeholder engagement (Ofgem 2012a).

Not all outputs under RIIO have financial incentives. For example, the Reliability and Safety Working Group rejected the use of incentives (financial or reputational) for safety, as it was felt they could result in unwanted implications for incident reporting (as occurred in California, described in the previous section). Moreover, utilities are already required to comply with health and safety standards set by another governmental agency, and would be subject to enforcement action from that agency in the event of non-compliance (Ofgem 2012a).

Some categories of outputs have "reputational" incentives, where results are published and utility performance compared against other utilities, but no financial incentives are imposed. For example, under the Business Carbon Footprint metric, each utility submits an annual report of its total CO_2 equivalent emissions, as well as the actions it has taken to reduce emissions relative to their baseline. This allows utilities to share best practices and learn from one another, while also providing time to refine data collection and analysis techniques to provide more reliable data prior to administering rewards and penalties (Ofgem 2012a).

In addition, Ofgem is careful to ensure that in areas where competition exists (such as connection services) no incentive benefits are provided to utilities that are not also available to independent providers. The total package of incentives are intended to be clear and balanced in order to prevent perverse incentives, and to ensure that utilities that provide value for customers' money earn a relatively high rate of return, while utilities that fail to deliver value earn low returns (Ofgem 2012a).

The following subsections summarize the performance incentive mechanisms currently in use or under development for RIIO. Utilities must also report on several performance metrics (such as noise, sulfur emissions) that do not have corresponding financial or other incentives and are therefore not listed in the table below. For more information, see Ofgem 2013a and Ofgem 2013b.

Environmental Impact

Currently two performance incentive mechanisms are associated with the environment impact category: electricity losses and business carbon footprint. UK utilities are contractually obligated to reduce losses as much as practicable, and can be found in violation of their license agreement if they fail to do so. If utilities are particularly successful or innovative in reducing losses, they may qualify for a reward, which increases over the duration of the PBR period in order to incentivize implementation of long-term solutions.

The incentive under the business carbon footprint is unusual in that it is reputational only, due to Ofgem's determination that data are not sufficiently reliable to form the basis for financial rewards or penalties (Ofgem 2012a).[29] Under this mechanism, utilities' performance is reported annually and made public by Ofgem. All utilities' results are aggregated into one table to facilitate comparisons across utilities.

Table 17. RIIO Environmental Impact Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Electricity losses	Discretionary reward of up to £4 million in year 2, £10 million in year 4, and £14 million in year 6 for utilities that exceed the loss reduction commitments in their business plans.	Utilities report annually on loss reduction activities undertaken, improvements achieved, and actions planned for the following year. Performance will be measured according to multiple criteria, including the effectiveness of actions taken to reduce losses, engagement with stakeholders, innovative approaches to loss reductions, and sharing of best practices with other companies.
Business Carbon Footprint (BCF)	Reputational	Annual reporting requirement on CO_2 equivalent emissions, actions taken to reduce emissions over the past year and their effectiveness. All utilities' performance on this metric summarized in one table.

Source: Ofgem 2012 and Ofgem 2013

[29] A distribution utility's business carbon footprint is in part based on contractor emissions, which may not be sufficiently reliable.

Customer Satisfaction and Social Obligations

Three performance incentive mechanisms are in place to measure customer satisfaction and the degree to which utilities fulfill social obligations such as assistance to vulnerable customers. Two of these performance incentive mechanisms, complaints and stakeholder engagement, are asymmetrical. Complaints are associated with a penalty only, while stakeholder engagement can only result in a reward.

Table 18. RIIO Customer Satisfaction and Social Obligations Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Customer satisfaction survey	Reward or penalty up to 1% of annual base revenue	A survey is used to measure the satisfaction of customers who have required a new connection, have experienced an interruption to their supply, or have made a request for a service or job to be completed. Performance is measured based on the response to the question: "Overall how satisfied were you with the service that you received?" The target score will be set at the beginning of the period, and will be set at a level that "can be objectively assessed to represent a good level of performance."
Complaints	Penalty of up to 0.5% of annual base revenue. No reward.	Complaints and their weightings are measured based on: (a) percentage of complaints that are outstanding after one day (10% weighting); (b) percentage of complaints that are outstanding after 31 days (30% weighting); (c) percentage of complaints that are repeat complaints (50% weighting); and number of Energy Ombudsman decisions that go against the utility as a percentage of total complaints (10% weighting). An industry target is set.
Stakeholder engagement	Reward of up to 0.5% of annual base revenue. No penalty.	The regulator will develop a mechanism for assessing the utilities' use of data and customer insight to understand and identify effective solutions for vulnerable consumers, as well as their ability to integrate this into core business activities.

Source: Ofgem 2012 and Ofgem 2013

Connections

In addition to the customer satisfaction survey (which measures, in part, satisfaction with the utility's service in interconnecting new customers or distributed generation facilities), two performance incentives encourage the utilities to efficiently interconnect residential customers and respond to the needs of large customers (including distributed generation). These incentives are asymmetrical; a reward (but no penalty) can be earned for the time required to process small customer interconnections, while the incentive for large connections (including distributed generation) is penalty-only.

Table 19. RIIO Connections Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Time to Connect Incentive for Small Connections	Reward of up to 0.4% of annual base revenue. No penalty.	Measures the time taken from initial application received to the issue of a quotation and the time taken from quotation acceptance to connection completion. Target based on historical performance data, and target will become more stringent over the period.
Incentive on Connection Engagement (ICE) for Large Connections	Penalty of up to 0.9% of annual base revenue. No reward.	Each utility must submit evidence of how they have identified, engaged with, and responded to the needs of their customers. These submissions will be compared to a set of minimum requirements, which will likely to require each utility to demonstrate how they have engaged with a broad range of customers, established relevant performance indicators, and developed a forward-looking work plan of actions to improve performance (with associated delivery dates). Separate submissions will be required for different market segments, including distributed generation customers. A penalty will be assessed for failing to meet the minimum requirements for that market segment. The regulator will also continue to engage with stakeholders to identify key issues and gather feedback on utility performance.

Source: Ofgem 2012 and Ofgem 2013

Reliability and Availability

Several performance incentive mechanisms are in place to ensure reliability and availability. These performance incentives carry sizeable rewards and penalties, based largely on studies of customers' willingness to pay. The interruptions incentive scheme is most comparable to SAIDI and SAIFI rewards and penalties in the United States, but has separate components for unplanned versus planned outages. Because the utilities provide prior notice to customers regarding planned outages, they are less disruptive to customers. For this reason, planned outages carry a lesser financial reward or penalty as compared with unplanned outages (Ofgem 2012b; Ofgem 2013b).

The guaranteed standards of performance incentives reflect a 2010 law (SI No. 698, 2010.27) that requires utilities to make payments to customers whenever performance falls below a certain level. For example, the 2010 law requires a payment from the utility directly to affected customers who experience outages lasting more than 18 hours, or who experience four or more outages a year. RIIO maintains or strengthens these existing standards.

Finally, RIIO also penalizes or rewards utilities that under- or over-deliver on the health and load indices of their assets. Utilities target a certain level of output delivery in their business plans, which then form the basis for their allowed revenues in this area. (These performance levels must be justified through both cost-benefit analysis and stakeholder engagement.) Under-performance therefore results in both a penalty and a downward adjustment to future allowed revenues, while over-performance results in a reward and higher future allowed revenues (Ofgem 2012b; Ofgem 2013b).

Table 20. RIIO Reliability and Availability Performance Incentive Mechanisms

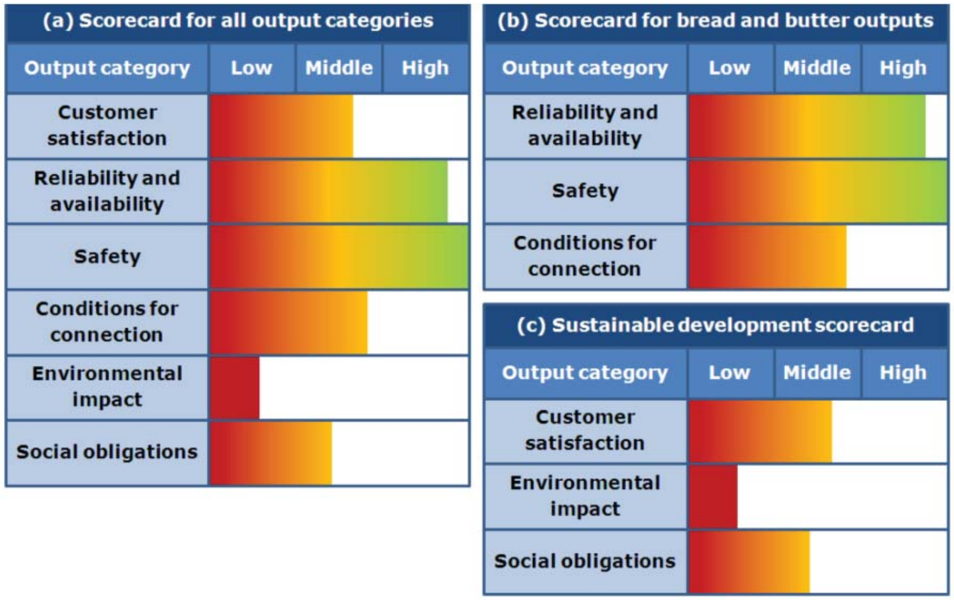
Deliverable	Penalty or Reward	Metric and Target Description
Interruptions Incentive Scheme	Penalty or reward of up to 250 basis points on rate of return per annum	Utilities are incentivized on the number and duration of network supply interruptions versus a target derived from benchmark industry performance. Planned and unplanned outages have separate targets, and planned outages are rewarded and penalized 50% less than unplanned outages. Annual utility targets for planned interruptions are set using a three-year rolling average, with a two-year lag. (That is, the 2015-16 target would be the average over the 2011-12 to 2013-14 period.) Unplanned outage targets are set using a combination of utility and industry average for Low Voltage (LV), Extra High Voltage (EHV), and 132kV. Exceptional events are excluded from the performance data. Utilities can propose alternative targets in their well-justified business plans.
Guaranteed Standards of Performance	Penalty: Direct payments to each customer affected, typically of approximately £30/customer	Customers are eligible for direct payment of specific fixed amounts where a utility fails to deliver specified minimum levels of performance. For example, if the duration or frequency of interruptions exceed a pre-specified level, the utility must make a payment to a customer. Vulnerable customers on the Priority Service Register will receive automatic payments, while other customers will need to apply to their utility for payment.
Health and Load Indices	Penalty for under-delivery equal to reduced future allowed revenues and 2.5% of the value of the under delivery, or a reward for over-delivery equal to 2.5% of the incremental costs associated with over delivery and an upward adjustment to future allowed revenue.	Risk reduction associated with the condition and loading of assets. These metrics encourage longer-term strategies by linking the longer-term reliability benefits of healthier and less highly-loaded assets to a measurable deliverable within the price control.

Source: Ofgem 2012b, Ofgem 2013b

Scorecard for Outputs

To facilitate comparison across companies, Ofgem intends to develop scorecards for each of the companies' performance across the categories of output. Although the details have not yet been fleshed out, the scorecard will measure performance relative to a normalized baseline, as presented in the illustrative example below.

Figure 9. Illustrative Scorecard for Outputs



Source: (Ofgem 2010)

Lessons Learned

Under RIIO, a suite of performance incentive mechanisms, together with a comprehensive revenue cap mechanism, has been designed to encourage utilities to meet the needs of their customers in a cost-effective manner. Even though this new PBR framework is still being developed and has yet to be applied, several lessons can be drawn from the UK experience.

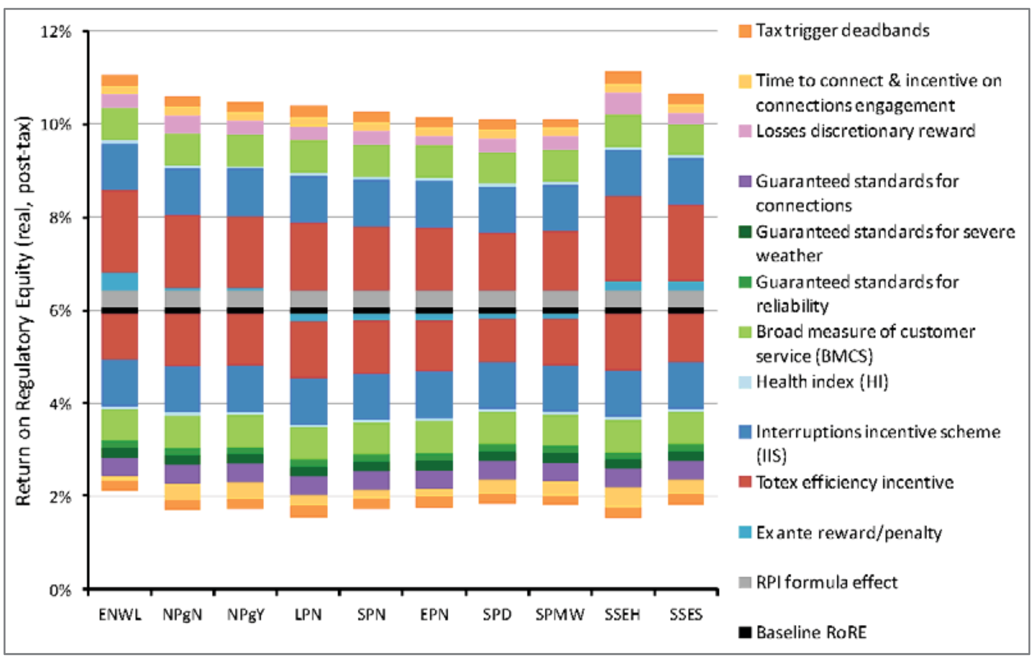
The evolution of the UK PBR framework provides an indication of the limitations to the simpler version of performance-based regulation that has been in place in the US, and the UK experience mirrors some of the challenges with PBR that US regulators have wrestled with in recent years. Many of the new RIIO elements described above (e.g., expanding the price control period, more focus on outputs, more attention to future planning in the business plans, increased use of capital cost trackers), reflect the aspects of simple PBR that have been insufficient in achieving PBR's ultimate goals. Regulators in the US who are looking to PBR as a new utility regulatory model should take note of the implications of these new RIIO elements.

One of the key lessons from the evolution of PBR in the UK relates to regulatory engagement. When PBR was introduced in the UK, and shortly after in the US, it was referred to as "hands-off" regulation. For example, the California PUC wrote that it hoped that PBR plans would help them find "new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations" (CPUC 2008, 3). However, the experience from the UK is just the opposite. It is clear that the new RIIO mechanism will requires significant utility and regulatory resources up front due to the extensive nature of the business plan development and review process, as well as the up-front effort necessary to create balanced and effective performance incentive mechanisms. Note that over the last five years, the number of Ofgem employees have doubled to more than 700 full-time employees.[30] Even after the development and approval of the utility business plan, Ofgem will probably need to dedicate considerable resources to the oversight and implementation of the performance incentives and the other components of the RIIO mechanism.

Relative to performance incentive mechanisms in the United States, RIIO places a large amount of revenues at stake. Potential rewards and penalties for outputs under the environmental, customer satisfaction, social obligations, and connections categories equate to approximately 3 percent of utility annual base revenues. Reliability-related rewards and penalties carry with them the possibility of an additional 250 basis points in rewards or penalties. The results of Ofgem's modeling suggest that utilities' realized return on equity may fluctuate by approximately +/- 300 basis points due to these performance incentive mechanisms (Ofgem 2014b).

These performance incentive mechanisms are integrated into a revenue cap plan that increases revenues each year at the rate of inflation and provides utilities with the ability to retain a significant portion of any cost efficiency savings. Allowed revenues are set using a 6 percent return on equity, but actual earnings may vary significantly based on utility performance. According to Ofgem's modeling, the actual ROEs for "slow-track" utilities are likely to range from approximately 2 percent to more than 10 percent, as shown in the figure below (Ofgem 2014b).

Figure 10. Plausible ROE Ranges for UK Distribution Utilities



Source: Ofgem 2014b, page 46

[30] The number of permanently-employed staff at Ofgem has grown from 310 employees in 2008/2009 to 761 in 2013/2014 (Ofgem 2009; Ofgem 2014a).

This wide variability of potential utility returns is by design, as Ofgem determined early on that high-performing utilities should have the opportunity to earn an ROE of greater than 10 percent, while poorly performing utilities could earn an ROE of less than the cost of debt. Ofgem notes that the results shown in the figure above indicate that the package of risk and incentives has been “appropriately calibrated” (Ofgem 2014b, 46). The relatively large magnitude of incentives under RIIO not only helps to focus management attention on the attainment of the established targets, but may also help to provide the revenues necessary for innovating and implementing new technologies.

The RIIO process for developing performance incentive mechanisms relied upon significant amounts of stakeholder feedback, ranging from utilities to consumer groups. However, not all of the performance incentive mechanisms appear to have been fully developed yet, particularly for stakeholder and customer engagement. This is perhaps not surprising, as metrics based upon more qualitative data are difficult to define and can be difficult to administer. Lessons learned from the UK’s experience with these more qualitative performance incentive mechanisms will be instructive for the development of similar valuable, but difficult-to-quantify performance targets elsewhere.

RIIO’s performance targets are generally linked directly to utility business plans or industry-wide performance levels, which helps to ensure that the targets are reasonable and that the utilities will have the funds required to make investments to meet these targets. In some cases, such as interruptions and availability, rewards and penalties are based on customer willingness-to-pay surveys in order to balance the value of improved reliability with the associated costs.

Lastly, RIIO’s use of “reputational” incentives for reducing carbon emissions provides an example of how simply displaying a comparison of utility performance in an easily and publicly accessible manner can encourage utilities to take steps to improve their performance, particularly for areas that are important for customers, such as carbon emissions. While the reputational incentive may not always be sufficient for achieving the level of performance desired, it represents a relatively simple and risk-free first step. Moreover, it allows data collection processes and definitions to be standardized and clarified prior to applying high-stakes financial incentives.

New York

During the 1990s, New York experimented with numerous performance incentive mechanisms for its electric and gas utilities. For example, the 1991 Measured Equity Return Incentive Program (MERIT) for Niagara Mohawk Power Company was designed to address a variety of aspects of the company's operations, including nuclear plant performance, the amount of payments to outside law firms, and environmental performance. The program resulted in significant improvements at Niagara Mohawk, and various performance incentive mechanisms were subsequently adopted at other New York utilities, generally under a comprehensive PBR plan with a price cap (Biewald et al. 1997).

The breadth of performance incentive mechanisms in use in New York was substantially reduced following restructuring as generation assets were spun off and subjected to the discipline of the market. Recently, however, New York has developed a renewed interest in performance incentive mechanisms as a means of reshaping utility incentives. In April 2014, the New York Public Service Commission (PSC) initiated the Reforming the Energy Vision docket with the goal of better aligning utility interests with state energy policy objectives. Although the docket is currently on-going, the initial straw proposal envisions moving toward a more "outcome-based approach to ratemaking" with metrics based on state energy policy goals (NY DPS Staff 2014).

A key component of the Reforming the Energy Vision (REV) proceeding is the desire to place distributed energy resources on a level playing field with traditional investments. While the REV proceeding is expected to develop a new ratemaking framework to achieve this goal, New York is already taking steps toward a new regulatory paradigm. In December 2014, the PSC approved incentives to reward the use of cost-effective distributed energy resources through a project called the Brooklyn Queens Demand Management (BQDM) program.

The Brooklyn Queens Demand Management program was proposed by Consolidated Edison Company (ConEd) to address load growth in the Brooklyn and Queens areas of New York. Rather than constructing a new area substation, a new switching station, and new subtransmission feeders (at a cost of approximately $1 billion), ConEd proposed to implement a portfolio comprised of distributed energy resources and other low-cost traditional utility-side solutions to address the forecasted summer overloads at a much lower cost (NY PSC 2014).

The PSC found that the BQDM project and associated incentives represented a valuable opportunity to explore changes to traditional utility operations and ratemaking, stating "this Commission must itself innovate in order to support innovation by utilities and third parties" (NY PSC 2014, 15). In order to ensure that the utility is indifferent to investments in distributed energy resources and traditional infrastructure investments, the Commission approved several financial incentives for ConEd. Specifically, the PSC approved:

- A regulated return on the alternative investments,
- A 10-year amortization period for the investments,

- A 100 basis point ROE adder on BQDM program costs tied to the achievement of specific outcomes related to achieving a certain capacity of alternative measures, increasing diversity of distributed energy resource vendor market, and implementing a portfolio that has a lower cost than the traditional solution. These performance incentives are defined in Appendix B of the order as follows (NY PSC 2014):

1) Quantity of Alternative Measures:
    a. Metric: Capacity of alternative measures installed
    b. Target: 41 MW
    c. Financial incentive: 45 basis points for meeting or exceeding target

2) Diversity of DER Vendor Marketplace:
    a. Metric: Normalized entropy index, calculated as follows:

$$normalized\ entropy\ index = \frac{\sum_{i=1}^{N} S_i \ln(S_i)}{\ln(N)}$$

    Where N is the number of DER Providers and S_i is the share, in MWh, of each provider in the selected portfolios.
    b. Target: Baseline set at 0.75; maximum reward occurs at 1.0
    c. Financial incentive: One basis point earned for each 0.01 increase in the normalized entropy index above the baseline (up to 25 basis points).

3) Reduction in Dollar/MW Costs:
    a. Metric: Assembling a portfolio of solutions that achieves a lower $/MW lifecycle cost (based on the net present value) than the traditional investment solution (30 basis points). The lifecycle costs will be calculated by January 31, 2017, using the Company's then-applicable Weighted Average Cost of Capital.
    b. Target: Baseline set at $6 million/MW based on the Company's estimated NPV revenue requirement of 915.6 million to achieve a total capability of 152 MW.
    c. Financial Incentive: For every full 1% reduction in the $/MW of the BQDM Program portfolio and associated investments relative to the baseline, the Company may earn 1 basis point (up to 30 basis points.)

Initial Assessment of the BQDM Performance Incentive Mechanisms

The adoption of the above performance incentive mechanisms provides a clear signal to New York's utilities that distributed energy resources should be valued in a manner similar to traditional investments, and that reducing costs for consumers will be rewarded. The three performance incentive mechanisms (quantity of alternative resources installed, diversity of market, and cost) simultaneously address several of the commission's objectives.

In addition, the commission's choice of incentive formulas appears reasonable. The Company will only be rewarded if it installs the amount of alternative resources required (41 MW), but will not be rewarded more for installing more resources than needed, thereby avoiding an incentive to procure excessive amounts of alternative resources. The choice of linear financial rewards for the diversity index and cost provide incentives to achieve the highest levels reasonably possible, while rewarding the Company proportionately for any improvements made.

However, two aspects of the performance incentive mechanism have some room for improvement: (1) the linkage between rate base and the financial incentive, and (2) the definition of the diversity index. The financial reward's direct link to rate base (through virtue of being an ROE adder) implies that increasing rate base will in turn increase the Company's financial reward, which may exacerbate the Averch Johnson effect and lead the utility to make unnecessary rate base investments. This issue is explored in more detail in the FERC Transmission Bonus ROE case study later in this appendix.

The second issue concerns the diversity index definition. On January 12, 2015, ConEd filed a petition requesting clarification and modification to several aspects of the performance incentive mechanism (ConEd 2015):

- First, the Company pointed out that, as currently defined, the diversity index focuses on the number of vendors who are awarded contracts through the BQDM Program, but does not include direct customers and subcontractors. It is likely that the Commission is also interested in increasing the number of customers who provide distributed energy resources (such as commercial buildings providing demand response) and vendor subcontractors, and therefore the diversity index should be expanded to include these entities.

- Second, the diversity index, as currently defined, does not measure diversity of technologies. If this is a priority for the Commission, this measure of diversity should also be included in the index.

- Third, the specific calculation of the entropy index appears to reward equal contributions of capacity more than the number of vendors. That is, under the current metric definition, the Company would earn the maximum reward if two vendors each contribute 50% or if five vendors each contribute 20% of the capacity.

For these reasons, ConEd has proposed that Staff and the Company collaborate to modify the diversity index metric.

Illinois

In October 2011, the Energy Infrastructure Modernization Act (EIMA) was signed into law by Illinois Governor Pat Quinn. The law authorized 10-year, $2.6 billion smart grid investment by Commonwealth Edison (ComEd) designed to modernize and upgrade its electric system, including investments in smart grid infrastructure ranging from distribution automation and substation upgrades to smart meters for customers.

To ensure that customers receive benefits from the upgrades, the law also set reliability and other performance metrics to be achieved incrementally over ten years. These metrics include:

- 20% improvement in SAIDI
- 15% improvement in CAIDI
- 20% improvement in SAIFI
- Improvement in total number of customers who exceed service reliability targets by 75%
- 90% reduction in estimated bills
- 90% reduction in consumption on inactive meters
- 50% reduction in unaccounted for energy
- $30 million reduction in uncollectible expense

The performance incentives were set to be penalty only, with progress required in equal segments for each goal in each year. For each year that a goal is unmet, the utility faces a reduction in return on equity by 5-7 basis points per goal, with the penalty increasing over time. To avoid a penalty, 100% progress is required on reliability goals, and 95% progress required on other goals (220 ILCS 5 §16-108.5).

While explicitly addressing the basic aspects of electricity delivery listed above, the performance incentive mechanisms established by EIMA failed to address numerous other potential benefits of smart grid investments for consumers and the environment. For this reason, several consumer and environmental groups initiated discussions with ComEd to track numerous additional performance metrics.

Expansion of Performance Metrics

In 2013 environmental and consumer groups reached an agreement with ComEd to track numerous additional performance metrics. The list of performance metrics co-developed by the utility and stakeholders is extensive, and includes the following (ComEd 2014):

- Reductions in greenhouse gas emissions (as measured through load shifting, system peak reductions, and reduced truck rolls due to smart meters)
- Load served by distributed resources

- Time required to connect distributed resources to grid
- Peak load reductions (enabled by demand response)
- Products with grid interoperability (retail product market animation)
- Customers enrolled in time-varying rates (e.g., peak time rebates)
- Customer awareness and use of ComEd's web portal for viewing usage information

Although these performance metrics do not include any rewards or penalties, they provide valuable information for regulators and stakeholders to monitor whether customers are receiving the full benefit of the multi-billion dollar smart grid infrastructure investment. In addition, these metrics provide valuable information going forward for regulators if it is determined that a financial reward or penalty is warranted.

Metric Definitions

More than sixty performance metrics were developed to be tracked. The table below lists and defines many of these metrics. A nearly complete list can be found in ComEd's 2014 Smart Grid Progress Report, while the greenhouse gas metric details were filed in Illinois Commerce Commission Case Number 14-0555.

Table 21. Selected Smart Grid Metrics in Illinois

Customers enrolled in Peak Time Rebate, Real Time Pricing, and other dynamic and time variant prices	Residential Customers: Number of customers on a time-variant or dynamic pricing tariff offered by ComEd. Expressed also as a percentage of customers in each delivery class.
	Residential Customers: Number of customers served by retail electric suppliers for which the supplier has requested monthly Electronic Data Interchange delivery of interval data. Expressed also as a percentage of customers taking supply from a retail electric supplier in each delivery class.
	Small Commercial Customers: Number of customers on a time-variant or dynamic pricing tariff offered by ComEd. Expressed also as a percentage of customers in the delivery class.
	Small Commercial Customers: Number of customers served by retail electric suppliers for which the supplier has requested monthly Electronic Data interchange delivery of interval data. Expressed also as a percentage of customers taking supply from a retail electric supplier in the delivery class.
Customer-side-of-the-meter devices sending or receiving grid related signals	Number of ComEd AMI meters with consumer devices registered to operate with the Home Area Network ("HAN") chip by tariffs under which customer receives delivery.
AMI Meter failures	Number of advanced meter malfunctions where customer electric service is disrupted.

Customers with net metering	Number of customers enrolled on Net Metering tariff and the total aggregate capacity of the group.
Peak load reductions enabled by demand response programs	Load impact in MW of peak load reduction from the summer peak due to AMI enabled, ComEd administered demand response programs such as the PTS program as a percentage of all demand response in ComEd's portfolio.
Customer Complaints	Number of formal ICC complaints, informal ICC complaints, and complaints escalated to ComEd's Customer Relations or Customer Experience departments related to AMI Meter deployment, broken down by type of complaint and resolution. AMI Meter deployment includes AMI Meter installation, functioning or accuracy of the AMI meter, and HAN device registration.
Customer premises capable of receiving information from the grid	Number of installed AMI Meters as of the last day of the calendar year that communicate back to the head end system.
	Number of installed AMI Meters as of the last day of the calendar year that communicate back to the head end system, divided by the total number of AMI meters installed.
	Number of customers who have accessed the web-based portal as of the last day of the calendar year as a percentage of customers with AMI Meters and as a percentage of ComEd customers in that delivery class.
	Number of customers who can directly access their usage data as of the last day of the calendar year as a percentage of customers with AMI Meters and as a percentage of ComEd customers in that delivery class.
Peak load reductions enabled by demand response programs	Load impact in MW of peak load reduction from the summer peak due to AMI enabled, ComEd administered demand response programs as a percentage of all demand response in ComEd's portfolio.
Reduction in greenhouse gas emissions enabled by smart grid	Load shifting: ComEd will calculate marginal emissions changes due to load shifting for smart meter customers versus non-smart meter customers at an hourly level.
	Reduction in system peak: ComEd will partner with a third-party entity to conduct a dispatch study of the impact of load shifting and peak load reduction enabled by smart meters, including increased adoption of electric vehicles, on PJM's system, and determine a GHG metric around resulting changes in generator dispatch and expected plant closures.
	Reduced truck rolls: ComEd will compare the aggregate annual GHG emissions of all meter reading vehicles assigned to a specific operating center in the year in which Smart Meters are deployed in that same operating center, to the average aggregate annual GHG emissions of the three years prior to the year in which Smart Meter installation for that specific operating center is completed. GHG emissions will be calculated by measuring fuel consumption and converting into fuel emissions via the Climate Registry emission factor.

Distributed generation projects	Number of locations and total MWs of customer owned distributed generation connected to the transmission or distribution system, broken down by connection to transmission and distribution system.
	Number of locations and total MWs of customer owned distributed generation connected to the transmission or distribution system, broken down by connection to transmission and distribution system.
Load served by distributed resources	Total sales of electricity to the grid from distributed generation (Rider POG or POG-NM customers) divided by zone energy plus distributed generation sales, with all data provided in sortable format.
System load factor and load factor by customer class	Total annual consumption for AMI meters (including, separately, small commercial customers) divided by the average demand across all AMI meters over the 5 peak hours multiplied by 8760 hours by customer class.
Products with end-to-end interoperability certification	ComEd will conduct an annual survey through a third-party provider to evaluate how products are being introduced in the smart grid enabled marketplace.
Network nodes and customer interfaces monitored in "real time"	Network nodes and customer interfaces monitored in "real time"
Grid connected energy storage interconnected to utility facilities at the transmission or distribution system level	Number of locations and total MWs of utility owned or operated energy storage interconnected to the transmission or distribution system as measured at storage device electricity output terminals.
	Number of locations and total MWs of utility owned or operated energy storage interconnected to the transmission or distribution system as measured at storage device electricity output terminals.
	ComEd will conduct an annual survey through a third-party provider to estimate similar measures of non-utility storage units.
Time required to connect distributed resources to grid	ComEd's response time to a distributed resource project application, and time from receipt of application until energy flows from project to distribution grid.
	ComEd's response time to a distributed resource project application, and time from receipt of application until energy flows from project to transmission grid.
Grid assets that are monitored, controlled, or automated	Number and percentage of ComEd substations (Distribution Center Substations ("DCs"), Substations ("SSs") Transmission Substations ("TSSs") and Transmission Distribution Centers ("TDCs")) monitored or controlled via Supervisory Control and Data Acquisition ("SCADA") systems.
	Number and percentage of ComEd distribution circuits (4kV, 12kV and 34kV) equipped with automation or remote control equipment including monitor or control via SCADA systems.

Customers connected per automated circuit segment	Average number of customers per automated three phase 12kV line segment. (An "automated line segment" is a segment of 12 kV three phase mainline circuit between automated devices which include circuit breakers, reclosers, automated switches, etc.)
Improvement in line loss reductions enabled by smart grid technology	Stakeholders agreed upon several research priorities for research about line loss reductions. ComEd is conducting a feasibility study regarding use of Voltage Optimization. Voltage Optimization is combination of Conservation Voltage Reduction and Volt-VAR Optimization. These programs are intended to reduce end use customer energy consumption and peak demand while also reducing utility distribution system energy losses.
Voltage and VAR controls	Number and percentage of distribution lines using sensing from an AMI meter as part of ComEd's voltage regulation scheme.
Tracking Actual Costs	The actual cost of the AMI deployment costs that ComEd has incurred, including both one-time and on-going operating costs.
Customer Applications	Bill impacts associated with the costs for implementation of ComEd's AMI Plan for low, average, and higher usage level customers pursuant to approved rates and surcharges.
	Number of customers that have created and viewed an account on ComEd.com – by usage levels, customer class, and low income customers. An account on ComEd.com is necessary for viewing the web portal.
	Number of customers with ComEd.com accounts that have viewed the web portal - by usage levels, customer class, and low income customers
	Change in customers' energy consumption for customers that have viewed the web portal. ComEd will work with the web presentment vendor to define business processes necessary to track an energy usage impact of accessing the web portal.
	Number of customers enrolled in the Residential Real Time Pricing ("RRTP") program (ComEd's hourly pricing program) by usage levels, customer class, and low income customers.
	Number of customers enrolled in ComEd's PTR program by usage levels, customer class, and low income customers.
Customer Outreach & Education	Awareness and Education - Awareness and understanding of AMI technology and benefits (survey metric)

Hawaii

In 2010, Hawaii adopted revenue decoupling for its electric utilities in order to encourage renewable resources, distributed generation, and energy efficiency. When it adopted the decoupling mechanism, the Commission declined to adopt any performance incentive mechanisms, as the decoupling mechanism did not place a hard cap on allowed revenues. In 2013, however, the Commission determined that it was appropriate to reexamine the decoupling mechanism, particularly its revenue adjustment mechanism, and determine whether any performance metrics or performance incentive mechanisms should be adopted.

Performance Metrics

Numerous parties suggested performance metrics for tracking the utilities' ability to achieve renewable energy goals, ensure reliability, and reduce costs. As a result, the Hawaii Public Utilities Commission adopted nearly 30 performance metrics, including:

- **System Reliability:** System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI)
- **Generator Performance:** Equivalent Availability Factor (EAF), Equivalent Forced Outage Rate Demand (EFORd), Equivalent Forced Outage Factor (EFOF)
- **Independent Power Producer (IPP) energy:** Measured as IPP energy / Net to System Energy
- **Renewable Energy:** System renewable energy (excluding customer-sited generation), total renewable energy (including distributed generation), renewable energy curtailments, and RPS compliance
- **Safety:** Public safety incidents, employee injury and illness rate, employee lost time rate, emergency response time
- **Distributed Energy Resources:** Number of net metering program participants and capacity of net metering program, demand response and storage enrollments
- **Customer service:** call center performance, customer complaints, appointments met, metering and billing accuracy, survey responses
- **Cost:** Metrics providing breakdowns of the contributing cost components to customer rates, and unaccounted for energy (HI PUC 2014).

Further, the Commission ordered that these metrics be posted on the Companies' websites in order to facilitate ease of access for utility customers.

Proposed Performance Incentive Mechanisms

During the second phase of the proceeding, parties proposed various forms of revenue cap mechanisms together with performance incentive mechanisms thought to be readily quantifiable, objective, and immune from gaming. Proposals varied widely, from traditional reliability and call center performance incentive mechanisms, to innovative mechanisms targeting reductions in fossil fuel use and the quality of utility resource planning.

Blue Planet, an intervenor in the case, proposed two environmental performance incentive mechanisms:

1) Reduction in carbon intensity of generation (as measured from the current baseline trend), with a potential reward of up to three cents per share.

2) Interconnection and utilization of non-utility, non-fossil generation and demand response resources, with a potential reward of several cents per share.

The Consumer Advocate proposed several performance incentive mechanisms, the most innovative of which was a mechanism for measuring the quality of the utilities' resource planning process, including stakeholder engagement, range of resources modeled, and follow-through on previous plans. The basis for this performance incentive mechanism was the Commission's IRP Framework, which was initially adopted in 1992 and revised in 2011. This PIM is described in greater detail below.

Resource Planning Performance Incentive Mechanism

Under this PIM, performance will be scored based on compliance with six principles and their associated metrics:

1) **Stakeholder Engagement:** The planning process should allow for meaningful stakeholder involvement throughout the planning process, and should incorporate stakeholder recommendations in the planning process as appropriate.[31]

   Metrics: Whether stakeholder input was adequately considered in establishing:

   a. Planning objectives
   b. Range of scenarios
   c. Resource options
   d. Assumptions, risks, and constraints
   e. Screening of options
   f. Criteria for ranking of resource plans
   g. The choice of final plan

[31] This principle measures the extent to which the Companies have complied with the Framework requirement V.B.1.b, which states: "consider the input, comments and suggestions provided by Advisory Group members and the general public, to the extent feasible," as well as compliance with requirement V.C.4.a (identification of planning objectives with input from advisory group).

2) **Evaluation of Resources:** The planning process should investigate a wide array of existing and emerging supply-side resources, including generation, transmission, and distribution opportunities, including utility-side smart grid options; as well as a wide array of existing and emerging demand-side options such as energy efficiency, demand response, distributed generation, storage technologies, and customer-facing smart grid options.[32]

   Metrics:

   a. Were appropriate modeling tools used?
   b. Were existing system and conditions adequately characterized?
   c. Was the range of new resources considered adequate?
   d. Were new resource options analyzed on a consistent and comparable basis, using reasonable estimates of the benefits and costs?
   e. Was adequate analysis performed to determine the risks and constraints of new resources?
   f. Did the analysis produce credible and reasonable results?

3) **Resource Scenarios and Resource Plans:** The planning process should include a transparent approach to identifying a reasonable set of resource scenarios and resource plans. From this set, the resource plans should be transparently prioritized or ranked based on previously identified key criteria such as minimization of the present value of revenue requirements, meeting environmental goals, maximizing customer benefits, and balancing risks.[33]

   Metrics:

   a. Was an appropriate range of scenarios examined (e.g., appropriate incorporation of various uncertainties; were scenarios extremes, or did they resemble what might actually occur)?
   b. Was there evaluation of an appropriate number of resource plans to ensure results of the process are meaningful?
   c. Were the criteria for determining the best resource plan clearly articulated at the outset?

---

[32] This principle measures compliance with several of the Framework requirements identified in section V.C., including V.C.2 ("Characterization of existing system and conditions"), V.C.3 ("Identification of uncertainties and factors that affect utility planning"), V.C.5 ("Determination of planning scenarios and forecasts"), V.C.6 ("Identification of resource options"), V.C.7 ("Models"), and V.C.8 ("Analyses").

[33] This principle measures compliance with Framework requirements V.C.8. (Analyses), V.C.6.d (screening out infeasible or inappropriate resource scenarios), V.C.4.b and V.C.4.c (use of planning principles), and V.C.9 (determination of resource plans).

d. Was the weighting and ranking to determine the best resource plans transparent and did it incorporated principles and objectives previously identified?
e. Was sufficient consideration given to whether resource plans are able to meet state energy policy goals?
f. Were measures and strategies identified to address limitations and constraints that may impact the utility's ability to achieve state energy policy goals.

4) **Action Plan:** The planning process should include an action plan that enables the utility to translate the results of its analyses into development of actual resources.[34]

   Metrics:

   a. Does the Action Plan articulate next steps for implementing those resources that will be implemented in the short-term?

   b. Does the Action Plan identify and address barriers to developing identified short-term resources?

5) **Strategic Planning:** This principle is intended to ensure that the companies' investments are guided by a long-term strategic vision that addresses the challenges faced by the companies and positions them to allow for agile response to changing system conditions.[35]

   Metrics:

   a. Do the companies clearly define a long-term strategic vision?
   b. Does the strategic vision discuss steps that the companies need to take in order to move toward a more sustainable business model?
   c. Does the strategic vision discuss the companies' strategy for ensuring that the investments made will enable the Companies to respond with agility to a range of possible future circumstances?
   d. Are specific desired outcomes defined and initiatives identified to achieve such outcomes?

6) **Follow-Through on Previous Action Plans:** Demonstrated progress should be made in undertaking and successfully completing initiatives identified in the previous action plan. The companies should not be penalized for making prudent adjustments to the action plan in light of new information or changed circumstances, but any such changes must be sufficiently justified by the companies.

[34] This principle measures compliance with Framework requirements V.C.9.

[35] This principle addresses the desire of the Commission to ensure that the Companies face adequate "incentives to make necessary and/or appropriate changes to utility strategic plans and action plans," as evidenced by this being a major topic for comment in Order No. 31635.

Metrics:

Metrics should be set at the conclusion of each major planning process, based on the specific investments, activities, and costs identified in the action plan. How well these are achieved will then be evaluated at the commencement of the following planning process.

Example: Did the Companies develop X resource in Y timeframe within Z cost?

Utility performance on each metric would be rated as "inadequate," "adequate," or "exemplary." A rating of "inadequate" would correspond to a score of 1.0, while "exemplary" would correspond to a score of 3.0. The scores for each metric would then be averaged for each principle.

The overall scorecard would be completed by an independent evaluator for the IRP process or similar entity in another planning process. The scorecard would be completed by the independent evaluator through a two-step process:

1) For the first principle regarding stakeholder engagement, stakeholders would complete a survey. If a stakeholder wished to score performance on a metric as either "inadequate" or "exemplary," the stakeholder would be required to provide a detailed explanation describing their rationale. The independent evaluator would then review all of the stakeholder scores and assign a composite score for each metric, taking into account the evidence presented by stakeholders.

2) The independent evaluator would conduct an evaluation of the planning process and score the companies' performance on each metric.

The scoring of the companies' planning performance would not replace the current evaluation process in which the independent evaluator files interim reports and a certification report to the commission, but would occur in addition to this process. The PIM scorecard would serve to summarize the overall conclusions of the independent evaluator.

The completed scorecard would then be filed together with any other final certification or process report by the independent evaluator. The companies would then be allowed to respond to and rebut the scores received. The commission may, at its discretion, also allow other stakeholders to comment on the scorecard and the companies' rebuttal. After considering any responses, the commission would then issue a final ruling regarding any penalty or reward.

Current Status of Performance Incentive Mechanisms

As of this writing, the commission had yet to issue an order regarding the proposed performance incentive mechanisms.

Performance Incentives Related to Fuel Adjustment Clauses

Fuel adjustment clauses have been widely adopted in many states to reduce the need for frequent rate cases due to fluctuations in fuel costs. However, these fuel adjustment clauses can reduce the incentive for utilities to operate efficiently, and can skew utilities' resource investment decisions, as the utilities are insulated from fuel price volatility. To address this, some jurisdictions modified their fuel cost pass-through mechanisms to allow only partial pass-through, or to make the pass-through contingent on the utility achieving a certain level of power plant efficiency. For example, prior to restructuring, New York adopted a mechanism by which utilities would absorb a portion (ranging from 20% to 40%) of fuel costs above its forecast. If costs came in below the forecast, the utility would retain a portion (20% to 40%) of the savings (Knittel 2002).

In Hawaii, the Energy Cost Adjustment Clause (ECAC) contains a heat rate efficiency factor. However, concerns were raised that the fixed sales target heat rate would penalize the utilities for introducing renewable energy, as lower capacity factors and higher ramping requirements can negatively impact thermal units' heat rates. In order to avoid the resulting disincentive for efficiency and renewable energy, a deadband of +/- 50 Btu/kWh sales was added to the heat rate target, and an agreement was reached to revisit the heat rate target upon the future addition of larger increments of renewable resources.

Conditioning cost recovery on power plant efficiency or using shared savings mechanisms can help distribute risk between the utility and ratepayers, and have been shown to be effective for improving power plant efficiency. A 2002 study analyzed the impacts of modified fuel adjustment clauses by comparing the efficiency of power plants under a full fuel cost adjustment clause with the efficiency of plants under a modified mechanism in which the utility must bear some of the risk for fuel cost overruns and can keep a portion of such savings. The author found that modified fuel adjustment clauses resulted in 9 percent more output produced for a given amount of input than mechanisms that passed through all of the fuel costs (Knittel 2002). This finding suggests that full fuel adjustment clauses do not encourage efficiency, but that a modified approach that incorporates shared savings can improve efficiency.

On a cautionary note, shared savings approaches related to fuel costs can be vulnerable to manipulation. For example, Nicor Gas, the largest gas utility in Illinois, has been ordered to refund more than $72 million to ratepayers due to allegations of fraud. The utility operated under an incentive that set a gas cost benchmark, and then allowed Nicor to keep half of any savings it achieved. According to allegations, the company manipulated its gas storage operation by improperly releasing low-cost gas put in storage under very low prices years before to artificially produce "savings" (Daniels 2013).

FERC's Bonus ROE for Transmission Projects

Pursuant to the Energy Policy Act of 2005, the Federal Energy Regulatory Commission (FERC) developed incentive-based rate treatments for transmission investments. As part of FERC's Order No. 679, transmission developers (utilities and stand-alone transmission companies) received higher rates of return on equity for new transmission investment in order to improve reliability and reduce congestion in order to lower delivered energy costs.

In practice, however, the incentive may have had effect of increasing delivered energy costs. By applying the ROE adder to the project's actual costs, developers were given a perverse incentive to *increase* the project costs (through, for example, delaying the construction), because they would earn the higher ROE on the total costs of the project. In this way, the incentive actually rewarded projects that came in over budget (American Forest & Paper Association, et al. 2011). It has been estimated that consumers in New England will pay more than an additional $100 million in adder charges for transmission projects because these projects have greatly exceeded their original costs (New England Conference of Public Utility Commissioners v. Bangor Hydro-Electric Co 2008).

Compounding this effect was the inability to demonstrate that the incentive would result in net benefits, as the Order did not require quantifying the benefits in relationship to the costs of the incentives. Further, applicants seeking the incentives were not required to show that the project would not be developed without the incentives (American Forest & Paper Association, et al. 2011).

Jim Tracy, Sacramento Municipal Utility District Chief Financial Officer, was one of many interveners who submitted comments in response to the FERC's Notice of Inquiry regarding the incentive mechanism. Having been involved in financing a large number of infrastructure projects, including transmission, distribution, and generation projects, Mr. Tracy noted that even if the net impact of the incentive was positive, the "costs of the incentives were almost certainly more than needed" (American Forest & Paper Association, et al. 2011, 143). He further commented that Commission's incentive rate may have resulted in excess transmission capacity.

According to Mr. Tracy, lenders are not influenced by higher rates of return for specific types of projects, but rather by the availability of mechanisms that reduce the risk that revenues will be interrupted during the recovery period. Further, because a utility's investment funds are limited, higher returns on certain types of projects can result in skewing the utility's investment choices away from alternatives that may be better for ratepayers (American Forest & Paper Association, et al. 2011).

Appendix B – Data Sources and Availability

The following tables contain data sources for the metrics discussed in this handbook. Table 22 includes metrics, metric formulas, and data sources, and Table 23 includes notes about the availability of data and weblinks. Note that the data sources presented below may not provide all the data needed for performance metrics, and we have not assessed the quality or reliability of the data in these sources.

Many of the metrics discussed in this report can be obtained or calculated using data from federal agencies and other national organizations. Where data are not available from a national source, regulators can collect them directly from their utilities (indicated by "Collect from utility" in the Data Source column). However, regulators should assure that the data collected from utilities are well-defined, consistent across utilities, and well understood, as discussed in Chapter 3.

Table 22. Metric Formulas and Data Sources

Performance Dimension	Metric or metric group	Metric formula	Data Source
Reliability	System Average Interruption Duration Index (SAIDI)	Total minutes of sustained customer interruptions / total number of customers	EIA Form 861
	System Average Interruption Frequency Index (SAIFI)	Total number of sustained customer interruptions / total number of customers	EIA Form 861
	Customer Average Interruption Duration Index (CAIDI)	Total minutes of sustained customer interruptions / total number of interruptions	Collect from utility
	Momentary Average Interruption Frequency Index (MAIFI)	Total number of momentary customer interruptions per year / total number of customers	Collect from utility
	Power quality	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker.	Collect from utility
Employee Safety	Total Case Rate (TCR)	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000) / Employee hours worked[36]	OSHA Form 300

[36] 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). (U.S. BLS 2013)

Performance Dimension	Metric or metric group	Metric formula	Data Source
	Days Away, Restricted, and Transfer (DART) case rate	(Number of work-related days away from work and job transfers or restrictions times 200,000) / Employee hours worked	OSHA Form 300
	Days Away From Work (DAFWII) case rate	(Number of work-related days away from work times 200,000) / Employee hours worked	OSHA Form 300
Public safety	Incidents, injuries, and fatalities (electric)	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity	Collect from utility
	Emergency response time (electric)	Percent of electric emergency responses within 60 min. each year	
	Incidents, injuries, and fatalities (gas)	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause (corrosion, natural forces, excavation, other outside force, pipe/weld/joint/equipment failure, incorrect operation, other cause)	PHMSA Form F 7100.1
	Emergency response time (gas)	Average minutes for gas emergency response	Collect from utility
	Leak repair performance (gas)	Average days for repair of minor and non-hazardous leaks	
Customer Satisfaction	Call center answer speed	Percentage of calls answered within 30 seconds	Collect from utility
	Transaction surveys	Percentage of customers satisfied with their recent transaction with the utility	Collect from utility
	Customer complaints	Formal complaints to the Commission (number per 1,000 customers)	Collect from utility
	Order fulfillment	Speed with which orders for service installation and termination, outage responses, and meter re-reading are fulfilled	Collect from utility
	Missed appointments	Percentage of appointments not met for meter replacements, inspections, or any other appointments in which the customer is required to be on the premises	Collect from utility
	Avoided shutoffs and reconnections	Disconnects and reconnections avoided by customer percentage of income payment plans or other means	Collect from utility
	Residential customer satisfaction	Electric Utility Residential Customer Satisfaction index, Gas Utility Residential Customer Satisfaction index	J.D. Power Electric Utility Residential Customer Satisfaction Study℠, J.D. Power Gas Utility Residential Customer Satisfaction Study℠

Performance Dimension	Metric or metric group	Metric formula	Data Source
	Business customer satisfaction	Electric Utility Business Customer Satisfaction index, Gas Utility Business Customer Satisfaction index	J.D. Power Electric Utility Business Customer Satisfaction Study^{SM}, J.D. Power 2014 Gas Utility Business Customer Satisfaction Study^{SM}
Plant Performance	Fuel usage	Quantity of fuel burned	FERC Form 1
	Heat rate	Average BTU per kWh net generation	FERC Form 1
	Capacity factor	Average energy generated for a period / energy that could be generated at full nameplate capacity	FERC Form 1
Costs	Capacity costs	Cost per kW of installed capacity	FERC Form 1
	Total energy costs	Expenses per net kWh	FERC Form 1
	Fuel cost	Average cost of fuel per kWh net gen and per Million BTU; total fuel costs	FERC Form 1
	Effective resource planning*	Numerous metrics regarding incorporation of stakeholder input, consideration of all relevant resources, use of appropriate assumptions and modeling tools, etc.	third-party evaluator
	Cost-Effective Alternative Resources*	$/MW cost of alternative portfolio relative to the $/MW cost of traditional investment	Collect from utility
System Efficiency	Load factor	Sector avg load / sector peak load	Collect from utility
		Monthly system average load / monthly system peak load	FERC Form 1
	Usage per customer	Sector sales / sector number of customers	FERC Form 1 (electric), Form EIA-176 (gas)
	Aggregate Power Plant Efficiency	System average BTU per kWh net generation (heat rate)	FERC Form 1
		Equivalent Forced Outage Rate (EFOR) = Equivalent Forced Outage Hours / (Period Hours – Equivalent Scheduled Outage Hours)	NERC Generating Availability Data System
		EFORd: variant of EFOR, measuring the probability that a unit will not meet its generating requirements demand periods because of forced outages or derates	NERC Generating Availability Data System
		Weighted equivalent availability factor: over a given operating period, the capacity-weighted average fraction of time in which a fleet of generating units is available without any outages and equipment or seasonal deratings	NERC Generating Availability Data System
	Flexible Resources	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)	Collect from utility
	System losses	Total electricity losses / MWh generation, excluding station use	FERC Form 1
		Total gas losses / total sales	Form EIA-176

Performance Dimension	Metric or metric group	Metric formula	Data Source
Customer Engagement	Energy efficiency (EE)	Percent of customers per year participating in EE programs	Collect from utility
		Annual and lifecycle energy savings	EIA Form 861 (electric), collect from utility (gas)
		Annual and lifecycle peak demand savings (MW)	EIA Form 861
		Program costs per unit of energy saved (MWh or therm)	EIA Form 861 (electric), collect from utility (gas)
	Demand response (DR)	Percent of customers per year	EIA Form 861 and FERC F1
		Number of customers enrolled	EIA Form 861
		MWh of DR provided over past year	EIA Form 861
		Potential and actual peak demand savings (MW)	EIA Form 861
	Distributed generation (DG)	Number of installations per year	Collect from utility
		Net metering installed capacity (MW)	EIA Form 861
		Net metering MWh sold back to utility	EIA Form 861
		Net metering number of customers	EIA Form 861
		MW installed by type (PV, CHP, small wind, etc.)	EIA Form 861
	Energy storage	Number of installations per year	Collect from utility
		MW installed by type (thermal, chemical, etc.)	Collect from utility
		Percent of customers with storage technologies enrolled in demand response programs	Collect from utility
	Electric vehicles (EVs)	Number of EVs added to the grid each year	Collect from utility
		Percent customers with EVs enrolled in DR programs	Collect from utility
	Information availability	Number of customers able to access daily usage data via a web portal	EIA Form 861
		Percent of customers with access to hourly or sub-hourly usage data via web	Collect from utility
	Time-varying rates	Number of customers on time-varying rates / total customers	EIA Form 861
Network Support Services	Advanced metering capabilities	Number of customers with AMI and AMR	EIA Form 861
		Energy served through AMI	EIA Form 861
	Interconnection support	Average days for customer interconnection	Collect from utility
		Customer satisfaction with interconnect process	Collect from utility
	Third party access	Open and interoperable smart grid infrastructure that facilitates third-party devices	Collect from utility
		Third party vendor satisfaction with utility interaction	Collect from utility
	Provision of customer data	Customers able to authorize third-party access electronically	Collect from utility
		Percent of customers who have authorized third-party access	Collect from utility
		Third party data access at same granularity and speed as customers	Collect from utility

Performance Dimension	Metric or metric group	Metric formula	Data Source
Environmental Goals	SO_2 Emissions	Tons per year	EPA Air Markets Program Data
	Avg NOx Rate	lbs/MMBtu	EPA Air Markets Program Data
	CO_2 emissions	Tons CO_2 per year	EPA Air Markets Program Data
	Carbon intensity	Tons CO_2 / customer	EPA Air Markets Program Data and EIA 861
	System carbon emission rate	Tons CO_2 / MWh sold	EPA Air Markets Program Data and EIA 861
	Clean Power Plan (CPP) emission rate	lbs CO_2 from fossil generators / (Fossil Fuel Generation (MWh) + 5.8% Nuclear Generation (MWh) + Renewable Generation (MWh) + Cumulative Energy Efficiency (MWh))	Collect from utility
	Fossil carbon emission rate	Tons CO_2 / MWh fossil generation	EPA Air Markets Program Data and EIA 861
	Fossil generation	Fossil percent of total generation	EIA Form 923 and EIA Form 860
	Renewable generation	Renewable percent of total generation	EIA Form 923 and EIA Form 860

**See Appendix A, New York and Hawaii case studies, for more information on these metrics.*

Table 23. Data Sources and Notes on Availability

Source	Notes on Availability	Link to Data
EIA Form 176	Form EIA-176 is designed to collect data on natural, synthetic, and other supplemental gas supplies, disposition, and certain revenues by state. It must be completed by interstate and intrastate natural gas pipeline companies; gas distribution companies; underground gas storage operators; synthetic natural gas plant operators; field, well, or processing plant operators that deliver natural gas directly to consumers (including their own industrial facilities) other than for lease or plant use or processing; field, well, or processing plant operators that transport gas to, across, or from a state border through field or gathering facilities; and liquefied natural gas (LNG) storage operators, both peaking facilities and marine terminals. (U.S. EIA 2015a)	http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1
EIA Form 860	Form EIA-860 collects data on the status of existing, grid connected electric generating plants with a nameplate capacity of 1 MW or greater and associated equipment (including generators, boilers, cooling systems and air emission control systems) in the United States, and those scheduled for initial commercial operation within 10 years (coal or nuclear) or 5 years (other energy sources). (U.S. EIA 2015b)	http://www.eia.gov/electricity/data/eia860/
EIA Form 861	All electric power industry entities complete 861, including: electric utilities, all DSM Program Managers, wholesale power marketers, energy service providers (registered with the states), and electric power producers. (U.S. EIA 2014c)	http://www.eia.gov/electricity/data/eia861/
EIA Form 923	Form EIA-923 collects information on the operation of electric power plants and combined heat and power (CHP) plants in the United States. Form EIA-923 is a mandatory report for all grid-connected electric power and CHP plants that have a total generator nameplate capacity (sum for generators at a single site) of 1 MW or greater. (U.S. EIA 2015b)	http://www.eia.gov/electricity/data/eia923/
EPA Air Markets Program Data	Data are available for power plants that are subject to various market-based regulatory programs, including the Acid Rain Program, NOx Budget Trading Program, and Clean Air Interstate Rule.	http://ampd.epa.gov/ampd/QueryToolie.html
FERC Form 1	FERC Form 1 is required for each major electric utility, licensees, or other (as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101)). Major is defined as having in each of the three previous calendar years, sales or transmission service that exceeds one of the following: (1) 1,000,000 MWh or more of total annual sales; (2) 100 MWh of annual sales for resale; (3) 500 MWh of annual power exchange delivered; or (4) 500 MWh of annual wheeling for others (deliveries plus losses). (FERC 2015)	http://www.ferc.gov/docs-filing/forms/form-1/data.asp

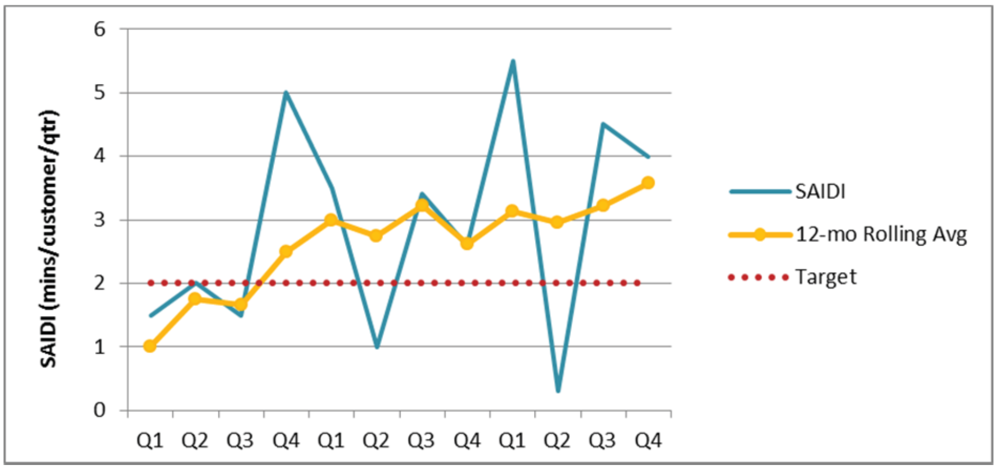
J.D. Power Electric Utility Business Customer Satisfaction Study^{SM}	Within each of the four geographic regions included in the study, utility providers are classified into one of two segments: large (serving 85,000 or more business customers) and midsize (serving between 25,000 and 84,999 business customers). The study is conducted annually. The 2014 Electric Utility Business Customer Satisfaction Study is based on responses from > 23,700 online interviews with business customers that spend at least $250 monthly on electricity.	http://www.jdpower.com/press-releases/2014-electric-utility-business-customer-satisfaction-study
J.D. Power Electric Utility Residential Customer Satisfaction Study^{SM}	The Study ranks midsize and large utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 100,000 and 499,999 residential customers, while companies in the large utility segment serve 500,000 or more residential customers. The Study has been conducted annually for 16 years. The 2014 Study was based on responses from 104,460 online interviews conducted from July 2013 - May 2014 among residential customers of the 138 largest electric utility brands across the U.S.	http://www.jdpower.com/press-releases/2014-electric-utility-residential-customer-satisfaction-study
J.D. Power Gas Utility Business Customer Satisfaction Study^{SM}	The study measures business customers' satisfaction with the nation's 55 largest gas utilities in four U.S. geographic regions: East, Midwest, South, and West. The study examines satisfaction across six factors—billing and payment; corporate citizenship; price; communications; customer service; and field service.	http://www.jdpower.com/resource/us-gas-utility-business-customer-satisfaction-study
J.D. Power Gas Utility Residential Customer Satisfaction Study^{SM}	The study ranks large and midsize utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 125,000 and 399,999 residential customers, and companies in the large utility segment serve 400,000 or more residential customers. The Study has been conducted annually for 13 years. The 2014 Gas Utility Residential Customer Satisfaction Study is based on more than 69,800 responses from residential customers of 83 large and midsize gas utilities across the continental United States. The study was fielded between September 2013 and July 2014.	http://www.jdpower.com/press-releases/2014-gas-utility-residential-customer-satisfaction-study
NERC Generating Availability Data System	For conventional generating units with a nameplate capacity of 20 MW and larger, GADS reporting is mandatory. Renewable generation (i.e., wind and solar) is not required to report. Conventional generating units less than 20 MW nameplate are invited to report to GADS on a voluntary basis.	http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx
OSHA Form 300	The Occupational Safety and Health (OSH) Act of 1970 requires certain employers to prepare and maintain records of work-related injuries and illnesses. OSHA Form 300 is only available for a small portion of all private sector establishments in the U.S. (80,000 out of 7.5 million total establishments).	https://www.osha.gov/pls/odi/establishment_search.html, http://ogesdw.dol.gov/views/searchChooser.php
PHMSA Form F 7100.1	Title 49 of the Code of Federal Regulations (49 CFR Parts 191, 195) requires pipeline operators to submit incident reports within 30 days of a pipeline incident or accident. The CFR defines accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety.	http://www.phmsa.dot.gov/pipeline/library/data-stats

APPENDIX C – DASHBOARD EXAMPLES

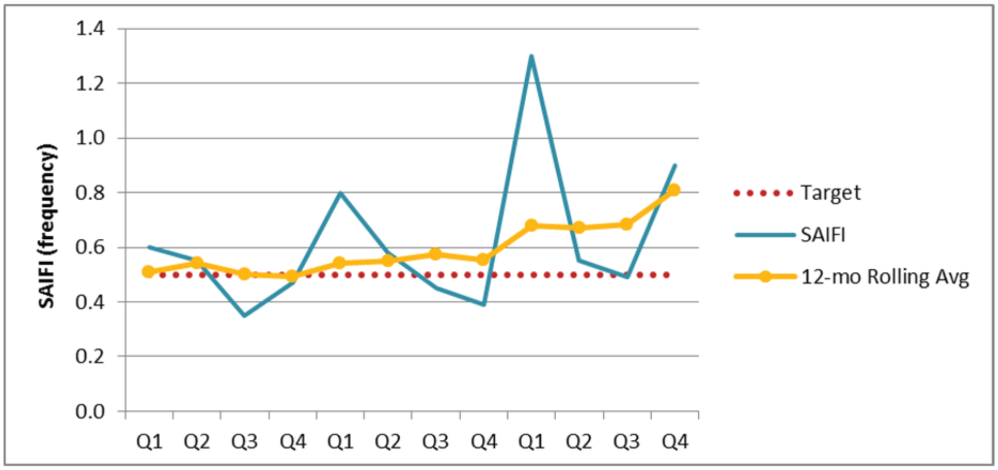
The following examples show how data dashboards can provide visual context for performance targets in terms of historical utility performance and trends. These examples are based on actual data (for unnamed utilities in western US states or on data for the entire United States) or they were fabricated for illustrative purposes.

Reliability

SAIDI is an indicator of sustained interruptions experienced by customers. SAIDI is defined as total minutes of sustained customer interruptions divided by total number of customers, over a period of time. This illustrative example shows a hypothetical utility's system wide SAIDI and 12 month rolling average over a three year period, along with its target.

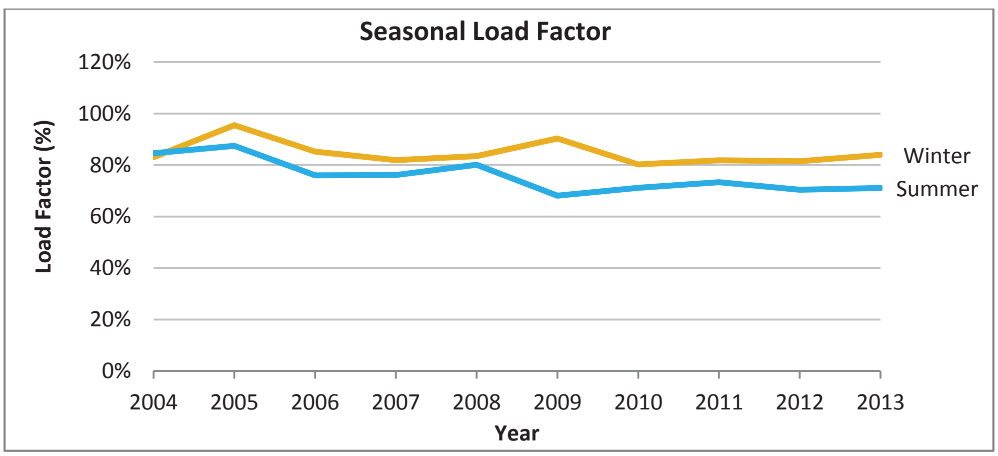


SAIFI is an indication of how many interruptions are experienced by customers over a period of time. SAIFI is defined as total number of sustained customer interruptions divided by total number of customers. This illustrative example shows a hypothetical utility's system wide SAIFI and 12 month rolling average over a three year period, and its performance target.



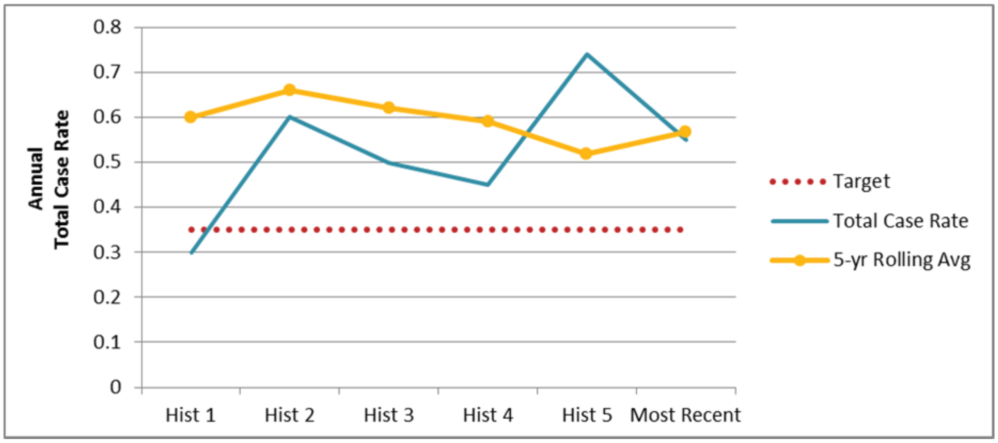
System Efficiency

As one metric for the efficient use of the electric system, load factor indicates the extent to which load occurs during peak periods. It is defined as the average load over a period of time divided by peak load. A dashboard can be used to show load factors for the entire system and for each customer sector over time. The example below shows the seasonal load factor for a western electric utility over ten years, obtained from FERC Form 1 data. Although FERC Form 1 provides energy and peak demand for the system as a whole, ideally load factors should be considered by consumer sector to allow for a targeted policy response.

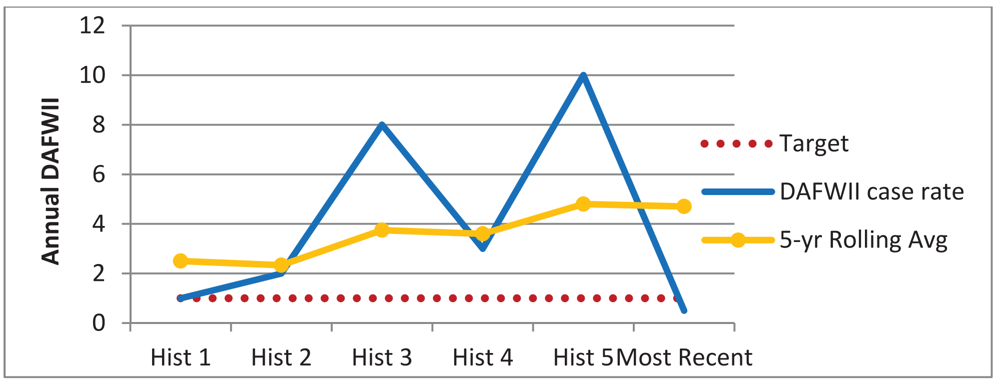


Safety

Employee safety can be measured using metrics. Standard metrics defined and reported by OSHA include work-related deaths, injuries, and illnesses (the Total Case Rate, or TCR); the Days Away from work, Restricted, or Transfer (DART) case rate; and the Days Away From Work (DAFWII) case rate. Because OSHA collects data from only a small fraction of companies, regulators should consider collecting data directly from utilities. Below is an illustrative example of a TCR for a hypothetical utility over a period of six years.

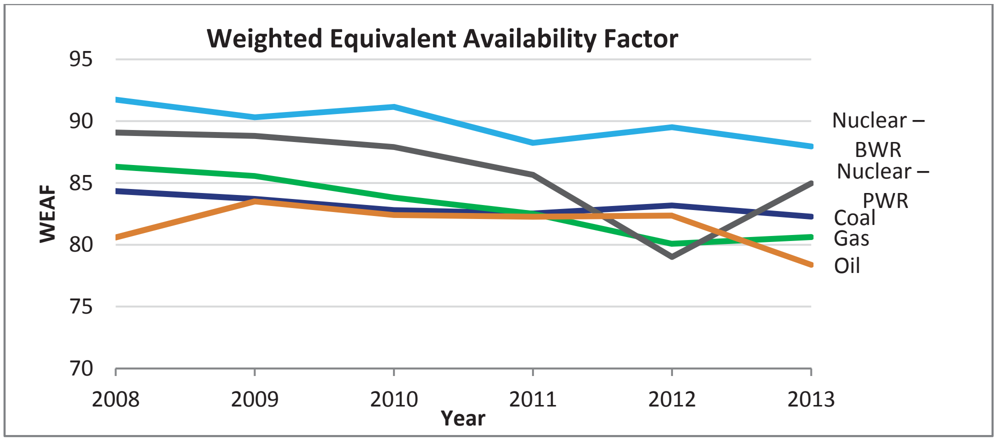


The following graph shows an illustrative example of a Days Away From Work (DAFWII) case rate over a period of six years for a hypothetical utility.

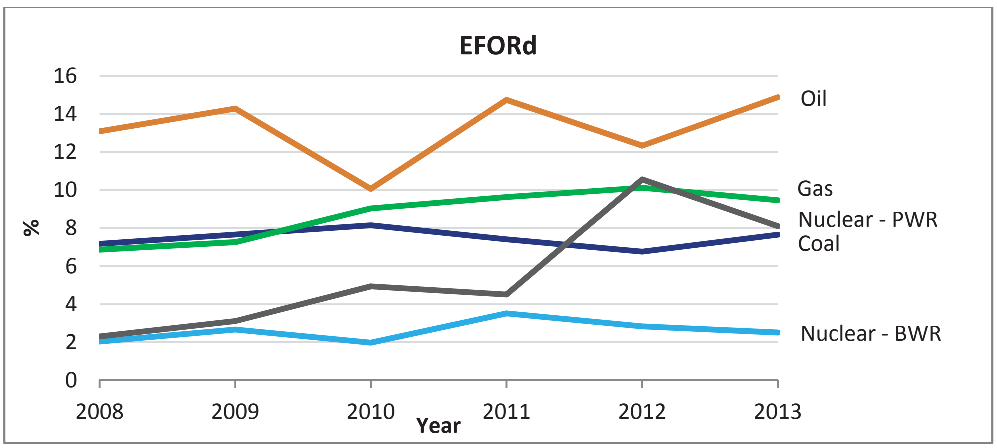


Power Plant Availability

Regulators often review the performance of individual power plants. However, regulators should consider the performance of the electric system as a whole, especially in the context of resource planning. The Weighted Equivalent Availability Factor (WEAF) is a metric indicating availability of supply side generation resources. Below is a graph showing the actual WEAF for the entire U.S. for six historical years, by fuel type.

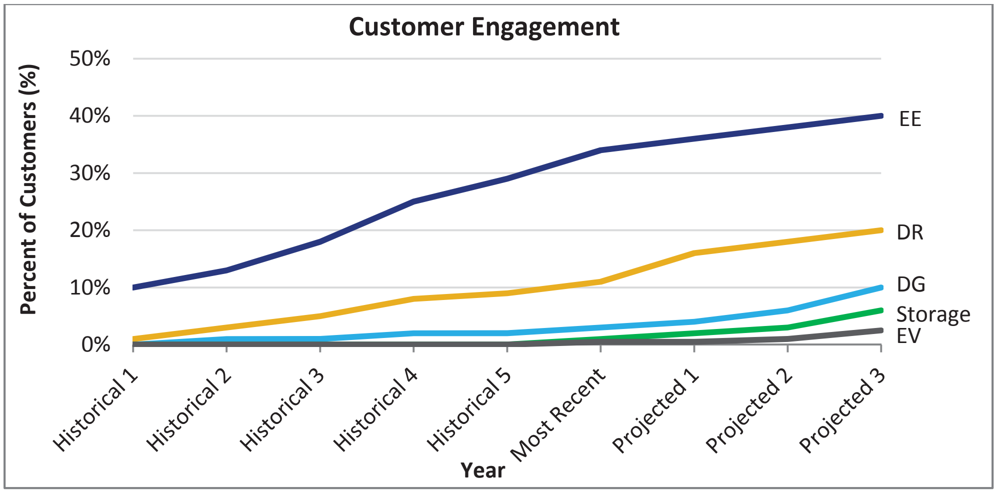


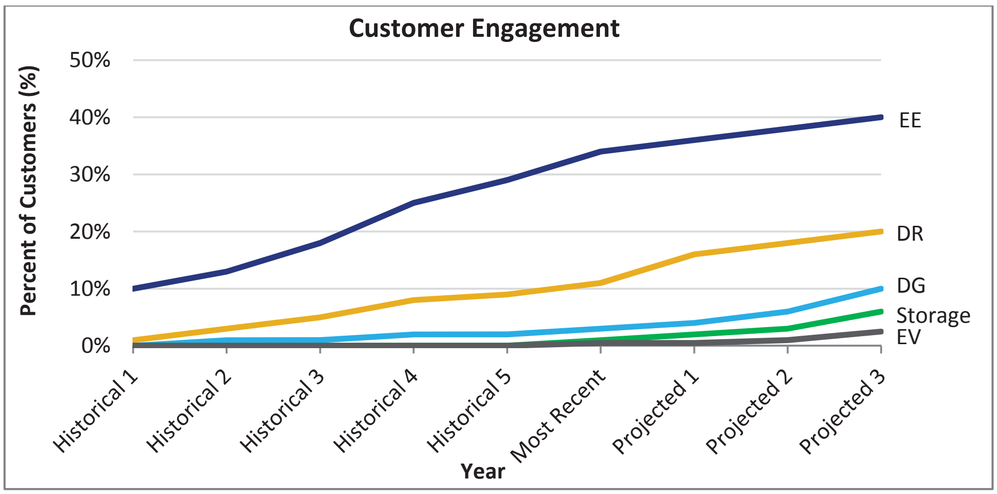
The Equivalent Forced Outage Rate Demand (EFORd) measures the probability that a unit (or group of units) will not meet demand periods for generating requirements because of forced outages or derates. Below, is a graph showing the actual EFORd by fuel type for the entire U.S. over six historical years.



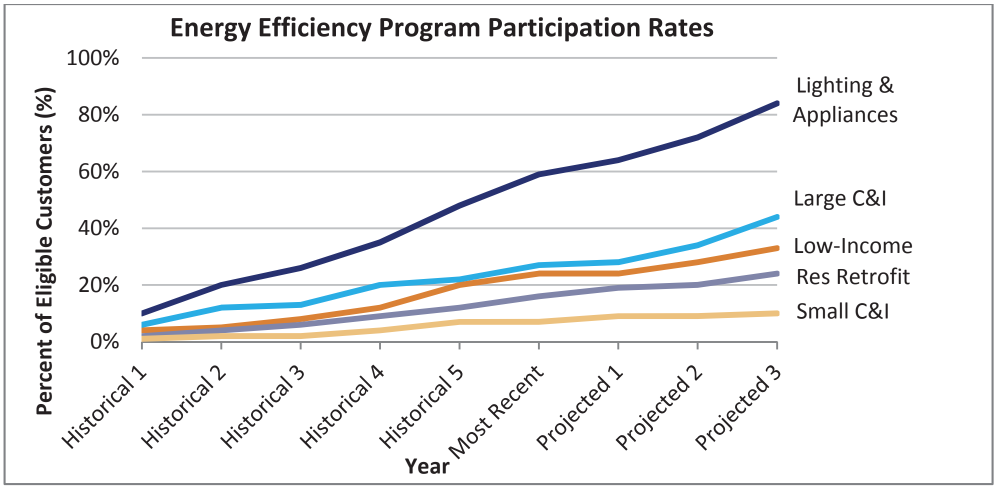
Customer Engagement

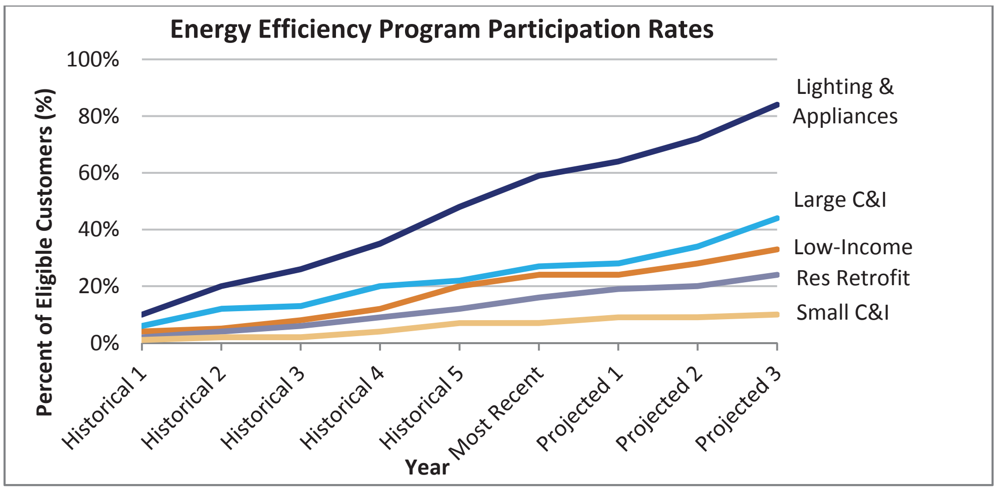
Customer engagement metrics indicate the extent to which customers are participating in demand-side programs or installing demand-side resources, which can reduce the need for new supply-side resources. The following graph shows historical and projected customer engagement for a hypothetical utility in five key areas: energy efficiency (EE), demand response (DR), distributed generation (DG), customer-sited energy storage, and electric vehicles (EV).





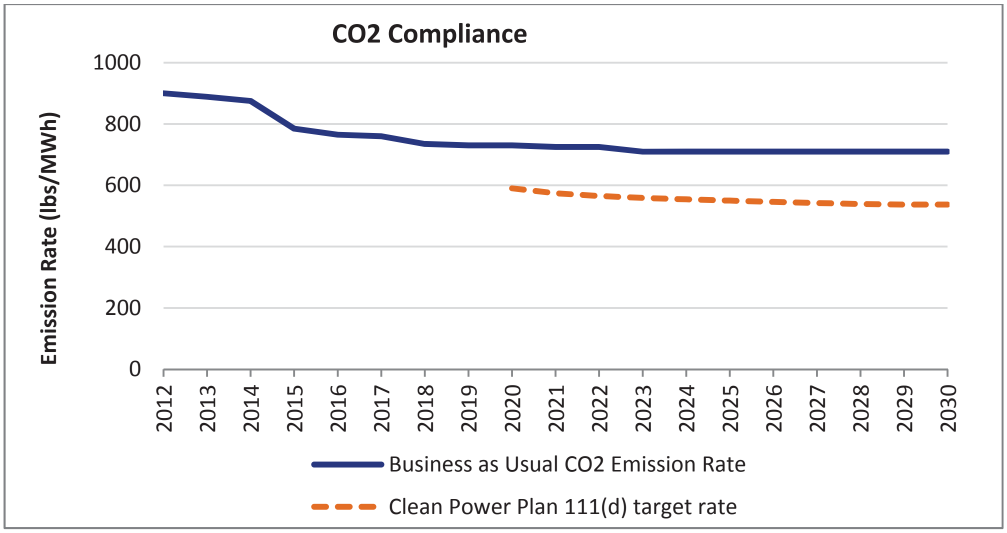
As an indication of which sectors are participating in energy efficiency programs, utilities and regulators may wish to examine participation in programs targeting specific customer segments, as a percentage of customers eligible for those programs. The following graph shows historical and projected participation rates for a hypothetical utility's lighting and appliances (for which data on participant customer types are rarely available), large commercial and industrial (C&I), low-income, residential (res) retrofit, and small C&I energy efficiency programs.



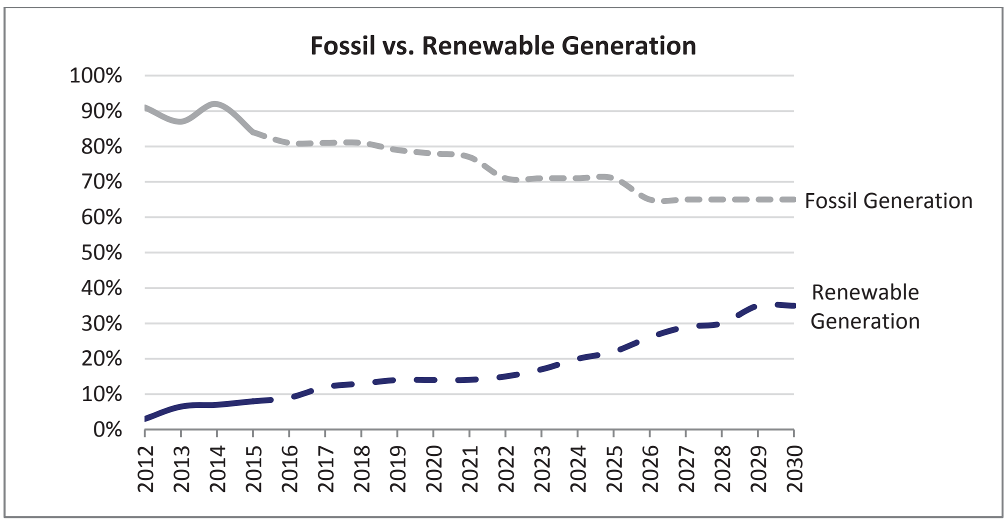


Environmental Goals

Environmental metrics indicate the extent to which the utility and its customers are reducing environmental impacts and can be particularly important with regard to ensuring that the state is on a path toward compliance with climate change regulations. Below is a graph showing the actual Clean Power Plan target CO2 rate for a western state, along with historical and hypothetical projected emissions rate under a business as usual scenario.



Below is an illustrative graph showing historical and projected fossil and renewable generation as a percent of total generation for a hypothetical utility.



Balancing Natural Gas Pipeline Safety with Economic Goals

Ken Costello, Principal

The National Regulatory Research Institute

May 2012

12–04

Acknowledgments

The author wishes to thank the Honorable Colette Honorable, Chairman, Arkansas Public Service Commission; the Honorable Paul Roberti, Commissioner, Rhode Island Public Utilities Commission; the Honorable Cheryl Roberto, Commissioner, Public Utilities Commission of Ohio; Robert Harding, Minnesota Public Utilities Commission; Randy Knepper, New Hampshire Public Utilities Commission; Professor Karl McDermott, University of Illinois Springfield; and NRRI colleagues Dr. Rajnish Barua and Dr. Sherry Lichtenberg. Any errors in the paper remain the responsibility of the author.

Online Access

The paper can be accessed online at

Executive Summary

Over the past two years, we have seen an abnormal number of gas-pipeline accidents. Gas-pipeline-related deaths, for example, more than doubled between 2009 and 2010. In response to these events, federal safety regulators and state utility commissions have expressed concerns over the integrity of local distribution systems. A primary concern is the age of old cast-iron and bare-steel pipes. Many of these pipes are several decades old and are susceptible to breaks or leaks. Aging gas pipes in particular have triggered a robust debate about the future safety of our pipeline system.

Federal safety regulators and others have articulated the importance of state utility commissions' giving utilities a reasonable opportunity to recover their costs for maintaining a safe pipeline system. They echoed this view at, among other places, the National Pipeline Safety Forum, hosted by the U.S. Department of Transportation in April 2011.

At the March 2011 hearing of the National Transportation Safety Board on San Bruno (California), a question arose as to whether a single entity, such as a state utility commission, should have responsibility for both pipeline safety and ratemaking. Some speakers alleged a possible inherent conflict that could compromise safety. As this paper discusses, divorcing safety from economics can lead to distorted decisions on safety and ratemaking. Safety regulators, who are not charged with the responsibility of considering economic factors, may de-emphasize the cost component while an economic regulator may not appreciate the importance of safety. Placing both elements under one regulatory umbrella may yield a better balance of these primary aspects of regulation. With a few exceptions, state utility commissions currently assume both functions.

This paper identifies four potential problems that confront state utility commissions when they address safety matters:

- A suboptimal level of safety (either excessive or deficient safety)
- Excessive costs for a given level of safety
- Poor utility incentives for safety activities
- An imbalance between safety and other regulatory objectives (e.g., those related to ratemaking)

This last problem can lead utilities to (a) underinvest in safety because regulation does not allow them a reasonable opportunity to earn their cost of return or precludes timely recovery of costs, or (b) overspend on safety activities because of inadequate regulatory oversight of costs or undue emphasis on safety relative to utility costs and rates. Specifically, utilities and their regulators might be overly risk averse regarding safety problems relative to society's risk aversion. The implication is that society would prefer to reallocate some of the money spent on safety to other activities offering greater benefits.

This paper highlights the responsibility of state utility commissions to assure the public that utilities perform at a high level in various dimensions, including economic efficiency, reliability, and safety. Safety is a prominent goal, but only one of several goals that commissions attempt to advance. Sometimes these goals conflict, requiring commissions to weigh their relative importance and make trade-offs that best serve the public interest.

One situation in which people make trade-offs involves buying a car. Most people do not buy a Hummer or Volvo, even though these makes might be the safest vehicles. We consider several attributes of a car before deciding on a particular make and model. Most people compromise safety for other attributes like fuel economy, maintenance costs, and appearance. They essentially balance the different attributes when deciding on a car that they prefer overall. Similarly, state utility commissions weigh different objectives in deciding on a specific matter that best advances the public interest. This balancing means that commissions are willing to "trade" some objectives in return for others. Achieving safety at any cost is not compatible with a balanced approach. One way to look at costs is that they represent lost opportunities to allocate funds to other activities. These activities have social benefits that might exceed the benefits gained from additional safety.

A perceived conflict exists between safety and "just and reasonable" rates. An example is achieving a certain level of safety at excessive cost or through "exorbitant" rate increases. State utility regulators are in the best position to balance safety and ratemaking goals, frequently confronting them with a difficult challenge.

One rule that utility regulators can consider is the following: Ensure that utilities make their pipes safe by spending prudently and efficiently. Another regulatory goal, reliable service, is complementary with safety. A pipeline incident would likely shut down at least part of the gas utility's operation. Thus, one benefit of improved safety would be more reliable utility service. Another benefit from improved pipeline safety—from pipeline replacement, for instance—is lower maintenance and operating costs. Overall, efforts directed at improving safety can have a payoff that goes beyond making pipelines merely safer.

Safety has a cost that utility commissions should take into account when evaluating a utility's proposal to invest in or spend on safety-related activities. Commissions must not only judge the justification for these costs in improving safety but also assess whether the underlying actions are least cost. The first justification requires a cost-benefit-type review, while the second justification applies a cost-effectiveness rule.

This paper addresses actions that state utility commissions may take to improve their policies on gas pipeline safety:

- State utility regulators are committed to pipeline safety, in many instances going beyond federal regulations.

- Gas utilities spend about $7 billion annually on safety. Regulators can help them spend that money more wisely.

- Good utility regulation requires balancing safety with other objectives, including just and reasonable rates.

- The fundamental economic criterion for evaluating any safety-improving activity is whether it increases social net benefits.

- Federal regulations required utilities to begin developing a distribution integrity management program (DIMP) by August 2, 2011.

- Criticisms that a single agency is regulating both utility rates and safety seem to overlook the importance and difficulty of balancing societal objectives.

- The socially optimal level of safety is less than "perfect."

- Gas utilities can overspend on safety from a societal perspective.

- State utility regulators should carefully evaluate accelerated pipeline replacement.

- A major determinant of the optimal level of safety is society's risk aversion regarding incidents.

- A utility's incentive for safety depends on several factors.

Appendix A lists the normal activities of safety regulators in fulfilling their duties, subject to federal and state regulations. Appendix B contains several questions that state utility regulators can ask both themselves and utilities in fulfilling their obligation to balance safety and other regulatory objectives.

Table of Contents

I. Basic Things to Know about Safety 3

- **A.** What is pipeline safety? 3
- **B.** Different utility actions affect safety 3
- **C.** Safety costs money 5

II. Federal-State Partnership 6

- **A.** Brief history 6
- **B.** Distribution Integrity Management Program (DIMP) 8
- **C.** New federal legislation 10

III. An Economic Perspective on Pipeline Safety 10

- **A.** "Perfect safety" is a poor policy goal 10
- **B.** Acceptable risk 12
- **C.** Optimal and cost-effective safety 13
  - **1.** Cost-effectiveness 13
  - **2.** Challenges with command-and-control regulation 14
  - **3.** Risk aversion and financial exposure 16
- **D.** Utilities have multiple incentives for ensuring safety 17
  - **1.** Incentive 17
  - **2.** Disincentive 18

IV. Recommendations for Safety and Utility Regulators 18

- **A.** Cost-effective actions 19

B. Enforcement 20

C. Balancing safety with ratemaking goals 21

1. Ratemaking and cost-recovery principles 22

2. The example of accelerated pipeline replacement 24

D. Why a single regulatory agency can better balance safety and economic goals 31

V. Conclusion 33

Appendix A: Major Tasks for Safety Regulations 34

Appendix B: Questions Related to Gas Pipeline Safety 35

Balancing Natural Gas Pipeline Safety with Economic Goals

While much has been done in the wake of San Bruno and other pipeline incidents, much more state and federal action is underway. And now is the time. We all—industry, regulators, one-call operators, and stakeholders—must redouble our efforts to ensure that we are giving our very best effort to protect the people we serve. I know that if we all focus at one time and with the same level of determination, working together to heighten our commitment to ensure a concentrated proactive effort, we can and will be successful in protecting the people we serve from future catastrophic pipeline incidents. We owe it to them. This is what keeps me up at night.[1]

Over the past two years we have seen an abnormal number of gas-pipeline accidents. Gas-pipeline-related deaths, for example, more than doubled between 2009 and 2010. In responding to these events, federal safety regulators and state utility commissions have expressed concerns over the integrity of local distribution systems.[2] A primary concern is the age of old cast-iron and bare-steel pipes. Many of these pipes are several decades old and are susceptible to breaks or leaks. Aging gas pipes in particular have triggered a robust debate about the current and future safety of our pipeline system.

Federal safety regulators and others have articulated the importance of state utility commissions giving utilities a reasonable opportunity to recover their costs for maintaining a safe pipeline system. They echoed this view at, among other places, the National Pipeline Safety Forum, hosted by the U.S. Department of Transportation (DOT) in April 2011.[3] At the hearing of the National Transportation Safety Board (NTSB) on the San Bruno (California) incident, some participants expressed concern at the idea of a single entity's—namely, a state utility commission's—having dual responsibility for the rates and safety of a utility.[4] One advocate for public safety raised the possibility of an inherent conflict that could compromise safety:

---

[1] Chairman Collette D. Honorable, "What's Keeping Me Up at Night? Pipeline Safety," *NRRI Monthly Essay*, November 2011.

[2] "Integrity" means the ability to keep flowing natural gas within the confines of the pipes. A leak or rupture can cause gas to leave a pipeline, inflicting serious damage. Ruptures are more likely to occur on high-pressure transmission pipes than on low-pressure distribution pipes. Distribution incidents typically start with a leak.

[3] *See* the proceedings of the forum at http://opsweb.phmsa.dot.gov/pipelineforum/docs/Webpage%20Lead%20Final.pdf. DOT held the forum in response to the series of pipeline explosions that occurred in 2010.

[4] As described in the Executive Summary of the NTSB's final report on the San Bruno incident:

I realize that commissions are concerned with safety, but it seems that their focus is on providing just and reasonable rates. If a board member needs to make a choice on a rate increase, is there an inherent conflict with having to spend more on safety when there are short-term pressures or pressures due to law? *The question is not intended to ask about the good will of any member but to [inquire] whether there is an inherent conflict for commissioners to approve spending on safety initiatives, which are long-term investments, due to short-term pressures.*[5] [Emphasis added]

This statement questions whether state utility regulators would jeopardize public safety for the sake of holding down rates in the short term. To the contrary, experience has shown that state utility regulators consider safety a top priority. Most states have safety regulations that go beyond federal requirements. The two issues that state utility regulators consider most important in overseeing the natural gas sector are (1) that distribution lines are adequately safe to minimize the chances of incidents and (2) that gas supplies are always available to customers when they need it, especially during the winter months. Rates have primary importance as well, but history has shown that state utility regulators are unwilling to jeopardize safe or reliable service just to keep rates down.

On September 9, 2010, [at] about 6:11 p.m. Pacific daylight time, a 30-inch-diameter segment of an intrastate natural gas transmission pipeline known as Line 132, owned and operated by the Pacific Gas and Electric Company (PG&E), ruptured in a residential area in San Bruno, California. The rupture occurred at mile point 39.28 of Line 132, at the intersection of Earl Avenue and Glenview Drive. The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. PG&E estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area. (*See* Pipeline Accident Report: PAR-11-01.)

The NTSB made several findings: that PG&E's integrity management program was "deficient and ineffective"; that PG&E's pipeline installation failed to comply with "accepted industry quality control and welding standards in 1956"; that federal and state regulatory oversight was inadequate; and that PG&E had "no comprehensive procedures for responding to a large-scale emergency." The California Public Utilities Commission (CPUC) has responded to the NTSB recommendations by taking various actions. *See* California Public Utilities Commission, *CPUC Implementation Status of NTSB and Independent Review Panel Pipeline Safety Recommendations Overview*, January 2012.

[5] Rick Kessler (Vice President, Pipeline Safety Trust), *Proceedings from the National Pipeline Safety Forum*, April 18, 2011, 9; emphasis added.

I. Basic Things to Know about Safety

A. What is pipeline safety?

"Pipeline safety" refers to a publicly acceptable condition state in which society is secured from incidents that lead to explosions or fires. Safety is strictly a physical concept, devoid of any economic connotation. A safe pipeline system is one that reasonably protects the public from incidents. For a pipeline, the probability of an incident is small, but the consequences of an incident can be substantial. Society often overestimates the risk from such events, placing undue emphasis on the possible serious consequences and insufficient attention on the events' extremely low probability. A significant component of safety is "pipeline integrity," which is the ability of a pipeline to prevent natural gas from escaping and causing deaths, injuries, and property damage. There are other components such as qualified personnel, adequate maintenance, robust emergency response, odorization, design, and testing.

Safety relates directly to risk. Specifically, it represents the inverse of risk. Risk itself is a measure of the probability and severity of an incident. Pipelines are, therefore, more safe when the expected social cost of incidents is lower. Safety-related activities either reduce the probability of an incident or reduce the damage done by an incident. Emergency evacuations and public awareness would fall in the second category; more thorough inspections and monitoring, leak surveys, and pipe replacements would fall in the first.

Many engineers contend that pipeline design should have the goal of *zero significant incidents*. If a pipeline is constructed, operated, and maintained according to its design, it should then operate without posing a safety risk to the public. For example, pipelines should have adequate strength and wall thickness to withstand the design's maximum operating pressure. Violations of these conditions include faulty material and welding, untrained personnel, lax monitoring and inspection, and poor maintenance practices. The job of safety regulators is to make sure that these violations do not occur, or that if they do the utility corrects these problems in the shortest possible time. Several states, for example, issue corrective-action orders, which require the utility to make specific safety-related improvements.

B. Different utility actions affect safety

A utility's "safety culture" should entail a holistic approach directed at minimizing incidents and their consequences. It represents an accumulation of all utility actions that directly or indirectly relate to safety. This approach involves a combination of investments, prudent operating practices, inspections and monitoring, and personnel training. Some actions are substitutable for others in achieving a targeted level of safety.

Overall, a utility's safety culture derives from the totality of its practices and policies in response to regulatory, economic, and legal pressures. Without these pressures, utilities will likely underspend on safety activities.[6]

The American Gas Association says the following about safety culture:

> A positive safety culture begins with the organization's top leaders. Management must emphasize and demonstrate that the safety of employees, customers, the public and our pipeline systems is a value that is paramount. All decisions must take into account the importance of safety. For example, production, cost, and schedule goals should be developed, communicated and implemented in a way that demonstrates that employee, customer, public and pipeline safety is an overriding priority.[7]

Another document, authored by Resources for the Future, lists features characterizing a firm with a positive safety culture:

> The literature emphasizes that safety culture must be advocated by upper management. Consider a few specific policies and procedures that are adopted at firms with a strong safety culture: redundancy; compensation schemes, including bonuses, that emphasize safety performance; hiring appropriately trained individuals and providing continual on-the-job training; and regular analysis of how changes affect safety (i.e., management of change).[8]

Utilities alone cannot control the safety of their systems. Past incidents have had different causes, some of which lie outside the control of the utility. The PHMSA lists eight categories of threats to pipeline safety:[9] (1) corrosion, (2) natural forces, (3) excavation damage, (4) other outside-force damage, (5) welding materials, (6) equipment failure, (7) incorrect operation, and (8) other concerns.[10] Responses from a survey by the American Gas Foundation

---

[6] One major reason is that the utility would perceive its benefits from safety as below those that society would receive. In other words, the social benefits would exceed the private benefits. Analysts refer to this condition as an "agency problem." Good safety regulation would create incentives for the utility that would align its interests with the public interest. One alternative is to set penalties at a level that would discourage utilities from violating regulations.

[7] *See* http://www.aga.org/our-issues/safety/Documents/AGA%20Safety%20Culture%20Statement_Feb%202011.pdf.

[8] Mark A. Cohen et al., *Deepwater Drilling: Law, Policy, and Economics of Firm Organization and Safety*, RFF DP 10-65, January 2011, 15.

[9] Threats are events that can lead to the unplanned release of natural gas.

[10] To the extent that incidents are stochastic (i.e., random or by chance), a utility might exert less effort on safety activities while blaming an incident on bad luck. The utility would argue that because it cannot be held responsible, it would be unfair for the regulator to impose a fine or penalty.

identified the following five items as having the greatest effect on safety: (1) cathodic protection of steel pipes, (2) leak surveys, (3) operator-training programs, (4) implementation of one-call systems, and (5) pipe-replacement programs.[11]

For most gas utilities, the greatest risks come from excavation damage, the corrosion of bare steel, and joint leaks and cracks on cast-iron pipes. Excavation is the leading cause of deaths and injuries from pipeline incidents.[12] Leakage is also a serious problem for distribution pipes. One sensible strategy for utilities is to spend money on those categories over which they have some control, either in preventing an incident or mitigating its consequences. Utilities, for example, can help mitigate excavation damage by making the public more aware of the dangers of digging without first contacting the gas utility to locate pipes. Another action may be to fine heavily contractors and others who do not contact the utility. Because of multiple threats to safety, utilities need to take a multifaceted approach, as no single action by itself can achieve satisfactory results.

C. Safety costs money

Safety has an economic cost that utilities incur and recover from their customers. Natural gas utilities and pipelines spend about $7 billion annually on safety activities.[13] These costs include: (1) personnel costs for safety-related training, routine operations, the handling of emergencies, and the hiring of safety experts; (2) capital costs for replacing cast-iron and bare-steel pipes, new technologies for inspection, and integrity-management programs;[14] (3) operating costs for maintenance and repairs, leak surveys, and control-room management; and (4) education expenses for public awareness and dissemination of information to customers and

---

[11] See American Gas Foundation, *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure*, January 2005, at http://www.gasfoundation.org/ResearchStudies/CompleteStudy.pdf.

[12] *See* ibid.

[13] See the AGA website at http://www.aga.org/our-issues/safety/Pages/default.aspx.

[14] As expressed in a paper by the Gas Technology Institute:

> Safety-related technologies to be created or enhanced include those to reduce or eliminate damage, improve leak detection and location, and detect unauthorized access or changes in condition that may require immediate response. The development and use of advanced global positioning and geographic information systems in conjunction with mobile and/or hand-held devices is another safety related area of technology advancement that complements all aspects of field construction, operations and maintenance.

Gas Technology Institute, "Natural Gas in a Smart Energy Future," GTI-11/0001, January 2011, 17 at http://media.godashboard.com/gti/Natural_Gas_in_a_Smart_Energy_Future_01-26-2011.pdf.

excavators. Hydrostatic pressure testing is one action that is expensive but often used in inspecting pipes.[15]

The safety level of a utility depends on the resources devoted to safety-related activities, as well as managerial allocation of those resources. Costs hinge on the incentive of the utility to use the right mix and level of resources. How much should a utility spend on safety? The theoretical answer is that the utility should achieve the socially optimal level of safety at least cost. The socially optimal level is difficult to determine. Besides, it falls outside the domain of utilities to determine. Utilities do, however, have control over the costs they expend to achieve the safety levels compatible with federal and state regulations.

II. Federal-State Partnership

A. Brief history

The federal government regulates natural gas pipeline safety under different laws and regulations. The Natural Gas Pipeline Safety Act of 1968 first authorized DOT to develop minimum safety standards for pipeline transportation. Over the years, newly enacted statutory and regulatory requirements helped increase the safety of natural gas pipelines, in addition to expanding the scope of safety regulations.[16]

DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for enforcing regulations pertaining to pipeline safety.[17] PHMSA's mission is "to protect people and the environment from the risks inherent in transportation of hazardous materials—by pipeline and other modes of transportation."[18] Federal safety regulations apply to all interstate and distribution pipelines in the country, including those that are not under the purview of economic regulators.

Two objectives of federal pipeline safety regulations are: (1) to assure safety in the design, construction,[19] inspection, testing, operation, and maintenance of pipeline facilities; and,

---

15 This procedure involves filling a section of pipe with water at a pressure much higher than that at which the pipe will ever operate with natural gas. The inspector monitors the pipe for several hours. Failure to pass the test will result in repair or retesting. Besides its high cost, hydrostatic testing requires pipelines to be out of service for some time and fails to detect some small defects that may cause serious problems later.

16 The federal rules governing pipeline safety are included in Title 49 of the Code of Federal Regulations (CFR), Parts 190-199.

17 For an overview of DOT activities on pipeline safety, *see* http://phmsa.dot.gov/pipeline.

18 *See* http://phmsa.dot.gov/about/mission.

19 Safety regulation includes, for example, inspecting construction materials' or pipe materials' strength, as well as any necessary welding.

(2) to set out parameters for administering the pipeline-safety program. Annually, PHMSA evaluates the state pipeline safety programs. Most state programs enforce standards included in their gas-pipeline safety codes.

State public utility commissions partner with DOT to comply with pipeline safety regulations. The states are responsible for virtually all gas-distribution pipelines, gas-gathering pipelines, and intrastate pipelines, assuming that their safety programs receive federal certification or they enter into an agreement with DOT. A major activity of state safety regulators is to conduct frequent inspections of pipeline facilities and utilities' records. They inspect, for example, pipeline construction, pipe corrosion, leak surveys, and damage prevention. Another major activity is conducting, and helping to coordinate, investigations of major safety incidents.

Federal pipeline statutes provide for exclusive federal authority to regulate the safety of interstate pipelines. DOT, however, may (and generally does) authorize a state to act as its agent. Federal regulators also provide comprehensive and up-to-date training programs for state regulators, partially finance state programs, and annually evaluate state regulators through field inspections, records and financial audits, and progress-report reviews.

The mission and duties of one state commission—the Public Utilities Commission of Ohio (PUCO)—exemplify those articulated in most other states:

> The PUCO is committed to ensuring the safe, reliable, and environmentally sound operation of Ohio's natural gas pipeline system. PUCO investigators inspect each natural gas pipeline system in the state at least once every two years and review records and procedures implemented by utilities. When violations are detected, the PUCO orders corrective action and may assess fines and other penalties to ensure that Ohio's natural gas pipeline systems continue to deliver natural gas safely and reliably.[20]

The federal/state partnership helps assure nationwide uniformity of the pipeline safety program. The states must enforce at least the federal regulations. As articulated by the National Association of Pipeline Safety Representatives (NAPSR), which is the national association representing state pipeline safety inspectors:

> The general responsibilities of a pipeline inspector include inspection of: safety records, facilities, construction, integrity management programs, other programs and investigation of accidents. As noted, most states go beyond the federal requirements and perform additional kinds of oversight. The goal of the state

[20] See http://www.puco.ohio.gov/puco/index.cfm/consumer-information/consumer-topics/natural-gas-pipeline safety-in-ohio.

> pipeline safety programs is to ensure the overall safety of the pipeline system for people, property, and the environment in their regions.[21]

The NAPSR report highlighted the fact that most states' regulations are stricter than federal regulations. The largest number of initiatives exceeding federal requirements for pipelines have centered on the functions of operation, maintenance, and record keeping.[22] State regulations take into account local conditions and other factors that affect pipeline-safety risk in developing more stringent state safety regulations.[23]

The Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES Act of 2006) expanded the federal pipeline safety program.[24] It represented an important piece of legislation that helped improve pipeline safety. The Act included major mandates that the natural gas industry is currently working with PHMSA to implement. The Act contains four core provisions that aim to improve distribution pipeline safety: (1) further emphasis on excavation damage prevention, (2) development and implementation of distribution integrity-management programs, (3) increased use of excess-flow valves, and (4) development of regulations regarding control-room management. It also authorized PHMSA to reimburse states for up to 80 percent of their safety-program costs as partners in enforcing federal regulations.[25]

B. Distribution Integrity Management Program (DIMP)

As of August 2, 2011, federal regulations require gas utilities to develop a distribution integrity management program (DIMP). Integrity management focuses on the allocation of utility resources to the areas of greatest risk. PHMSA considers DIMP an effective means for reducing the number of pipeline incidents. One benefit comes from mitigating and preventing problems prior to inspection. The utility can gather evidence showing where repairs, for example, were not effectively performed in the past. As expressed on PHMSA's website:

> The Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006 (PIPES) mandated that PHMSA prescribe minimum standards for integrity management programs for distribution pipelines. The law provided for PHMSA to require

---

[21] *See* National Association of Pipeline Safety Representatives, *Compendium of State Pipeline Safety Requirements and Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations*, September 30, 2011, 7, at http://napsr.org/Compendium%20FINAL%20NAPSR%20Oct%2028%202011%20First%20EditionR%20.pdf.

[22] Ibid., 10.

[23] Ibid., 10.

[24] *See* PIPES Act of 2006 at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ468.109.pdf.

[25] The actual percentage has been much less.

> operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective given the diversity in distribution systems and the threats to which they may be exposed.[26]

This formalized program requires gas utilities to identify, assess, and prioritize safety risks on a system-wide basis. DIMP requires a gas utility to take seven major steps: (1) develop and implement a written integrity management plan; (2) acquire knowledge of the distribution system;[27] (3) identify existing and potential threats; (4) analyze, assess, and prioritize risks; (5) mitigate risk by identifying and implementing safety actions; (6) measure, monitor, and evaluate performance; and (7) report the results. Risk assessment, for example, is a systematic method for determining the probability and consequences of pipeline incidents, such as deaths, injuries, and property damage. It asks the questions: What can go wrong? What is the likelihood that something would go wrong? What are the consequences? Risk management, in contrast, asks the questions: What can a utility do, and what options does it have? What trade-offs does a utility face in terms of costs, benefits, and risks?

Safety inspectors will have three broad tasks for enforcing DIMP: (1) review the plan, (2) monitor execution of the plan, and (3) evaluate *ex post* the effectiveness of the plan. This information should foster more cost-effective measures in mitigating safety risks. Specifically, DIMP can help utilities rank actions on the basis of cost and effectiveness in achieving a tolerable risk level for their entire gas distribution system. Cost-effectiveness requires that the last dollar spent in different safety activities have the same effect on safety as the first. This condition results in diminishing returns, by which the incremental effect on safety for each dollar spent falls as the utility spends more money on safety. Cost-effectiveness relates to the question: How can we gain the "most bang for the buck"?

As early as 2005, NARUC passed a resolution in support of DIMP. The resolution encourages

> states, the Federal Office of Pipeline Safety, gas distribution pipeline operators, and other stakeholders to develop an approach to distribution integrity management that uses risk-based, technically sound and cost-effective measures, which reflect that stakeholders are: knowledgeable of the infrastructure; can identify threats against their systems; and can take appropriate measures to reduce the risk of system failures while balancing the needs to ensure continued safe

[26] See http://primis.phmsa.dot.gov/dimp/docsf/faq.pdf

[27] Formally knowing the risk aspects of its distribution system should enable a utility more effectively to manage its assets by having a better understanding of the cause and effect of safety problems.

operation, reliable service, and the implications of any increased financial demands on the consumer.[28]

C. New federal legislation

New federal legislation signed into law on January 3, 2012 addressed several problems for which parties reached consensus.[29] The law, among other things:

- Imposes higher penalties for operators that violate regulations; [30]
- Provides an additional incentive for states to remove current one-call exemptions by requiring all entities that excavate around pipelines to call a hotline before they dig; [31]
- Requires automatic and remote-controlled shut-off valves on new pipelines;
- Requires the Secretary of Transportation to evaluate the effectiveness of expanding pipeline-integrity management and leak-detection requirements; and
- Increases the budget for additional federal pipeline inspectors.

III. An Economic Perspective on Pipeline Safety

A. "Perfect safety" is a poor policy goal

From an economic perspective, utilities can have overly safe pipelines. The view that "we can't compromise on safety" ignores the fact that safety carries a cost that policymakers should compare with the benefits. Some readers might find this statement provocative, but it reflects the reality that lowering safety can produce a net gain to society. Generally, as safety increases, the incremental cost increases but the marginal benefit decreases. For example, at low

---

[28] National Association of Regulatory Utility Commissioners, *Resolution on Distribution Integrity Management*, adopted on February 16, 2005, 2 at http://www.naruc.org/Resolutions/distributionintegritymgmt_w05.pdf.

[29] SNL Energy, "Obama Signs Pipeline Safety Legislation," *Daily Gas Report*, January 5, 2012, 2. The legislation—the Pipeline Safety, Regulatory Certainty, and Job Creation Act—reauthorizes federal pipeline safety programs through fiscal year 2015. *See* the text of the signed legislation at http://www.pipelinelaw.com/files/Uploads/Documents/PipelineLaw/HR_2845_signed_into_law_1.3.12.pdf.

[30] Specifically, the legislation doubles the maximum fines that pipeline operators face for safety violations.

[31] "One-call" refers to parties' calling a toll-free number prior to digging. It is a federal law to call unless a party receives an exemption.

levels of safety the utility could increase safety at a lower incremental cost than at higher levels. The assumption is that the utility would pursue the most efficient actions at each point in time.[32] As they undertake additional actions, these actions' effect on safety continuously decreases. There is some level of safety beyond which the additional benefits are less than the additional costs. Thus, society can have too much safety.[33]

Because safety has a cost, a utility should limit the amount of money spent on safety. To say that a pipeline is "safe enough" might be a good rule for utilities to apply. The phrase "safe enough" implies that even though the utility can spend more money on safety, the benefits would be marginal. From a cost-benefit perspective, the social value of more safety would fall short of the additional cost. It might be hard for some readers to imagine that a utility could have pipelines that are too safe, but, as discussed earlier in this paper, the opportunity cost of expending more resources on safety can exceed the benefits. As an example, if society spends an additional $10 million on safety, the reduction in the expected number of incidents and their consequences might be minimal. That is, marginal benefits would fall well short of $10 million. If, instead, the utility spent the $10 million on improving its internal operating efficiencies, the net benefit might be positive, or at least less negative than spending the money on additional safety.

A goal of "perfect safety" implies intolerance of any risk. The regulator may find disagreeable any pipeline incident that results in death or injury. The utility would not have to make trade-offs, as safety would dominate all other objectives and cost would not become a factor. One problem with this strategy is that the utility would spend money on mitigating "negligible risk" that most likely would fail a cost-benefit test.[34] As an example, the utility could spend $20 million on reducing the "last ounce" of risk, with incremental benefits valued at much less. One situation in which people make trade-offs involves buying a car. Most people do not buy a Hummer or Volvo, even though these makes might be the safest vehicles. They consider several attributes of a car before deciding on a particular one. Most people compromise safety for other attributes, such as fuel economy, maintenance costs, and appearance. We essentially balance the different attributes in deciding on a car that overall we prefer. Similarly, state utility commissions weigh different objectives in deciding on a specific matter that best advances the public interest. This balancing means that commissions are willing to "trade" some objectives in return for others. Achieving safety at any cost is not compatible with a balanced approach. One way to look at costs is that they represent lost opportunities to allocate money to other activities that might have greater societal benefits.

---

[32] If this condition does not hold, the utility could have a lower marginal cost for safety at higher levels.

[33] There is no empirical evidence showing that this condition exits for gas pipelines.

[34] A cost-benefit test places primary importance on economic efficiency while deemphasizing equity and political factors. Policymakers should, therefore, supplement the information from a cost-benefit analysis with other considerations that affect the public interest.

One common interpretation of a safe pipeline is that the probability of an incident is small. A small probability does not preclude the possibility of an incident that has serious consequences. When an operator says that its pipelines are "safe," it is not clear what he means. It is wrong to think that the pipelines are guaranteed against possible future incidents.

In almost everything in life, including pipelines, the probability of an undesirable outcome is greater than zero. Even walking out the door has a nonzero risk. We all accept some level of risk. Rational people and organizations manage risks to maximize their well-being. Their actions then require that they weigh reducing risk against the additional cost or the impeding of other objectives.[35] They implicitly perform a cost-benefit calculation to determine how much risk they are willing to bear. In virtually all situations, the optimal risk is greater than zero. Where it would be possible to reduce the probability to zero, the costs would inevitably be prohibitive. Think of the effort and cost required to make something perfectly safe, much safer or even marginally safer than what it is currently. Demanding a risk-free pipeline system—if that state is even practicable—does not recognize the cost trade-offs that would make such a goal irrational.

Overall, the level of pipeline safety requires judgment in which the utility weighs the risk versus the costs. Although a utility has to abide by federal and state regulations, it has discretion on how to satisfy those regulations and how much money to spend.

B. Acceptable risk

As mentioned above, one indicator of adequate safety is that "pipelines are safe enough." One interpretation of this condition is that an acceptable but nonzero probability exists that an incident will occur. Safety below this level would be considered unacceptable either because implicitly the probability of an incident is too high or because the pipeline operator could better mitigate the potential consequences of incidents.[36] The operator, for example, could address the latter concern by designing a better emergency-response strategy. Because utilities are subject to both federal and state regulations, the minimum level of safety should reflect compliance with these regulations.

Public perception is essential in judging whether pipelines are safe. Unless the public has confidence that pipelines are safe, more effort needs to be put forth. Although safety is an objective and probabilistic matter for analysts, public acceptability depends on personal and social value judgments. Especially after an incident, public officials and utilities should inform the public that pipelines are safe and that the incident resulted from an isolated event. One

---

[35] These other objectives include reliability, equity, economic efficiency, and advancement of social objectives.

[36] The Army Corp of Engineers assesses the safety of levees, classifying some as unacceptable. To the Corp, "unacceptable" does not necessarily mean unsafe under most conditions; it suggests only a non-minimal risk of failure under extreme flooding. See "With Levees Rated 'Unacceptable,' Officials along the Mississippi Fight Back," *The New York Times*, February 5, 2012, 13.

critical piece of information for safety experts is whether the root causes are isolated events or systemic in nature; for example, an incident may represent an isolated event that occurred at a particular location, but it is not an isolated event when it occurs at multiple locations nationwide and across different time periods.[37]

From a purely economic perspective, it is hard to say whether current safety levels are too low or too high. Because quantification of the social benefits from safety is subject to a high degree of imprecision, policymakers should concentrate their efforts on ensuring that the politically acceptable level of safety is achieved most cost-effectively. Because safety regulations allow utilities flexibility in their actions, state utility regulators should ensure that utility customers are not paying excessively for safety levels complying with those regulations.

C. Optimal and cost-effective safety

The fundamental economic criterion for evaluating any safety-improving activity is whether it increases social net benefits. A sound public policy on safety would apply the same standard. Although regulators can easily measure the costs, they will find measuring the benefits much more challenging. One such benefit relates to the value placed on a human life, which is controversial and difficult to measure. Analysts find it difficult to measure how a safety initiative would improve overall safety, let alone the dollar value of any improvement.

1. Cost-effectiveness

In the absence of measuring benefits, the cost-effectiveness rule becomes important for how utilities make decisions on safety.[38] Because resources are scarce, utilities should allocate them most productively. Specifically, they should allocate each resource on the margin to those activities that would most improve safety. With resource constraints, utilities should equate the effectiveness of the last dollar spent on each safety activity. They should prioritize their activities so that as they spend more money on safety they achieve declining returns.[39]

Under this cost-effectiveness rule, the utility compares the costs of alternative approaches to maintain the existing level of safety or improve safety by a specified level.[40] It would then

[37] I thank Randy Knepper for this thought.

[38] A cost-beneficial action is not a sufficient condition to undertake an action. Because a utility has a limited budget, it should only choose those cost-beneficial actions that are most cost-effective.

[39] Although perhaps not that pertinent for gas pipelines, more cost-effective safety might come from increased attention placed on the role of consumer or worker behavior than on technology. Studies have shown, for example, that the behavior of mechanical-device operators is much more frequently responsible for accidents than the device itself.

[40] Because safety regulations as designed allow utilities flexibility in their actions, regulators should review whether the selected actions are the most cost-effective.

select those alternatives that have the lowest costs.[41] Cost-effectiveness has the effect of saving lives or reducing injuries and property damage for a given amount of dollars spent on safety activities. As an illustration, suppose that a utility has $100 million to spend on one of two actions to improve safety.[42] Assume that a study shows that one action would be expected to save 200 lives and the other action to save 50 lives. As a matter of cost-effectiveness, the utility should undertake the first action: It spends $500,000 per expected life saved, while the second action would spend $2 million per expected life saved. Clearly, the first action is preferable from a cost-effectiveness perspective. Whether a utility should spend $100 million on safety is not as obvious. If evidence shows, for example, that the expected value of a life saved is $300,000, then society is spending $100 million to receive a benefit of $60 million ($300,000 · 200), which would fail a cost-benefit test. On the other hand, if the expected value of a life saved is, say, $3 million, then spending the $100 million would clearly be cost-beneficial.

2. Challenges with command-and-control regulation

Studies have shown that the largest source of waste from health, safety, and environmental regulations is the inability to achieve cost-effective outcomes because of detailed command-and-control rules.[43] These rules mandate certain technologies and actions that serve to drive up the cost of meeting regulatory goals. Because technology-based standards mandate a specific technology, they ignore other options that might be cost-effective for a subgroup of utilities. On the positive side, technology mandates might be justified in combating a high risk against which the specified technologies are known to work well, while the effectiveness of alternative actions is suspect. The regulator would prescribe, for example, specific technologies and actions and then check to see if utilities are in compliance.[44]

Less waste and more cost-effective behavior can result from performance-based regulations that set "outcome" targets instead of technological and other mandates that prescribe

---

[41] While eliminating some waste of resources, cost-effectiveness does not assure that existing levels of safety or safety regulations are optimal. Given safety regulations or safety targets, cost-effectiveness merely results in the lowest cost. "Lowest cost" means that society is using its lowest-valued resources to meet existing regulations or prescribed targets.

[42] Unlike a cost-benefit test, cost-effectiveness specifies a fixed amount of dollars as a goal or target. Although this amount is considered, in some rough way, desirable, it does not represent the optimal level of money that society should spend on safety in the sense of producing the highest net benefits.

[43] *See*, for example, Clifford Winston, *Government Failure versus Market Failure: Microeconomics Policy Research and Government Performance* (Washington, D.C.: AEI-Brookings Joint Center for Regulatory Studies, 2006).

[44] In past years, federal safety regulators assumed responsibility mainly by requiring pipeline operators to comply with uniform minimum standards. More recently, regulators have turned to a more risk-based approach—pipeline and distribution-system integrity-management programs that give utilities added flexibility in their actions, for instance.

specific actions. Even though performance-based regulation would not mandate the adoption of certain technologies, it should encourage utilities to deploy new and other "best practice" technologies when they are economical and more effective than alternate technologies. These technologies can help utilities prevent and detect problems, as well as repair pipes that pose a safety threat.[45]

By giving firms flexibility in achieving a target and assuming that they achieve these targets at different costs, the total costs for safety-related activities would tend to be lower.[46] A performance-based approach, as one illustration, would look at public awareness of potential safety problems without requiring utilities to take specific actions. It would also examine: (1) the number of incidents and their trends over time, (2) repairs of leaks that a utility would report, (3) the number of corrosion leaks per mile, and (4) the percentage of pipes replaced over a specified time. Regulators should first identify what they wish to accomplish. Then they need to set performance metrics to determine whether actual outcomes agree with the objectives. As three illustrations, if the objective is:

- To reduce leaks, an appropriate metric is leaks per mile;
- To reduce incidents resulting from maintenance failures, an appropriate metric is the percentage of work orders completed on time; and
- To reduce pipe damage from excavations, an appropriate metric is lines that are correctly located.

Take the example in which a person is contemplating purchasing a fire extinguisher for his house. Assume that the fire extinguisher costs $100 and has the capability to put out a kitchen fire. Assume also that the probability of a fire is 0.1 percent and that the fire extinguisher expects to avoid fire damage in the amount of $50,000. The expected benefit from the fire extinguisher is therefore $50 (0.001 · $50,000), which is half the fire extinguisher's cost.[47] It appears that the person should not purchase the fire extinguisher: Spending $100 for

---

[45] For a sample of new technologies enhancing safety in the natural gas industry, *see* Ron Edelstein, "Pipeline Safety Technology Needs," presentation at the NARUC Summer Committee Meetings, July 18, 2011 at http://www.narucmeetings.org/Presentations/NARUC%20Pipeline%20Safety%200711%20GTI.pdf.

[46] Government intervention in safety matters fall into one of three broad categories: (a) a "Big Brother" approach in which strict standards prevent consumers or firms from exercising any choices—sometimes referred to as "benign paternalism," (b) a performance-based approach in which consumers or firms can choose among different actions as long as they meet prespecified "outcome" targets; and (c) a "kind mother" approach in which the government gives consumers or firms accurate and easy-to-understand information to help them make better decisions.

[47] The fire extinguisher improves safety not by reducing the probability of a fire but by reducing damage in the event of a fire. Actually, it may increase the probability of a fire by making the person less careful in preventing a fire because he has the extinguisher to mitigate fire damage. A similar example is people tending to drive more safely when they do not have car insurance, or people tending to drive less

an expected benefit of $50 seems irrational. But if the person is risk averse, assigning a high value to avoiding a loss of $50,000, it might seem more sensible for the person to purchase the fire extinguisher. When we buy insurance, for example, our premiums can be much higher than the expected benefits. We buy the insurance because we want to avoid a large loss that could jeopardize our financial well-being.

A more relevant point is that buying a fire extinguisher might not be cost-effective. The person could buy fire alarms or take other actions that would reduce the risk from fire at lower cost. Given a fixed amount of money dedicated to risk reduction, a rational person would allocate it to achieving the greatest reduction. Like a gas utility, the person can spend her money either to reduce the probability of an accident or mitigate the consequences of accidents that occur. Under a command-and-control regime, the government would require all households to have fire extinguishers. The outcome would be non-optimal: Some households would value the fire extinguisher less than the costs—they would exhibit little risk averseness toward a fire, for instance; other households would find cheaper alternatives to a fire extinguisher in reducing the risk from a fire—they might purchase several fire alarms or a new furnace that is safer than their current furnace.

Determining how much a utility should spend on pipeline safety should involve recognizing the small probability of an incident as well as the possibility for substantial consequences. Loss of life, injuries, and property damage can have huge costs. Because of this possibility, some readers might believe that society cannot overspend on safety. But with a small probability of incidents, a rational response would place a limit on spending that is linked to the expected benefits.

3. Risk aversion and financial exposure

Both utilities and utility regulators—assuming they are risk averse—would be willing to improve safety beyond the level where incremental costs equal expected benefits. We can also assume that society is risk averse toward pipeline incidents that can have serious consequences. Because of risk aversion, we should assume that utilities spend more on safety than on the expected benefits. The degree of risk aversion exhibited by utilities and regulators is arguably greater than that of society. Decisions by these two groups can then result in safety-related activities and expenditures that are beyond those that society would prefer. As an example, utilities' and regulators' view of adequate safety might focus on a highly improbable worst-case

---

cautiously when they wear seat belts. *See,* for example, Sam Peltzman, "The Effects of Automobile Safety Regulation," *Journal of Political Economy*, vol. 83 (August 1975): 677-725. These examples relate to what analysts call "moral hazard," in which the "insured" (the homeowner and the driver) may be less cautious because "insurance" (the fire extinguisher and the seat belts) provides a safety net against an accident. These examples illustrate the fact that actual safety relies on consumer behavior and opportunity cost. A regulation or action that aims to improve safety can end up decreasing safety because of unintended consequences. For gas pipelines, if a regulation mandates the adoption of a certain safety technology, the money spent to satisfy this requirement might have improved overall safety more if the utility had the discretion to allocate that money to some other activity.

scenario rather than on the more realistic expected outcome (which corresponds to mean risk values or the most likely outcome). Their actions may then seem conservative, and even irrational, reflecting a highly risk-averse disposition toward pipeline incidents.[48]

Another factor affecting the willingness of parties to improve safety is the extent to which one absorbs the cost of an accident. In our previous example, if the person had no insurance against a fire, he would be more inclined to buy a fire extinguisher. Parallel to this logic, the greater a utility's financial exposure to pipeline incidents, the greater its incentive to avoid an incident.[49] Financial exposure, in turn, depends on the insurance that the utility purchased for such events, its legal liability,[50] and whether the utility and safety regulators believed that the utility was at fault for an incident. The last factor could result in the regulators' penalizing the utility.

D. Utilities have multiple incentives for ensuring safety

1. Incentive

Because a serious incident can cause financial problems for a utility in addition to damaging its reputation, it may have a strong incentive to avoid incidents. Overall, a utility would probably shirk less on safety than would unregulated firms operating in a highly competitive environment. For both financial and nonfinancial reasons, a utility would likely go to great lengths to avoid an incident. As long as the utility can with high certainty and in a timely manner recover its costs for safety, it should have little reason not to maintain a high level of safety. Incidents jeopardize the goodwill that a utility has with the public and its regulators, in addition to inviting lawsuits with a potentially crippling effect on a utility's finances.

A difficult question for utility regulators is whether shareholders should bear the financial brunt of a pipeline incident not attributable to utility negligence. The answer would likely affect how utilities perceive safety and their efforts to maintain it. A moral-hazard[51] outcome can occur when a utility suffers little consequence from an incident, as its management and owners then have less incentive to engage in safety activities to avoid an incident. If instead the utility is held strictly liable for incidents and is unable to pass through costs to its customers and any insurance

[48] Specifically, both utilities and regulators would be disposed to err on the side of too much safety to avoid an incident that would incur a substantial negative public reaction. As noted later in this paper, one possible example is excessive pipeline replacement in the near term.

[49] A utility might have reasons other than financial to maintain a high level of safety. It might, for example, perceive a high cost from the loss in goodwill if an incident occurs.

[50] With unlimited liability, for example, utility shareholders will want managers to have a strong safety culture that minimizes the chances of a major pipeline incident.

[51] "Moral hazard" refers to a situation in which people or organizations will tend to take excessive risks when they do not have to bear the consequences.

deductions, it would have a greater incentive to prevent incidents. This policy, however, may conflict with "fairness" standards that state utility regulators establish.

2. Disincentive

On the other hand, the utility might compromise safety because of financial considerations. When a utility earns a higher profit from spending less money on safety or suffers little profit decline from an incident, it might find slacking on safety irresistible. A utility might also be in a budget-cutting mode that compromises safety. Other reasons for inadequate safety are a lax safety culture within the utility and negligence on the part of utility management. Negligence can lead to operating errors, poor record keeping, malfunctioning equipment, subpar damage prevention, and lack of an emergency-response strategy.

Utilities may underinvest in safety for other reasons, including limited liability and subsidized insurance, in addition to ineffective regulatory oversight and enforcement.[52] A fundamental question is whether gas utilities have adequate incentives to minimize harm to third parties. Third parties include residents, businesses, and others who would suffer property damage or injury from a pipeline incident. The objective of safety regulations is to compensate for deficient control of externalities (i.e., spillover effects) by utilities that compromises or imperils safety. In other words, because a utility may not bear the full cost of a pipeline incident, it may devote less effort toward safety activities than what is socially preferred.

IV. Recommendations for Safety and Utility Regulators

Safety regulations are premised on the market's failure to produce the socially optimal level of safety. In other words, government intervention may be justified if the private market fails to produce the socially preferable outcome. This perspective derives from welfare economics, which emphasizes an economically efficient outcome. Economic efficiency requires the utility's incentive for safety to align with the public interest, which in turn means the social costs from a pipeline incident are fully internalized by the utility. Economic efficiency takes into account (a) the cost to society from satisfying the demands of utility consumers (i.e., productive efficiency) and (b) the value that consumers place on utility service (i.e., allocative efficiency). The keys to achieving economic efficiency are to set rates based on marginal-cost principles and to give utilities strong incentives to operate and invest efficiently. Economic efficiency helps to avoid resource waste from both consumption and production. Economic efficiency involves maximizing total net economic value, while fairness involves the distribution of net value among producers and consumers. Another way to look at the two concepts is that what matters to economic efficiency is maximizing the size of the pie, while fairness cares about the slicing of the pie. Ratemaking, as an example, involves treating these two concepts interdependently, because maximizing the size of the pie requires efficient pricing for consumers, which therefore encompasses slicing the pie at the same time.

[52] For example, most utilities have insurance for pipeline incidents. Their customers generally pay the premiums, and, in the event of an incident, they may have to pay the deductible as well.

Safety regulations attempt to control externalities—i.e., spillovers from normal business activities—that compromise or imperil safety. The market, for instance, might not take into account (1) the third-party effects of an incident or (2) inadequacy of information available to individuals or firms, which would prevent them from making informed decisions. A third rationale for government intervention comes from what analysts call the "agency problem." The incentives of the utility's owners to have a strong safety culture might not coincide with the managers'. Managers might not find it in their interest to spend time on promoting safety within the utility, while the shareholders would desire a strong safety culture to avoid costly lawsuits and other financial repercussions from a pipeline incident. In other words, for various reasons, the utility's managers might not act in the best interest of shareholders.

A last possible problem justifying government intervention is irrationality on the part of a market participant. Consumers might underestimate the probability of a certain event, resulting in their spending deficiently on safety. If the market contains any of the four problems, safety regulations become tenable.

Even though a market failure might exist, good regulation requires regulators to choose optimally among different alternatives available to them. Safety regulators should ask the fundamental question: What is the most effective and efficient way to compensate for a market failure that jeopardizes safety? Command-and-control regulations with detailed rules, as discussed earlier, would almost always violate this condition.

Achieving optimal safety rules poses a special challenge when regulators make decisions based on the input of different stakeholders with varying and sometimes conflicting interests. Stakeholders at PHMSA rulemaking proceedings include (a) local and state governments, (b) federal and state utility regulators, (c) public-interest groups, (d) the public, (e) trade associations, (f) federal safety regulators, and (g) pipeline operators. The main factor for decision making may well be the consensus of stakeholders, not the findings of any empirical or theoretical analysis.

A. Cost-effective actions

One problem occurs when a utility achieves a targeted safety level at a cost higher than what is most efficient. As an example, if a utility wants to improve safety, it should look at different options and select those with the lowest cost. Failing to take the least-cost action can violate the prudence standard.[53] In addition, it always means that utility customers are paying more for safety than they should. As an example, because pipe replacement is expensive, other approaches to improving safety might be more economical and yet improve safety to comparable levels. Safety regulations should include follow-up information on the effectiveness of specific actions in addressing threats underlying the regulations themselves.

[53] Under most legal interpretations, the prudence test requires only reasonableness under the circumstances at the time that a utility made a decision or undertook an action; the test excludes consideration of later facts or what some analysts call "second-guessing."

A regulation that mandates the installation of excess-flow valves (EFVs) represents what analysts refer to as a command-and-control, technology-based form of regulation.[54] Empirical studies have found command-and-control regulations to result in wasteful costs because they preclude the possibility of applying less costly options for individual firms that could attain a comparable objective (e.g., a specified improvement in safety). The overall safety of a gas distribution system depends on myriad actions, one of which could include the installation of EFVs. Other actions conceivably could be taken more cheaply than by installing EFVs and yet obtain the same or a higher safety level for a gas-distribution system.[55] By assessing various safety actions and identifying those that are most effective and cheapest, say, within a DIMP, the utility would achieve a cost-effective result.

B. Enforcement

Notwithstanding safety regulations, no matter how strict they might be, a firm may skirt them when enforcement is lax. Safety regulators apply different enforcement procedures. As expressed in a NAPSR report:

> Enforcement actions vary from state to state, but generally, when a safety violation is discovered during an inspection, the state inspector will submit a report of the findings for follow-up actions. Depending on the state's laws, the agency will determine the severity of the violation and the next course of action.[56]

Economics tells us that compliance with a law or regulation is more likely if the cost of compliance to a firm is less than the expected penalties from noncompliance.[57] If penalties for

[54] An EFV is a device that restricts the flow of gas in a customer's service line when a severe rupture in the line occurs. Most breaks are caused by excavation and vehicular accidents. By restricting gas flow, an EFV may help to prevent deaths, injuries, and property damage. Back in the early 2000s, whether gas utilities should install EFVs was a major topic in the debate over the safety of local gas distribution systems. *See* Ken Costello, *Treatment of Excess Flow Valves by State Public Utility Commissions*, NRRI 05-07, July 2005.

[55] Although justification can exist for government intervention with regard to EFVs, it may not necessarily be in the form of a command-and-control mandate. When a customer makes a decision regarding whether or not to install an EFV on her service line, she takes into account the potential effects on her, including property damage and loss of life or injury, but probably not the consequences for her neighbors. In other words, by not considering the effects of an incident on her neighbors, the customer will underestimate the aggregate societal benefits from purchasing an EFV. As another reason for government intervention, customers may not have good information on the benefits of an EFV. The end result is that, from a societal perspective, utility customers would tend to under-purchase EFVs.

[56] National Association of Pipeline Safety Representatives, *Compendium of State Pipeline Safety Requirements and Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations*, 6.

[57] When a firm expects to spend substantial sums of money to satisfy a regulation, safety-related or otherwise, regulators should not assume that it would take the necessary actions to achieve compliance.

noncompliance are low, unless the probability of detecting infractions is high, firms would have little incentive to comply with a law or regulation.[58] Fines for violations should exceed the expected damage from an incident to the extent that the probability of detection is less than one.[59] An alternative approach for motivating utilities to operate safely is to impose an "incident tax." Utilities would have the leeway to select the most cost-effective actions to prevent incidents, for which they could pay a high tax.[60] As a condition, they should not be able to recover from their customers any taxes paid.

States might want to review their methods for determining fines. A review might lead to revised methods that assess higher and more appropriate fines for violations of pipeline safety codes.

C. Balancing safety with ratemaking goals

State utility regulators face pressure to approve safety actions and allow utilities to recover their costs. Federal authorities might exert this pressure. It becomes difficult for state utility regulators to resist it; they might face criticism if an incident occurs later. Utility regulators, however, owe their customers a thorough review of the utility's proposed actions to improve safety and how they would recover their costs. State statutes require most utility regulators to undertake this duty. Federal safety regulators tend to slight the cost and rate implications, as they understandably place most of their emphasis on safety.

Safety regulations require utility regulators to allow utility spending for maintaining minimum safety standards; but state legislative and judicial mandates restrict them to allow "just and reasonable" rates for gas utilities. These mandates reflect standard legal requirements imposed by court interpretations of statutes and the Constitution. Although interpreted differently by state utility regulators, "just and reasonable" rates typically include two broad features: (1) They reflect the costs of an efficient or prudent utility, and (2) they allow the

---

[58] In 2004, the U.S. Government Accountability Office issued a report critical of the federal safety regulator, the Office of Pipeline Safety, for imposing small fines and collecting only a portion of those fines. See U.S. Government Accountability Office, *Pipeline Safety: Management of the Office of Pipeline Safety's Enforcement Program Needs Further Strengthening*, GAO-04-801, July 2004 at http://www.gao.gov/assets/250/243540.pdf.

[59] Some state safety regulators do not initially fine a utility when they detect a violation. The utility has an opportunity first to mitigate the problem.

[60] One issue would be the size of the tax. It could correspond to the value placed on the loss of human life, injuries, and property damage; or on some multiple of the losses. If the tax is too low, from a societal perspective utilities would tend to have a deficient incentive to prevent an incident. They might decide, for example, that it is more profitable to forgo expenditures on safety and risk paying a tax for an incident.

efficient or prudent utility a reasonable opportunity to earn a return sufficient to attract new capital.[61]

1. Ratemaking and cost-recovery principles

Ratemaking requires that regulators take into account statutes and legal rules, economic principles, precedent, and the trade-offs among different regulatory objectives. Regulators need to judge (1) what objectives ratemaking should achieve, (2) the relative import of each objective, and (3) their willingness to impede certain objectives to advance others (e.g., the loss of economic efficiency from "fairer" rates). Good ratemaking also requires unbiased analysis and making information accessible to regulators in reaching a decision that advances the public interest.

To emphasize, ratemaking decisions typically have conflicting consequences. That is, the selected ratemaking method advances some particular regulatory objectives while impeding others. The classic example is marginal cost pricing. (Marginal cost pricing sets price equal to the cost to the utility of the last unit of service.) This pricing rule promotes economic efficiency by providing consumers with proper price signals while, some observers would argue, clashing with the objectives of equity and gradualism.

a. Prudent and reasonable costs

One defensible regulatory objective is "adequate safety at reasonable cost." It coincides with the requirement of "just and reasonable" rates to prevent customers from paying for costs that the utility could have avoided with efficient or prudent management. Regulators attempt to protect customers from excessive utility costs by scrutinizing those costs.

In the context of this paper, regulators would need to review a utility's safety actions. Prudent costs reflect cost-effective actions (as defined earlier). A more desirable standard would be to align costs with benefits. But because utilities have to abide by safety regulations—even those that do not pass a cost-benefit test—utility regulators cannot expect them to satisfy this standard. When safety regulations are prescriptive—mandating certain technologies, for instance—utility regulators should expect utilities to take some actions that would fail a cost-effectiveness test as well. The fault, of course, does not lie with utilities.

b. Fair cost recovery for the utility

Fair cost recovery[62] prevents severe cash-flow problems for the utility while also protecting customers against excessive costs. Some ratemaking mechanisms, such as an

[61] The second feature permits the utility an opportunity to recover the costs (including its cost of debt and equity) incorporated into the rates approved by the regulator in the last rate case. A regulator generally sets rates so that a utility has an *opportunity* to earn a fair or reasonable rate of return for shareholders, assuming efficient and economical management; but the regulator does not guarantee that return. A frequent area of contention in rate cases is the interpretation of the term "opportunity."

infrastructure surcharge,[63] achieve the first outcome while violating the second in the absence of a thorough regulatory review of costs. Good regulation would allow utilities a reasonable opportunity to earn their authorized rate of return, as long as they were prudent. If utilities have to spend money because of safety regulations, and they spend this money prudently, they should be able to recover all of their costs in a manner that avoids severe financial problems. For example, if the utility regulator previously approved "safety" investments, such as pipe replacements, and determined that the utility managed them prudently, it should allow the utility to earn an adequate rate of return on those investments. On the other hand, when a utility is not prudent, it would be unfair to its customers if it were allowed to recover all of its costs. In both instances, "just and reasonable" rates would require these regulatory actions.

c. No rate shock

State utility regulators are more favorably disposed toward new rates if the methods used to determine them have some historical coherence. Especially troublesome are new rates that increase unexpectedly and are well above previous rates for particular classes of customers. Allowing a utility to recover the costs for an expensive safety-improving project, such as a pipeline replacement program, on an annual basis outside of a general rate case can help lessen any dramatic one-time rate increase that could otherwise occur. Particularly during hard economic times, a gradual increase in rates might be more politically palatable.

d. The right incentives

In an ideal world, utilities would be motivated to achieve the right level of safety at least cost. "The right level" means safety that accounts for the marginal benefits and marginal costs at the level where they are equal. This condition requires that utilities be held accountable for incidents, especially those within their control.

e. Public acceptability

This principle refers to how utility customers, the public, and political actors will respond to higher rates related to safety improvements. Utility regulators like to avoid negative public

---

[62] "Cost recovery" refers to the timing and methodology used for the inclusion of allowable costs in rates.

[63] Infrastructure surcharges come under different labels—for example, capital expenditure tariff tracker (Rhode Island), utility enhancement infrastructure rider (Michigan, New Jersey), accelerated main-replacement program (Indiana, Kentucky), infrastructure replacement rate surcharge (Georgia, Kansas, Missouri, Nebraska) interim rate adjustments/rate-stabilization tariff (Texas, Virginia), main-replacement program rider (Arkansas), and cast-iron bare-steel replacement program (New Hampshire). A general definition of surcharges is that they represent an adjustment to the customer bill that raises rates by a specified amount for a limited time. *See* Paul Roberti, "Regulatory Efforts to Enhance Pipeline Safety," presentation at the AGA Reauthorization and Transmission Pipeline Design, Construction and Operations Workshop, February 29, 2012, 8.

reactions to their decisions, as this places them in an unfavorable light and is more likely to trigger legislative intervention. Public acceptability should result in minimal customer complaints, legislative intervention, and negative media publicity. If the utility can justify expenditures on safety activities—claiming that necessary risk reduction requires an aggressive pipeline-replacement program, for instance—its customers will be more accepting of any rate increase. Utility regulators should not view public acceptability as something necessarily outside the control of the ratemaking process. How the public reacts to a particular rate increase would depend, for example, on efforts to educate customers on the justification for the increase.

f. Promotion of a specified goal

The utility regulator might feel strongly about mitigating the probability of pipeline incidents and their consequences. In achieving this goal, the regulator might want to approve a special tariff or a nontraditional treatment of the costs, such as a tracker or rider in which the utility could recover "safety" expenditures outside of a rate case.

g. Balancing of conflicting objectives

The proper balancing would result in cost considerations not jeopardizing safety, or in prompt cost recovery that coexists with prudent utility behavior or the most cost-effective actions.

2. The example of accelerated pipeline replacement

A primary concern is the age of old cast-iron or bare-steel pipes, many of which are susceptible to breaks or leaks.[64] Many of these pipes are several decades old and are either cast iron or bare steel. Cast-iron and bare-steel pipes account for a disproportional percentage of leaks.[65] The replacement of old pipes is a costly endeavor. One estimate is that replacing all

---

[64] Cast-iron pipes were installed into the 1940s and still make up about 3 percent of all distribution pipelines. Small-diameter pipes are susceptible to breaks under extreme weather conditions from earth movements. Bare-steel pipes were mostly installed between 1940 and 1970. These pipes are more tolerant of bending than cast-iron pipes but are susceptible to corrosion because of the lack of coating or cathodic protection. After 1970, regulations required coating and cathodic protection. Bare-steel comprises about one percent of the distribution system. Early plastic pipes can crack under bending stress. Plastic pipes are also susceptible to immediate failure under a severe impact.

[65] In Pennsylvania, for example, bare-steel and cast-iron pipes together account for only 5 percent of distribution pipes (in terms of miles), but they bear 95 percent of the leaks. Pennsylvania gas utilities expect to spend $13 billion over the next 20 years for pipe replacements. *See* Paul Metro, "Pennsylvania Natural Gas Summit—PUC Jurisdiction," Pennsylvania Natural Gas Summit, November 18, 2009 at http://www.puc.state.pa.us/transport/gassafe/pdf/Presentation-NG_Summit111809.pdf. In Ohio, the four largest gas utilities have together budgeted around $6.3 billion to their accelerated pipeline-replacement programs. *See* Cheryl Roberto, "Pipeline Safety Program: Ohio Highlights," presentation at the Annual NARUC Meeting, November 15, 2011 at http://www.narucmeetings.org/Presentations/Roberto_SafetyFirst_Tuesday.pdf.

pre-1960 pipes in the U.S. would cost around $150 billion, or $2,100 per customer.[66] This amount seems politically unpalatable, especially in these hard economic times.[67]

Although we have seen a downward trend in pipeline accidents over the past several years, the age and other features of existing gas pipes have raised legitimate questions about the future safety of our pipeline system. Safety experts contend that decisions to repair, rehabilitate, or replace pipe should depend on different factors in addition to age. These factors include: (a) the operating history of the pipeline, (b) pipeline protection against corrosion, (c) materials used during pipeline construction, (d) pipeline construction methods, and (e) soil movement around the pipeline and other environmental conditions.[68] Pipeline safety experts refer to the term "fitness for service" as a more broadly based standard for determining appropriate actions. This standard relies on operating history, as well as inspection and testing results.

Several state regulators are asking whether gas utilities should accelerate their replacement of old cast iron and bare-steel pipes.[69] PHMSA is encouraging state regulators to accelerate pipe replacement:

> Pipeline infrastructure replacement programs for gas distribution systems exist in nearly 30 states. Some state public utility commissions have used their traditional ratemaking authority to approve these programs, the terms and conditions of which are established under a generally applicable statutory provision. Other state public utility commissions have specific authority to approve such programs. The terms, conditions, and cost recovery mechanisms of these programs vary by statute. Whether as part of the traditional ratemaking process or in a separate proceeding, PHMSA is encouraging the states to accelerate the remediation of high-risk gas pipeline infrastructure.[70]

---

[66] *See* Rocco D'Alessandro, "Pipeline Safety: Planning for a Safer Future," NARUC 122nd Annual Conference, November 2010, 9.

[67] The expectation of low wholesale natural gas prices over the next few years may, however, make the high cost of replacement more politically palatable.

[68] *See* Rocco D'Alessandro, "Pipeline Safety: Planning for a Safer Future," 12.

[69] Even new pipelines have risks. Their overall risk depends on operator qualifications, construction procedures and materials, and the number and thoroughness of inspections.

[70] U.S Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *White Paper on State Pipeline Infrastructure Replacement Programs*, December 2011,1 at http://opsweb.phmsa.dot.gov/pipelineforum/docs/PHMSA%20111011-002%20NARUC.pdf. PHMSA specifically wants state regulators to consider having utilities accelerate pipe replacements for certain pipes. They include cast-iron gas mains, plastic pipes manufactured from the 1960s through the early 1980s, bare-steel pipes without cathodic protection or coating, and older pipes.

PHMSA is even offering to assist state regulators who are seeking to establish or improve programs for the repair, rehabilitation, and replacement of high risk pipeline infrastructure. Such assistance could include offering testimony at legislative hearings or in state proceedings, providing technical expertise in identifying high-risk pipeline infrastructure, and ensuring that state pipeline safety regulators are effectively implementing the integrity management requirements for natural gas transmission and distribution lines.[71]

Utilities will eventually have to replace their old pipes.[72] The question is whether they should replace them at a faster pace than they have done historically. One observer contended that "the best method to insure the integrity of the system is to have an effective replacement program to eliminate [the most hazardous] leaks as the system is replaced, as opposed to fixing each joint that is weeping one at a time."[73] Federal safety regulators can order pipe replacement only under the condition of an "imminent hazard." In their eyes, pipelines only have to be "fit for service." A consensus is that state regulators should seriously look at accelerating pipeline replacement, especially for old pipes that may pose an immediate danger. Waiting too long could result in any replacement's becoming a response to an emergency situation rather than a reasonably deliberate action.

a. Reviewing the cost-effectiveness

Assume that a utility proposes to spend large amounts of money on accelerated pipeline replacement over the next ten years. It should then demonstrate to the utility regulator that the strategy is: (1) cost-effective in improving safety at the lowest cost and (2) needed to address an imminent threat to safety.[74] Steps that the utility can take to determine the cost-effectiveness, or the expected costs and benefits, of accelerated pipeline replacement are as follows:[75]

---

[71] Ibid., 17.

[72] In some programs, replacements involve bare-steel mains, cast-iron mains, pre-1971 coated-steel mains and services, certain first-generation plastic pipes, and isolated bare-steel services.

[73] *See* the comments of Sue Fleck, Vice President, Engineering, National Grid representing the AGA in the *Proceedings from the National Pipeline Safety Forum*, hosted by the U.S. Department of Transportation, April 2011, 18.

[74] In regulatory jargon, the utility should demonstrate that its pipeline replacement plan is "prudent and reasonable."

[75] The reference case from which to calculate the benefits and costs is a strategy that spreads out replacements over more years based on historical experience. For a presentation on quantifying the benefits and costs of accelerated pipeline replacement, *see* Frontier Economics, "Evaluating the Gas Mains Replacement Programme—Preliminary Findings," prepared for the Capex Working Group, November 15, 2010 at http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/WorkingGroups/Documents1/Frontier%20repex.pdf. For the particular case examined by Frontier Economics, the net benefits from accelerated pipeline replacement were negative for several scenarios.

- *Determine whether current leak rates require accelerated pipeline replacement:* Are alternatives to accelerated pipe replacement inadequate to address the problem at hand, even though they are less expensive? Alternative actions can include pipe repair or pipe replacement at a slower pace.

- *If feasible, estimate the expected reduction in deaths, injuries, and property damage from accelerated pipeline replacement:* Do federal or state safety regulators have historical information on the reduced risk from accelerated pipeline replacement relative to a reference-case pipeline replacement?

- *If feasible, calculate the reliability and environmental benefits from accelerated pipeline replacement:* What exactly are these benefits? How can the utility measure them?

- *Calculate the opportunity costs of accelerated replacement:* Could the money the utility dedicated to accelerated replacement be better allocated to reduce risk by other actions? In other words, could these actions reduce risk more than the lower risk from accelerated replacement? Which options are most cost-effective given the monies available for safety actions? What other utility actions would reduce safety risk, and what are their costs? Because pipeline replacement is extremely expensive, can a utility spread it out over more years without jeopardizing safety?

- *Calculate the lower operating costs that would result from fewer leaks and lower maintenance costs:* How should utility customers receive the benefits from these cost savings?[76]

- *Identify pipe segments that are at the greatest risk and demand immediate attention*: What is the threat in the absence of immediate action? To what extent would a non-accelerated replacement program pose risk to the pipeline system? Do the results from a risk analysis show the urgency of replacing "at risk" pipes over an accelerated time frame?

The study estimated that replacing 25 percent of the pipes most at risk removes 60 percent of the system-wide risk. This outcome suggests declining returns from additional dollars spent on pipeline replacement.

[76] One study calculated that the largest benefit from accelerated pipeline replacement derives from reduced gas losses, which has both an economic and an environmental dimension. The latter benefit includes a reduction in the amount of greenhouse gas emissions. S*ee* Frontier Economics, "Evaluating the Gas Mains Replacement Programme—Preliminary Findings," 8.

- *Calculate the investment costs and compare with reference-case investment costs:* Accounting for inflation and discount rates, what would be the present-value cost of an accelerated program relative to a program based on historical replacement trends?[77]

- *Calculate the annual budget for accelerated pipeline replacement:* How precise are the budget numbers? Should the utility have a contingency budget for unexpected events?

- *Calculate the net benefits from accelerating pipeline replacement:* What are the total costs and benefits of accelerating pipeline replacement relative to a plan based on historical trends?

b. Appropriate cost recovery for investments

One justification for infrastructure surcharges is that investments in refurbishing or replacing aging pipelines (e.g., cast-iron and bare-steel pipes) do not generate additional revenues for the utility.[78] Surcharges can offer utilities the following advantages: (1) shortening the time lag between the incurrence of a cost and its recovery in rates (i.e., curtailing regulatory lag), (2) increasing cost-recovery certainty, and (3) lessening regulatory scrutiny of costs. Utilities like infrastructure surcharges because they allow cost recovery without a general rate case.[79] Overall, surcharges lower a utility's financial risk by stabilizing its earnings and cash flow.

---

[77] One would expect that for accelerated pipeline replacement, investment costs in present-value dollars (assuming that the discount rate is greater than the construction-cost inflation rate) would be higher than under the reference case. *See* Frontier Economics, "Evaluating the Gas Mains Replacement Programme—Preliminary Findings," 19.

[78] Examples of two states with infrastructures surcharges are Ohio and Rhode Island. *See* Cheryl Roberto, "Pipeline Safety Program: Ohio Highlights," presentation at the Annual NARUC Meeting, at http://www.narucmeetings.org/Presentations/Roberto_SafetyFirst_Tuesday.pdf; and Paul Roberti, "Regulatory Efforts to Enhance Pipeline Safety: The Rhode Island Experience," presentation at the Annual NARUC Meeting, November 15, 2011, at http://www.narucmeetings.org/Presentations/Roberti_SafetyFirst_Tuesday.pdf.

[79] Pipe replacement should reduce a utility's operating costs from fewer leaks that waste gas and from lower maintenance costs. Any surcharge should subtract these cost savings from the amount charged to customers. Such an adjustment is particularly important when a utility is unlikely to file a rate case for a number of years. One gas utility estimated that its proposed accelerated pipeline-replacement program, relative to a "slower pace" program, would reduce operation and maintenance costs by $244 million during the period 2011–2059. The accelerated program would reduce the amount of leak repairs, leak surveys, leak rechecks, emergency responses, regulator station inspection and maintenance, vault survey and maintenance, lost gas, and inside safety inspections. *See* Illinois Commerce Commission, *Proposed General Increase in Natural Gas Rates (Tariffs Filed on February 25, 2009)*, Order, Docket

An important incentive for cost efficiency on the part of regulated utilities is the threat of cost disallowance from retrospective review. To the extent that infrastructure surcharges reduce the effectiveness of these reviews, further erosion of incentives for cost management occurs. With less regulatory oversight and auditing, which often accompany rate cases, a utility might have less concern over its costs. Regulators have long recognized the importance of retrospective reviews in motivating a utility to control costs. Many regulatory experts view retrospective reviews as dissuading a utility from poor decisions with the threat of a penalty—making the utility more diligent and careful in its planning and operations, for instance.

PHMSA favors surcharges because it wants utilities to replace their old pipes in the shortest possible time. Surcharges for safety expenditures can diminish any disincentive that utilities might otherwise have to invest in safety. Particularly when a utility is able to defend large investments in safety, prompt cost recovery can be appropriate.[80] Surcharges permit the utility an opportunity to recover substantial costs (including costs of debt and equity) incurred since the last rate case. A regulator generally sets rates so that a utility has an opportunity to earn a fair or reasonable rate of return for shareholders, assuming efficient and economical management, but the regulator does not guarantee that return. A frequent area of contention in rate cases is the interpretation of the term "opportunity." A highly expensive investment that generates no additional revenues for the utility would seem to be a good candidate for special cost-recovery treatment. Waiting to recover costs through a litigated rate case could place the utility in financial jeopardy.[81]

From an earlier discussion, the utility should first convince the utility regulator that the investments are preferable, from a cost-benefit or cost-effectiveness perspective, to alternate actions. As NARUC president David Wright recently expressed in an interview with the natural gas industry:

Nos. 09-0166 and 09-0167, January 21, 2010, 134 at http://www.icc.illinois.gov/docket/files.aspx?no=09-0166&docId=145807.

[80] Another large investment might involve replacing manual values with automatic shut-off valves. On a nationwide scale, the cost could be as much as $12 billion. (*See* Christina Sames, American Gas Association, National Transportation Safety Board Hearing, March 3, 2011.) Some industry people have argued that automated valves would have marginal benefits because most of the damage caused by a pipeline explosion occurs within 30 seconds. On the other hand, when a utility spends several hours looking for shut-off valves while gas is "blowing" out of a ruptured pipe, the possibility exists for hours of fire and massive property damage. I thank Bob Harding for this last point.

[81] The term "financial jeopardy" has different interpretations. This state, no matter how it is defined, has the potential to harm customers as well as the utility shareholders. It could, for example, cause (a) the deferment of needed capital investments to prevent unsafe pipelines and unreliable service, (b) the lowering of the utility's credit rating, and (c) an increase in the utility's cost of capital. The time period over which these effects would harm utility shareholders generally would be more immediate than that for the harm to customers.

> The best way we can expedite natural gas infrastructure replacement programs is for us to have a dialogue with everyone involved. Safety is job number one, and we will do all we can to provide the industry with the resources it needs to ensure the safety of its systems. It is incumbent upon the industry, however, to be proactive and tell us what problems exist and where the problems are. Regulators can't act unless we have a request in front of us, and your requests must demonstrate, in an open and transparent process, what you need and why. We know we have an aging infrastructure problem, and we rely on you to give us the specifics.[82]

The economic justification for accelerated pipeline replacement prevents customers from paying for costs that the utility could have avoided with a more efficient or prudent choice. Regulators attempt to protect customers from excessive utility costs in general by scrutinizing a utility's costs in a rate case or by applying an incentive mechanism (with explicit rewards and penalties) that motivates a utility to act efficiently. Ratemaking practices can affect the propensity of a utility to act efficiently. Cost riders (such as an infrastructure surcharge), especially when they preclude certain costs from undergoing a thorough review by the regulator,[83] can weaken a utility's incentive to control those costs, all else being equal.[84]

---

[82] American Gas Association, "Go, Team!" *American Gas*, February 2012, 22.

[83] The utility may also have an incentive for "mission creep," whereby it would shift costs not related to safety activities to a rider such as an infrastructure surcharge. The motivation for the utility is get more prompt and certain recovery of these costs.

[84] *See*, for example, Ken Costello, *How Should Regulators View Cost Trackers?* NRRI 09-13, September 2009, at http://nrri.org/pubs/gas/NRRI_cost_trackers_sept09-13.pdf. Cost riders for which relevant costs do not undergo a thorough review by the regulator can weaken a utility's incentive to control those costs, all else being equal. They can also diminish the effect of regulatory lag on a utility's cost performance. Alternatives to an infrastructure surcharge are deferred accounting and tracker accounts. Each accounting procedure preserves the cost-recovery issue until the utility files its next rate case. As one state commission has expressed about deferred accounting:

> Deferred accounting is a valuable regulatory tool used primarily to hold utilities harmless when they incur out-of-test-year expenses that, because of their nature or size, should be eligible for possible rate recovery as a matter of public policy. Traditionally, deferred accounting has been reserved for costs that are unusual, unforeseeable, and large enough to have a significant impact on the utility's financial condition. Deferred accounting has also sometimes been permitted when utilities have incurred sizeable expenses to meet important public policy mandates. (*Minnesota Public Utilities Commission, Order Granting Deferred Accounting Treatment Subject to Conditions and Reporting Requirements*, G-002/M-10-422, January 12, 2011, 1.)

Several state utility regulators have approved surcharges for accelerated pipeline replacement.[85] A common rationale is that they would:

- Avoid cash-flow problems and other financial risks for utilities incurred from undertaking large investments to assure a safe pipeline system;
- Reduce the number of full rate cases;[86]
- Mitigate short-term high rate increases (i.e., rate shock);
- Allow utility regulators to periodically (e.g., annually) review the prudence of a project;
- Promote intergenerational equity; [87]
- Eliminate any disincentive that a utility would otherwise have to replace pipelines at an accelerated pace; and
- Promote safety by encouraging replacement of pipelines at high risk.

D. Why a single regulatory agency can better balance safety and economic goals

Criticisms about a single regulatory agency's regulating both utility rates and safety seem to overlook the importance and difficulty of balancing societal objectives. An argument made in this paper is that balancing goals becomes easier when one agency regulates both rates and safety. State utility regulators have to abide by federal safety regulations[88]—federal regulations, in other words, set a floor—but federal regulations pay little attention to (although they do not completely ignore) the ratemaking goals of state utility regulation. A safety regulator divorced

---

[85] *See* U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, *White Paper on State Pipeline Infrastructure Replacement Programs*; and American Gas Association, "Infrastructure Cost Recovery Update," Natural Gas Rate Round-Up, January 2012. The last publication noted that "currently, more than 40 utilities in 19 states serving 20 million residential natural gas customers are using full or limited special rate mechanisms to recover their replacement infrastructure investments, and 6 utilities have such mechanisms pending in 3 other states [p. 1]." Incidentally, the Federal Energy Regulatory Commission has no special rate treatment for safety activities by interstate pipelines.

[86] Rate cases absorb substantial staff resources and time, diverting those scarce resources from other commission activities.

[87] The apparent reason is that current customers would be beneficiaries, so they should start paying for the pipe replacements as soon as possible.

[88] As noted earlier, most states have safety regulations that are more stringent than federal regulations.

from cost-recovery authority—that is, removed from the responsibility of determining how utilities will recover the costs—will tend to overemphasize safety relative to ratemaking goals. In other words, federal safety regulators, who are responsible and politically accountable for pipeline safety, will tend to be highly risk averse toward incidents, enacting regulations that mostly ignore their economic effects. A likely consequence is an overly safe pipeline system.

A single regulator would be better positioned to strike the balance between competing goals needed to achieve a socially optimal outcome. These goals are primarily a safe pipeline and "just and reasonable" rates. The regulator can assign greater importance to safety relative to ratemaking goals and still achieve a balanced outcome that is in the public interest. Even if one disagrees that policymakers should make trade-offs between these goals—that safety is too important to compromise, for instance—one should at least strive to achieve a given level of safety at least cost. Because federal regulations have increasingly allowed utilities discretion in their safety activities, regulatory oversight becomes important for assuring utility customers that they are not overpaying for safety.[89]

The main point conveyed here is that state utility regulators are the only agency that has a vested interest in considering both safety and the cost of safety to those who pay for it. This balancing requires utility regulators to ensure not only that utilities operate safely but also that they provide safety at a reasonable cost that reflects prudent and efficient action. While utility regulators have a strong commitment to safety,[90] they also have an obligation to assure utility customers that they do not pay more for utility service than is necessary. It is this responsibility of state utility regulators that makes their work so challenging and singular. The public holds them accountable for excessive rates and deficient safety. Overall, the preferred institutional arrangement would seem to call for a single agency—a state utility regulator subject to a federal floor on safety regulations—with jurisdiction over safety and ratemaking matters that allows it to harmonize and balance symmetrically different social objectives, which sometimes conflict. It is this harmony and balance that can best advance the public interest and justify single-agency authority over both the safety and economic functions of utilities.

When two regulators have authority over utility activities, the responsibilities of each should be clearly defined to avoid duplication, jurisdictional uncertainty, and turf battles. Because safety standards directly affect utilities' costs and rates, state utility regulators should assume an advisory role in developing federal safety regulations.

[89] If, instead, federal regulations were predominately command-in-control in nature, utilities would have less discretion, and prudence reviews would be less demanding and important.

[90] It is hard to question the commitment of states to pipeline safety because most of them, as mentioned earlier, have stricter safety regulations than the federal regulations. This situation implies that states are willing to have utility customers pay higher rates in return for greater safety.

V. Conclusion

This paper highlights the responsibility of state utility regulators to assure the public that utilities perform at a high level in various dimensions, including economic efficiency, reliability, and safety. Safety is a prominent goal, but only one of several goals that regulators attempt to advance. Sometimes these goals conflict, requiring regulators to weigh their relative importance and make trade-offs that best serve the public interest. State utility regulators need to engage themselves in a robust dialogue at the federal level, explaining the importance of economic factors in developing new laws and regulations.

One possible conflict exists between safety and "just and reasonable" rates. An example is achieving a high level of safety at excessive costs or with "exorbitant" rate increases. State utility regulators are in the best position to balance the safety and ratemaking goals, frequently confronting them with a difficult challenge. One rule that utility regulators can consider is the following: Ensure that utilities make their pipes safe by spending prudently and efficiently. Another regulatory goal—reliable service—is complementary with safety. A pipeline incident would likely shut down at least part of the gas utility's operation. One benefit of improved safety is, therefore, more reliable utility service. Another benefit of improved pipeline safety—from pipeline replacement, for instance—is lower maintenance and operating costs. Overall, efforts to improve safety can have a payoff that transcends making pipelines safer.

Safety has a cost that state utility regulators must take into account when evaluating a utility's proposal to invest in or spend on safety-related activities. Regulators must not only judge whether these costs actually improve safety but also assess whether the underlying actions are least cost. The first justification requires a cost-benefit-type review, while the second justification applies a cost-effectiveness rule. Good regulation requires these actions, although state utility commissions have limited authority to determine whether safety actions are cost-beneficial because of federal regulations.

A policy goal of "perfect safety" is contrary to how state utility regulators operate and their mandate to serve the public interest. This policy is inconsistent with the common interpretation of "just and reasonable rates." It also contradicts how rational individuals and organizations behave; all make trade-offs that generally compromise safety for other objectives they deem important. Specifically, they prefer to live with some risk rather than to spend additional money and time on reducing any residual risk. Spending excessive money on safety might result in less money being available to improve productivity or customer service. The "balancing act" of regulation—which history has shown best promotes the public interest—requires utility regulators to consider safety jointly with other objectives aligned with the public interest. Without this joint consideration, an imbalance and an asymmetrical outcome will likely compromise the public interest.

Appendix A: Major Tasks for Safety Regulations

- Inspect pipeline design and construction (e.g., material used, construction procedures, necessary welding) for compliance with regulations.

- Identify the riskiest segments of pipes that require repair, rehabilitation, or replacement.

- Review, monitor, and evaluate DIMP.

- Require operators to report on incidents and their causes.

- Require operators to report leaks and take appropriate actions in response to those leaks.

- Investigate incidents as to their causes and the utility's response.

- Inspect operator activities, such as leak surveys and corrosion, maintenance,[91] operations conducted by qualified personnel, emergency preparedness and response, and damage prevention.

- Oversee rehabilitation projects.

- Monitor compliance with standards and other requirements, such as operators periodically inspecting pipes and keeping records for review.[92]

- Enforce federal and state regulations by issuing fines, warning letters, or letters of concern for violations.

[91] Federal regulations require operators, for example, to document their procedures for carrying out maintenance activities.

[92] Another requirement is for contractors, excavators, and other parties to call 811 before digging and 911 in an emergency.

Appendix B: Questions Related to Gas Pipeline Safety

Core questions

1. What are the major decisions that regulators have to make about utility safety activities?

2. What criteria should regulators apply in making those decisions?

3. What incentives do gas utilities have to achieve safety?

    a. Are these incentives compatible with the utilities' undertaking cost-effective safety activities?

    b. How risk averse are utilities toward pipeline incidents relative to society's risk aversion?

4. What is the threshold for "safe is safe enough"?

    a. Who should make this determination?

    b. How do regulators know if utilities are meeting this threshold?

5. Why isn't zero tolerance for safety risk optimal from society's perspective?

    a. What would be the costs?

    b. What would be the benefits?

6. How can safety regulators best enforce laws and regulations?

    a. How high should regulators set fines?

    b. What factors should affect the size of fines?

Cost-effective/cost-beneficial actions

1. How do utilities determine where and how much to spend on safety?

2. How do regulators know whether utilities were prudent in their safety-related activities?

    a. How should regulators define and measure prudence when it comes to safety activities?

b. How can regulators know when utilities overspend on safety activities?

3. Should utilities apply a cost-benefit or a cost-effectiveness rule for evaluating safety activities?

4. What are the social benefits of safety? To what extent can utilities quantify them?

5. How can utilities exploit DIMP to better achieve cost-effective safety activities?

Balancing safety and other utility objectives

1. What potential conflict exists between safety and "just and reasonable" rates?

2. What constitutes "just and reasonable" rates that reflect a utility's safety-related costs?

3. Are safety and ratemaking activities mutually exclusive, or are they interconnected, requiring joint action?

4. How much safety should we have or can we afford? How much weight should regulators place on safety relative to other objectives?

5. Should the responsibility for economic and safety regulation of a utility reside in different government entities?

   a. What are the arguments for and against separate entities?

   b. What is the justification for assigning safety and ratemaking authority to a single agency?

Accelerated pipe replacement

1. On what basis should gas utilities accelerate pipe replacement? Is this action least costly for achieving a certain level of safety?

2. What are the benefits of accelerated pipe replacement? To what extent can a utility quantify these benefits?

3. What can regulators do to support accelerated pipe replacement, when found appropriate?

   a. How should they allow utilities to recover their costs?

   b. How should they monitor and evaluate expended costs as to their prudence?

Guidance[1] for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics

[1] This document is to provide guidance describing methods to evaluate and measure IM program effectiveness. This document is not a regulation and creates no new legal obligations.

7/10/2014

Table of Contents

1. Purpose 1
2. Background 1
3. Overview of Process for Rigorous Program Evaluation 2
4. Establish Safety Performance Goals 4
 4.1. Safety Performance Goals 4
 4.2. System Specific Safety Performance Goals 4
 4.3. Senior Management Commitment 4
 4.4. Safety Performance Goal Communication 5
 4.5. Safety Performance Goal Review 5
5. Identification of Required Performance Metrics 5
 5.1. Required IM Metrics 5
 5.2. Other Required Metrics 6
6. Selection of Additional Meaningful Metrics 6
 6.1. IM Program Element Implementation Metrics 6
 6.2. Operational Implementation Metrics 7
 6.3. System Specific Metrics 7
 6.4. Threat Specific Metrics 7
 6.5. Characteristics of Effective Indicators (Metrics) 8
7. Performance Metrics Data Collection and Recording 9
 7.1. Performance Metrics Collection 9
 7.2. Metrics Records Management 9
8. Program Evaluation Using Metrics 9
 8.1. Assessment of Program Effectiveness 10
 8.2. Metric Trends 10
 8.3. Program Evaluation Reviews 10
 8.4. Performance Feedback 10
 8.5. Corrective Actions 10
 8.6. Threat Identification and Risk Analysis Updates 10
 8.7. Program Evaluation Process Reviews 11
 8.8. Safety Performance Goal Confirmation 11
 8.9. Metric Updates 11
9. Definitions 12
Table 1 - Calendar Year GT and HL IMP-related metrics from the Annual Reports 13
Table 2 - Other Required Metrics for Gas Transmission Systems 15
Table 3 - IM Programmatic Performance Metrics 16
Table 4 - System and Threat-Specific Performance Measurement 21
Appendix A - Elements of a Mature Program Evaluation Process 29

Guidance for Strengthening Pipeline Safety through Rigorous Program Evaluation and Meaningful Metrics

1. Purpose

This document provides guidance on the elements and characteristics of a mature program evaluation approach utilizing processes created to define, collect and analyze meaningful performance metrics. This guidance uses the basic requirements and processes previously developed and documented in ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, API Standard 1160, Managing System Integrity for Liquid Pipelines, ANSI / GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2012 Edition and the Part 192 and 195 Integrity Management (IM) rules.

The guidance builds on this foundation to provide more detailed and comprehensive descriptions of the activities / steps involved in program evaluation as well as in the selection of meaningful performance metrics to support this evaluation. It clarifies and expands the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) expectations for operator requirements to measure IM program effectiveness. In addition to the rule requirements and the noted standards, PHMSA inspectors will rely upon this guidance to assure operators are developing sound program evaluation processes and applying a robust and meaningful set of performance metrics in their program evaluation process.

2. Background

PHMSA has long recognized and communicated the critical importance of operator self-evaluation as part of an effective safety program. PHMSA has promoted and required the development, implementation and documentation of processes to perform program evaluations, including the regular monitoring and reporting of meaningful metrics to assess operator performance. PHMSA emphasizes the importance of the operator's management responsibility to fully understand and acknowledge the implications of these program evaluations and to take the necessary steps to address deficiencies and make necessary program improvements.

PHMSA's pipeline IM regulations require operators to establish processes to evaluate the effectiveness of their IM programs. Program evaluation is one of the key required program elements established in the IM rules. Additionally, operator senior management is required to certify the IM program performance information submitted annually to PHMSA.

Specific sections in the Federal IM regulations that directly require operator program evaluation and the use of meaningful performance metrics include the following:

- For hazardous liquid pipelines, §§195.452(f)(7) and 195.452(k) require methods to measure program effectiveness. Appendix C to 49CFR195 provides more specific guidance on establishing performance metrics to support the understanding and analysis of integrity threats to each pipeline segment. API Standard 1160, Managing Integrity for Hazardous Liquid Pipelines, also provides additional guidance on the program evaluation process in which the analysis of these metrics is used to improve performance.
- For gas transmission pipelines, §§192.911(i) and 192.945 define the requirements for establishing performance metrics and evaluating IM program performance. The gas

requirements invoke ASME B31.8S-2004, Managing System Integrity of Gas Pipelines. Section 9 of this standard provides guidance on the selection of performance metrics.

- For gas distribution systems, §192.1007(e) requires development and monitoring of performance measures to evaluate the effectiveness of IM programs. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. The guidance from ANSI / GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2012 Edition and ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, Section 9 can be used for the selection of performance metrics that can be applied to gas distribution systems.
- Advisory Bulletin ADB–2012–10 was published in the Federal Register on December 5, 2012, to remind operators of their responsibilities under current regulations to perform evaluations of their IM programs using meaningful metrics.

3. Overview of Process for Rigorous Program Evaluation

Program evaluation is an ongoing process to measure, assess and evaluate program and piping system performance using both leading and lagging performance metrics. Effective corrective actions addressing the evaluation outcomes should be taken to improve both programmatic activity and pipeline system performance and integrity. Leading and lagging indicators are defined as:

- Leading indicators measure the accomplishment and effectiveness of operator programs and activities to control risk. They provide insight into how well the operator is implementing the various elements of its IM or safety management program.
- Lagging metrics measure the outcomes of the programs and activities to manage risk. They provide the documented success or failure of these activities (results).

The program evaluation process should be formally controlled through, and be an integral part of, the pipeline operator's quality control / quality assurance program. The formal process should include management's commitment to monitor and evaluate performance measures. The program evaluation process is most effective when utilizing the four-step Deming Cycle activities of "planning, "doing," "checking" and "acting". Specifically, program evaluation is the fundamental process of an organization's efforts to facilitate continuous improvement

- PLAN: establish the objectives and processes necessary to deliver results in accordance with the organization’s policies and the expected output (goals). By establishing output expectations, the completeness and accuracy of the process is also a part of the targeted improvement.
- DO: implement / execute the processes and collect information / data for analysis as part of the “CHECK” and “ACT” steps.
- CHECK: analyze the information / data against policies, objectives and requirements; report the results to determine if objectives and expected results are being achieved; look for trends and deviations in implementation from the goals of the plan; and analyze the differences to determine their root causes and what corrective actions may be implemented to improve the process or the results.
- ACT: identify and implement the corrective actions where significant differences between actual and planned results have been identified. These corrective actions may apply to the completeness and accuracy of the procedures and process as part of the targeted improvement.

Specifically, program evaluation is the fundamental process of an organization's efforts to achieve a continuous improvement process. The following diagram, Figure 3.1, highlights the elements of an expected program evaluation process.

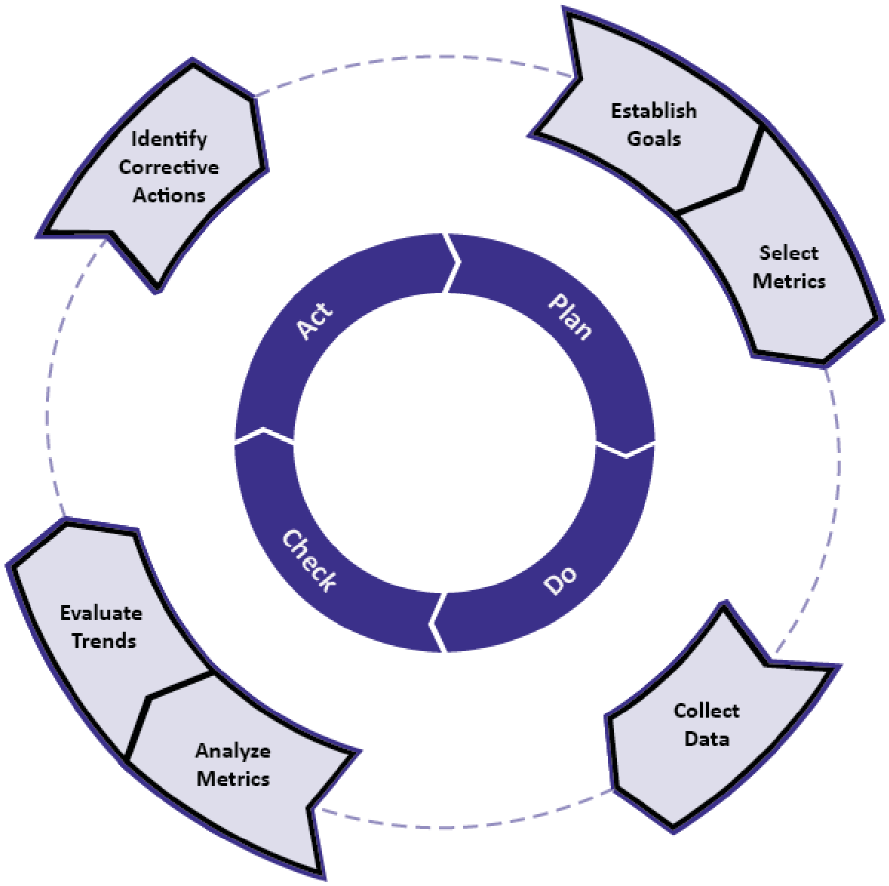


Figure 3.1, Elements of a Program Evaluation Process

Guidance related to these program evaluation elements is discussed in the following sections and is diagramed in Appendix A, Elements of a Mature Program Evaluation Process:

Section 4. Establish Safety Performance Goals
Section 5. Identification of Required Performance Metrics
Section 6. Selection of Additional Meaningful Metrics
Section 7. Performance Metrics Collection and Recording
Section 8. Program Evaluation Using Metrics
Section 9. Definitions

4. Establish Safety Performance Goals

Pipeline operators should establish their company's specific IM goals and objectives. The following sections outline the steps for selection, documentation, and communication of safety performance goals.

4.1. Safety Performance Goals - Safety performance goals should be documented and reviewed periodically, typically annually, as part of an operator's required program evaluation. These goals should support both the operator's short and long-term organizational objectives. The basis for their selection should be documented. Examples are:

- Documented program implementation - Who, What, When, Where and Why.
- On time implementations (e.g., scheduled integrity management assessments, preventive and mitigative measures).
- Reduction in the number of unintended releases or leaks (e.g., expressed as a reduction in the number of releases by "x"% with an ultimate goal of zero).
- Reduction in the volume of spills and leaks.
- Reduction in the number of "legacy" pipe failures.
- Reduction in the number of operator error events.
- Reduction in the number of public pipeline encroachments.
- Percentage of IM activities completed versus those scheduled during the evaluation period.
- Improved effectiveness of community outreach activities.

Safety performance goals should be established as appropriate at the operator / company / business unit levels that can be supported by performance metrics.

4.2. System Specific Safety Performance Goals - Additional safety performance goals should be established for any unique system configurations or situations. Unique system applications could include:

- Piping systems transporting products differing from the operator's primary product (e.g., highly volatile liquids, corrosive gas, CO_2).
- Piping systems having unique operating parameters (e.g., piping system that is susceptible to liquid entrainment).
- Piping systems having unique threat profiles (e.g., piping system susceptible to stress corrosion cracking, located in areas having high population density, industrial, or construction activity).

4.3. Senior Management Commitment - Senior management should be engaged in the development and review of the safety performance goals. Management provides input to the development of these goals. Management is expected to approve and endorse the final goals and to take an active role in communicating the goals to the appropriate levels of the organization. Senior management is also responsible for providing the necessary resources to make identified improvements, taking corrective actions and to ensure other company goals are consistent with safety goals.

4.4. Safety Performance Goal Communication - Safety performance goals should be routinely communicated within the operator's organization. An assessment of the organization's success, or failure, in meeting those goals should be communicated following each program evaluation, or at least annually. Typically, communication of the safety performance goals is implemented through:

- Company-wide e-mail communications.
- Documented discussions in staff and / or safety meetings.
- Documented tailgate safety meetings in the field prior to commencing work activities.
- Posters placed in prominent locations within the work place.
- Company internal web sites.
- Documented dissemination with contractor personnel who perform work.

4.5. Safety Performance Goal Review - Safety performance goals should be established or reaffirmed on a periodic basis. The operator reviews the appropriateness of its defined safety performance goals. The existing goals should be affirmed as appropriate for the operator's mission or refined / revised as needed to meet current conditions. Following the annual establishment or affirmation of safety performance goals, the goals should be communicated within the organization consistent with Section 4.4, Safety Performance Goal Communication.

5. Identification of Required Performance Metrics

Pipeline IM regulations specify performance metrics that are to be measured, tracked, and in certain cases, reported to PHMSA. These performance measures are valid meaningful performance metrics that should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics. Sections 5.1, Required IM Metrics, and 5.2, Other Required Metrics, identify those required performance metrics that all operators are required to measure, track, and report to PHMSA.

5.1. Required IM Metrics - Table 1, Calendar Year IM Program-Related Metrics from the Annual Reports, lists the Required IM Performance Metrics measured and reported to PHMSA by operators each calendar year.

- Gas Transmission Annual Report IM performance metrics are included in the Annual Reports required by §191.17 and are submitted on the Annual Report Form. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.
- Hazardous Liquid Annual Report IM performance metrics are included in the Annual Reports required by §195.49 and are submitted on the Annual Report Form. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.
- Gas Distribution System Annual Report IM performance metrics are included in the Annual Reports required by §192.1007(g) and are submitted on the Annual Report Form. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.

5.2. Other Required Metrics - Other Metrics Required by §§192.911(i), 192.945, & ASME B31.8S Section 9 (GT); §§195.452(f), 195.452(k), 195 Appendix C & API-1160 Section 12 (HL); and §192.1007(e) (GD)

- 49CFR192.911(i) requires the establishment of a performance plan as outlined in ASME / ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of §192.945. These additional threat specific metrics for gas transmission systems are included in Table 2, Other Required Metrics for Gas Transmission and Distribution Systems. These metrics are to be considered where applicable in the operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.

- 49CFR195.452(k) requires measurement of hazardous liquid IM program effectiveness. The rule does not specify what methods are required to be used but provides example metrics in 195 Appendix C that could be used for performance measurement. The example metrics from this guidance are included, along with other examples in Table 3, IM Programmatic Performance Metrics, and Table 4, System and Threat-Specific Performance Measurement, and should be considered for selection under the process discussed in Section 6, Selection of Additional Meaningful Metrics.

- 49CFR192.1007(e) for gas distribution systems requires development and monitoring of performance measures to evaluate the effectiveness of IM programs. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. Two performance metrics are required beyond those reported to PHMSA in the Annual Reports. These two addition metrics are included in Table 2, Other Required Metrics for Gas Transmission and Distribution Systems. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.

6. Selection of Additional Meaningful Metrics

To fully comply with measurement of IM program effectiveness requirements established by §§192.945, 192.1007(e) and 195.452(k), operators must effectively measure the performance of their IM programs. Operators may need to consider additional metrics beyond those required metrics defined by Section 5, Identification of Required Performance Metrics, to enable a better understanding of the program implementation and the performance of specific systems or segments within systems. This is particularly important for the threat-specific metrics. It is also important to specify leading indicator metrics to identify potential organizational or programmatic inadequacies or failures that often contribute to a pipeline incident / accident. Operators should select metrics to effectively monitor and measure the company's methodology to achieve the safety performance goals established under Section 4, Establish Safety Performance Goals, of this guidance. They should also document the basis for the metrics selection. A description of the characteristics of effective performance indicators (metrics) is provided in Section 6.5, Characteristics of Effective Indicators (Metrics).

6.1. IM Program Element Implementation Metrics - Program implementation leading indicator metrics are used to identify potential organizational or programmatic inadequacies or failures that may contribute to a pipeline incident / accident. Operators should define performance metrics to effectively monitor and measure the company's program implementation. They should also document the basis for those metrics utilized. Table 3, IM Programmatic Performance Metrics, provides guidance for selection of these metrics. The suggested metrics may be applied to gas transmission, hazardous liquid transmission and gas distribution (where appropriate) and includes guidance for selecting process/operational activity, operational deterioration and failure metrics.

6.2. Operational Implementation Metrics – Operational implementation leading indicator metrics are used to identify potential operational activity inadequacies or failures (such as failure to follow procedure) that may contribute to a pipeline incident / accident. Operators should define performance metrics to effectively monitor and measure the activities associated with the safety programs including code-based requirements. They should also document the basis for those metrics utilized. Table 3, IM Programmatic Performance Metrics, provides guidance for selection of these metrics. The suggested metrics may be applied to gas transmission, hazardous liquid transmission and gas distribution pipelines where appropriate.

6.3. System Specific Metrics - Operators should establish system-specific performance metrics for any systems having unique operations, hazards or threats. System specific performance metrics may be required due to:

- Unique nature of product transported - CO_2, HVLs, bio-fuels, sour crude oil, etc.
- Unique hazards other company systems are not susceptible to - population growth in area of pipeline, unusual number of encroachments, electrical current.
- Unique threats other company systems are not susceptible to - stress corrosion cracking, selective seam corrosion, geological, environmental conditions in the pipeline area, bare pipe, etc.
- The presence of interacting threats (more than one threat occurring on a section of pipeline at the same time) that a company's system is susceptible to (e.g., corrosion at a location that has third party damage).
- Company systems with insufficient data on material attributes necessary to determine MOP / MAOP.

Metrics may also be useful to examine the performance of specific types of equipment and assets (e.g., facilities, breakout tanks, valves, pumps / compressors).

6.4. Threat Specific Metrics - Threat-Specific performance metrics are important to an effective program evaluation program. Table 4, System and Threat-Specific Performance Measurement, provides guidance for developing metrics that evaluate operator program effectiveness in managing the different transmission and distribution pipeline safety threats. This table is constructed similar to the example used in API 1160 with the threat guidance from ANSI / GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2012 Edition included.

An appropriate mix of performance metrics includes the following metric categories:

- Process /operational activity metrics monitor the surveillance and preventive activities undertaken by the operator. These are typically leading indicators of potential issues.
- Operational deterioration metrics are operational and maintenance trends that indicate when the integrity of the system is reduced despite preventive measures. These may be either leading or lagging indicators.
- Failure measures indicate the ultimate objective of the program has not yet been achieved, but hopefully will indicate progress towards goals (e.g., fewer spills, less damage, faster response, more effective cleanup). These are lagging indicators that undesirable outcomes have occurred.

6.5. Characteristics of Effective Indicators (Metrics) - Characteristics of effective performance indicators (metrics) are provided below. These characteristics are from ANSI/API RP 754-2010, Process Safety Performance Indicators for the Refining and Petrochemical Industries:

- Reliable: They are measurable using an objective or unbiased scale. To be measurable, an indicator needs to be specific and discrete.
- Repeatable: Similar conditions will produce similar results and different trained personnel measuring the same event or data point will obtain the same result.
- Consistent: The units and definitions are consistent across the company. This is particularly important when indicators from one area of the company will be compared with those of another.
- Independent of Outside Influences: The indicator leads to correct conclusions and is independent of pressure to achieve a specific outcome.
- Relevant: The indicator is relevant to the operating discipline or management system being measured; they have a purpose and lead to actionable response when outside the desired range.
- Comparable: The indicator is comparable with other similar indicators. Comparability may be over time, across a company, or across an industry.
- Meaningful: The indicator includes sufficient data to measure positive or negative change.
- Appropriate for the Intended Audience: The data and indicators reported will vary depending upon the needs of a given audience. Information for senior management and public reporting usually contains aggregated or normalized data and trends, and is provided on a periodic basis (e.g. quarterly or annually). Information for employees and employee representatives is usually more detailed and is reported more frequently.
- Timely: The indicator provides information when needed based upon the purpose of the indicator and the needs of the intended audience.
- Easy to Use: Indicators that are hard to measure or derive are less likely to be measured or less likely to be measured correctly.
- Auditable: Indicators should be auditable to ensure they meet the above expectations.

7. Performance Metrics Data Collection and Recording

Operators should have formalized processes to control and document collection of programmatic, operational and threat-specific performance measures.

7.1. Performance Metrics Collection – The details associated with the collection of performance metric data must be included in written plans or procedures which are managed through defined management systems and should include:

- Organizational responsibility for collection of information / data.
- Qualifications of personnel gathering and processing the metric data.
- Timing for collection of information / data.
- Data sources for metric data.
- How metric data is recorded.
- How raw metric data is processed, such as methods to normalize data by pipeline mileage, timeframe, or quantity of product transported.
- Technical review / validation of collected metric data to identify potential errors, including identification of measurement uncertainty, accuracy, and completeness.

7.2. Metrics Records Management - The written program should address records management requirements for maintaining measure data, analysis results and corrective actions taken. A mature program should have controlled systems or databases for retention, retrieval, and analysis of the performance maintained in an easily retrievable format and system.

8. Program Evaluation Using Metrics

As required by the IM rules, operators must implement processes to measure the effectiveness of their programs. The objective of these processes is to determine whether the program meets its intended objective of improving the safety and integrity of pipeline systems. Program evaluations support better management decision-making in support of continual improvement. These evaluations are to gauge the level to which an operator’s performance is meeting its identified safety performance goals.

Program and other evaluations may be conducted at different levels including the company or corporate level, at a system level to gauge one pipeline system's performance against that of other systems within the organization, or for selected assets with similar characteristics. Effective program evaluations should include all aspects of an operator’s organization, not just the integrity group.

Incident / accident investigations, abnormal operations and root cause analysis frequently reveal that management systems and organizational program deficiencies or failures are important contributors to pipeline accidents. For this reason, it is important that program evaluations also identify and correct potential organizational or programmatic deficiencies and failures that could have the potential to lead to pipeline incidents / accidents.

An effective operator program should have the characteristics identified below.

8.1. Assessment of Program Effectiveness - Periodic self-assessments, internal and/or external audits, management reviews, or other self-critical evaluations are used to assess program effectiveness. For the methods used, documented procedures or plans describe the:

- Scope, objectives, and frequency of program evaluations.
- Program evaluation process steps and documentation requirements.
- Responsibility, by organizational group or title, for both conducting the audits and implementing the required corrective actions.
- Evaluation of performance measures and the success in meeting safety, performance and integrity goals.
- Communication of evaluation results within the operator's organization.
- Management review and approval authority of program evaluation results.

8.2. Metric Trends - Program effectiveness is determined through the analysis of the performance measures selected under Section 5, Identification of Required Performance Metrics, and Section 6, Selection of Additional Meaningful Metrics. Performance metrics are reviewed to identify trends in the data collected for individual performance metrics. Positive and negative trends are documented. Risk reduction measures to address any negative trends are identified and documented. The performance metrics review includes an assessment of the success in meeting the safety performance goals described in Section 4, Establish Safety Performance Goals.

8.3. Program Evaluation Reviews - Program evaluation reviews should be conducted by the appropriate operator organizational groups to validate conclusions and the appropriateness of recommended corrective actions, including preventive or mitigative measures. Senior management should approve program evaluations and provide resources to address adverse performance trends identified by the program evaluation.

8.4. Performance Feedback - Performance feedback to the appropriate personnel and organizations responsible for the different aspects of the IM program should be provided. This feedback includes lessons learned, insights from the performance metric analysis, and best practices. Recommendations and action items should be communicated to the responsible managers in the organization.

8.5. Corrective Actions - Corrective actions should be formally tracked until completion. Documentation of corrective actions should be maintained for the life of the pipeline. Corrective actions should be monitored in future program evaluations to assess effectiveness of the actions taken. Corrective actions resulting in significant technical, physical, procedural, and organizational changes should be coordinated through the operator's management of change processes. Corrective actions should be implemented within designated timeframes commensurate with the action's importance to safety.

8.6. Threat Identification and Risk Analysis Updates - Periodic updates to the IM threat identification and risk analysis process consider the program evaluation outcomes, insights, and identified trends. This helps assure that the risk analysis tools used to support future safety and integrity decisions accurately reflect the operational history, asset condition, and program experience.

8.7. Program Evaluation Process Reviews - The program evaluation process itself should be reviewed at least annually to identify opportunities for improvement. Examples of opportunities for program improvement could include:

- Application of additional resources for performing program evaluations.
- Improvements to data validation processes.
- Improvements in the data collection and recording process.
- Streamlining of databases for data input, querying, and reporting.
- Revisions to program evaluation procedures.

8.8. Safety Performance Goal Confirmation - New safety performance goals should be established or the current set reaffirmed annually, based on the results of the program evaluation. The operator should review the appropriateness of their defined safety performance goals. The existing goals should be affirmed as appropriate for the operator's safety and IM programs or refined/revised as needed to meet current conditions.

8.9. Metric Updates - Metrics should be updated to address any improvements identified by the program evaluation and updated safety performance goals. The operator should eliminate non-useful metrics.

9. Definitions

9.1. **Deterioration Metrics** - Operation and maintenance non-release data trends that indicate when the integrity of the system is weakening despite operational programs and preventive measures. This category of performance metrics may indicate that the system condition is deteriorating despite well-executed preventive activities. These may be leading or lagging indicators and provide signals that improvement may be warranted. (API 1160-2001; §195 Appendix C, V.B(2))

9.2. **Failure Metrics** - Failure data reflecting whether the program is effective in achieving the objective of improving integrity. These are typically lagging indicators that measure undesired outcomes such as the number of releases, the volume released, etc. (API 1160-2001; §195 Appendix C, V.B(3))

9.3. **Performance Analysis -** The comparison of the performance measures against objectives / goals to determine effectiveness.

9.4. **Program Evaluation** - Individual assessments to determine how well a program is working. Program evaluations support management decisions makers to implement continual process improvement. Program evaluations may be conducted at the company/corporate level or conducted at a unique system level to gauge one system's performance against that of other systems within the organization. Program evaluations may include comparing internal performance with performance of other similar external organizations (e.g., industry benchmarking).

9.5. **Performance Measurement** - Regularly monitoring and reporting on a program's progress and accomplishments using pre-selected performance measures or metrics. By establishing program metrics, an organization can gauge whether its program is meeting goals and objectives and can identify where changes in the program are warranted.

9.6. **Performance Metrics** - The type of information or data to be utilized to determine if objectives are being met. This information or data are parameters or measures of quantitative assessment used for measurement, comparison or to track safety performance. Performance measures form a continuum from leading indicators (before releases or failures) to lagging (after releases or failures), and include process measures, measures of deterioration and measures of actual failures or releases. (API 1160-2001)

9.7. **Required Performance Metrics** - Those performance metrics that operators are required to measure and track in accordance with §§191.17, 195.49, 192.945, 192.1007(g) and Section 5 of this guidance document.

9.8. **Selected Process (Activity) Measures** - Metrics that monitor the surveillance and preventive activities undertaken by the operator. These measures indicate the level at which an operator is implementing the various elements of the IM program and are generally considered to be leading indicators. (e.g., API 1160-2001; §195 Appendix C, V.B(1))

9.9. **System Specific Performance Metrics** - Performance metrics that apply to a single system or set of similar systems with unique operations, hazards or threats. These performance metrics are a subset of the Metrics established by an operator and not required by §§191.17, 195.49, 192.911(i) or 192.1007(g).

PHMSA's annual reporting forms, "F 7100.2-1" for Gas Transmission and "F 7000-1.1" for Hazardous Liquid Transmission, which operators must submit per §§191.17 and 195.49, require that operators submit the following information:

1. MILEAGE INSPECTED USING ILI
    a. Corrosion or metal loss tools.
    b. Dent or deformation tools.
    c. Crack or long seam defect detection tools.
    d. Any other internal inspection tools.
    e. Total tool mileage inspected using ILI.

2. ACTIONS TAKEN ON ILI
    a. Total number of anomalies excavated because they met the operator's criteria for excavation.
    b. Total number of anomalies repaired both within and outside HCA.
    c. Total number of conditions repaired WITHIN AN HCA SEGMENT:
        i. Immediate repair conditions.
        ii. One-year conditions [HL: 60-day].
        iii. Monitored conditions [HL: 180-day].
        iv. Other Scheduled conditions [HL: This item is NA].

3. MILEAGE INSPECTED AND ACTIONS TAKEN BASED ON PRESSURE TESTING
    a. Total mileage inspected by pressure testing in calendar year.
    b. Total number of pressure test failures (ruptures and leaks) repaired, both within and outside HCA.
    c. Total number of pressure test ruptures (complete failure of pipe wall) repaired WITHIN AN HCA SEGMENT.
    d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired WITHIN AN HCA SEGMENT.

4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)
    a. Total mileage inspected by each DA method in calendar year:
        i. ECDA
        ii. ICDA [HL: This item is NA]
        iii. SCCDA [HL: This item is NA]

    b. Total number of anomalies identified by each DA method and repaired based on the operator's criteria, both within and outside HCA:
        i. ECDA
        ii. ICDA [HL: This item is NA]
        iii. SCCDA [HL: This item is NA]

    c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:
        i. Immediate repair conditions
        ii. One-year conditions [HL: 60-day]
        iii. Monitored conditions [HL: 180-day]
        iv. Other Scheduled conditions [HL: This item is NA]

5. MILEAGE INSPECTED AND ACTIONS TAKEN BASED ON OTHER INSPECTION TECHNIQUES
    a. Total mileage inspected by inspection techniques other than those listed above.
    b. Total number of anomalies identified by other inspection techniques and repaired based on the operator's criteria, both within and outside HCA .
    c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of:
        i. Immediate repair conditions
        ii. One-year conditions [HL: 60-day]
        iii. Monitored conditions [HL: 180-day]
        iv. Other Scheduled conditions [HL: This item is NA]

6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR
    a. Total mileage inspected .
    b. Total number of anomalies repaired both within and outside HCA.
    c. Total number of conditions repaired WITHIN AN HCA SEGMENT.

7. MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS (HCA Segment miles ONLY)
    a. Baseline assessment miles completed during the calendar year.
    b. Reassessment miles completed during the calendar year.
    c. Total assessment and reassessment miles completed during the calendar year.

8. [Gas Only] Leaks, failures, and incidents during calendar year [Incident and Leak data breakdown not currently required for HL annual report]
    a. Breakdown by HCA and Non-HCA.
    b. Breakdown by transmission and gathering.
    c. Breakdown by the nine B31.8S cause categories (Table 2, Other Required Metrics for Gas Transmission and Distribution Systems).

PHMSA's annual reporting form, "F 7100.1-1" for Gas Distribution systems, which operators must submit per §192.1007(g), requires that operators submit the following information:

1. Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by cause: corrosion, natural forces, excavation damage, materials or welds, equipment, incorrect operations, other.

2. Number of excavation damages.

3. Number of excavation tickets (receipt of information by the underground facility operator from the notification center).

4. Total number of leaks either eliminated or repaired, categorized by cause: corrosion, natural forces, excavation damage, materials or welds, equipment, incorrect operations, other.

Table 2 - Other Required Metrics for Gas Transmission and Distribution Systems

Required by §192.945 and ASME B31.8S-2004, Table 9 for Gas Transmission Pipelines:

Threat	Performance Metrics for Prescriptive Programs
External corrosion	Number of hydrostatic test failures caused by external corrosion
	Number of repair actions taken due to in-line inspection results
	Number of repair actions taken due to direct integrity assessment results
	Number of external corrosion leaks
Internal corrosion	Number of hydrostatic test failures caused by internal corrosion
	Number of repair actions taken due to in-line inspection results
	Number of repair actions taken due to direct integrity assessment results
	Number of internal corrosion leaks
Stress corrosion cracking	Number of in-service leaks or failures due to SCC
	Number of repair replacements due to SCC
	Number of hydrostatic test failures due to SCC
Manufacturing	Number of hydrostatic test failures caused by manufacturing defects
	Number of leaks due to manufacturing defects
Construction	Number of leaks or failures due to construction defects
	Number of girth welds / couplings reinforced / removed
	Number of wrinkle bends removed
	Number of wrinkle bends inspected
	Number of fabrication welds repaired / removed
Equipment	Number of regulator valve failures
	Number of relief valve failures
	Number of gasket or O-ring failures
	Number of leaks due to equipment failures
Third-party damage	Number of leaks or failures caused by third-party damage
	Number of leaks or failures caused by previously damaged pipe
	Number of leaks or failures caused by vandalism
	Number of repairs implemented as a result of third-party damage prior to a leak or failure
Incorrect operations	Number of leaks or failures caused by incorrect operations
	Number of audits / reviews conducted
	Number of findings per audit / review, classified by severity
	Number of changes to procedures due to audits / reviews
Weather related and outside forces	Number of leaks that are weather related or due to outside force
	Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

Required by §192.1007(g) for Gas Distribution systems, but not required to be reported on PHMSA's annual reporting form, "F 7100.1-1" for Gas Distribution systems:

1. Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material.
2. Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

Table 3 - IM Programmatic Performance Metrics

This table provides guidance for operators and inspectors to identify meaningful metrics to help understand and measure the effectiveness of the individual program elements and processes used in an IM program. The table lists required IM program elements and some candidate metrics that might be developed. The metrics for each program element are examples and do not represent a complete list. Operators may find that metrics other than those listed here are best suited for their operations and IM program. Operators may also have other important processes that are critical to managing integrity on their assets that are not listed here. In these situations, metrics to indicate the effectiveness of those activities should be developed.

Operators are not necessarily expected to develop and track metrics in all of the areas listed below. However, they should select a set of meaningful metrics that indicates whether the elements of its IM program are functioning as intended. The first 12 program elements apply to gas transmission and hazardous liquid transmission. Gas distribution could also address some of these program elements. The last program element, “Knowledge”, specifically applies to gas distribution systems.

Following a structure similar to that in API-1160 and ASME B31.8S, this table features three different types of performance metrics.

1. IM Process, Operational or Activity Metrics. These are metrics that reflect the implementation of the IM program elements, demonstrating that the program is being implemented as designed. These are typically leading indicators.
2. Operational Deterioration Indicators. These are metrics that indicate when the operator’s IM program processes and activities might be degrading despite the implementation of the processes noted in item 1.
3. Failure or Direct Integrity Metrics. These are clear, generally lagging, indicators that the IM program element’s objective of release prevention has not been achieved, but that over time may show trends toward improving safety.

Although this table does identify a number of specific metrics, an operator must tailor the specific metrics it uses to the design of its IM program, the specifics of the assets being managed, as well as the operator’s unique organizational needs. This table includes performance measurement opportunities for gas transmission, hazardous liquid transmission and gas distribution pipelines that are useful for identification of both programmatic and organizational deficiencies.

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators---*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
1. Identification of pipeline segments that could impact HCAs	● Frequency of updates to segment identification analysis ● Frequency and nature of reviews conducted to identify new HCAs ● Frequency of field district surveys or ROW inspections identifying new HCAs – or segments that could affect HCAs ● Frequency and nature of review of procedures and assumptions made in identifying segments that could affect HCAs ● Frequency of updates to aerial photography used for HCA segment analysis ● Frequency of contacts with public safety officials and others having local knowledge for information on potential "identified sites" or could affect segments	● No. of newly acquired or newly identified assets not incorporated within the IMP within the required timeframe ● No. of previously mis-identified HCAs identified as HCAs in updates to the segment identification analysis ● No. of PIR calculations using an inappropriate formula for product transported (Gas Trans) ● No. of new HCAs or could affect segments identified due to changing conditions (pipeline modifications, new public construction, change in public use of existing buildings, etc.) ● No. of abnormal weather conditions (e.g., stream flow rate) that exceed assumptions used in HCA or could affect segment identification	● No. of releases which reached an HCA from pipe that was not determined to be a "could affect" segment (Haz Liq) ● No. of releases with adverse impacts beyond the PIR (Gas Trans) ● No. of releases which had different impacts to HCAs than determined by the "could affect" analysis ● No. of releases which reached different HCAs than determined by the "could affect" analysis ● No. of releases that exceeded the highest estimated volume that could be released in a segment (Haz Liq)
2. Threat Identification and Risk Assessment	● Threat identification program ● Identification of interacting threats ● Frequency and nature of reviews for previously unidentified threats ● Processes to account for "missing data" ● Conformance with operator's risk assessment process procedures and practices ● Frequency and nature of risk assessment algorithm and / or model reviews ● Frequency of updates for data used in risk assessment; incorporation of new information in a timely manner ● Progress in addressing situations where documentation and records are absent. ● Timely integration of integrity assessment (e.g., ILI) results / insights into risk assessment ● Comprehensiveness of data sources ● Potential threat identified for monitoring or actions	● No. of mitigation activities for interacting threats (e.g., cyclic fatigue interaction with SCC) ● No. of mitigation activities for unstable threats ● Correlation of threat-specific deterioration and failure metrics with risk analysis results (i.e., are the metrics indicative of the most problematic technical areas consistent with the predictions of the risk model) ● No. of revisions or modifications to the threat identification process or tools as a result of IM Program evaluations ● No. of revisions or modifications to the risk assessment process or tools as a result of IM Program evaluations ● Destructive or non-destructive test results which indicate inaccuracies in material or component records – diameter, wall thickness, grade, seam type, toughness, coating type, etc.	● No. of releases involving a previously unidentified threat ● No. of releases involving an underestimated or misunderstood threat ● No. of releases involving two or more interacting threats. ● No. of releases in segments not identified as high risk ● No. of releases where lack of integration of information and / or data was a contributing factor ● No. of releases where the appropriate ILI tool or integrity assessment methodology was not employed ● No. of releases that exceeded the consequences considered in the risk analysis ● No. of failures of an expected stable manufacturing defect
3. Direct Assessment	● Conformance with operator's direct assessment procedures and practices ○ ECDA ○ ICDA ○ SCCDA ○ CDA	● Integrity assessment frequency ●Time remaining until next scheduled integrity assessment ● Time passed since most recent integrity assessment ● No. of revisions or modifications to the DA process as a result of IM Program evaluations	● Releases following direct examination and repair ● Releases that occurred at locations where direct examination was not conducted: ○ Mischaracterized indication severity ○ No indication was identified by DA tools / methods chosen ○ Defect growth rate underestimated
4. Repair	● Repair method selection criteria ● Development of prioritized remediation schedule ● Pipe replacement criteria ● Amount of pipe replaced on schedule ● Weld repair criteria ● Criteria for temporary pressure reductions	● Moving average of repairs by threat / cause category ● Moving average of repairs by integrity assessment method ● Moving average of repairs by HCA / non-HCA ● Trends in the type of repairs made ● No. of repairs not completed within the required timeframe ● No. of temporary pressure reductions	● Releases following integrity assessment and repair by detectable cause

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators--*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
5. In-line Inspection	● Amount of baseline and reassessment miles by integrity assessment type ● Integrity assessment frequency determination process ● Integrity assessment tool selection process ● Time passed since most recent integrity assessment ● Interaction criteria ● Tool accuracy or other specs (e.g., % of system or miles of tool runs with accuracy > [insert criteria] … to track that operators are using the best available tools and most current technology ● Fraction of HCA-affecting pipe assessed for each type of threat	● Anomalies repaired by repair criteria ● Features requiring excavation and repair per mile for each type of integrity assessment ● Features requiring excavation and repair per mile by pipe age ● Number of immediate repair conditions discovered in the n^{th} integrity assessment versus the $(n-1)^{th}$ integrity assessment. ● Anomalies (number and size) remaining in pipe. If done properly, this in combination with tool specs could be combined to calculate probability of injurious defects remaining in pipe after integrity assessment ● No. of continuing integrity assessments not conducted within the required timeframe ● No. of revisions or modifications to the ILI selection and execution process as a result of IM Program evaluations ● Presence of interactive threats such as metal loss and cracking, dents and cracking, disbonded coating and SCC, etc.	● Number of leaks and ruptures in HCAs by cause ● Releases that occurred at locations where integrity assessment was not conducted ● Releases following integrity assessment and repair by detectable cause ● Releases following integrity assessment without repair: ○ Defect under-called – no plans to repair ○ Defect not identified because interacting threats were not considered ○ Tool accuracy not appropriately considered in making repair decision ○ Defect not identified by integrity assessment method ○ Failure occurred before defect repaired ○ Defect growth rate underestimated ○ ECA not performed for remaining defects ○ B31G / RSTRENG overestimated burst pressure ○ Poor, out-of-spec ILI tool performance (without validation digs to calibrate interpretation of ILI logs)
6. Pressure test	● Integrity assessment method selection and frequency process ● Spike test vs. standard hydro ○ 1.25 x MOP / MAOP ○ 1.39 x MOP / MAOP	● Selective Seam Corrosion, Stress Corrosion Cracking, or other crack defects identified by ILI following previous pressure test ● No. of revisions or modifications to the pressure test process as a result of IM Program evaluations ● Upward trend in pressure reversals indicating an increasing amount of near-critical manufacturing flaws present in line pipe	● Releases after successful integrity assessment by pressure test ● Pressure reversals indicating an increasing amount of near-critical manufacturing or other flaws present in line pipe ● Pressure test pipe failures
7. Preventive Measures	● Frequency and nature of preventive measure identification ● Use of risk analysis in identifying and evaluating preventive measures ● Criteria used to select measures (e.g., No. of safety improvements with benefit-to-cost ratios in excess of predefined criteria that are implemented) ● Employee safety improvement projects implemented ● Progress in implementing preventive measures – e.g., pipe replacement program, recoating program, depth of cover survey, etc.	● No. or quantitative measure of specific preventive measures taken: ○ Pipe replacement ○ Recoating ○ CIS ○ ACVG / DCVG ○ Added cover ○ Increased patrols ○ Product quality improvement ○ More frequent integrity assessments ○ Changes in internal corrosion monitoring program results ○ Inhibitor injection ○ Addition of separators ○ Deformation, geometry, or DA findings for dents or expansion ● No. of revisions or modifications to the prevention and mitigation process as a result of IM Program evaluations	● Failure rates per mile in HCA segments compared to non-HCA segments ● Failure rates pre- and post-IM ● Volumes released per incident / accident in HCA segments compared to non-HCA segments ● Release volumes per incident / accident pre- and post-IM ● No. of releases involving a previously employed or identified preventive measure which did not prevent the release ● No. of releases where the SCADA and / or Leak Detection system(s) did not function as designed or anticipated to prevent the volume of the release ● No. of releases where the Control Center procedures and actions did not function as designed or anticipated to prevent the release

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators---*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
8. Mitigative Measures	● Frequency and nature of mitigative measure identification ● Use of risk analysis in identifying and evaluating mitigative measures ● Criteria used to select mitigative measures (e.g., No. of safety improvements with benefit-to-cost ratios in excess of predefined criteria that are implemented) ● Update and re-evaluation of RCV / EFRD needs analysis ● Update and improvements to leak detection capability and enhancements analysis ● Progress in implementing mitigative measures – e.g., installation of RCV / EFRDs, leak detection improvements, emergency response procedures, etc.	● No. or quantitative measure of specific mitigative measures taken: ○ EFRD's (e.g., % of system with EFRDs deployed that meet [insert criteria based on Valve Study]) ○ Leak Detection (e.g., % of system with LD capability that meets [insert criteria based on LD study]) ● No. of revisions or modifications to the prevention and mitigation process as a result of IM Program evaluations	● Failure rates per mile in HCA segments compared to non-HCA segments ● Failure rates pre- and post-IM ● Volumes released per incident / accident in HCA segments compared to non-HCA segments ● Release volumes per incident / accident pre- and post-IM ● No. of releases involving a previously employed or identified mitigative measure which did not result in the full, desired mitigative effect ● No. of releases where the SCADA and / or Leak Detection system(s) did not function as designed or anticipated to mitigate the volume of the release ● No. of releases where the line segment or facility isolation did not function as designed or anticipated to mitigate the volume of the release ● No. of releases where the Control Center procedures and actions did not function as designed or anticipated to mitigate the release ● No. of releases on pipe segments evaluated as requiring EFRDs, but the EFRD has not yet been installed ● Volume of releases on pipe segments evaluated as requiring EFRDs, but the EFRD has not yet been installed
9. Internal and External Audits and Procedure Reviews	● Internal and external audit program procedures ● Frequency of internal and external audits ● Timeliness of corrective actions ● Level of management sponsorship ● Program reviews of operating and maintenance procedures ● Program reviews of integrity management procedures	● No. of findings of inadequacies or issues ● Effectiveness of corrective actions ● Corrective actions taken, planned, and outstanding based on annual review of operator's normal O&M procedures ● Corrective actions taken, planned, and outstanding based on review of response by operator personnel to abnormal operating conditions (AOCs) ● Corrective actions taken, planned, and outstanding based on post-incident / accident investigation(s) ● Corrective actions taken, planned, and outstanding based on response using emergency O&M procedures ● No. of reported / repaired damage without a release	● No. of releases that occurred prior to implementation of planned corrective actions
10. External Communications Plan	● Percentage of Landowners / Tenants along the ROW contacted by the operator ● Percent of public officials in municipalities and other local governments along the pipeline route contacted by the operator ● Indicators that audience is receiving and understanding pipeline safety message	● Attendance at operator sponsored events. ● 811 / safe digging awareness levels ● First / emergency responder participation in operator drills and exercises ● Operator participation in first / emergency responder drills and exercises ● KPIs from operator formal public awareness plans	● Incidents / accidents where landowners, public officials, or emergency responders did not behave as expected per the operator's communication plans. (e.g., a landowner not calling 811 prior to excavation, an emergency responder not utilizing information provided by the operator in responding to an event)
11. Internal Communication Plan	● Indicators that the internal communications plan is effective in communicating key IM program insights and results ● Periodic communication of IM program performance measures	● No. of employees who have not completed routine IM program refresher orientation / training ● Percentage of intended audience reached by internal communications plan	● Releases associated with ineffective or no routine IM program refresher orientation / training

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators---*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
12. General release response	● No. of lines without leak detection systems ● No. of lines or facilities not continuously monitored via SCADA or Control Room ● No. of post-incident / accident investigations where process or procedural inadequacies or improvement areas were identified ● No. of post-incident / accident investigations where equipment additions or improvements were identified ● No. of failure investigations where improvements were noted	● Average volume released per accident for: ○ Corrosion ○ 3rd Party Excavation Damage ○ All failures ○ Tank bottom failures ○ Tank overfills ● Time to shutdown from identification of release or other upset ● Time to isolation from identification of release or other upset ● Percent of released volume recovered	● No. of incidents / accidents or upsets where release volume was not minimized to the extent possible with existing equipment and procedures ● No. of releases where release volume was not minimized to the extent possible due to availability and location of personnel
13. Knowledge (Gas Distribution)	● Identification of pipeline's design, operations and environmental factors ● Information gained from past design, operations and maintenance ● Plan to identify addition information needs over time ● Procedure to account for collection of "missing data" ● The capture and retention of data on new pipeline installations	● Percentage of system not having all required Knowledge elements	● No. of incidents / accidents on segments without documentation of relevant data

Table 4 - System and Threat-Specific Performance Measurement

This table provides guidance for operators and inspectors to identify meaningful threat-specific metrics that may be required to effectively measure the performance of gas transmission, hazardous liquid transmission and gas distribution pipeline IM programs. The table lists the major pipeline failure mechanisms and some candidate activities for which metrics might be developed. Operators are not expected to develop and track metrics in all of the areas listed below. However, they should select a meaningful set of metrics that provides indication as to whether the operator's significant threats are being effectively managed. While this list is lengthy, it is certainly not complete. Operators will typically have other activities important to preventing specific threats that are not listed here. In these situations, metrics to indicate the effectiveness of those activities should be developed.

Following a structure similar to that in API-1160 and ASME B31.8S, this table features three different categories for which performance metrics should be developed.

1. Process or Operational Activities for Threat Prevention or Management. These are the surveillance, maintenance, and other risk prevention / control activities or operator programs used by operators to address specific pipeline threats. Metrics that that reflect the implementation of these activities and their effectiveness can be useful leading indicators.
2. Operational Deterioration Indicators. These are operational or maintenance parameters that indicate when the integrity of the system might be degrading despite the presence of the risk control and prevention activities noted in item 1, and typically reveal themselves prior to an actual pipeline failure and / or release.
3. Failure or Direct Integrity Metrics. These are clear indicators that the objective of preventing releases from specific threats has not been achieved, but that over time may show trends toward improving safety.

For the most part, this table does not identify specific metrics. It identifies operator programs or activities for which metrics should be developed. This approach has been taken because meaningful metrics must be tailored to the actual nature and manifestation of the threat on the operator's system, as well as an operator's unique risk management activities and organizational needs. In many cases, critical facilities for which consequences of a release could be significant (for example, aboveground and below ground storage facilities, tanks, or spheres), will warrant their own set of monitored performance metrics.

This table includes performance measurement opportunities for gas transmission, hazardous liquid transmission and gas distribution pipelines.

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators--*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Mechanical Damage			
First-party (operator) and second-party (contractor) damage	● Operator procedures for excavation on or near its own pipeline ● Contractor procedures for excavation on or near the pipeline ● Use of current system / facility maps	● No. of improper locates ● No. of excavations outside locate area ● No. of incidents / accidents where procedures were not followed or where appropriate care was not exhibited ● No. of damages not reported ● No. of enforcement actions taken by enforcement authority ● Increase in frequency of damage	● Releases due to first or second party damage
Third-party excavation, construction or other work at the time of failure Excavation, construction or other work activity occurring at some time prior to failure	● Damage prevention program ● Public awareness program ● Active participation in appropriate one-call systems ● Notification of public and specific others on use of one-call system ● Identification of public and other stakeholders along the ROW and notification of pipeline location, threats, etc. ● Identification and education of contractors and excavators that normally engage in excavation in area of pipeline ● Locator training and qualification ● Inspection and monitoring program for high-risk excavations ● Patrolling to gather and record damage prevention information ● Line marking program to locate and replace line markers as needed ● Depth of cover program ● Alignment with "common ground" best practices ● Use of Damage Information Reporting Tool (DIRT) report data ● Incorporation and utilization of PIPA Recommended Practices ● Excavation practices ● Use of current system / facility maps ● 811 / call before you dig awareness measurement ● Analysis of damage data, to include root causes of damages ● Loading calculations for third party crossings or blasting ● Monitoring of construction activity in area of pipeline ● Location of systems in areas where excavation requires the use of explosives	● No. of ROW encroachments ● No. of one-call tickets (comparison of third-party damage to one call tickets) ● Timeliness of one-call notification ticket responses ● No. of improper and inaccurate locates or other inadequate one-call follow-up ● No. of unreported excavation damage ● No. of unmonitored excavations ● No. of excavations performed without calling for locates ● No. of excavation related near-miss incidents / accidents ● Increase in frequency of damage ● No. of damage incidents without release due to third party damage ● No. of excavations outside the locate area ● No. of excavations involving unsafe excavation practices, such as failure to hand-dig when required ● No. of high risk and other excavations monitored ● No. of inadequate participation in one-call system ● Incomplete and / or inaccurate identification of public and other stakeholders along the ROW ● Incomplete and / or inaccurate identification of contractors and excavators that normally engage in excavation in area of pipeline ● No. of affected stakeholders without adequate knowledge of pipeline location or threats ● Percentage of pipeline mileage whose ROW has been cleared consistent with operator's clearing requirements. ● No. off aerial patrol reports with no one-call ● No. of pig runs with indicated mechanical damage ● No. of enforcement actions taken by enforcement authority	● Releases due to third-party damage ● Third-party damage from excavations that should have been monitored by operator but that were not ● Releases following targeted ILI tool run or pressure test ● Third party damage incidents / accidents without a release ● Cover increases causing load issues ● Occurrences of unmonitored blasting ● Releases experienced in areas where previous damage has occurred

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators--*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Other Third Party Damage, including vandalism, third-party vehicle contact with facility, interferences and other intentional or unintentional acts	● ROW and patrolling program ● Line marking program ● Training and OQ tasks ● Depth of Cover survey program ● Use of Damage Information Reporting Tool (DIRT) report data ● Public awareness program ● Physical protection of aboveground facilities	● No. of patrol reports that have not had necessary follow-up completed ● Reports by law enforcement agencies and first responder agencies ● No. of pig runs with indicated damage ● No. of sites lacking security fencing and / or cameras or other features ● No. of susceptible sites lacking vehicle impact barriers ● No. of aboveground facilities hit by vehicles ● No. of vandalism incidents without a release ● Incidents of damage due to underground inference with adjacent structures, utilities, etc.	● Releases due to third-party damage ● Releases due to prior excavation-related damage ● Releases due to prior non-excavation-related mechanical damage

Table 4 - System and Threat-Specific Performance Measurement

	Leading ---------------------------------------Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Corrosion - Impact on bare steel pipe, cast iron pipe, coated and wrapped steel pipe, other metallic materials			
External corrosion	● Cathodic protection system performance testing program ● Exposed pipe examination program ● Protective coating application program ● Electrical isolation program ● Interference current control and remediation program ● Training and OQ tasks ● Stray current surveys	● No. of pig runs or ECDA excavations with indicated corrosion ● No. of close interval surveys ● Trends in performance of external corrosion protection program ● No. of annual cathodic protection exception reports ● No. of ineffective impressed current system survey results ○ Insufficient number of anodes ○ Low CP current ○ High CP current ○ Failed rectifiers ○ Damaged test leads ○ Changes in soil resistivity ○ Consecutive low CP readings in same location (failure to correct deficiencies) ● No. of ineffective sacrificial anode system survey results ○ Insufficient number of anodes ○ Ineffective anodes ○ Changes in soil resistivity ● No. of damaged coatings as indicated by ACVG, DCVG, CIS, or PCM ● No. of disbonded coating as indicated by ECDA, ACVG / DCVG, ILI, Hydro, EMAT, or excavations ● No of interference currents / stray currents identified ○ Electrical surveys ○ Current sources ● No. of indications of MIC ○ Water samples from disbanded coating ○ Soil sample for bacteria ● No of exposed pipe inspections indicating external corrosion ● No of indications of atmospheric corrosion (in addition to coating / CP metrics) ○ Inspection reports ○ Splash zone locations ● Percentage of bare pipe in the system ● No. of cast iron or ductile iron components / fittings in the system	● Releases due to external corrosion ● Failures following targeted ILI tool run or pressure test ● Releases following targeted NDT ● Releases following targeted ECDA

Table 4 - System and Threat-Specific Performance Measurement

	Leading ---Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Internal corrosion	● Internal coupon monitoring program ● Product / commodity quality monitoring ● Separator performance monitoring ● Inhibitor injection program ● Dead leg monitoring program ● Training and OQ tasks	● Trends in performance of internal corrosion protection program ● No. of coupon tests ● No. of ER probes ● No. of electrochemical probes ● No. of metallurgical analyses completed ● No. of gas processing upsets ● No. of pig runs or ICDA excavations with indicated corrosion ● Time interval between scraper runs ● Time interval between inhibitor injection ● No of piping inspections indicating internal corrosion ● No. of product / commodity quality checks ○ Inhibitor quantity ○ Water content ○ H_2S content ○ CO_2 content ○ Microbe content ○ Sediment content ○ Low flow	● Releases due to internal corrosion ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT
Stress Corrosion Cracking	● SCC monitoring program and susceptibility criteria ○ Soil conditions ○ Operating pressure and temperature ○ Coating type ○ Process for coating application	● No. of pig runs or SCCDA excavations with indicated cracks or crack-like anomalies ● No. of times SCC identified during bell hole exam ● No. of hydrostatic test failures ● No. of times soil / water pH exceeds criteria ● No. of indications of disbonded coating discovered through ECDA, ACVG / DCVG, ILI, Hydro, EMAT, Excavations, other ● Upward trend in pressure reversals indicating an increasing amount of near-critical flaws present in line pipe	● Releases due to SCC ● Pressure reversals indicating an increasing amount of near-critical flaws present in line pipe ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT
Selective Seam Corrosion	Same as external corrosion plus ● Coating type ● Seam type – ERW, FW ● Disbonded coating	Same as external corrosion plus ● No. of indications of disbonded coating near the long seam discovered through ACVG / DCVG, ILI, Hydro, Excavations, other ● No. of pig runs with indications of corrosion metal loss, cracks, or crack-like anomalies near the long seam	● Releases due to SSC ● Pressure reversals indicating an increasing amount of near-critical flaws present in line pipe ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators--*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Material Failures			
Pipe materials, including pipe seam ● Year of manufacture ● Manufacturer ● Pipe type ● Seam type ● Material properties ● Manufacturing specifications ● Mill test results	● Pipeline replacement and rehabilitation to address the risks associated with specific pipe materials, seam type, manufacturer, vintage, etc. ● Integrity assessment and monitoring programs to address the risks associated with specific pipe materials, seam type, manufacturer, vintage, etc. ● No. of pipe segments with Legacy Pipe ● No. of pipe segments with Legacy Pipe which have not been appropriately assessed ● Design and construction controls ● Pre-operational testing ● Testing of new or replacement materials to ensure specifications meet requirements ● Usage of the following pipe materials: ○ Century Utility Products ○ Low-ductile inner wall Aldyl pipe manufactured by DuPont prior to 1973 ○ PE 3306	● ILI tool run results with tools capable of detecting pipe body defects (laminations, hard spots, hook cracks, blisters, etc.) ● No. of surveys indicating high CP ● No. of hydro-test failures ● No. of pressure excursions > MAOP / MOP ● No. of indications of high cyclic loading ● No. of occurrences where the NOP / MOP(or MAOP) ratio approaches unity ● Destructive or non-destructive test results indicate inaccuracies in material or component records ● No. of manufacturing defects identified ● No. of failures due to workmanship defects	● Leak or rupture due to material defects ● Pressure reversals indicating an increasing amount of near-critical flaws present in line pipe ● Seam failures ● No. of pressure excursions > 110% MAOP / MOP ● Releases following targeted ILI tool run or pressure test ● Release following targeted NDT ● In-service failure of expected stable manufacturing flaws
Construction girth welds, including repair welds	● Construction specifications ● Welding specifications ● Weld procedures and technique ● Welder qualification program ● Welding inspection / NDT program ● No. of pipe segments with Legacy Construction Techniques ● No. of pipe segments with Legacy Construction Techniques which have not been appropriately assessed	● No. of indications of weld fit-up errors / misalignment ● No. of indications of inadequate weld quality ● Percentage of initial NDT results indicating inadequate weld quality ● No. of hydro-test failures ● Trends in failures by repair type methodology (welded sleeves, composite, etc.) ● No. of pressure excursions > MAOP / MOP ● No. of indications of high cyclic loading ● No. of occurrences where the NOP / MOP(or MAOP) ratio approaches unity ● Percentage of new pipeline construction monitored continuously by operator inspectors ● No. of failures due to workmanship defects	● Girth weld failures ● Failure of weld joints other than girth welds ● Repair weld failures ● No. of pressure excursions > 110% MAOP / MOP ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT
Transportation and Construction damage	● Construction procedures ● Transportation procedures ● Field coating application procedures ● Wrinkle bends ● No. of pipe segments with Legacy Construction Techniques ● No. of pipe segments with Legacy Construction Techniques which have not been appropriately assessed	● No. of ILI indications of rock dents, wrinkle bends, or construction damage ● No. of indications of coating damage ● No. of indications of ineffective repair of damaged coating ● No. of hydro-test failures ● No. of pressure excursions > MAOP / MOP ● No. of indications of high cyclic loading ● No. of occurrences where the NOP / MOP(or MAOP) ratio approaches unity	● Releases due to construction damage ● Releases due to transportation damage ● No. of pressure excursions > 110% MAOP / MOP ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT

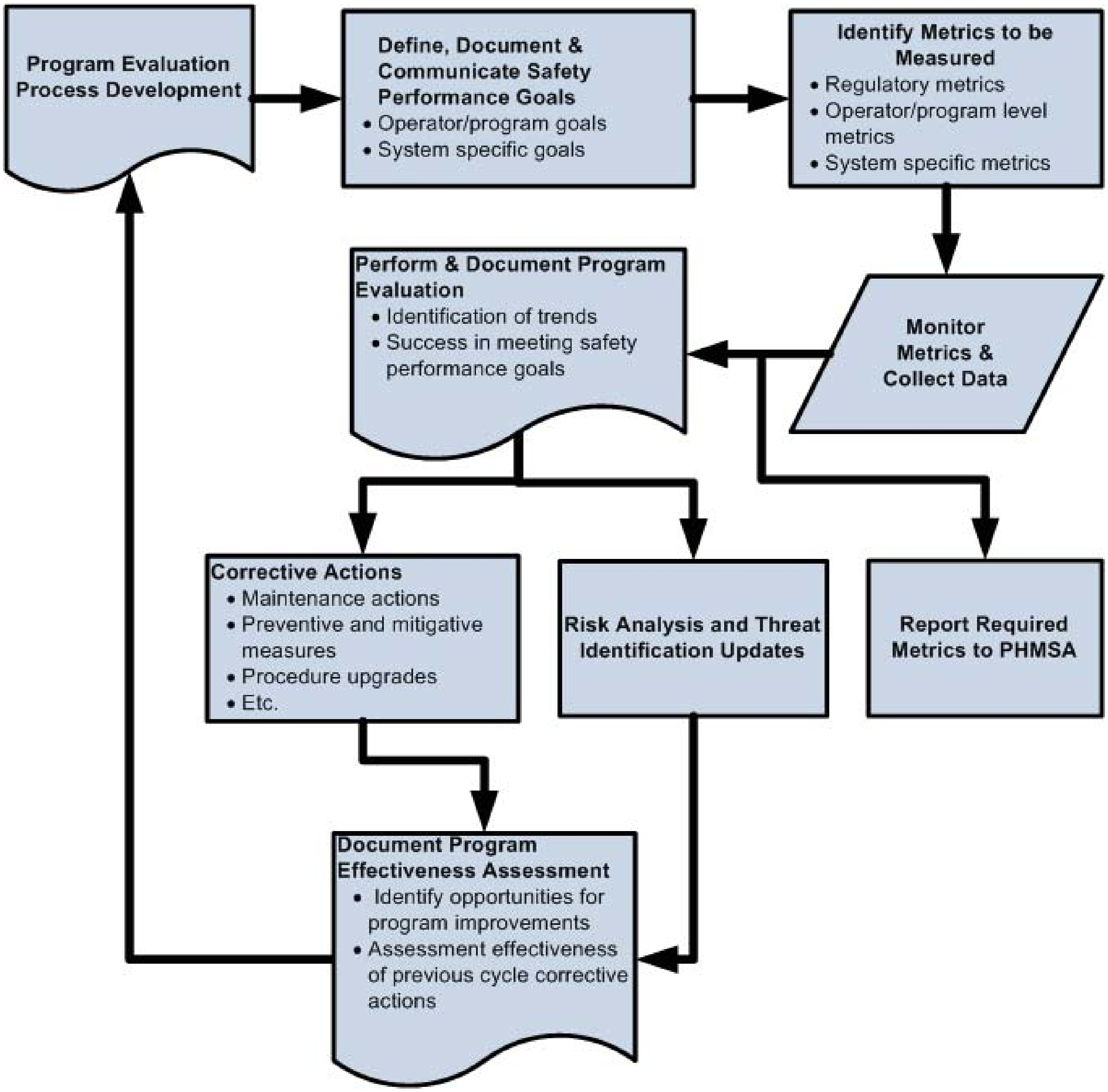
Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Equipment Failure			
Equipment malfunction or failure of non-pipe component	● Equipment specifications and materials ● Testing program and procedures for ○ Pumps ○ Control valves ○ High pressure shutdown devices ○ Relief valves ○ Block valves ● Maintenance and operations training ● Maintenance procedures ● Tank inspection program ● Tank corrosion control program ● Root cause failure analysis program for systemic problems ● Implementation of preventive maintenance program	● No. of API 653 inspections ● No. of API 570 inspections ● No. of relief valve malfunctions ● Mean time between failures (MTBF) ● No. of occurrences having excessive vibration ● No. of control malfunctions ● Percentage of safety-critical equipment that performs to specification when inspected or tested. ● Percentage of planned maintenance activities completed on time. ● Trends of equipment failures prior to the expected life cycle period ● Destructive or non-destructive test results indicate inaccuracies in material or component records ● No. of manufacturing defects identified	● Corrosion failure ● Releases due to gasket and packing failures ● Releases due to tank failure ● Sump tank leaks ● Failure of fittings, threaded connections, couplings, non-threaded connections, tubing, equipment body ● Pump and compressor failure ● Amount of gas released ● Barrels spilled ● Equipment failures prior to the expected life cycle ● Regulator or pressure control failure ● Over-pressure control failure ● Valve leak or failure
Operational Error			
Valve left or placed in wrong position	● Operating procedures ● Training and OQ program	● No. of relief valves operating ● No of relief valve failures ● No. of incorrect operations resulting in contamination ● No of pressure excursions > MAOP / MOP (percentage of events for which overpressure protection devices functioned as intended) ● Percentage of relief valves tested which function as intended ● No. of failures due to inadequate procedures / safety practices ● No. of failures due to a failure to follow procedures	● Over pressure ● Releases ● Tank overflow ● Sump or other overflow
Incorrect start / stop of pump or compressor	● Operating procedures ● Training and OQ program	● No. of relief valves operating ● No. of incorrect operations resulting in contamination ● No. of pressure excursions > MAOP / MOP ● No. of failures due to inadequate procedures / safety practices ● No. of failures due to a failure to follow procedures	● Relief valve failure ● Over pressure ● Releases ● Tank overflow
Tank overfilled	● Operating procedures ● Shipper schedule changes or unscheduled deliveries ● Alarm monitoring and testing program ● Training and OQ program	● No. of alarm failures or malfunctions ● No. of tanks without redundant overfill protection ● No. of tanks with inadequate diking ● No. of failures due to inadequate procedures / safety practices ● No. of failures due to a failure to follow procedures	● Tank overflow

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Other human errors	● Operator qualification audits ● CRM operator training and qualification audits ● Training and staff qualification program	● No. of relief valves operating ● No. of relief valve failures ● No. of errors resulting in contamination ● No of motor vehicle impacts ● No. of pressure excursions > MAOP / MOP ● No. of relief valves or shutdown devices inoperable for long periods of time ● No. of times that line pressure was not temporarily reduced when it was required ● Percentage of individuals who take the correct action in response to an abnormal operating condition or incident / accident ● No. of failures due to inadequate procedures ● No. of failures due to a failure to follow procedures	● Over pressurization of system ● Releases due to operator error ● Tank overflow ● Failure to shut down system, when appropriate
Natural Forces - Impact on steel pipe, plastic pipe, cast iron pipe			
Cold Weather	● Inspection program to identify frost heave	● Frost heave	● Releases due to frost heave ● Releases due to freezing conditions ● Damage due to increased loading from ice / snow
Heavy rains / flooding	● Water crossing inspection program ● Strain based design parameters	● No. of exposed pipe segments ● No. of indications of overstrained pipe ● No. of stream crossing washouts ● Damage without a release due to weather conditions	● Releases due to heavy rains / flooding
Lightning	● Lightning protection program ● Tank floating roof seal inspection program	● No. of station shutdowns due to ground faults ● No. of tanks lacking fire suppression systems ● No. of tanks lacking lightning arrestors	● Releases due to lightning
Earth movement	● Strain based design parameters ● Girth weld inspection program ● Identification of areas of known land subsidence, landslides. earthquake fault zones, and washouts	● No. of occurrences of earthquakes or seismic activity ● No. of occurrences of ground sloughing ● No. of occurrences of subsidence ● No. of ILI indications of overstrain	● Releases due to overstrain ● Girth weld failure due to soil movement ● Failure of weld joints other than girth welds due to soil movement

Appendix A - Elements of a Mature Program Evaluation Process

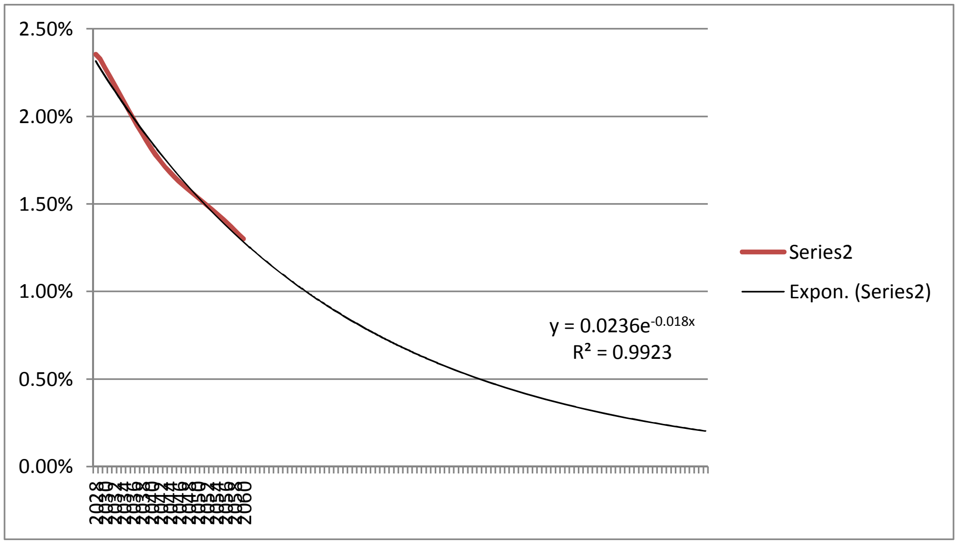


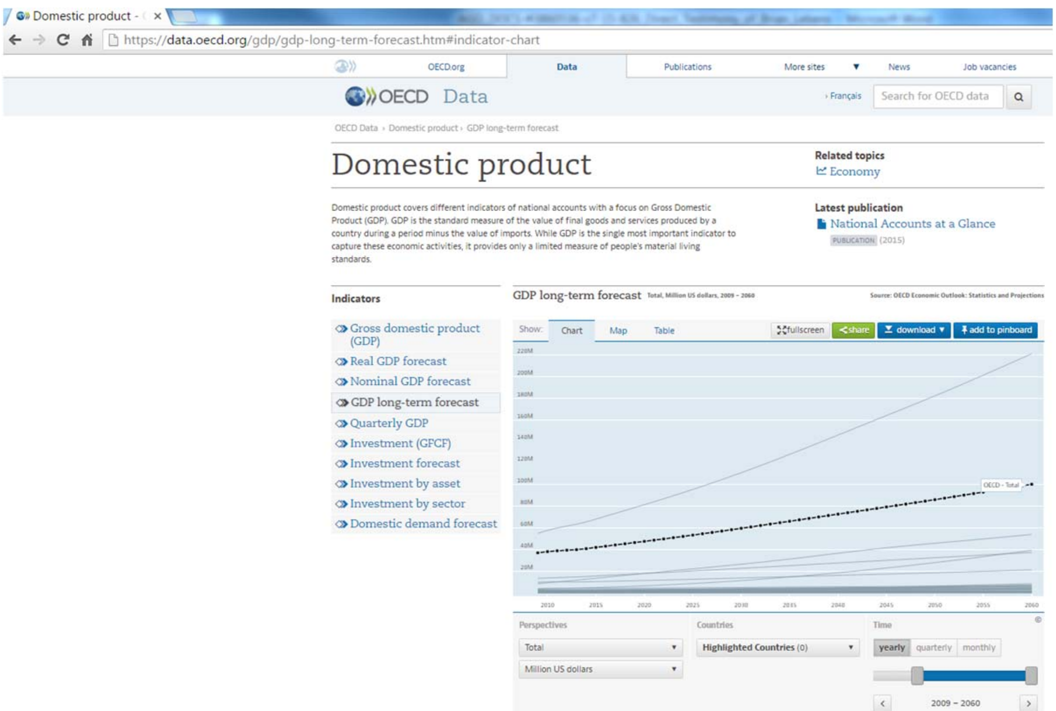
APPENDIX

F

LOCATION	INDICATOR	SUBJECT	MEASURE	FREQUENCY	TIME	Value	Growth
USA	GDPLTFORECAST	TOT	MLN_USD	A	2009	13,263,170	
USA	GDPLTFORECAST	TOT	MLN_USD	A	2010	13,595,648	2.51%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2011	13,846,806	1.85%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2012	14,231,650	2.78%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2013	14,498,952	1.88%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2014	14,898,390	2.75%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2015	15,423,341	3.52%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2016	15,928,727	3.28%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2017	16,401,209	2.97%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2018	16,854,354	2.76%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2019	17,299,339	2.64%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2020	17,743,025	2.56%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2021	18,189,112	2.51%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2022	18,639,481	2.48%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2023	19,095,177	2.44%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2024	19,556,981	2.42%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2025	20,025,623	2.40%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2026	20,502,008	2.38%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2027	20,987,134	2.37%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2028	21,481,323	2.35%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2029	21,981,214	2.33%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2030	22,482,236	2.28%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2031	22,983,846	2.23%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2032	23,485,734	2.18%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2033	23,987,555	2.14%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2034	24,488,756	2.09%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2035	24,988,766	2.04%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2036	25,487,157	1.99%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2037	25,983,743	1.95%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2038	26,478,465	1.90%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2039	26,971,187	1.86%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2040	27,461,839	1.82%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2041	27,950,685	1.78%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2042	28,438,332	1.74%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2043	28,925,353	1.71%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2044	29,412,141	1.68%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2045	29,898,935	1.66%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2046	30,386,016	1.63%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2047	30,873,747	1.61%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2048	31,362,302	1.58%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2049	31,851,655	1.56%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2050	32,341,599	1.54%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2051	32,831,958	1.52%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2052	33,322,633	1.49%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2053	33,813,350	1.47%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2054	34,303,649	1.45%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2055	34,792,848	1.43%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2056	35,280,357	1.40%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2057	35,765,758	1.38%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2058	36,248,677	1.35%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2059	36,728,931	1.32%
USA	GDPLTFORECAST	TOT	MLN_USD	A	2060	37,206,576	1.30%

https://data.oecd.org/gdp/gdp-long-term-forecast.htm#indicator-chart





APPENDIX

G

Inflation	DATE	5 YR	7 YR	10 YR	20 YR	30 YR
Inflation	Average	1.88	1.96	2.01	2.00	2.10
Inflation	12/16/2016	1.75	1.87	1.86	1.86	1.99
Inflation	12/19/2016	1.74	1.84	1.86	1.87	1.99
Inflation	12/20/2016	1.8	1.89	1.9	1.9	2.01
Inflation	12/21/2016	1.74	1.83	1.91	1.93	2.02
Inflation	12/22/2016	1.86	1.95	1.95	1.95	2.06
Inflation	12/23/2016	1.84	1.93	1.97	1.99	2.09
Inflation	12/27/2016	1.88	1.96	1.99	1.99	2.1
Inflation	12/28/2016	1.85	1.92	1.95	1.97	2.07
Inflation	12/29/2016	1.81	1.92	1.94	1.96	2.06
Inflation	12/30/2016	1.84	1.92	1.95	1.97	2.07
Inflation	1/3/2017	1.86	1.96	1.98	2	2.1
Inflation	1/4/2017	1.86	1.96	1.99	2	2.1
Inflation	1/5/2017	1.83	1.92	1.95	1.96	2.07
Inflation	1/6/2017	1.84	1.93	1.96	1.97	2.07
Inflation	1/9/2017	1.85	1.92	1.95	1.95	2.06
Inflation	1/10/2017	1.84	1.9	1.95	1.95	2.06
Inflation	1/11/2017	1.85	1.91	1.99	1.97	2.08
Inflation	1/12/2017	1.87	1.94	1.98	1.98	2.14
Inflation	1/13/2017	1.85	1.92	1.99	1.99	2.1
Inflation	1/17/2017	1.84	1.9	1.97	1.98	2.06
Inflation	1/18/2017	1.86	1.94	2	2	2.08
Inflation	1/19/2017	1.9	1.98	2.04	2.02	2.11
Inflation	1/20/2017	1.92	2	2.04	2.03	2.11
Inflation	1/23/2017	1.86	1.91	2.02	2.01	2.1
Inflation	1/24/2017	1.93	2.01	2.06	2.03	2.12
Inflation	1/25/2017	1.96	2.04	2.08	2.06	2.14
Inflation	1/26/2017	1.94	2.03	2.08	2.06	2.14
Inflation	1/27/2017	1.96	2.03	2.08	2.06	2.15
Inflation	1/30/2017	1.95	2.02	2.07	2.06	2.14
Inflation	1/31/2017	1.94	2	2.05	2.04	2.12

	DATE	5 YR	7 YR	10 YR	20 YR	30 YR
Real	12/16/2016	0.32	0.54	0.74	1.05	1.2
Real	12/19/2016	0.29	0.51	0.68	0.98	1.13
Real	12/20/2016	0.26	0.49	0.67	0.98	1.14
Real	12/21/2016	0.3	0.52	0.64	0.93	1.1
Real	12/22/2016	0.18	0.41	0.6	0.91	1.06
Real	12/23/2016	0.2	0.42	0.58	0.87	1.03
Real	12/27/2016	0.19	0.41	0.58	0.89	1.04
Real	12/28/2016	0.17	0.4	0.56	0.86	1.02
Real	12/29/2016	0.15	0.38	0.55	0.86	1.02
Real	12/30/2016	0.09	0.33	0.5	0.82	0.99
Real	1/3/2017	0.08	0.3	0.47	0.78	0.94
Real	1/4/2017	0.08	0.3	0.47	0.78	0.95
Real	1/5/2017	0.03	0.26	0.42	0.73	0.89
Real	1/6/2017	0.08	0.3	0.46	0.76	0.93
Real	1/9/2017	0.04	0.26	0.43	0.74	0.91
Real	1/10/2017	0.05	0.28	0.43	0.74	0.91
Real	1/11/2017	0.04	0.27	0.39	0.71	0.88
Real	1/12/2017	0	0.23	0.38	0.7	0.87
Real	1/13/2017	0.05	0.28	0.41	0.72	0.89
Real	1/17/2017	0	0.24	0.36	0.68	0.87
Real	1/18/2017	0.07	0.3	0.42	0.74	0.92
Real	1/19/2017	0.07	0.3	0.43	0.75	0.93
Real	1/20/2017	0.03	0.28	0.44	0.76	0.94
Real	1/23/2017	0.02	0.28	0.39	0.71	0.89
Real	1/24/2017	0.01	0.26	0.41	0.75	0.93
Real	1/25/2017	0.03	0.29	0.45	0.78	0.96
Real	1/26/2017	0.01	0.27	0.43	0.76	0.94
Real	1/27/2017	-0.02	0.25	0.41	0.74	0.91
Real	1/30/2017	-0.01	0.26	0.42	0.76	0.94
Real	1/31/2017	-0.04	0.24	0.4	0.74	0.93

Nominal	Date	5 Yr	7 Yr	10 Yr	20 Yr	30 Yr
Nominal	12/16/2016	2.07	2.41	2.6	2.91	3.19
Nominal	12/19/2016	2.03	2.35	2.54	2.85	3.12
Nominal	12/20/2016	2.06	2.38	2.57	2.88	3.15
Nominal	12/21/2016	2.04	2.35	2.55	2.86	3.12
Nominal	12/22/2016	2.04	2.36	2.55	2.86	3.12
Nominal	12/23/2016	2.04	2.35	2.55	2.86	3.12
Nominal	12/27/2016	2.07	2.37	2.57	2.88	3.14
Nominal	12/28/2016	2.02	2.32	2.51	2.83	3.09
Nominal	12/29/2016	1.96	2.3	2.49	2.82	3.08
Nominal	12/30/2016	1.93	2.25	2.45	2.79	3.06
Nominal	1/3/2017	1.94	2.26	2.45	2.78	3.04
Nominal	1/4/2017	1.94	2.26	2.46	2.78	3.05
Nominal	1/5/2017	1.86	2.18	2.37	2.69	2.96
Nominal	1/6/2017	1.92	2.23	2.42	2.73	3
Nominal	1/9/2017	1.89	2.18	2.38	2.69	2.97
Nominal	1/10/2017	1.89	2.18	2.38	2.69	2.97
Nominal	1/11/2017	1.89	2.18	2.38	2.68	2.96
Nominal	1/12/2017	1.87	2.17	2.36	2.68	3.01
Nominal	1/13/2017	1.9	2.2	2.4	2.71	2.99
Nominal	1/17/2017	1.84	2.14	2.33	2.66	2.93
Nominal	1/18/2017	1.93	2.24	2.42	2.74	3
Nominal	1/19/2017	1.97	2.28	2.47	2.77	3.04
Nominal	1/20/2017	1.95	2.28	2.48	2.79	3.05
Nominal	1/23/2017	1.88	2.19	2.41	2.72	2.99
Nominal	1/24/2017	1.94	2.27	2.47	2.78	3.05
Nominal	1/25/2017	1.99	2.33	2.53	2.84	3.1
Nominal	1/26/2017	1.95	2.3	2.51	2.82	3.08
Nominal	1/27/2017	1.94	2.28	2.49	2.8	3.06
Nominal	1/30/2017	1.94	2.28	2.49	2.82	3.08
Nominal	1/31/2017	1.9	2.24	2.45	2.78	3.05

APPENDIX

H

Gas Proxy Group - Yahoo Growth

Company	Ticker	Min Price (30 Calendar Days)	Average Price (30 Calendar Days)	Max Price (30 Calendar Days)	Dividend	Dividend Forecast	Yahoo Finance Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
Atmos Energy Corporation	ATO	$ 73.21	$ 74.69	$ 76.18	$ 1.80	$ 1.87	7.30%	2.45%	2.50%	2.55%	9.80%
Chesapeake Utilities Corporation	CPK	$ 63.40	$ 64.78	$ 67.15	$ 1.22	$ 1.26	5.80%	1.87%	1.94%	1.98%	7.74%
New Jersey Resources Corporation	NJR	$ 34.25	$ 35.93	$ 37.70	$ 1.02	$ 1.05	6.00%	2.79%	2.92%	3.07%	8.92%
Northwest Natural Gas Company	NWN	$ 57.65	$ 58.60	$ 60.07	$ 1.88	$ 1.92	4.00%	3.19%	3.27%	3.33%	7.27%
South Jersey Industries, Inc.	SJI	$ 31.50	$ 32.47	$ 34.21	$ 1.09	$ 1.12	6.00%	3.28%	3.46%	3.56%	9.46%
Southwest Gas Corporation	SWX	$ 76.02	$ 78.18	$ 80.57	$ 1.80	$ 1.84	4.00%	2.28%	2.35%	2.42%	6.35%
Spire Inc	SR	$ 63.70	$ 64.74	$ 65.60	$ 2.10	$ 2.14	4.18%	3.27%	3.31%	3.37%	7.49%
Mean							5.33%	2.73%	2.82%	2.90%	8.15%
σ							1.19%				
-1 σ							4.14%				
+1 σ							6.51%				

Gas Proxy Group - Yahoo Growth

		30 Trading Days										
Company	**Ticker**	**Min Price**	**Average Price**	**Max Price**	**Dividend**	**Dividend Forecast**	**Yahoo Finance Growth**	**Min Yield**	**Mean Yield**	**Max Yield**	**Mean Constant Growth DCF**
Atmos Energy Corporation	ATO	$ 73.21	$ 74.57	$ 76.18	$ 1.80	$ 1.87	7.30%	2.45%	2.50%	2.55%	9.80%
Chesapeake Utilities Corporation	CPK	$ 63.40	$ 65.92	$ 70.00	$ 1.22	$ 1.26	5.80%	1.79%	1.90%	1.98%	7.70%
New Jersey Resources Corporation	NJR	$ 34.25	$ 36.05	$ 37.70	$ 1.02	$ 1.05	6.00%	2.79%	2.91%	3.07%	8.91%
Northwest Natural Gas Company	NWN	$ 57.65	$ 59.01	$ 61.01	$ 1.88	$ 1.92	4.00%	3.14%	3.25%	3.33%	7.25%
South Jersey Industries, Inc.	SJI	$ 31.50	$ 33.06	$ 34.68	$ 1.09	$ 1.12	6.00%	3.24%	3.40%	3.56%	9.40%
Southwest Gas Corporation	SWX	$ 75.43	$ 77.53	$ 80.57	$ 1.80	$ 1.84	4.00%	2.28%	2.37%	2.43%	6.37%
Spire Inc	SR	$ 63.70	$ 64.65	$ 65.60	$ 2.10	$ 2.14	4.18%	3.27%	3.32%	3.37%	7.50%
Mean							5.33%	2.71%	2.81%	2.90%	8.13%
σ							1.19%				
-1 σ							4.14%				
+1 σ							6.51%				

Gas Proxy Group - Zacks Growth

Company	Ticker	Min Price	Average Price	Max Price	Dividend	Dividend Forecast	Zacks Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
		30 Calendar Days									
Atmos Energy Corporation	ATO	$ 73.21	$ 74.69	$ 76.18	$ 1.80	$ 1.86	7.00%	2.45%	2.49%	2.54%	9.49%
Chesapeake Utilities Corporation	CPK	$ 63.40	$ 64.78	$ 67.15	$ 1.22	$ 1.26	6.00%	1.87%	1.94%	1.98%	7.94%
New Jersey Resources Corporation	NJR	$ 34.25	$ 35.93	$ 37.70	$ 1.02	$ 1.05	6.50%	2.79%	2.93%	3.07%	9.43%
Northwest Natural Gas Company	NWN	$ 57.65	$ 58.60	$ 60.07	$ 1.88	$ 1.92	4.00%	3.19%	3.27%	3.33%	7.27%
South Jersey Industries, Inc.	SJI	$ 31.50	$ 32.47	$ 34.21	$ 1.09	$ 1.14	10.00%	3.35%	3.52%	3.63%	13.52%
Southwest Gas Corporation	SWX	$ 76.02	$ 78.18	$ 80.57	$ 1.80	$ 1.84	4.45%	2.28%	2.35%	2.42%	6.80%
Spire Inc	SR	$ 63.70	$ 64.74	$ 65.60	$ 2.10	$ 2.15	4.41%	3.27%	3.32%	3.37%	7.73%
Mean							6.05%	2.74%	2.83%	2.91%	8.88%
σ							1.93%				
-1 σ							4.12%				
+1 σ							7.98%				

Gas Proxy Group - Zacks Growth

Company	Ticker	Min Price	Average Price	Max Price	Dividend	Dividend Forecast	Zacks Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
		30 Trading Days									
Atmos Energy Corporation	ATO	$ 73.21	$ 74.57	$ 76.18	$ 1.80	$ 1.86	7.00%	2.45%	2.50%	2.54%	9.50%
Chesapeake Utilities Corporation	CPK	$ 63.40	$ 65.92	$ 70.00	$ 1.22	$ 1.26	6.00%	1.80%	1.91%	1.98%	7.91%
New Jersey Resources Corporation	NJR	$ 34.25	$ 36.05	$ 37.70	$ 1.02	$ 1.05	6.50%	2.79%	2.92%	3.07%	9.42%
Northwest Natural Gas Company	NWN	$ 57.65	$ 59.01	$ 61.01	$ 1.88	$ 1.92	4.00%	3.14%	3.25%	3.33%	7.25%
South Jersey Industries, Inc.	SJI	$ 31.50	$ 33.06	$ 34.68	$ 1.09	$ 1.14	10.00%	3.30%	3.46%	3.63%	13.46%
Southwest Gas Corporation	SWX	$ 75.43	$ 77.53	$ 80.57	$ 1.80	$ 1.84	4.45%	2.28%	2.37%	2.44%	6.82%
Spire Inc	SR	$ 63.70	$ 64.65	$ 65.60	$ 2.10	$ 2.15	4.41%	3.27%	3.32%	3.37%	7.73%
Mean							6.05%	2.72%	2.82%	2.91%	8.87%
σ							1.93%				
-1 σ							4.12%				
+1 σ							7.98%				

Gas Proxy Group - Value Line Growth

Company	Ticker	Min Price	Average Price	Max Price	Dividend	Dividend Forecast	Value Line Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
		30 Calendar Days									
Atmos Energy Corporation	ATO	$ 73.21	$ 74.69	$ 76.18	$ 1.80	$ 1.86	6.50%	2.44%	2.49%	2.54%	8.99%
Chesapeake Utilities Corporation	CPK	$ 63.40	$ 64.78	$ 67.15	$ 1.22	$ 1.27	8.50%	1.89%	1.96%	2.01%	10.46%
New Jersey Resources Corporation	NJR	$ 34.25	$ 35.93	$ 37.70	$ 1.02	$ 1.04	3.00%	2.75%	2.88%	3.02%	5.88%
Northwest Natural Gas Company	NWN	$ 57.65	$ 58.60	$ 60.07	$ 1.88	$ 1.95	7.00%	3.24%	3.32%	3.38%	10.32%
South Jersey Industries, Inc.	SJI	$ 31.50	$ 32.47	$ 34.21	$ 1.09	$ 1.11	3.00%	3.23%	3.41%	3.51%	6.41%
Southwest Gas Corporation	SWX	$ 76.02	$ 78.18	$ 80.57	$ 1.80	$ 1.86	7.00%	2.31%	2.38%	2.45%	9.38%
Spire Inc	SR	$ 63.70	$ 64.74	$ 65.60	$ 2.10	$ 2.19	9.00%	3.35%	3.39%	3.45%	12.39%
Mean							6.29%	2.74%	2.83%	2.91%	9.12%
σ							2.23%				
-1 σ							4.05%				
+1 σ							8.52%				

Gas Proxy Group - Value Line Growth

Company	Ticker	Min Price (30 Trading Days)	Average Price (30 Trading Days)	Max Price (30 Trading Days)	Dividend	Dividend Forecast	Value Line Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
Atmos Energy Corporation	ATO	$ 73.21	$ 74.57	$ 76.18	$ 1.80	$ 1.86	6.50%	2.44%	2.49%	2.54%	8.99%
Chesapeake Utilities Corporation	CPK	$ 63.40	$ 65.92	$ 70.00	$ 1.22	$ 1.27	8.50%	1.82%	1.93%	2.01%	10.43%
New Jersey Resources Corporation	NJR	$ 34.25	$ 36.05	$ 37.70	$ 1.02	$ 1.04	3.00%	2.75%	2.87%	3.02%	5.87%
Northwest Natural Gas Company	NWN	$ 57.65	$ 59.01	$ 61.01	$ 1.88	$ 1.95	7.00%	3.19%	3.30%	3.38%	10.30%
South Jersey Industries, Inc.	SJI	$ 31.50	$ 33.06	$ 34.68	$ 1.09	$ 1.11	3.00%	3.19%	3.35%	3.51%	6.35%
Southwest Gas Corporation	SWX	$ 75.43	$ 77.53	$ 80.57	$ 1.80	$ 1.86	7.00%	2.31%	2.40%	2.47%	9.40%
Spire Inc	SR	$ 63.70	$ 64.65	$ 65.60	$ 2.10	$ 2.19	9.00%	3.35%	3.39%	3.45%	12.39%
Mean							6.29%	2.72%	2.82%	2.91%	9.10%
σ							2.23%				
-1 σ							4.05%				
+1 σ							8.52%				

Electric & Gas Proxy Group - Yahoo Growth

Company	Ticker	Min Price	Average Price	Max Price	Dividend	Dividend Forecast	Yahoo Finance Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
		30 Calander Days									
Ameren Corporation	AEE	$ 51.69	$ 52.18	$ 53.10	$ 1.76	$ 1.81	5.85%	3.41%	3.47%	3.50%	9.32%
Avista Corporation	AVA	$ 38.11	$ 39.18	$ 39.87	$ 1.37	$ 1.41	5.65%	3.53%	3.60%	3.70%	9.25%
CenterPoint Energy, Inc.	CNP	$ 24.59	$ 25.44	$ 26.21	$ 1.07	$ 1.11	6.63%	4.22%	4.34%	4.50%	10.97%
CMS Energy Corporation	CMS	$ 41.51	$ 41.98	$ 42.60	$ 1.33	$ 1.38	7.26%	3.24%	3.28%	3.32%	10.54%
NiSource Inc.	NI	$ 21.84	$ 22.23	$ 22.68	$ 0.70	$ 0.73	9.20%	3.23%	3.29%	3.35%	12.49%
NorthWestern Corporation	NWE	$ 56.41	$ 57.08	$ 57.51	$ 2.00	$ 2.04	4.34%	3.55%	3.58%	3.62%	7.92%
SCANA Corporation	SCG	$ 68.13	$ 70.93	$ 73.28	$ 2.30	$ 2.37	5.70%	3.23%	3.33%	3.47%	9.03%
Vectren Corporation	VVC	$ 51.72	$ 53.78	$ 55.03	$ 1.68	$ 1.72	4.57%	3.12%	3.20%	3.32%	7.77%
Wisconsin Energy Corporation	WEC	$ 57.98	$ 58.60	$ 59.38	$ 2.08	$ 2.15	6.73%	3.62%	3.67%	3.71%	10.40%
Mean							6.21%	3.46%	3.53%	3.61%	9.74%
σ							1.39%				
-1 σ							4.82%				
+1 σ							7.60%				

Electric & Gas Proxy Group -
Yahoo Growth

Company	Ticker	Min Price (30 Trading Days)	Average Price (30 Trading Days)	Max Price (30 Trading Days)	Dividend	Dividend Forecast	Yahoo Finance Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
Ameren Corporation	AEE	$ 51.60	$ 52.19	$ 53.10	$ 1.76	$ 1.81	5.85%	3.41%	3.47%	3.51%	9.32%
Avista Corporation	AVA	$ 38.11	$ 39.44	$ 40.77	$ 1.37	$ 1.41	5.65%	3.46%	3.57%	3.70%	9.22%
CenterPoint Energy, Inc.	CNP	$ 24.29	$ 25.17	$ 26.21	$ 1.07	$ 1.11	6.63%	4.22%	4.39%	4.55%	11.02%
CMS Energy Corporation	CMS	$ 41.30	$ 41.86	$ 42.60	$ 1.33	$ 1.38	7.26%	3.24%	3.29%	3.34%	10.55%
NiSource Inc.	NI	$ 21.84	$ 22.22	$ 22.68	$ 0.70	$ 0.73	9.20%	3.23%	3.29%	3.35%	12.49%
NorthWestern Corporation	NWE	$ 56.41	$ 57.06	$ 57.51	$ 2.00	$ 2.04	4.34%	3.55%	3.58%	3.62%	7.92%
SCANA Corporation	SCG	$ 68.13	$ 71.97	$ 74.69	$ 2.30	$ 2.37	5.70%	3.17%	3.29%	3.47%	8.99%
Vectren Corporation	VVC	$ 51.72	$ 53.32	$ 55.03	$ 1.68	$ 1.72	4.57%	3.12%	3.22%	3.32%	7.79%
Wisconsin Energy Corporation	WEC	$ 57.90	$ 58.55	$ 59.38	$ 2.08	$ 2.15	6.73%	3.62%	3.67%	3.71%	10.40%
Mean							6.21%	3.45%	3.53%	3.62%	9.75%
σ							1.39%				
-1 σ							4.82%				
+1 σ							7.60%				

Electric & Gas Proxy Group - Zacks Growth

Company	Ticker	Min Price	Average Price	Max Price	Dividend	Dividend Forecast	Zacks Growth	Min Yield	Mean Yield	Max Yield	Mean Constant Growth DCF
		30 Calander Days									
Ameren Corporation	AEE	$ 51.69	$ 52.18	$ 53.10	$ 1.76	$ 1.82	6.50%	3.42%	3.48%	3.52%	9.98%
Avista Corporation	AVA	$ 38.11	$ 39.18	$ 39.87	$ 1.37	NA	NA	NA	NA	NA	NA
CenterPoint Energy, Inc.	CNP	$ 24.59	$ 25.44	$ 26.21	$ 1.07	$ 1.10	5.00%	4.18%	4.31%	4.46%	9.31%
CMS Energy Corporation	CMS	$ 41.51	$ 41.98	$ 42.60	$ 1.33	$ 1.37	6.00%	3.22%	3.26%	3.30%	9.26%
NiSource Inc.	NI	$ 21.84	$ 22.23	$ 22.68	$ 0.70	$ 0.73	7.22%	3.20%	3.26%	3.32%	10.48%
NorthWestern Corporation	NWE	$ 56.41	$ 57.08	$ 57.51	$ 2.00	$ 2.05	5.00%	3.56%	3.59%	3.63%	8.59%
SCANA Corporation	SCG	$ 68.13	$ 70.93	$ 73.28	$ 2.30	$ 2.37	5.67%	3.23%	3.33%	3.47%	9.00%
Vectren Corporation	VVC	$ 51.72	$ 53.78	$ 55.03	$ 1.68	$ 1.72	5.33%	3.13%	3.21%	3.33%	8.54%
Wisconsin Energy Corporation	WEC	$ 57.98	$ 58.60	$ 59.38	$ 2.08	$ 2.14	6.00%	3.61%	3.66%	3.70%	9.66%
Mean							5.84%	3.44%	3.51%	3.59%	9.35%
σ							0.72%				
-1 σ							5.12%				
+1 σ							6.56%				

Electric & Gas Proxy Group - Zacks Growth

		30 Trading Days										
Company	**Ticker**	**Min Price**	**Average Price**	**Max Price**	**Dividend**	**Dividend Forecast**	**Zacks Growth**	**Min Yield**	**Mean Yield**	**Max Yield**	**Mean Constant Growth DCF**
Ameren Corporation	AEE	$ 51.60	$ 52.19	$ 53.10	$ 1.76	$ 1.82	6.50%	3.42%	3.48%	3.52%	9.98%
Avista Corporation	AVA	$ 38.11	$ 39.44	$ 40.77	$ 1.37	NA	NA	NA	NA	NA	NA
CenterPoint Energy, Inc.	CNP	$ 24.29	$ 25.17	$ 26.21	$ 1.07	$ 1.10	5.00%	4.18%	4.36%	4.52%	9.36%
CMS Energy Corporation	CMS	$ 41.30	$ 41.86	$ 42.60	$ 1.33	$ 1.37	6.00%	3.22%	3.27%	3.32%	9.27%
NiSource Inc.	NI	$ 21.84	$ 22.22	$ 22.68	$ 0.70	$ 0.73	7.22%	3.20%	3.26%	3.32%	10.48%
NorthWestern Corporation	NWE	$ 56.41	$ 57.06	$ 57.51	$ 2.00	$ 2.05	5.00%	3.56%	3.59%	3.63%	8.59%
SCANA Corporation	SCG	$ 68.13	$ 71.97	$ 74.69	$ 2.30	$ 2.37	5.67%	3.17%	3.29%	3.47%	8.96%
Vectren Corporation	VVC	$ 51.72	$ 53.32	$ 55.03	$ 1.68	$ 1.72	5.33%	3.13%	3.23%	3.33%	8.56%
Wisconsin Energy Corporation	WEC	$ 57.90	$ 58.55	$ 59.38	$ 2.08	$ 2.14	6.00%	3.61%	3.66%	3.70%	9.66%
Mean							5.84%	3.44%	3.52%	3.60%	9.36%
σ							0.72%				
-1 σ							5.12%				
+1 σ							6.56%				

Electric & Gas Proxy Group - Value Line Growth

		30 Calander Days									
Company	**Ticker**	**Min Price**	**Average Price**	**Max Price**	**Dividend**	**Dividend Forecast**	**Value Line Growth**	**Min Yield**	**Mean Yield**	**Max Yield**	**Mean Constant Growth DCF**
Ameren Corporation	AEE	$ 51.69	$ 52.18	$ 53.10	$ 1.76	$ 1.81	6.00%	3.41%	3.47%	3.51%	9.47%
Avista Corporation	AVA	$ 38.11	$ 39.18	$ 39.87	$ 1.37	$ 1.39	3.00%	3.49%	3.55%	3.65%	6.55%
CenterPoint Energy, Inc.	CNP	$ 24.59	$ 25.44	$ 26.21	$ 1.07	$ 1.08	2.00%	4.12%	4.25%	4.39%	6.25%
CMS Energy Corporation	CMS	$ 41.51	$ 41.98	$ 42.60	$ 1.33	$ 1.37	6.00%	3.22%	3.26%	3.30%	9.26%
NiSource Inc.	NI	$ 21.84	$ 22.23	$ 22.68	$ 0.70	$ 0.71	1.50%	3.11%	3.17%	3.23%	4.67%
NorthWestern Corporation	NWE	$ 56.41	$ 57.08	$ 57.51	$ 2.00	$ 2.07	6.50%	3.59%	3.62%	3.66%	10.12%
SCANA Corporation	SCG	$ 68.13	$ 70.93	$ 73.28	$ 2.30	$ 2.35	4.50%	3.21%	3.32%	3.45%	7.82%
Vectren Corporation	VVC	$ 51.72	$ 53.78	$ 55.03	$ 1.68	$ 1.76	9.00%	3.19%	3.26%	3.39%	12.26%
Wisconsin Energy Corporation	WEC	$ 57.98	$ 58.60	$ 59.38	$ 2.08	$ 2.14	6.00%	3.61%	3.66%	3.70%	9.66%
Mean							4.94%	3.44%	3.51%	3.59%	8.45%
σ							2.28%				
-1 σ							2.67%				
+1 σ							7.22%				

Electric & Gas Proxy Group - Value Line Growth

		30 Trading Days										
Company	**Ticker**	**Min Price**	**Average Price**	**Max Price**	**Dividend**	**Dividend Forecast**	**Value Line Growth**	**Min Yield**	**Mean Yield**	**Max Yield**	**Mean Constant Growth DCF**
Ameren Corporation	AEE	$ 51.60	$ 52.19	$ 53.10	$ 1.76	$ 1.81	6.00%	3.41%	3.47%	3.51%	9.47%
Avista Corporation	AVA	$ 38.11	$ 39.44	$ 40.77	$ 1.37	$ 1.39	3.00%	3.41%	3.53%	3.65%	6.53%
CenterPoint Energy, Inc.	CNP	$ 24.29	$ 25.17	$ 26.21	$ 1.07	$ 1.08	2.00%	4.12%	4.29%	4.45%	6.29%
CMS Energy Corporation	CMS	$ 41.30	$ 41.86	$ 42.60	$ 1.33	$ 1.37	6.00%	3.22%	3.27%	3.32%	9.27%
NiSource Inc.	NI	$ 21.84	$ 22.22	$ 22.68	$ 0.70	$ 0.71	1.50%	3.11%	3.17%	3.23%	4.67%
NorthWestern Corporation	NWE	$ 56.41	$ 57.06	$ 57.51	$ 2.00	$ 2.07	6.50%	3.59%	3.62%	3.66%	10.12%
SCANA Corporation	SCG	$ 68.13	$ 71.97	$ 74.69	$ 2.30	$ 2.35	4.50%	3.15%	3.27%	3.45%	7.77%
Vectren Corporation	VVC	$ 51.72	$ 53.32	$ 55.03	$ 1.68	$ 1.76	9.00%	3.19%	3.29%	3.39%	12.29%
Wisconsin Energy Corporation	WEC	$ 57.90	$ 58.55	$ 59.38	$ 2.08	$ 2.14	6.00%	3.61%	3.66%	3.70%	9.66%
Mean							4.94%	3.42%	3.51%	3.60%	8.45%
σ							2.28%				
-1 σ							2.67%				
+1 σ							7.22%				

APPENDIX

I–N

Appendices I through N have been filed as Excel files separately in this docket.