Comments by Francis J. Cronin

In the matter
of the
Ontario Energy Board's

Comparison of Distributor Costs Consultation
on Consultant's Report (EB-2006-0268)

On behalf
of
Power Workers' Union

June 26, 2007

Executive Summary

On April 27, 2007 the Ontario Energy Board (OEB or Board) released for comment a report by Board staff consultant, Pacific Economic Group (PEG) on a methodology for comparing electricity distribution costs, "Benchmarking the Costs of Ontario Power Distributors". The Board noted that the release of the PEG report "is a step in the evolution of the Board's consideration and development of regulation of the sector." According to the Board, this report is a continuation of work on costs and cohorts begun in the 2006 Electricity Distribution Rate initiative with an October 2005 study conducted by Christensen Associates, "Methods and Study Findings: Comparators and Cohorts Study for 2006 EDR".

PEG's report recommends the use of econometric modeling and multivariate indexing "to compare relative distributor performance and also recommends that for the current analysis only aggregated operations, maintenance and administration (OM&A) costs be benchmarked." PEG also recommends that their benchmarking approach be used in the upcoming 2008 rate approval process to identify local distribution companies (LDC) that "merit expedited processing" or that require "especially thorough prudence reviews" based on their "favorable" or "poor scores" as determined by PEG's proposed benchmarking method. The Board also noted that, depending on the robustness of the techniques, potential uses of the comparative analysis could include: benchmarking expense levels; informing the development of incentive regulation (IR); and, in particular, in addressing the issue of variable, or utility-specific, productivity factors.

This report contains my comments on PEG's report and my recommendations on an approach to cost benchmarking of the Ontario electricity distribution LDCs prepared on behalf of the Power Workers' Union.

Given the intended ultimate use of these benchmarking techniques and their potential impact on an LDCs revenues, the benchmarking proposals must pass a two-part sufficiency test: first, in terms of whether or not the proposals are based on the precepts of accepted, rigorous, academic research; and, second, whether or not they are analytically structured to reflect an LDC's distribution business. In light of these considerations the PEG report's analysis and proposals are examined from the perspective of the following requirements that, they:

1. reflect the full extent and integrated nature of a utility's distribution business,
2. encompass cost measures reflective of a distributor's actual and total cost comparison, i.e., whether PEG's proposed cost benchmarks accurately depict the state of each utility's costs and relative efficiency,
3. specify cost measures that actually represent a consistently defined activity across LDCs in terms of their underlying costs, burdens and allocations,
4. reflect a breadth of methodologies to test for robustness in results, and
5. encompass specifications and sensitivity tests of inputs, outputs and cost/production relations that appropriately reflect the electric distribution business sensitivity.

Finally, evaluating whether a rate is just and reasonable requires that we consider the associated distribution service quality/reliability. Service quality/reliability varies among electric distributors and those utilities providing higher levels of service quality/reliability can be expected to have higher costs. Therefore, since service quality/reliability is part of distribution output that entails costs on the part of a utility, and service quality/reliability and its associated costs vary across utilities, the following requirement must be included:

6. consideration of service quality/reliability in any quantified multivariate output variable or other scheme used as a benchmark to assess a utility's production.

In assessing whether PEG's report meet these requirements, I examine:

1. the proposal to see if it spans a range of methodological approaches and sensitivity tests.
2. the proposed approach for the appropriateness of estimation techniques within the limited span of methodologies actually employed.

3. the model(s) to see whether their specifications appropriately reflect electricity distribution.
4. the robustness and appropriateness of the data used in the proposed models.
5. the role of reliability in PEG's proposal.
6. and, finally, based on recent advances in Service Quality Regulation (SQR), particularly in Europe, I discuss how the Board should integrate SQR into utility benchmarking.

There are a multitude of benchmarking methods available to researchers and it is essential to compare results using different methods to gain confidence that the method selected provides scores that are realistic, and not reflective of the method used. PEG uses only one technique and two variants of the technique. This failure to examine multiple widely employed benchmarking methods severely limits the confidence we can place in the results obtained using PEG's proposed method.

For the cost functions estimated by PEG, the explanatory variables are required to be outside the control of the LDCs whose costs are being estimated. Despite this requirement, PEG includes the following as explanatory variables: (1) the percent of wires placed underground; (2) the circuit miles of wire; and, (3) the number of transformers. The percent of wires placed underground is clearly under the control of LDC management or policymakers as it is determined by the LDC or shareholders. The circuit miles of wire and the number of transformers are to varying degrees under LDC discretion based on topology, system design and prices. Therefore all three categories are not truly outside of the control of the LDCs. As such their inclusion as explanatory variables in the model means that a more appropriate estimation technique such as two-stage least squares (TSLS) should have been employed to correct for effects that are outside of the LDCs control. PEG's proposed approach therefore does not rely on appropriate estimation techniques and seriously compromises statistical results.

Presumably, for the purposes of benchmarking total LDC performance one would employ a properly specified cost function with total cost as the dependent variable which the model would put on one side and, to explain the differences in costs, the model would put all input prices (i.e., capital, labour, line losses) and measures of output (i.e., number of customers and kWh and reliability) on the other side. With such a specification one obtains a complete picture of an LDCs' cost structure and all the associated complementary and substitute relationships among inputs. This information is critical as the cost shares of individual input components have been found to vary considerably between the Ontario LDCs. Therefore the model specifications should consider total cost and as such include capital, OM&A and line losses. Because PEG uses OM&A but does not use information on service quality and reliability it is an "apples to oranges" approach since an LDCs costs for reliability are included in OM&A. We can simply not make any sense out of a comparison that starts out with data of such a highly inconsistent nature.

Importantly, the use of OM&A as the benchmark means that, by definition, we can not examine the size and extent of allocative inefficiency (i.e., the cost of using say capital and labour in non-optimal proportions due generally to one input, say capital, having a non-market price for extended periods of time or receiving other regulatory, preferential treatment like rate basing contributed capital).

Historically, the Ontario distributors had achieved a robust rate of productivity growth (i.e., efficiency improvement), reaching 2 percent a year over the 1993 to 1997 period among a large cohort of utilities. In fact, across the industry the level of associated technical efficiency (which is the result of productivity change) had already achieved a superior level before the 2000 restructuring. Research found that by 1997, the average LDC had an almost 93 percent score on technical efficiency (meaning that on average the LDCs were only 7 percent less efficient then the most technically efficient distributor).[1]

[1] This research has its genesis in a paper originally prepared as a kickoff to a potential research program for the OEB for a yardstick regulation regime for Ontario LDCs, presented at the Canadian Economics Association 35th Annual Meeting at McGill University, Montreal, Quebec Footnote continued on next page.

Therefore, by 1999, it would appear that the LDCs had already achieved a superior level of efficiency with respect to OM&A and that at that time efforts to raise technical efficiency would be like raising a math grade from "A" to "A+." Maybe a better approach would be to identify areas where more effort might raise a grade from "C" to "B" or "B+."

What about allocative (in)efficiency? That research, however, also found that some utilities had a non-optimal mix of inputs (i.e., had become too capital intensive) and that these utilities could achieve significant allocative efficiency gains, (i.e., the cost savings from using inputs in more optimal combinations, usually in ratios of use that better track market input prices rather than the price of regulated inputs like capital). In terms of our grades above, this would receive a "C." *Non-optimal factor mixes, and the associated excess costs, are not reflected in productivity or technical efficiency statistics.*

In fact, the PEG report, like other recent Board staff and staff consultants reports seems to consider operational efficiencies as being synonymous with technical efficiency (i.e., achieving the maximum output to input ratio) while ignoring allocative inefficiency, traditionally a larger source of inefficiency. Researchers in other jurisdictions have found allocative inefficiency can be two to three times as large as technical ineffeciency. My research on Ontario LDCs also finds that to be true for some LDCs. Unfortunately, focusing attention on OM&A and ignoring capital costs would preclude any possibility of correcting the existent capital cost problem.

In order to correct the non-optimal input mix among some Ontario distributors, consideration of capital costs in the benchmarking approach is an essential requirement. Without information on the magnitude of both measures of inefficiency, we are flying blind in setting meaningful regulatory parameters.

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in June 2001: Frank J. Cronin and Stephen A. Motluk, "Inter-Utility Differences in Technical and Allocative Efficiency." This presentation is reproduced in Appendix E.

Rather than using the “conventional” and “rigorous” methodology for calculating the amount of capital used by an LDC PEG chooses a short cut expedient gross book value (i.e., GBV) that bears no resemblance to an individual LDC’s actual quantity of capital. *Worse, it actually shows some LDCs to use more capital than other LDCs when in fact they use less.* The effect of such data errors would likely cause the model to produce dramatically inaccurate results.

While PEG admits that power losses are a key distribution input, PEG does not include a critical input price, the price of power losses. This statistical problem, called “the problem of left out variables,” would result in wrong estimated impacts associated with the included variables. In addition, the lack of this price term (i.e., the price of line loses) means that we are not capturing key input relationships among input prices, including line loses, labour and capital, i.e., among the actual substitute-complementary relationships that actually exist for distribution utilities.

PEG mis-specifies the LDC output variable by including km of circuit wire as an output while km of line is an investment input. But unlike wires, PEG defines the number of transformers as an “Other Business Condition” presumably outside of the control of the LDC.

PEG also mis-specifies the LDC output variable by leaving out the level of reliability achieved by each LDC. We have discussed above the biases engendered by including reliability-related costs within OM&A but not including the reliability associated with such costs as an output. This is the “apples to oranges” comparison. But regulatory requirements regarding a just and reasonable rate also raise concerns here.

In sum PEG’s specified short-run function is seriously compromised. However, even if the specification and data issues could have been overcome, the specification employed by PEG assumes that capital is fixed, i.e., that it does not respond to changes in such important determinants as price. But, research on Ontario LDCs, indicates that capital does respond to altered circumstances, e.g., price or regulatory changes, and does so, even partially, within a 3 - 5 year period.

PEG should estimate a properly specified long-run cost function with correct data. This would allow a full range of input substitution-complementary relationships to be observed with their associated cost impacts. Estimating some form of frontier analysis based on properly specified total costs would also prove useful in developing appropriate regulatory benchmarks. Properly done, both models have something to offer in improving our understanding of these LDC costs issues and in answering key questions related to developing an appropriate regulatory framework. For example, given the distribution of estimated inefficiencies in the late 1990s, rate freezes or productivity targets would not necessarily be a productive framework for improving LDCs efficiencies.

In evaluating whether a rate is just and reasonable requires that we consider the associated distribution service quality/reliability. Service quality/reliability varies among electric distributors and those utilities providing higher levels of service quality/reliability can be expected to have higher costs. Therefore, since service quality/reliability is part of distribution output that entails costs on the part of a utility, and reliability and its associated costs vary across utilities, service quality/reliability must be included in any quantified multivariate output variable used as a benchmark to assess a utility's production.

The benchmarking approach proposed by PEG in ignoring service quality/reliability will likely penalize the high-reliability LDCs and reward the low-reliability LDCs. Such a backwards reward/penalty scheme could then incent the high-reliability LDCs to reduce their OM&A expenses to improve their benchmarking scores; reliability would most likely decline as well. This is not the result we would expect from a well-structured benchmarking scheme.

Imprudent curtailments in OM&A have been shown to significantly lower LDC reliability. Regulators in both North America and Europe have recently responded to profit-driven OM&A cuts with new regulatory initiatives. Below, we examine some of the critical interlocking relationships among incentive regulation (IR), profit motives, cost impacts, reliability, and benchmarking and the steps that regulators in other jurisdictions have taken, particularly the path breaking work on service quality regulation in Europe.

Both the experiences among North American as well as European energy regulators to this potential IR-induced, service degradation phenomenon are discussed. Among the former, following a series of significant outages often caused by imprudent reductions in OM&A expenses, regulators have increasingly imposed on their utilities mandates covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing necessary to fulfill the regulations.

In Europe, regulators such as the Council of European Energy Regulators (CEER) have encouraged the adoption of service quality/reliability regulation (SQR) which combines distribution continuity (i.e., reliability) standards with incentive/penalty schemes on revenues as well as single-customer guarantees with monetary payments for nonperformance.[2] CEER's benchmarking report on SQR for its 19 constituent members since 2002, notes that quality may have a "long recovery time after deterioration." and that quality of service is usually regulated over more than one regulatory period

Indeed, some regulators have taken "willingness to pay" (WTP) information from customer research and explicitly incorporated the customer interruption values into their distribution price regulation. That is, what would a customer pay to avoid an outage or improve service. Ofgem in the UK has set the penalties for its single-customer guarantee standards based on WTP surveys of residential and commercial/industrial customers.

[2]Council of European Energy Regulators (CEER), Third Benchmarking Report on Quality of Electricity Supply – 2005, Ref: C05-QOS-01-03, December, 2005.

This is a beginning step in attempting to have the distributors factor into their operational decisions the costs borne by customers.

In Norway, the regulator finds that the annual costs of customer interruptions are larger than the amount spent annually by distributors on OM&A and about 60 – 75 percent of the amount spent on investments. In this case, the regulator has specified a goal of achieving a socially optimal level of reliability by recognizing that customer interruption costs must be considered equally with a utility's capital and OM&A costs in utility planning and regulatory benchmarking.

In conclusion, PEG's analysis and proposals fail to meet the six requirements identified in that it does not take into account the full extent and integrated nature of a utility's distribution business. It does not encompass cost measures reflective of a distributor's actual and total cost comparison, nor specify cost measures that actually represent a consistently defined activity across LDCs in terms of their underlying costs, burdens and allocations. It fails to reflect a breadth of methodologies to test for robustness in results, and does not encompass specifications and sensitivity tests of inputs, outputs and cost/production relations that appropriately reflect the electric distribution business sensitivity. Last, but not least, service quality/reliability is not included in any quantified multivariate output variable used as a benchmark to assess a utility's production. Unless these short comings are addressed, especially those with respect to total costs and reliability, the Board should not proceed with benchmarking the costs of the electricity LDCs. PEG's proposed benchmarking includes perverse incentives and will likely lead to perverse results.

I am not suggesting that PEG's short cuts are inadequate in order to pursue a "perfect" benchmarking approach. Clearly the Board needs an approach that can be effectively implemented. However, in such an effort the Board should ensure that the approach does not result in perverse incentives and outcomes. It is dangerous to implement a scheme that is "not up to standard" and which could actually make things worse.

My recommendations are as follows:

- The original purpose of the baseline and annual PBR filings can, and should, still be fulfilled. The Board should move to update the initial PBR submissions with the subsequent annual PBR filings and distributors' submissions. This would provide the Board a world-class resource capable of more than adequately handling cost analysis, cost comparisons, and benchmarking among Ontario distributors.

- Given the risks to customers, shareholders, and LDCs associated with inadequate benchmarking regimes, the Board should not implement any benchmarking of Ontario LDCs until this can be done correctly, i.e., with the full, properly specified costs of distribution together with each LDCs reliability level as a foundation of the framework. Total cost benchmarking better reflects an LDC's cost structure and input choices, is more equitable, permits an evaluation of societal resource usage, and limits inappropriate regulatory incentive. The Board should develop the appropriate capital cost information necessary to properly benchmark Ontario electric utilities. A very good starting point is the 1999 PBR Baseline Surveys which covered decades of capital components and, as of that time, had calculated the total costs of distribution, including capital costs, for those LDCs in the 1999 Staff report as well as others. Even with the subsequent substantial mergers and amalgamations since 1999, the Board could update the initial PBR submissions with the subsequent annual PBR filings and other distributors' submissions.

- Proper benchmarking needs to include the correct measure of capital as described by PEG for "rigorous" analysis, but which PEG did not employ in the benchmarking approach recommended in their report. Capital is a critical infrastructure resource. The Board should not lay out inappropriate precedents inconsistent with proper cost analyses and benchmarking because the correct approach is time consuming and difficult. A past effort collected PBR capital data from the 1970s to 1997 and PBR operating/financial/demand data from 1988 to 1997, including "environmental" factors potentially affecting an LDC's performance. This effort was augmented by directed PBR filings among Ontario LDCs for at least the years 2001 and 2002. It is possible as well as preferable to update this data as must surely have been the intent in collecting the data from the LDCs on an on going basis. These critical data and what must mount up to thousands of man hours of effort expended collectively to compile, process and analyze this wealth of information should not be ignored. Updating the 1999 data would cost no more, and probably less, than efforts to start in 2007 and work backward. It is not clear if the latter approach is even feasible, and it would most certainly produce less robust data and almost certainly take longer to complete.

- Benchmarking for regulatory incentives/penalties should be done on a utility's total costs. Use of partial cost measures whether it be OM&A or capital suffers from the fact that some inputs are substitutes and LDCs combine them in different ways. Without a correct measure of capital to examine, OM&A costs can and do present biased results of LDC performances since they reflect inconsistent approaches to labour burdens and capitalization. Even adjusting the reported OM&A for allocations differences will still not present a plausible efficiency result since many combinations of capital and labour can be employed by equally efficient utilities. In addition, LDCs have different levels of reliability and different levels of associated costs, i.e., higher reliability costs more. When we observe different OM&A costs among Ontario LDCs without the associated reliability information, we can not assume that an LDC with higher OM&A is less efficient, it may simply be providing a higher-valued output for its customers. This difference among LDCs with respect to reliability needs to be accounted for just as does the differing labour capitalization rate.

- The issue of scale economies seems to have become an unnecessary preoccupation by policy makers and regulators. Research supports the conclusion that there are no substantial unrealized economies of scale in the Ontario distribution sector; rather, there may be diseconomies. A market-based, policy-neutral merger framework should be adopted. NVE's conclusion appears reasonable for Ontario as well: "As far as NVE is aware, there are as yet no scientific studies of unrealized efficiency gains related to economies of scale within the Norwegian electricity transmission and distribution sector. Even if NVE had the power to dictate mergers, this would probably not lead to the most efficient solutions."

- Due to the distortions caused by non-market prices for capital, it is essential that benchmarking cost measures reflect the full set of factor input choices and their associated costs. Conventional measures of capital costs must be calculated and included for efficient and equitable cost comparisons among Ontario LDCs.

- Service quality/reliability must be included in any quantified multivariate output variable used as a benchmark to assess a utility's production integrating utility cost benchmarking with service quality and reliability regulation. Although the Board's work to establish meaningful service quality standards was prematurely curtailed, it is abundantly clear that a substantial amount of work has already been accomplished. We should not now be debating the need to implement meaningful standards, nor their integration into an IR framework, but rather the manner in which this should be done. European regulators have made substantial progress in the area of service quality standard implementation. The Board can use these standards, presented in Appendix B, to help guide its efforts.

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1 Introduction

On April 27, 2007 the Ontario Energy Board (OEB or Board) released for comment a report by Board staff's consultant, Pacific Economics Group (PEG), on a methodology for comparing electricity distributor costs, "Benchmarking the Costs of Ontario Power Distributors" (the PEG report). The Board noted that release of the PEG report "is a step in the evolution of the Board's consideration and development of regulation of the sector." According to the Board, this report is a continuation of work on costs and cohorts begun in the 2006 Electricity Distribution Rate initiative with a October 2005 study conducted by Christensen Associates, "Methods and Study Findings: Comparators and Cohorts Study for 2006 EDR" (the Christensen report).

This report contains my comments on PEG's report and recommendations on an approach to cost benchmarking of the Ontario electricity distribution LDCs prepared on behalf of the Power Workers' Union.

The PEG report recommends the use of econometric modeling and multivariate indexing "to compare relative distributor performance and also recommends that for the current analysis only aggregated operations, maintenance and administration (OM&A) costs be benchmarked." PEG also appraised staff's distributor peer grouping and cost benchmarking.

The Board also noted that:

> Depending on the robustness of the techniques, potential uses of the comparative analysis could include:
> - screening rate applications (similar to 2006);
> - supplemental information available to parties in rate rebasing proceedings (e.g., as a basis for formulating interrogatories);
> - benchmarking expense levels; and
> - informing the development of incentive regulation, and in particular the issue of variable, or utility-specific, productivity factors.

The Board has invited comments on the PEG Report. In particular, the Board has noted its interest in comments on:

- the application and value of benchmarking in ratemaking;
- the relative merits of PEG's and Board staff's proposed benchmarking methodologies; and
- any alternative methodologies that the Board should consider (including the rationale for the alternative and how it might be implemented).

Finally, the Board notes that the PEG report

> recommends some improvements in data capture, including the collection of certain additional capital expenditure data. Some of this information may already be on file with the Board as part of a distributor's rate application filings. It would be of assistance if interested parties could suggest alternatives for the timing and manner of collection of the additional data should the Board decide that collection of additional data is warranted.

In this review, the report's analysis and proposals are examined from the perspective of the following requirements in particular that, they:

1. reflect the full extent and integrated nature of a utility's distribution business,
2. encompass cost measures reflective of a distributor's actual and total cost comparison, i.e., do PEG's proposed cost benchmarks accurately depict the state of each utility's costs and relative efficiency,
3. specify cost measures that actually represent a consistently defined activity across local distribution companies (LDC) in terms of their underlying costs, burdens and allocations,
4. reflect a breadth of methodologies to test for robustness in results, and
5. encompass specifications and sensitivity tests of inputs, outputs and cost/production relations that appropriately reflect the electric distribution business sensitivity.

Finally, evaluating whether a rate is just and reasonable requires that we consider the associated distribution service quality/reliability. Service quality/reliability varies among electric distributors and those utilities providing higher levels of service quality/reliability can be expected to have higher costs. Therefore, since service quality/reliability is part of distribution output that entails costs on the part of a utility, and reliability and its associated costs vary across utilities, the following requirement must be included:

6. consideration of service quality/reliability in any quantified multivariate output variable or other scheme used as a benchmark to assess a utility's production.

2 Benchmarking Ontario Utility Distributors Must be Reflective of the Full Extent and Integrated Nature of Electric Distribution

In this section the need to reflect the full extent and integrated nature of the electricity distributors in a cost benchmarking approach by using a comprehensive measure of capital cost is established. In doing so, first, an overview of recent benchmarking considerations for the Ontario LDCs is provided. The availability of data for a comprehensive, conventional and rigorous benchmarking approach is then identified. Finally, the Board's 1999 consultation process used in the determination of Ontario LDCs' efficiency based on a comprehensive approach for the first generation performance based regulation (PBR) plan is described. This process is presented as a way of overcoming a critical gap in PEG's benchmarking in particular in the use of a properly specified measure of capital cost.

2.1 *Overview and Background of Benchmarking Ontario Distributors*

Since the first generation PBR implementation in 1999-2000 Board staff consultants, and Government have issued discussion papers, reports, and recommendations on PBR, incentive regulation (IR), and benchmarking. These include:

- Board Staff Discussion Paper, "Review of Further Efficiencies in the Electricity Distribution Sector," February, 2004. (2004 Staff report)
- Ontario Ministry of Energy, "Electricity Transmission and Distribution in Ontario — A Look Ahead", December 21, 2004. (EDTO)
- Christensen Associates, "Methods and Study Findings: Comparators and Cohorts Study for 2006 EDR, October, 2005. (the Christensen report)
- Pacific Economics Group, "Benchmarking the Costs of Ontario Power Distributors," April, 2007. (the PEG report)

The 2004 Staff report detailed the Board's thoughts on achieving further efficiencies in the distribution sector. As noted in the Paper, "the Board's objective is to consider if further efficiencies are available, and if so, how to achieve them. … the paper identifies approaches available to the Board to drive further efficiencies in the electricity distribution sector." Consistent with the theme of government over the last decade, the paper places a heavy reliance on mergers and achieving scale but offers little to substantiate the savings expectations.

The 2004 Staff report seems to consider operational efficiencies as being synonymous with technical efficiency (i.e., achieving the maximum output to input ratio) while ignoring allocative inefficiency, traditionally a larger source of inefficiency (i.e., having the wrong mix of resources given relative prices, e.g., too much capital based on capital costs that were below market capital costs). Allocative inefficiency can be two to three times as large as technical inefficiency.

Finally, the paper seems to make the same assumption that most restructurings have made over the past twenty years: *the regulator will find and correct existing inefficiencies and determine just what further efficiencies are feasible.*

Indeed, a recent paper examined the asymmetric problem facing regulators: despite the best of efforts the regulator can never have the kind and quality of information and insight held by the firms being regulated. What the regulator can do to overcome this inherent and universal deficiency is to implement true yardstick competition among the firms creating competition among similarly situated firms in which the best practice firms establish the benchmark. Operational improvements by the utilities relative to this benchmark are determined subsequently by the endogenous pursuit of efficiency by firms in the "market."[3] However, this scheme assumes that the benchmark costs are properly and fully specified.

In the ETDO report, the Ontario Ministry of Energy noted its perception of a lack of measures upon which to benchmark utilities:

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[3] Cronin, F. J. and Motluk, S. A., "The Road Not Taken: PBR with Endogenous Market Designs," *Public Utility Fortnightly*, March, 2004. An earlier version of this paper was presented at the Michigan State University, Institute for Public Utilities Annual Regulatory Conference, Charleston, S.C. December, 2003.

> one important challenge facing the distribution sector is the lack of formal measurement of efficiency gains in the sector…Stakeholders have suggested that the regulator should determine areas where efficiencies and inefficiencies exist and develop benchmarks, efficiency targets, and performance measures.

This was also the conclusion among most stakeholders in the first generation PBR process almost 5 years earlier (discussed further in section 2.3 below). But, economists have long had straightforward measures of efficiency: the primary roadblock to their implementation has been the availability of properly specified and collected data, including both properly specified capital and Operating, Maintenance and Administrative (OM&A) costs. But, the ETDO report, the 2004 Staff report, the Christensen report, and now the PEG report, largely focus their attention on only OM&A costs. These reports maintained a myopia on OM&A costs. Unfortunately, this myopia deals with the wrong issue (i.e., OM&A) and ignores the issue (i.e., capital and allocative inefficiency) that really does need to be corrected.

Historically, the Ontario distributors had achieved a robust rate of productivity growth (i.e. efficiency improvement), reaching 2 percent a year over the 1993 to 1997 period among a large cohort of utilities. In fact, across the industry the level of associated technical efficiency (which is the result of productivity change) had already achieved a superior level before the 2000 restructuring. Research found that by 1997, the average LDC had an almost 93 percent score on technical efficiency (meaning that on average the LDCs were only 7 percent less efficient than the most technically efficient distributor).[4] Therefore, it would appear that the LDCs have already achieved a superior level of efficiency with respect to OM&A and that the further pursuit of OM&A efficiency would be inappropriate.

[4] This research has its genesis in a paper originally prepared as a kickoff to a potential research program for the OEB for a yardstick regulation regime for Ontario LDCs, presented at the Canadian Economics Association 35th Annual Meeting at McGill University, Montreal, Quebec in June 2001: Frank J. Cronin and Stephen A. Motluk, "Inter-Utility Differences in Technical and Allocative Efficiency." (see Appendix E)

However, that research also found that some utilities had a non-optimal mix of inputs (i.e., had become too capital intensive) and that these utilities could achieve significant allocative efficiency gains, (i.e., the cost savings from using inputs in more optimal combinations, usually in ratios of use that better track market input prices rather than the price of regulated inputs like capital)[5]. Non-optimal factor mixes are not reflected in productivity or technical efficiency statistics. Unfortunately, focusing attention on OM&A and ignoring capital costs would preclude any possibility of correcting the existent capital cost problem. In order to correct the non-optimal input mix among some Ontario distributors, consideration of capital costs in the benchmarking approach is an essential requirement.

2.2 *The Proposed Benchmarking of Electric Utilities Ignores the Existence, Extent, and Importance of Allocative Inefficiency*

A firm's efficiency or, conversely inefficiency, can be decomposed into two parts. First, technical efficiency which measures the ability of the firm to produce the maximum output for the inputs selected. It is changes in technical efficiency that we measure when we calculate changes in total factor productivity. Second, allocative efficiency which measures whether the firm has selected the optimal combination of inputs given its production function and the prices of inputs. Without information on the magnitude of both measures of inefficiency, we are flying blind in setting meaningful regulatory parameters.

Measuring Inefficiencies

Following Farrell[6] and others, suppose we have an industry that uses two inputs, x_1 and x_2, to produce one output, y, under the assumption of constant returns to scale (CRS). If the unit isoquant of the efficient firm is known, technical or productive efficiency (TE)

[5] Potential allocative efficiency gains have been documented by numerous utility research studies because utilities often are faced with non market price for capital. Furthermore, allocative inefficiency has been found to be a substantially more significant problem among utilities in numerous jurisdictions (e.g., US, Canada, and Japan).

[6] Farrell M.J, "The Measurement of Productive Efficiency," *Journal of the Royal Statistical Society*, Series A, Part III, Vol. CXX (1985): 253-290.

can be determined. In Diagram 1, SS′ represents the unit isoquant of the efficient firm.

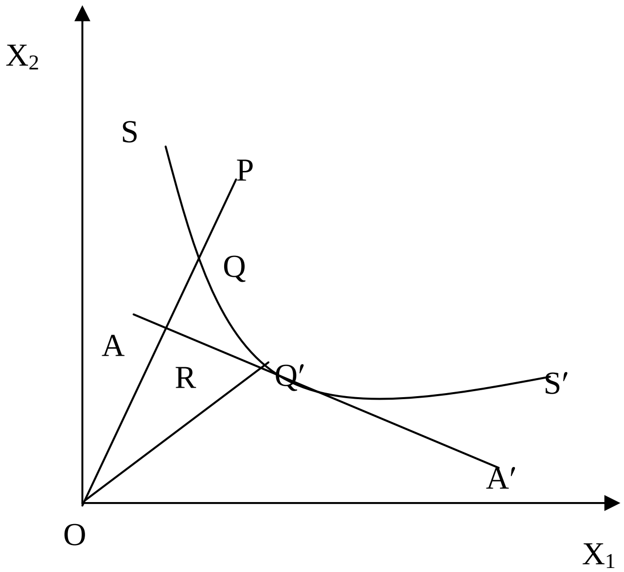

Diagram 1 – Farrell Efficiency Measures

If a firm produces a unit of output using quantities of inputs x_1 and x_2 defined by point P, the distance QP represents the technical inefficiency of that firm (i.e., both inputs could be reduced proportionately by QP without a reduction in output). In percentage terms, the firm's technical efficiency can be represented by the ratio OQ/OP and the firm's technical inefficiency is the ratio QP/OP (1 – OQ/OP). If TE = 1, the firm is fully technically efficient and is producing on the isoquant SS′ (for example, point Q)[7].

Allocative efficiency (AE) can also be measured if the input price ratio is known, i.e., by the slope of the isocost line AA′ in Diagram 1. The AE of the firm operating at point P can be represented by the ratio OR/OQ, and the allocative inefficiency represented by RQ, which is the savings the firm could realize if it produced at point Q′. The firm is both allocatively and technically efficient, if it produces at point Q′. Total economic efficiency (EE) of the firm producing at point P can be represented by the ratio OR/OP =

[7] An isoquant is a contour line drawn through sets of points representing inputs at which a firm's output remains constant while the quantities of the input change. Isoquants deal with cost minimizing behavior and are often depicted with capital and labour on the axes. Isoquants show the firm's ability to substitute between the two inputs and still hold output constant.

$(OQ/OP)\cdot(OR/OQ) = TE\cdot AE$.

In fact, given the incentives which exist under rate of return/cost of service regulation, researchers have often found that among utilities allocative inefficiency is substantially larger than technical inefficiency. Furthermore, research has also often found that regulated firms such as utilities are overcapitalized, that is their total costs could be lowered by decreasing the amount of capital employed and increasing other inputs such as labour. IR or benchmarking plans that focus exclusively on Total Factor Productivity (TFP) or OM&A costs may improve technical inefficiency at the margin but will do little to improve input selection. It would seem that the proposal in the PEG report completely ignores the potential for significant allocative inefficiency as well as any examination of an appropriate adjustment period.

The Incentive to Over Capitalize

The issue of overcapitalization had been examined by a number of studies including Courville (1975),[8] Petersen (1975),[9] and Spann (1974).[10] Fare et al, (1985) find allocative inefficiency to be a substantially greater problem than technical inefficiency for utilities.[11] The authors employ 1970 data on U.S. electricity utilities. While their focus is on generation, it is significant to note that the authors find technical efficiency to average about 75 percent but allocative efficiency to average only 29 percent. The authors conjecture that utilities are minimizing with respect to shadow rather than market prices, i.e., these firms are basing input decisions on the regulated price of capital not the market price.

[8] Courville, L., "Regulation and Efficiency in the Electric Utility Industry," *The Bell Journal of Economics,* Spring 1975:53-74.

[9] Petersen, H., "An Empirical Test of Regulatory Effects," *Bell Journal of Economics and Management Science,* Spring 1975: 111-126.

[10] Spann, R., "Rate of Return Regulation and Efficiency in Production: An Empirical Test of the Averch-Johnson Thesis," *The Bell Journal of Economics,* 5 (Spring 1974): 38-52.

[11] Fare, R., S. Grosskopf, and J. Logan, "The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities," *Journal of Public Economics* 26 (1985): 89-106.

More recently, Nemoto and Goto use data from 1981 to 1998 for 9 Japanese electricity transmission and distribution utilities.[12] As the authors note, without information on total (in)efficiency, the regulators will not be able to properly gauge the extent of potential cost improvement.

> Without allocative efficiency, it is impossible to measure how much costs could be saved if all inputs would be used optimally. However, the regulator needs information on reducible costs to provide sufficient incentives for a firm to produce on the efficient frontier.

Indeed, they find widespread inefficiency: "results show that observed costs are 9 to 40 percent higher than the efficient level… We also find substantial over-utilization of capital for all utilities….This is consistent with the Averch-Johnson effect…"

> …the transmission-distribution sector of the Japanese electric sector utilities over-utilized capital relative to labor and vice versa under-utilized labor relative to capital….The most efficient utility is Shikoku that over-utilized capital by 36 to 41 percent and under-utilized labor by 41 to 42 percent…Tokyo, the most inefficient utility, over-utilized capital by 61 to 69 percent and under-utilized labor by 55 to 56 percent. Interestingly, there is a tendency for larger utilities to behave more inefficiently.
>
> This overcapitalization is consistent with the rate of return regulation applied to Japanese electric utilities in the period analysis. The overcapitalization during the 1981- 1998 period is also consistent with the fact that Japanese electric utilities have curtailed expenses for investment in fixed assets since the market was partially liberalized in 2000…

The authors also address the issue of returns to scale among the electric utilities in their sample. They find that "the scale elasticities are not significantly different from one, indicating constant returns to scale." By CRS, economists refer to a situation in the production of a commodity or good whereby doubling all inputs would exactly double

[12] Nemoto, J. and M. Goto, Estimating a CES Cost Frontier with Panel Data: an Application to Japanese Transmission-Distribution Electricity," paper presented at the North American Productivity Workshop, Union College.

output, holding the state/level of technology constant. This means that firms of all sizes are equally efficient with no economies or diseconomies of scale. In the case of the Japanese utilities, these results mean that the smaller utilities in the sample were just as efficient as the large, or, put the other way, the large utilities in the sample were just as efficient as the small utilities.

2.3 *The PEG report and the "Special Challenges" Related to the Development of Capital Costs*

The PEG report purports that capital costs present "special challenges" (p iii). As discussed above in section 2.2, PEG claims that the issue of capital costs is adversely affected by the lack of good capital data in Canada, unlike in the U.S (p 32). Given these "challenges," PEG seems to postpone indefinitely the objective of total cost benchmarking of electric distributors.[13]

The PEG report focuses largely on OM&A costs and states:

> We are particularly concerned about the inability of current methods to control for differences between distributors in customer mix, capital usage, system age, and deliveries to other distributors. There are noteworthy deficiencies in the data available for benchmarking. (p vi)

If true, this implies that both LDC outputs and capital data have serious biases before PEG even begins their analysis.

Rather than trying to overcome the perceived lack of capital data, which would indeed be a critical deficiency in benchmarking if left unresolved, PEG recommends the following approach which does little to overcome their stated challenges:

[13] On the other hand, PEG seems to have little difficulty in collecting the relevant data to calculate capital stock of the major gas distributors in Ontario. Interestingly, in 1999 the OEB received 285 PBR filings that covered dozens of variables related to utility performance. Many of these utilities also filed capital component data that permitted Board staff and staff's consultants to develop capital stock, capital input and capital prices for 20 years. This was documented in the 1999 Staff report.

> Board staff have developed an approach to the benchmarking of power distributor cost that features simple unit cost metrics (*e.g.* cost per customer)… This approach should be upgraded if it is to be used in ratemaking. Two steps are especially essential:
>
> 1. Focus on the cost of total OM&A expenses for the next round of rate cases.
> 2. Instead of simple unit cost metrics, use unit cost indexes with multidimensional output quantity treatments such as those that we have developed from our econometric work. The Board should also consider replacing or supplementing indexing with direct econometric cost benchmarking. All of these steps can be implemented now in time for use in the upcoming EDR applications. (p v.)

Indeed, later in their report PEG states that capital quantities and costs are unavailable for Canada:

> Benchmarking is also complicated by the unavailability of important data. One major problem is the unavailability of good capital data. Adequate data for the calculation of standardized capital costs and quantities are not available for Canada or most other countries of the world. The United States is a prominent exception to this rule since detailed capital cost data have been reported there by major investor-owned utilities for decades.

However, the above statement does not appear to be accurate. At least in Ontario, both the major gas distributors and the electric distributors have maintained detailed capital records for years.

PEG's Use of Capital Data from Ontario Gas Distributors

For the gas utilities (i.e., Union and Enbridge), PEG employed capital data from both companies in their analysis provided in the Ontario Energy Board's key initiative, the **Multi-Year Incentive Rate Regulation for Natural Gas Utilities (EB-2006-0209).** In its report, "Price Cap Index Design for Ontario's Natural Gas Utilities" (Gas IR report) PEG documented both the capital cost data and methodology used in their analysis.

In the Gas IR report (p 21-22), PEG details their cost approach and calculations for Ontario gas distributors:

> The cost of capital was calculated using two approaches: geometric decay ("GD") and a novel approach to capital costing that is designed to reflect how capital cost is calculated under cost of service ("COS") regulation. The GD approach is the one that PEG conventionally uses in its productivity research and that consultants for Union Gas used in its previous PBR proceeding. This approach features replacement (current dollar) valuation of utility plant and a constant rate of depreciation. The value of plant increases each year at the same rate as construction costs. However, cost is calculated net of any resulting capital gains. The salient features of the COS approach to capital costing are a book (historic dollar) valuation of plant and straight line depreciation. The comparative advantages of these approaches are discussed further in section 2.5 below.

It is interesting to note that PEG states that the GD approach is what is conventionally used in their work and was used by Union's consultants in an earlier PBR filing with the OEB.[14] That being said, neither the GD nor the COS approach is used in the PEG report.

> Both capital costing methods require the decomposition of cost into a price and a quantity in order to calculate industry input price and productivity trends. The cost of capital is thus the product of a capital quantity index and an index of the price of capital services. This "service price" approach to capital costing has a solid basis in economics and is well established in the scholarly literature. The capital quantity index is, effectively, an index of the real (inflation-adjusted) value of plant where indexes of utility construction costs are used as deflators. The capital service price indexes include, for both approaches to capital costing, terms for opportunity cost (return to debt and equity holders) and depreciation.

Thus the Gas IR report notes that the "service price" approach to capital cost has a "solid basis in economics… and scholarly literature" just as PEG noted that this was the "rigorous" approach. This was the approach used in the 1999 Ontario Energy Board Staff Report, *Productivity and Price Performance for Electric Distributors in Ontario*[15] (1999 Staff report). The service price approach to capital costing calculates annual cost of capital (i.e., expenses) from a calculated stock of capital (i.e., quantity).

Decades of Detailed Capital from Ontario Electric Distributors

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[14] RP-1999-0017

[15] Cronin, F.J., et al, 1999, *Productivity and Price Performance for Electric Distributors in Ontario*, Ontario Energy Board Staff Report.

In the case of the Ontario electricity LDCs, PEG's statement about the lack of capital data in Canada is also surprising since the LDCs have historically maintained detailed capital components data (i.e., GBV, depreciation, additions, and retirements) as well as highly detailed investment by category for decades under their previous regulator, Ontario Hydro. In addition, in developing the first generation PBR plan for the electricity LDCs, the Board requested PBR cost data filings in 1999 that included pertinent capital cost information (described in section 2.4 below). During the development of the first generation PBR, OEB staff and staff's consultants identified the existence, consistency and value of this information. Indeed, it proved to be of critical importance in a broad selection of cost, cost shares, productivity, efficiency and cost modeling research. In consultation with stakeholders, Board staff and staff's consultants concluded that this detailed capital cost and investment data covered decades of activity in a consistent format. Exhibit 2.1 presents a slice out of the capital tables compiled by Board staff and staff's consultants during the development of first generation PBR and which are presented in the 1999 Staff report. The complete table is reproduced from the 1999 Staff report in Appendix D1-D3.

In both the Gas IR report and the PEG report, PEG notes the superior ability of the "service price" approach to reflect capital cost as having a "solid basis in economics… and scholarly literature" and as a "rigorous" and "conventional" approach. Furthermore, the existence of the required capital data for the service price approach as described above is well established. Yet, despite their observations on the service price approach and the availability of the capital data requirements for this approach, PEG opts for an inappropriate short cut approach based on LDC's GBV. PEG offers no explanation for selecting an approach that is neither "conventional" nor "rigorous". Furthermore, having decided to pursue an inadequate methodology on capital costs, PEG undertakes no analysis to examine the consequences on using the GBV approach on its calculated capital costs for individual LDCs relative to the conventional service price approach. Since capital costs constitute almost half or more of some of the LDCs costs it is imperative that this analysis is undertaken to justify the use of the GBV approach over the service price approach.

In section 4, below some observations and conclusions are discussed: it is highly likely that the use of GBV produces sizeable distortions between the calculated capital based on GBV and the conventionally calculated capital used in scholarly research. These distortions could lead to errors of 100 percent or more depending on the LDC's system age, with older systems likely experiencing the largest distortions.

Exhibit 2.1: PBR Data Collected in 1999. Gross Book Value, Depreciation, Amortization, Retirements, and Additions; Capital Investment Category 1973 to 1995

	Gross Book	Depreciation Expense	Amortization Expense	Retirements	Additions Total	Land	Land Rights	Buildings & Fixtures
1973	11,417,589	348,783	0	14,873	2,619,551	0	683	1,248
1974	12,233,949	344,925	0	35,570	852,591	51,513	3,060	3,215
1975	13,672,265	395,944	0	89,662	1,523,535	0	338	0

Exhibit 2.1: PBR Data Collected in 1999. Gross Book Value, Depreciation, Amortization, Retirements, and Additions; Capital Investment Category 1973 to 1995, continued

	Generating Assets	Transmission Line	Transmission Station Equipment	Distribution Station Equipment	Sub Feeder Overhead	Sub Feeder Underground	Distribution Lines Overhead	Distribution Lines Underground
1973	0	0	173,954	0	64,476	0	100,952	191,048
1974	0	0	29,717	0	19,002	0	122,195	176,094
1975	0	0	239,067	0	25,995	0	320,098	371,041

Exhibit 2.1: PBR Data Collected in 1999. Gross Book Value, Depreciation, Amortization, Retirements, and Additions; Capital Investment Category 1973 to 1995, continued

	Leasehold Improve	Rolling Stock	Misc Equipment (Tools, Meter read)	Water Heaters	Load Management Control	System Supervisory Equipment (SCADA)	Sentinel Lights	Contributed Capital/Develop Charges
1973	0	46,103	2,264	76,518	0	0	647	0
1974	0	96,389	24,168	86,925	0	0	0	0
1975	0	70,748	22,657	115,597	0	0	0	0

Source: 1999 Staff report.

2.4 *The Yardstick Task Force*

As far back as 1999, the overwhelming consensus among stakeholders in the first generation PBR implementation process and the Yardstick (or Benchmarking) Task Force members in particular was that appropriate utility benchmarking should be instituted as part of the second generation PBR. However, as reviewed by the Yardstick

Task Force during the winter of 1998-1999 and endorsed in their Report,[16] such benchmarking should be done on the totality of a utility's costs including capital. Therefore, it was imperative that the Board build on the PBR data collected in the 1999 PBR cost/information filings[17] through the continued requirement for annual PBR data filings which the LDCs file with the Board.

PEG reports (p 32):

> At current input prices, capital inputs typically account for between 45 and 60 percent of the total cost of local power delivery and constitute the single most important input group. Capital inputs play important roles in utility operations. They are especially important in network businesses like power transmission and distribution. In these businesses, capital typically accounts for half or more of total cost. It follows that, in the long run, the success utilities have at holding down their costs depends greatly on their management of capital costs. (p 22)

Yet, despite the availability of appropriate capital data, PEG recommends the use of only OM&A as an appropriate yardstick for use in the upcoming electricity distribution rate applications. Such benchmarking would be used initially to identify superior performing utilities and underperforming LDCs. In the short run, these improperly identified "less efficient performers" will be subjected to prudence reviews and even more stringent and adverse consequences in the future.

2.5 The 1999 PBR Baseline Filings

In this section the consultations and data collection considerations and process used to obtain the 1999 PBR data used in the 1999 Staff report is described to illustrate the adequacy of the baseline date available to the Board for a comprehensive, conventional and rigorous approach to the benchmarking of the LDCs.

[16] Yardstick Task Force Final Report, OEB, May 1999.
[17] These filings covered hundreds of LDCs and involved two sets of data. The first covered cost, financial and operating data covering outputs, inputs and prices including complete coverage of capital cost components. The second covered the characteristics of each utility and its service territory.

As documented in the 1999 Staff report, total cost benchmarking was carried out for 48 of Ontario's large, medium and small utilities in existence at that time. This analysis found that capital, properly measured, accounts for between about 35 to about 60 percent of an LDCs total costs. Line losses, also ignored by PEG were found to account for another 6 to 20 percent.

These extensive PBR filings covered both utility characteristics and service area features as well as operating, financial and capital data. For the PBR Yardstick Filing, the OEB received responses from 285 LDCs covering dozens of items such as: area; peak load; power factor seasonality; transformer, distribution, voltages, transmission, and generation assets, etc as well as special features noted by individual utilities (see Appendix C for data requested).

The PBR Operating Cost and Capital Data filing covered dozens of variables related to utility performance over a 10 year period: including operating data covering all forms of utility output (e.g., kW, kWh, number of customers), revenues by class, all utility inputs including labour, materials, line losses, and capital, as well as input prices. The PBR data also included information on capital stock, additions, depreciation, and retirements generally for a 20 year record. The PBR capital data also included close to a 20 year record of investments by category including transformers, meters, lighting, stores, office equipment, computers, rolling stock, etc. See Appendix D1 to D3 for one of these filings.

The PEG report does make a brief reference to the post 1999 PBR filings that were mandated to enable the OEB to update the initial 1999 PBR filings.

> A potentially important supplemental source of Ontario cost data is the Performance Based Regulation ("PBR") reports. These are prepared annually by distributors as provided for under Section 2.1.5 of the Board's RRRs. (p 37)
>
> The PBR data also include information on output, revenue, and utility characteristics. Data on billed kWh, billed kW, total revenue, and the number of customers served… (p 37)

> PBR data include, as well, the total wholesale and retail kWh…. Data are also available on…characteristics of a distributor's network and service territory… (p 38)

As discussed in the 1999 Staff report (p 7):

> Deployed capital in distribution networks can and does last for many decades. In addition, distribution utilities have deployed capital at various times. Therefore, in constructing the capital quantity index we need to account for both these facts in order to consistently measure a utility's use of capital. Thus, we need to start (i.e., pick our benchmark year) decades ago to capture the deployment of capital accurately, to adjust capital deployed prior to our start date (i.e., our benchmark year) for asset price changes, and, to adjust subsequent additions and retirements for such changes in price.

2.6 Stakeholder Input during the PBR Process

Unfortunately, the PEG report makes no mention of the 1999 Baseline PBR yardstick and operating/capital cost filings. These filings were fashioned based on stakeholder feedback on an approach to PBR for Ontario electricity LDCs received at two OEB kickoff workshops and ten subsequent OEB regional workshops during the fall and early winter of 1998. During these workshops, participants provided the OEB their input and feedback.

Following these workshops and, based in part on them, Board staff consultants assisted the OEB in preparing a survey of LDCs directed at information on costs and cost drivers. In their responses to this request, LDCs and other stakeholders provided important feedback including detailed information on "yardstick" characteristics and circumstances that the utilities believed affected their operations and costs. Board staff consultants examined this information and together with the other survey findings, assisted in the presentation of this data at five regional workshops (i.e., London, Thunder Bay, Sudbury, Ontario and Kingston) in November of 1999 attended by representatives from most of the LDCs and other stakeholders.

LDC responses noted the varying operational characteristics (i.e., environmental circumstances and situations) and how they varied across the utilities. These circumstances included but were not limited to: density, customer class loads, geographic (e.g., distance, service territory configuration), geologic, legacy systems (e.g., multiple and diverse distribution systems), and of course size since the utilities ranged from hundreds to hundreds of thousands of customers.

Following additional examinations of the varying circumstances facing electric distribution utilities in Ontario, a Staff report was published in December 1999, offering preliminary thoughts on possible approaches. During the latter part of this phase, it became apparent that extensive as well as intensive outreach would be required on the part of the OEB. Consultations led to the formation of 4 Task Forces, including one on Yardstick Competition (Yardstick Task Force).

The Yardstick Task Force addressed the issues of desirability, form, requirements, data, coverage and consequences for benchmarking. Significant exploratory examinations of existing data filed with the previous regulator, Ontario Hydro, were undertaken. The Yardstick Task Force reached critical conclusions, which shaped the considerations of the feasibility of yardstick competition at that point in time.

The Yardstick Task Force examined a multiplicity of implementation and design issues. The group worked along two parallel paths. First, the group developed a survey instrument covering dozens of environmental or characteristic factors which were deemed to have a potentially material impact on costs - - and were to some degree beyond management's control. Second, the group intensively examined the pros and cons of varying design issues (e.g., approach or formula to apply) as well as such implementation issues as which LDCs to include in what groups.

Extensive examinations and discussions were held on the range of approaches including the use of simple averages, distributional rankings, and data envelopment analysis (DEA) among others. Extensive discussions were held on the issue of technique versus transparency, that is, on the practicality of the approaches.

The Distributor Cost and Productivity Data Base: The PBR survey was designed to collect the necessary financial, economic, and operating data by time period from individual distribution utilities to augment the information reviewed and collected from such sources as Statistics Canada, Ontario Hydro Annual Statistical Yearbooks on the Ontario Municipal Electric Utilities, and Hydro One's LDC financial database (MUDBANK). This request to the distribution utilities covered information on:

- Demand by customer class for revenue and usage for 10 years
- Customer numbers by class for 10 years
- Expenses in total and by category for 10 years
- Labour compensation and employment for 10 years
- Line losses and total energy purchases for 10 years
- Capital costs covering as much as a twenty- year history for stock, additions, retirements, depreciation, and contributions
- Capital additions by asset category

This information was then combined with information from the former Municipal Electric Association (wage rates), Statistics Canada (bond rates, capital asset prices for distribution network components), and the Ontario Hydro Annual Reports.

Functional Expenditure and Capitalization Analyses: Originally, the Staff Report contained results for 40 utilities. Ultimately, full costs, productivity and price calculations were performed on 48 LDCs. As part of the analysis, detailed data was collected from a smaller sample of utilities focusing on such potentially important issues as functional expenditures (e.g., administration, billing and OM&A) and the policies and procedures for "capitalized labour" and capital allocations to OM&A. That is, how much non capital input is bundled into capital and how much capital is bundled into OM&A.

The Staff Report on Costs and TFP: The 2004 Staff report laid out the calculations underpinning costs, TFP and input price index (IPI) and provided an extensive real world application to an actual LDC in the ten-page Appendix. The Report contained significant findings documenting the wide variance in costs per customer across the LDCs. The Report documented many of the sensitivity tests conducted by Board staff consultants on such parameters as weighting schemes, factor input inclusion (e.g., line losses), and utility size.

2.7 *Model of Electricity Distribution*

The PEG report describes the distribution business and related inputs as follows:

> Power flows to the customer through wire conductors. Other capital inputs used in local delivery include poles, conduits, station equipment, meters, vehicles, storage yards, office buildings, and information technology ("IT") inputs such as computer hardware and software. Distributors commonly operate and maintain such facilities and are also frequently involved in the construction of distribution plant. These activities require labour, materials, and services. Local delivery also typically requires a certain amount of power in the form of line losses. Opportunities are available to outsource many OM&A and construction activities. Distributors vary greatly in the extent of their outsourcing. (p 28)

Yet, despite their own description of the importance of capital and power losses, PEG recommends neither in its proposed cost benchmarking framework. Just how are capital and line losses integrated by each utility in the distribution of power? This question is addressed in the following description of a model of electricity distribution.

The distribution of electricity can be represented by equation (1) which expresses the relationship between the quantity of distribution output produced, Q, and the inputs of labour, L, materials, M, capital, K, and system losses of electricity, SL. Electric distributors produce and sell a multi-dimensional output to their customers. Clearly, the customer service, reliability (or continuity for the Europeans) and voltage quality, among others, can vary substantially, producing different products depending on the mix of characteristics delivered to the customers. Since reliability and associated costs vary across LDCs and the observed LDCs' costs reflect these differences in reliability, benchmarking an LDC's efficiency must include its reliability as an output. Definitions are discussed below.

(1) $Q = f(L, M, K, SL)$

The first two inputs are commonly labelled OM&A. Some labour associated with deploying capital assets is capitalised. Indeed, distribution utilities are capital intensive operations. Cost shares among inputs are reported as 45 percent capital, 42 percent OM&A, and 13 percent system losses. The Norwegian regulator (NVE) includes system losses and has done so within a model based on equation (1).

Capital is represented by the conventional net real capital. The share of capital among utilities ranges from about 35 percent to about 65 percent. Clearly, utilities can substitute between OM&A and capital and do so. As PEG notes (p 50), and I agree with, "Capital often serves as a substitute for OM&A inputs, and companies vary in their propensity to capitalize OM&A expenses. OM&A expenses should thus be lower the higher is the capital quantity…" That is, when two inputs are substitutes a firm can produce the same level of output with varying amounts of the two inputs.

Numerous Ontario utilities relying on the substitution possibilities among their inputs attempt to optimize their production with different input mixes based on substitution possibilities, circumstances and prices. So, two LDCs might produce the same output but one uses more capital and less labour while the second uses less capital and more labour.

Distribution utilities act as middleman selling and transporting electricity from wholesale to retail markets. Resistance to the flow of electric current throughout the distribution network causes a portion of the electricity entering the network to be lost in the form of heat. Network characteristics such as conductor size, type of transformers, end-user power factors, and non-optimal loads and voltage can affect system losses which range from 6 to 8 to over 20 percent as a share of total distribution costs. During energy price spikes, the cost associated with the physical loss of electricity can increase dramatically. Between 1988 and 1993, the wholesale price of power increased 45 percent in Ontario. Indeed, the price of power rose faster than other inputs between 1988 and 1993 and between 1988 and 1997. Such energy "crises" have sparked intense system audits by some utilities to identify the sources of losses and potential network remedies.

These remedies include the use of:

1. higher cost, high-efficiency transformers which reduce losses associated with transformer activation (core) and/or load (winding),
2. system regulators to optimise voltage,
3. system automation equipment to optimise load,
4. capacitors to compensate for low power factors among some end users, and
5. reconductoring to increase conductor size and reduce resistance.

Clearly, the use of such remedies to reduce system losses means that greater amounts of capital are being employed. Some of these remedies also require higher levels of OM&A. For example, the use of capacitors to correct the effect of reactive power from certain end-users applications means that equipment is being more widely dispersed and that equipment failures increase as more fuses, switches and controls are deployed closer to the customer. Installation of system voltage optimisation and phase current balancing equipment increases the OM&A associated with such regulating equipment.

Unlike equation (1) and the comprehensive depiction of distribution inputs, some researchers and regulators have based their evaluations of efficiency on some variant of equation (2) or (3). Here, the differing levels of reliability are not accounted for in Q.

(2) $Q = g(\text{O\&M}, \text{NK})$

(3) $(Q, \text{NK}) = h(\text{O\&M})$

Where, NK represents the number of transformers, the aggregate capacity of transformers, or the circuit length of the network. Note in equation (2) and (3), system losses are ignored. Not only does this remove 10 to 20 percent of costs from the efficiency comparisons, more importantly, it eliminates the "benefit of lowered losses" for those utilities that increased inputs like OM&A, for higher power efficiency (i.e., lower losses); the higher usage OM&A remains to be interpreted as lower production efficiency.

Instead of the correct capital data, i.e., the net real stock of capital, short-cut measures of physical counts of transformers or circuit miles instead of constant dollar stock of total capital (and the service flows from that) have sometimes been employed in benchmarking electric utilities. Transformers represent only 10 to 20 percent of capital asset valuations for a distribution utility; distribution lines might represent slightly more. As the importance of computers, software and communications grow with market openings, billing complexities, and real-time network operations, these shares will fall.

Some researchers have employed physical counts that view capital as exogenous to the utility; such efficiency comparisons have been made largely on OM&A expenditures, taking the capital measures and output as fixed. Thus, in this approach a utility's decisions regarding half of capital is taken as given, its remaining capital and line losses ignored, as are the interrelationships among these factors and OM&A.

The failure of some analysts to evaluate performance based on monetary values for capital including capitalised labour means that utility evaluations fail to reflect the cost of different choices for capital and allocations, and the fundamental trade-offs between capital and OM&A. For example, transformers might be high-efficiency models or lower cost, higher maintenance models. A circuit km might be overhead, underground or reconductored, wider lines. While km may be similar, costs for these installation options can vary by several hundred percent and there are differences in maintenance as well. And, utilities employing higher labour capitalisation rates (which lowers near term costs) are evaluated as more efficient since their non-capital costs are lower.

2.8 *The Baseline PBR Data Could be Updated with Subsequent Annual PBR and Distributor Submissions*

It is important to note that the extensive PBR Baseline filings were always intended to be the foundation of the future economic/regulatory research by the OEB. Baseline submissions were designed to provide the near totality of information required for rigorous, robust and extensive work on cost, productivity, efficiency, and benchmarking research on Ontario distributors. In fact, the Annual PBR submissions were designed to update the baseline, allowing the data to cover an increasing span of time.

Recommendation: The original purpose of the baseline and annual PBR filings can, and should, still be fulfilled. The Board should move to update the initial PBR submissions with the subsequent annual and distributors' submissions. This would provide the Board a world-class resource capable of more than adequately handling cost analysis, cost comparisons, and benchmarking among Ontario distributors.

3 Benchmarking Ontario LDCs Must Encompass Cost Measures Reflective of a Distributor's Actual Total Costs: the OEB's Benchmarking Should Reflect the Large Amount of Work Previously Undertaken by the Board

The PEG report describes the costs of distribution as follows:

> The total cost of local delivery service comprises OM&A expenses and the costs of plant ownership. At current capital inputs typically account for between 45 and 60 percent of the total cost of local power delivery and constitute the single most important input group. The exact cost share of capital depends on the age of a system and the manner in which plant is valued. The relative shares of labour and other OM&A inputs vary greatly. Prices for labour, capital and other inputs are important drivers of power distribution cost. (p 29)

The cost of local distribution must also include the power or line losses as was noted by PEG above in section 2.4. These can range from a low of 6 to 8 percent of total distribution costs to as high as 20 or more percent. In the case of Ontario distributors, an OEB Staff Report examined the cost structures of electric utilities.[18] Cost shares among inputs are reported as 45 percent capital, 42 percent OM&A, and 13 percent system losses. Utilities that chose to use labour to substitute for line loses and capital will be prejudicially judged less efficient by the OEB benchmarking even if they are in fact more efficient on a total cost basis.

3.1 *Correctly Measuring and Pricing Capital Services is Critical to any Understanding of Utility Performance*

Indeed, the issue of correctly measuring and pricing capital services is critical to any understanding of utility performance, even more so with an attempt to compare across utilities to evaluate relative efficiency. Allocative inefficiency is a major component of the total economic inefficiency that exists among some Ontario distributors. No doubt, this is due to the availability of virtually "free" access to capital that some utilities in the

[18] Cronin, F.J., et al, 1999, *Productivity and Price Performance for Electric Distributors in Ontario*, Ontario Energy Board Staff report; available at http://www.oeb.gov.on.ca

province had through the use of customer "contributed capital" and all-equity financing at below market costs of capital prior to restructuring in 1999 - 2000. [19]

Previous regulatory rules actually encouraged utilities to make use of this form of third-party capital asset financing and rate-basing of contributed capital, and in doing so, incented a non-market (i.e., inefficient) mix of input factors. The regulatory framework adopted for electric utility benchmarking must accurately reflect the distribution production process across all its major inputs and the fact that due to substitution possibilities discussed in section 2.7 individual LDCs have chosen different input combinations in delivering power to their customers. This framework must also ensure that the incidence of allocative inefficiency found across many jurisdictions and network industries can be examined and evaluated in the case of Ontario.

But, the focus of the Board's efforts over the past few years seems to deal almost exclusively with operational efficiencies (i.e., OM&A) as being synonymous with technical efficiency (i.e., achieving the maximum output to input ratio).[20] First the ETDO, then the Christensen report, and now the PEG report. This focus ignores the existence and extent of allocative inefficiency, traditionally a larger source of inefficiency (i.e., having the wrong mix of resources given relative prices, e.g., too much capital based on capital costs that were below market capital costs). Indeed, allocative inefficiency can

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[19] Cronin, F. J. and Motluk, S. A., The Effects of Regulatory Changes and Third Party Financing on Utility Costs and Factor Choices, forthcoming, *Annals of Public and Cooperative Economics.*

[20] In 2003-04, the OEB sponsored a "Consultation into Further Efficiencies in the Electricity Distribution Sector," and issued a Staff Report on furthering LDC efficiencies (RP-2004-0020 available at http://www.oeb.gov.on.ca/html/en/industryrelations/archivedinitiatives/regulatorydirection/consultation_electricity_distribution.htm) and the Province's Ministry of Energy initiated a consultation on Distribution and Transmission – A Look Ahead" in 2004-05 which considered further efficiencies from rationalization (available at http://www.energy.gov.on.ca/index.cfm?fuseaction=english.news&body=yes&news_id=86). F.J. Cronin and S.A. Motluk's submission on this consultation, raising these and other issues, can be found at the following link: http://www.energy.gov.on.ca/english/pdf/electricity/review/gps-2005-p005.pdf

be two to three times as large as technical ineffeciency.[21] Appropriately structured benchmarks are necessary to deal with the type of inefficiency, i.e., technical v. allocative.[22] More is said about allocative efficiency below.

I am not suggesting that PEG's short cuts are inadequate in order to pursue a "perfect" benchmarking approach. Clearly the Board needs an approach that can be effectively implemented. However, in such an effort the Board should ensure that the approach does not result in perverse incentives and outcomes. It is dangerous to implement a scheme that is "not up to standard" and which could actually make things worse.

3.2 *Cost Shares for Ontario Distributors*

Exhibit 3.1 is taken from the 1999 Staff report and is based on the 1999 PBR filings. It presents the 1993 cost shares by size class. In the 4-factor analysis about 45 percent of an average utility's total cost is related to capital. Note that this analysis placed a market-based rate of return on net real distribution assets so it is comparable to current LDC cost shares with assets earning a market return. Remaining cost shares are on average 29 percent for labour, 13 percent for material and 13 percent for line losses on average. Medium-sized utilities tend to have a slightly higher share for capital and slightly lower shares for labour and material than large and small utilities.[23]

[21] Cronin, F. J., Motluk, S. A., *Inter-Utility Differences in Efficiency*, presented at the Canadian Economics Association Meeting, McGill University, Montreal, 2001.

[22] Cronin, F. J. and Motluk, S. A., *The (Mis)Specification of Efficiency Benchmarks among Electric Utility Peer Groups*. Presented at the North American Productivity Workshop II, Union College, NY, 2002.

[23] These share are consistent with findings in other jurisdictions, see Grasto, K., 1997, "Incentive-Based Regulation of Electricity Monopolies in Norway," NVE working paper.

Exhibit 3.1: 1993 Average Cost Shares for Ontario Distributors

	4 Factor					3 Factor		
	Capital	**Line Loss**	**Labour**	**Materials**		**Capital**	**Labour**	**Materials**
Large	45	12	30	13		51	34	14
Medium	49	12	28	12		55	31	13
Small	40	16	30	14		48	35	17
All	45	13	29	13		52	34	15

Source: 1999 Staff report.

In fact, the analysis of cost shares among Ontario LDCs over the 1988 to 1997 period found a very substantial range of cost shares among utility inputs (see Exhibit 3.2). For example, looking at all 10 years of data for only a subset of 19 LDCs finds that the share of capital can range from a low of 33.1 percent to a high of 63.2 percent. Associated with these data points are line loss cost shares of 5.1 percent and 10.0 percent. Combined capital and line loss shares range from a low of 38.2 percent to a high of 73.2 percent.

Conversely, we find that the share of labour can range from a low of 18.8 percent to a high of 44.4 percent. Associated with these data points are material cost shares of 8.0 percent and 17.4 percent. Combined labour and materials shares range from a low of 26.8 percent to a high of 61.8 percent. Had the totality of filed cost data been examined, even greater differences among LDCs may well have been found in terms of their cost shares.

Indeed, the PEG report notes, and I would agree, that shares do vary:

> At current input prices, capital inputs typically account for between 45 and 60 percent of the total cost of local power delivery and constitute the single most input group. The exact cost share of capital depends on the age of a system and the manner in which plant is valued. The relative shares of labour and other OM&A inputs vary greatly. Prices for labour, capital and other inputs are important drivers of power distribution cost. (p 29)

Exhibit 3.2: Range of Annual Cost Shares for Ontario Distributors 1988 - 1997

	Capital	Line Losses	Combined	Labour	Materials	Combined
Minimum	33.1	5.1	38.2	18.8	8.0	26.8
Maximum	63.2	10.0	73.2	44.4	17.4	61.8

Source: Data examined in 1999 Staff report.

3.3 *Capital Deployment Policies*

In part, these results reflect differences among LDCs on capital deployment policies. For example, during the PBR cost filings in 1999, an examination of functional cost assignments among a small sample of Ontario LDCs was undertaken. It was found that Ontario LDCs were operating under a wide range of labour capitalization rates. The percent of total labour capitalized among this small sample of Ontario LDCs ranged from about 15 to about 30 percent with substantial differences in the burdens placed by utilities on direct labour costs. Had a broader sample of LDC policies been examined with respect to labour capitalization, even greater differences among LDCs in terms of their rates of capitalization and burden assignments may have been found.

3.4 *Inappropriate Incentives, Substitution, and Partial Cost Benchmarking*

These possibilities for altering factor mix among LDCs imply that partial cost benchmarking could fail to recognize input savings on factor A through greater use of factor B: some LDCs will have lower OM&A costs because they have higher capital costs. The bottom line: only when LDCs are appropriately examined on the totality of their inputs can stakeholders make sense of the societal resource usage employed in distribution and judge the comparative performance of individual firms together with their management and operational choices.

Furthermore, the current period factor mix is influenced by the state of choices that faced the utility 3 to 5 years ago; LDCs do not adjust instantly/completely to altered prices or regulatory incentives. However, substantial changes in the input mix across all inputs including capital, can be made within a reasonable period.

Recommendation: Given the risks to customers, shareholders, and LDCs associated with inadequate benchmarking regimes, the Board should not implement any benchmarking of Ontario LDCs until this can be done correctly, i.e., with the full, properly specified costs of distribution together with each LDCs reliability level as a foundation of the framework. Total cost benchmarking better reflects an LDC's cost structure and input choices, is more equitable, permits an evaluation of societal resource usage, and limits inappropriate regulatory incentive. The Board should develop the appropriate capital cost information necessary to properly benchmark Ontario electric utilities. A very good starting point is the 1999 PBR Baseline Surveys which covered decades of capital components and, as of that time, had calculated the total costs of distribution, including capital costs, for those LDCs in the 1999 Staff report as well as others. Even with the subsequent substantial mergers and amalgamations since 1999, the Board could update the initial PBR submissions with the subsequent annual PBR filings and other distributors' submissions.

4 Both Gross Book Value and OM&A Fail to Reflect the Correct and Appropriate Cost Measures for Benchmarking: Benchmark Costs Must Represent a Consistently Defined Activity across LDCs in Terms of their Underlying Costs, Burdens and Allocations

Both the 2004 Staff report and the PEG report offered inadequate short cuts for benchmarking distribution rates. Such short cuts have "come up short" in other jurisdictions that failed to properly examine inter-utility costs and efficiency.[24] In fact, prior efforts by the Board during the first generation PBR successfully specified and collected the type of data, necessary to make appropriate comparisons including the appropriate information on capital costs. Those data have subsequently been used to undertake efficiency benchmarking.[25]

Economists have long had straightforward measures of efficiency: the primary road block to their implementation has been the availability of properly specified and collected data. Fortunately, extensive, appropriate data was collected for the development of the first generation PBR plan and provided the Board with a wealth of information on the historic and at that time current costs (e.g., total, by input, capital), cost structure, and productivity growth of Ontario LDCs. From this data it is possible to extract the correctly specified costs for benchmarking and then examine the cost measures (e.g., OM&A and GBV) used by PEG to see how they compare.

4.1 *Biases in the Capital Costs Employed in the PEG Report and their Consequences*

The PEG report correctly notes the important role capital plays in electric distribution. In fact, the PEG report concludes that a utility's long run success in cost containment depends on "their management of capital costs."

[24] For a review of regulatory applications which employed partial cost, physical counts or other misspecifications in their benchmarking models, see, F. Cronin and S. Motluk, forthcoming, "Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks" originally *The (Mis)Specification of Efficiency Benchmarks among Electric Utility Peer Groups*. Presented at the North American Productivity Workshop II, Union College, NY, 2002

[25] F. Cronin and S. Motluk, "Inter-Utility Differences in Technical and Allocative Efficiency." Canadian Economics Association 35th Annual Meeting at McGill University, Montreal, Quebec June 2001

> Capital inputs play important roles in utility operations. They are especially important in network businesses like power transmission and distribution. In these businesses, capital typically accounts for half or more of total cost. It follows that, in the long run, the success utilities have at holding down their costs depends greatly on their management of capital costs. (p 22)

The PEG report also describes the correct methodology for calculating capital cost for analysts undertaking "rigorous research on capital costs." According to PEG:

> A means of computing capital cost has been developed by scholars to help finesse these problems. This method is commonly employed in rigorous research on capital cost. The basic idea is to recompute the cost of capital using a standardized treatment of depreciation and historical data on net plant value in a certain benchmark year and on plant additions in subsequent years. The methodology involves the calculation of a capital quantity index using a perpetual inventory equation. The intent is to base capital cost calculation as much as possible on the plant *additions* data, which are less idiosyncratic. (p 23)

This rigorous research approach described by PEG is consistent with the approach used by the Board in the development of the first generation PBR. That is, **gross book value** in a benchmark year (some decades previous) is revalued to put each year's plant in constant dollars. Adjustments are then made for revalued additions, retirements and depreciation to calculate a **net real stock of capital**, i.e., the amount of constant dollar net assets existing in any year after adjusting for all previous year's additions, retirements and depreciation. Annual c**apital expenses** are calculated based on opportunity costs, depreciation, and taxes.[26]

[26] Standard utility accounting of capital costs is based on book valuation (i.e., historical prices) and fails to reflect changing assets prices over time. The capital quantity index employed in the 1999 Board Staff Report was constructed using inflation – adjusted values for historical capital stock deployed before a benchmark year, as well as for subsequent additions and retirements, each adjusted for inflation. Real stock in 1980, the benchmark year, was estimated by deflating undepreciated capital by a capital asset price constructed by "triangularizing" the pre-benchmark asset prices back to 1960. The capital asset price index, CAP, is the electric utility distribution system construction price index published by Statistics Canada. The standard treatment of capital in productivity research expresses subsequent values of the capital quantity index as a perpetual inventory model adjusted for annual depreciation rate, additions and retired capital. The annual depreciation rate is calculated as the average annual share of depreciation to gross book value. Retirements are assumed to have aged 15 years. Both additions and retirements are inflation adjusted. The capital service price index is then equal to rate of the depreciation plus opportunity
Footnote continued on next page.

Let us look at these calculations in more detail to understand what the PEG report describes as the "rigorous" approach. Exhibit 4.1 presents a sample of such calculations for one Ontario distributor from the 1999 PBR filings examined in the 1999 Staff report. (see Appendix D1-D3 for the full set of calculations.) We start with the gross stock (nominal) in 1980 of $14.77 million. This is revalued in constant dollars to $37.29 million. Capital additions, retirements, and depreciation must all be revalued and used to adjust the real stock at the start of year. This produces a constant stock of net capital or net real stock of $36.45 million at the start of 1981.

Exhibit 4.1: Capital Stock, Additions, Depreciation, and Retirements 1980 to 1982

A	B	C	D	E	F	G	H
	Stock* (nominal) [start of year]	Stock (real, 1986$) [start of year]	Capital Additions (nominal)	Capital Additions (real, 1986$)	Depreciation** (real, 1986$)	Retirements*** (real, 1986$)	Constant $ Stock of Capital
1980	14,771,522	37,291,508	1,152,953	1,608,024	2,076,697	368,607	36,454,228
1981		36,454,228	2,206,708	2,821,877	2,106,242	197,006	36,972,858
1982		36,972,858	2,681,409	3,136,150	2,160,426	24,576	37,924,006

Source: Ontario Energy Board, 1999 PBR Filing, Capital Components 1980 to 1997

Capital inputs or expenditures are calculated by applying depreciation and opportunity costs to nominal capital stock. So for 1994 we apply a depreciation rate of 5.39 percent and an 8.6 percent opportunity cost to the capital stock of $40.75 million. The 5.39 percent depreciation rate is calculated from the LDCs historical data as the average annual share of depreciation to GBV. The opportunity cost in this case was based on the Canadian long bond rate. This produces a capital expense of $9.06 million for this distributor in 1994 (see Exhibit 4.2).

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costs adjusted by the construction price index. Capital costs are then the capital quantity index times the capital service price index. See 1999 Staff report.

Exhibit 4.2: Capital Stock, 1994 to 1995

	Capital Stock Nominal	Average Depreciation Rate	Bond Rate Opportunity Cost of Capital	P_k =(L+M)*J/100	Capital Price Index (1988=1)	Capital Expense
1994	40,748,208	5.390%	8.600%	0.176	1.032	9,064,561
1995	38,617,408	5.390%	8.350%	0.182	1.066	9,329,258

Source: Ontario Energy Board, 1999 PBR Filing, Capital Components 1980 to 1997

Recall now that PEG used GBV as a proxy for the correct measures of capital (i.e., net real stock or capital expenses), and recall that "rigorous research" would have used net real stock or capital expenses (CE). We know from PEG's own conclusion that GBV is the wrong measure. The real question is how much error is produced by the use of such short-cut methodologies. More specifically, how might the benchmarking of individual electric utilities be affected by using these incorrect cost measures?

With the above calculations of gross GBV, Net Real Capital (NRC) and CE available for many Ontario distributors from the 1999 PBR filing, we could examine the consequences on individual LDCs of using GBV rather then NRS or CE. How would the short cuts affect an LDC's costs and efficiency ranking?

Exhibit 4.3: Illustrative Comparison of PEG's Capital Variable (Gross Book Value) to the Correctly Calculated Capital Stock Variable (Net Real Capital) and Capital Expenses (millions of dollars)

	Gross Book Value	Net Real Capital	GBV/NRC (approx)	Capital Expenses	GBV/CE
Utility 1	150	115	1.3	15	10
Utility 2	105	75	1.4	12	10
Utility 3	195	120	1.6	18	9
Utility 4	245	95	2.6	16	16

Source: Illustrative example similar to LDCs situation in the initial PBR.

Exhibit 4.3 presents the calculations of GBV, NRS, and CE for 4 illustrative Ontario distributors. Utility 1 has a GBV of \$150m, a NRS of \$115m, and a CE of \$15m. It has a ratio GBV to NRS of 1.3 (i.e., GBV is 30 percent larger than NRS) and a ratio of GBV to CE of 10 (i.e., GBV is 10 times larger then CE). However, utility 4 has a GBV to NRS ratio of 2.6 (GBV is 160 percent larger then NRC) and a ratio of GBV to CE of 16 (i.e., GBV is 16 times larger then CE).

The average GBV to NRS ratio is about 1.8, that is, for the average utility GBV is 80 percent larger than NRS. We can now see that for some utilities however, the ratio of GBV to NRS is much lower than the average (utility 1 has a ratio about 30 percent below the mean) while for other utilities the ratio is much higher than the mean (utility 4 has a ratio 40 percent higher then the mean). The average GBV to CE ratio is about 11 that is, for the average utility GBV is about 11 times larger then CE. We can now see that for some utilities however, the ratio of GBV to CE is much lower than the average (utility 1 has a ratio almost 10 percent below the mean) while for other utilities the ratio is much higher then the mean (utility 4 has a ratio over 40 percent higher than the mean).

This means that for utilities like 4 above, the use of GBV by PEG to proxy distributors' capital costs greatly overstates their capital cost relative to other distributors while for utilities like 1 and 2 the use of GBV greatly understates their capital stock relative to others. More problematic is the fact that rankings based on these costs would be seriously biased: *in fact, our illustrative utility 4 actually uses more than 15 percent less capital stock than utility 1 (i.e., $95m v. $115m) but appears based on the PEG approach to use 60 percent more capital (i.e., $245 v. $150).* These illustrative figures would have produced drastic errors and drastic miss rankings.[27] In section 5, we deal more extensively with the impact of miss specified costs on efficiency rankings among LDCs.

The danger here is that mis-specified LDC benchmarks can and do lead to large biases in the resulting assessments of inter-utility efficiency by the regulator. My research has found that such quick fix approaches to benchmarking can lead to inaccuracies of 10, 20

[27] No doubt, we can now see why the PEG statistical analysis has a high error rate for some utilities between actual OM&A and model predicted OM&A.

and 30 percentage points or more in inter-utility efficiency rankings (out of a hundred).[28] Such results *undermine* the confidence in the validity and robustness of the efficiency comparisons.

Used in a benchmarking approach for rate setting purposes it results in insufficient revenue for the maintenance of on going service quality for some LDCs and a windfall rate of return for others.

Indeed, the issue of yardstick competition has been on the table since the winter of 1998-1999.[29] The intent of the PBR filings in 1999 and those subsequent to the baseline was to build an unparalleled set of information upon which to structure the preeminent benchmarking regime in the world.

Especially disappointing is that in the name of expediency, the PEG report makes the same mistaken use of GBV as a proxy for capital cost as did the Christensen report: presumably because it exists and is available. While that report purports to develop total cost estimates for distribution utilities in the Province, it ignores almost entirely the issue of capital measurement and pricing. Thus, utility cost cohorts would be developed ignoring the most important cost component. Not only is this measure of capital employed (i.e., GBV) incorrectly, it biases the results in significant and uncertain ways from one LDC to another. Biases such as that produced by the use of short cut and inappropriate capital measures can penalize the wrong LDCs and possibly reward less efficient LDCs.

Recommendation: Proper benchmarking needs to include the correct measure of capital as described by PEG for "rigorous" analysis, but which PEG did not employ in the benchmarking approach recommended in their report. Capital is a critical infrastructure resource. The Board should not lay out inappropriate precedents inconsistent with proper cost analyses and benchmarking because the correct approach is time consuming and

[28] Cronin, F. J. and Motluk, S. A., forthcoming, "Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks," Originally, *The (Mis)Specification of Efficiency Benchmarks among Electric Utility Peer Groups*. Presented at the North American Productivity Workshop II, Union College, NY, 2002.

[29] See, *PBR Option for Ontarios,* OEB Staff Report, Fall 1998.

difficult. A past effort collected PBR capital data from the 1970s to 1997 and PBR operating/financial/demand data from 1988 to 1997, including "environmental" factors potentially affecting an LDC's performance. This effort was augmented by directed PBR filings among Ontario LDCs for at least the years 2001 and 2002. It is possible as well as preferable to update this data as must surely have been the intent in collecting the data from the LDCs on an on going basis. These critical data and what must mount up to thousands of man hours of effort expended collectively to compile, process and analyze this wealth of information should not be ignored. Updating the 1999 data would cost no more, and probably less, than efforts to start in 2007 and work backward. It is not clear if the latter approach is even feasible, and it would most certainly produce less robust data and almost certainly take longer to complete.

4.2 *Biases in the OM&A Costs Employed in the PEG Report and the Consequences*

The PEG report notes that among distributors the shares of capital, OM&A and labour "vary greatly."

> At current input prices, capital inputs typically account for between 45 and 60 percent of the total cost of local power delivery and constitute the single most important input group. The exact cost share of capital depends on the age of a system and the manner in which plant is valued. The relative shares of labour and other OM&A inputs vary greatly. Prices for labour, capital and other inputs are important drivers of power distribution cost. (p 29)

Indeed, among Ontario distributors whose 1999 PBR filing were examined, shares of capital ranged from 33.1 percent to 63.2 percent. Conversely, the share of labour ranges from a low of 18.8 percent to a high of 44.4 percent. The fact that labour and capital are substitutes and that utilities can operate under different cost combinations under different circumstances or input price structures is noted (see Exhibit 4.4).

Exhibit 4.4: Range of Some Cost Shares for Ontario Distributors 1988 - 1997

	Capital	Labour
Minimum	33.1	18.8
Maximum	63.2	44.4

Source: 1999 Start report

However, there are also administrative and accounting reasons why different utilities might show different shares of labour or OM&A versus capital. Burden allocations can be expected to vary markedly across utilities based on utility policy and practice differences.[30] Furthermore, even within a utility, burdens on capitalized labour can be markedly higher then the burdens put on labour assigned to OM&A functions. Finally, the share of labour that LDCs choose to capitalize can vary substantially.

The PEG report notes:

> Companies are inconsistent in their capitalization of OM&A expenses. A good example is the treatment of software maintenance expenses. Companies that outsource customer care tasks will report more of their IT costs as OM&A expenses. (p 34)
>
> Benchmarking of detailed customer care cost items can be especially problematic due to the cost allocation inconsistencies we have discussed. (p 35)

In fact, of three "high-priority" data improvements identified by PEG two have to do with the capitalization or reporting of labour. (p 41)

> Improvements in the data can make it possible to expand the role of benchmarking in Ontario regulation. Here is a suggested list of high-priority upgrades:
>
> > Tighten data reporting rules and enforcement so as to encourage more consistent allocations of labor costs between distributor functions.
> >
> > Make public the share of net OM&A expenses attributable to labor, ideally with itemization with respect to the major distributor functions. (p41)

Finally, the PEG report noted:

> The Board has established itself in recent years as a leader in the gathering of data that are useful in power distribution cost benchmarking. Despite the progress made, the data have flaws that limit their usefulness in benchmarking. Improvements in the data gathering and collection process

[30] Along with the direct expenses associated with these various tasks, LDCs must decide administratively how to allocate overhead costs such as supervisory, engineering, or management expenses. These overhead costs are recovered by putting an indirect cost burden on the direct costs of labour.

> can lead to better benchmarking and an expanded role for benchmarking in regulation. The following reforms are especially worthwhile:
>
> > better guidelines for, and public reporting of, the share of salaries and wages in net OM&A expenses;
> >
> > greater consistency in the assignment of labor costs to the major categories of distributor activities; (p iv)

But even having noted the "problematic" and "inconsistent" treatment of labour capitalization policies among Ontario LDCs and the "high-priority," "worthwhile" improvements in the accounting and reporting of labour expenses, the PEG report ignores its own advice by benchmarking Ontario distributors on only OM&A. No attempt appears to have been made to do even a minimum analysis of the biases associated with differing burden and capitalization policies as was done in the development of the first generation PBR during the winter of 1998-1999.

We know that some portion of the reported differences in labour and thus OM&A among LDCs are due to differences among LDCs on burden rates and capital deployment policies.

Each utility must cost out the inputs it uses in carrying out the work associated with its distribution activities. Some of these work tasks, for example, have to do with construction or equipment installation and would be considered capital activities. Some work tasks have to do with, say maintenance or billing, and would be considered OM&A.

Along with the direct expenses associated with these various tasks, LDCs must decide administratively how to allocate overhead costs such as supervisory, engineering, or management expenses. These overhead costs are substantial and can be on the same order of magnitude as an LDCs total payroll cost. Different utilities consider different costs as overhead and within the same utility, may apply different overhead rates to labour applied to capital, maintenance or billing-collecting.

An illustrative example from the 1999 PBR filing would be the following rough approximations: labour burdens applied to billing-collecting were about 33 percent, labour burdens applied to OM&A and capital were about 90 percent. Choices ranged widely in the burden rates applied to different cost categories. Finally, each utility must decide how much labour to capitalize, i.e., include in the rate base and pay off over time as opposed to labour included in OM&A which is paid for as you go each year.

During the PBR cost filings in 1999, we undertook an examination of functional cost assignments among a small sample of Ontario LDCs. We found that Ontario LDCs were operating under a wide range of burden and labour capitalization rates. In fact, we found that the percent of total labour capitalized among this small sample of Ontario LDCs ranged from about 15 to about 30 percent. Had we examined a broader sample of LDCs' policies with respect to labour capitalization, we may well have found even greater differences among utilities in terms of their rates of capitalization and burden assignments.

What bias might there be with just using OM&A with differing capitalization policies? Lets say that we have two LDCs with the same average cost of $500 per customer per year which was about the average cost among large and medium distributors based on the 1999 PBR filing (see Exhibit 4.5). Lets also assume that each has the average share of labour observed in the PBR filing, 29 percent: each would then have $145 of labour costs.

However, if one LDC capitalizes 30 percent of labour and the other capitalizes 15 percent we would observe $123 in labour expenses in the latter, but only $102 in labour expenses in the former, a 17 percent difference in "perceived labour costs." Using the average share of materials, there would be $167 in OM&A in the high capitalization LDC compared with $188 in OM&A in the low capitalization utility: a difference of 11.2 percent due simply to differences in the accounting of labour applied to capital.

Exhibit 4.5: Comparing 2 Illustrative Utilities with the Same Costs but Differing Labour Capitalization Policies

Capitalization Policy	Total Costs Per customer	Total Labour Costs @ 29 percent	Percent Labour Capitalized	Labour Assigned To OM&A	Reported OM&A Expenses
High Capitalization Utility	$500	$145	30	**$102**	**$167**
Low Capitalization Utility	$500	$145	15	**$123**	**$188**

Source: Ontario Energy Board, 1999 PBR filing and author calculations.

Since each of the two LDCs has the same $500 per customer costs, benchmarking on total costs per customer would rank the two utilities equally. But, the PEG proposal benchmarks only OM&A, so any errors due to accounting allocation differences will not be accounted for. Indeed, if we examined the actual accounting policies with respect to overhead burdens and capitalization among a broader sample of Ontario LDCs, we may well have found even greater differences among those LDCs in terms of perceived differences in OM&A that are simply due to accounting allocations. The consequences of such benchmarking inconsistencies in the PEG approach undermine any confidence that differences in reported costs are in fact differences in the underlying efficiencies among the LDCs or if they simply reflect different administrative policies.

Recommendations: Benchmarking for regulatory incentives/penalties should be done on a utility's total costs. Use of partial cost measures whether it be OM&A or capital suffers from the fact that some inputs are substitutes and LDCs combine them in different ways. Without a correct measure of capital to examine, OM&A costs can and do present biased results of LDC performances since they reflect inconsistent approaches to labour burdens and capitalization. Even adjusting the reported OM&A for allocations differences will still not present a plausible efficiency result since many combinations of capital and labour can be employed by equally efficient utilities. In addition, LDCs have different levels of reliability and different levels of associated costs, i.e., higher reliability costs more. When we observe different OM&A costs among Ontario LDCs without the associated reliability information, we can not assume that an LDC with higher OM&A is less efficient, it may simply be providing a higher-valued output for its customers. This difference among LDCs with respect to reliability needs to be accounted for just as does the differing labour capitalization rate.

5 Efficiency, Scale and Regulatory Incentives

Since restructuring in 1999-2000, the Ontario Government has embarked on an apparent policy to reduce the number of distribution utilities in the Province, despite little evidence to suggest real welfare gains. In fact, prior empirical analyses suggested negligible returns to scale from distribution mergers. Indeed, previous research undertaken on behalf of the OEB, found the largest distribution utilities had the highest cost per customer and the lowest rate of productivity increase (1999 Staff report).

5.1 *Overview*

Following the Board's 2000 PBR Decision, research was undertaken by the Board to examine several of the issues raised during the first generation PBR implementation.[31] These issues included benchmarking approaches; contributed capital; and inter-utility differences in technical and allocative efficiencies.

As hypothesized by some stakeholders, significant allocative inefficiency in the distribution sector was found from over capitalization.[32] This was caused in part by regulatory policies toward capital that incented some utilities to favor capital over other inputs, even in non-optimal amounts. Indeed, the vast majority of distribution inefficiency in Ontario (about 70 to 80 percent) is allocative. On average Ontario LDCs could reduce costs 30 percent while holding output constant.

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[31] This research has its genesis in a paper originally prepared as a kickoff to a potential research program for the OEB for a yardstick regulation regime for Ontario LDCs, presented at the Canadian Economics Association 35th Annual Meeting at McGill University, Montreal, Quebec in June 2001: Frank J. Cronin and Stephen A. Motluk, "Inter-Utility Differences in Technical and Allocative Efficiency."

[32] The policy implications of this work are discussed in Cronin and Motluk, "The Road Not Taken: PBR with Endogenous Market Designs," *Public Utilities Fortnightly*, March 2004. An earlier version of this paper *Restructuring Monopoly Regulation With Endogenous MarketDesigns* was presented at the Michigan State University, Institute for Public Utilities, *Annual Regulatory Conference*, Charleston, S.C. December, 2003. Results from this research have also been used as the basis for an invited seminar on improving utility benchmarking at Camp NARUC, "*Restructuring Monopoly Providers or Regulation through Revelation*," 46th Annual Regulatory Studies Program Michigan State University, Institute for Public Utilities, Regulatory Studies Program, August 2004.

5.2 *Efficiency and Scale*

Research does not generally support the notion of substantial unrealized economies beyond a relatively modest size in distribution. While some researchers have found economies of scale, others have found diseconomies beyond moderate size, or for limited scope for economies of scale. One study had looked at the distribution sector in Ontario in the mid 1990's (Yatchew, 2000)[33] . Unfortunately, this study has serious specification and data limitations, especially with respect to capital. That being said, the author finds minimum efficient scale occurs at about 20,000 customers with diseconomies for larger LDCs.

No doubt, the problem is complex. For example, researchers have generally found returns from energy density (consumption per customer), sometimes from scope, and sometimes from customer density, but even the latter appears to have decreasing returns beyond some point.

With respect to scale economies, the PEG report states (pp 52 – 53)

> Our research suggests that economies of scale are available over a wide range of output in Ontario. For example, at sample mean values of our three output variables, it can be seen that the sum of the elasticities is .938 (.576+.224+.138). Thus modest incremental scale economies are available at the average level of operating scale. This finding is consistent with our cost research over the years using U.S. power distribution data, which has found that incremental scale economies are not exhausted until a level of output has been reached that is somewhat above the Ontario mean.
>
> Our research suggests that scale economies confer on the larger Ontario utilities a material unit cost advantage over smaller utilities. The potential of a company to realize scale economies should therefore be recognized in responsible benchmarking work. The research results can also be used to assess the potential OM&A cost savings from mergers. Better estimates of scale economies will be possible as additional years of data become available for use in the econometric sample.

[33] Yatchew, A. "Scale economies in electricity distribution: a semiparametric analysis," *Journal of Applied Econometrics*, Issue 2, 2000: 187 – 210.

Despite PEG's claims of a material cost advantage, the cost elasticity reported by PEG (i.e., .938) would translate into a scale economy of .066. That is, if a utility at the mean increased its inputs by 100 percent, its outputs would increase by 106.6 or 6.6 percent more than the increase in inputs. Indeed, given the misspecification of the model identified in section 5.7 used by PEG, it is not even clear that this result would hold up with a correctly specified model.

The 1999 Staff report examined costs by size among Ontario distributors. These results are shown in Exhibit 5.1. While there was substantial variation among utilities in each size class, average costs were lower for small utilities than for medium and lower for medium than for large. In addition, both small and medium utilities had higher rates of total factor productivity growth.

Exhibit 5.1: Average Total Cost Per Customer and Annual Percentage Change in TFP by Size Class*

	Total Cost per customer ($C)	**Annual % change in productivity (1988-1997)**
Large	504	0.6
Medium	484	1.0
Small	385	0.9

* Small utilities have less than 10,000 customers, medium 10,000 to 50,000, and large more than 50,000.

Source: 1999 Staff report.

Given the lower costs for smaller Ontario utilities found in the 1999 Staff report, one would presumably want to have solid research findings upon which to base a policy with contrary assumptions (i.e., that substantial unrealized economies of scale exist over a wide range of production).

Norway's Water Resources and Energy Directorate (NVE)

Ontario may well benefit from examining the practices in other jurisdictions. One jurisdiction of great interest is Norway. Restructuring began there in 1990. Norway had about 235 electricity utilities at the time of restructuring. Interestingly, the 1990 Energy Act identified mergers as a possible goal.

However, research undertaken for the regulator, NVE, indicated

> NVE neither has the power nor the desire to dictate mergers. The main reason for this is that it is very difficult for NVE to know precisely where there are unrealized economies of scale. As far as NVE is aware, there are as yet no scientific studies of unrealized efficiency gains related to economies of scale within the Norwegian electricity transmission and distribution sector. Even if NVE had the power to dictate mergers, this would probably not lead to the most efficient solutions.[34]

NVE adopted a light-handed, market-driven approach for its utilities. Under the first generation PBR, NVE incented utilities to undertake appropriate mergers by allowing any merger savings above the allowed return to be retained by the utilities. As noted by NVE staff, "Efficiency gains will result in increased profit – in the long run, this will also result in reduced prices."

5.3 *Scale and Scope Economies among Ontario LDCs*

Thus, prior research: Yatchew, (2000), 1999 Staff report, and other jurisdictions (Nemoto and Goto),[35] have found little/no evidence for economies of scale. More recent evidence by PEG seems to offer somewhat conflicting results. PEG finds slight economies they label "modest" (+ 6.6) and report that these economies are exhausted at slightly above the mean-sized Ontario LDC (now about 40,000). Even if we ignore the serious model misspecifications by PEG discussed below and the inadequate measures of cost employed, PEG results indicate that scale effects are almost nonexistent among Ontario LDCs even if we accept the term "modest" in their description.

Recommendation: The issue of scale economies seems to have become an unnecessary preoccupation by policy makers and regulators. Research supports the conclusion that there are no substantial unrealized economies of scale in the Ontario distribution sector; rather, there may be diseconomies. A market-based, policy-neutral merger framework should be adopted. NVE's conclusion appears reasonable for Ontario as well: "As far as

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[34] See Grasto, K., "Incentive-Based Regulation of Electricity Monopolies in Norway – Background, Principles and Directives, Implementation and Control Systems. Norwegian Water Resources and Energy Adminisration, p.22.

[35] Nemoto, J. and M. Goto, Estimating a CES Cost Frontier with Panel Data: an Application to Japanese Transmission-Distribution Electricity," paper presented at the North American Productivity Workshop, Union College.

NVE is aware, there are as yet no scientific studies of unrealized efficiency gains related to economies of scale within the Norwegian electricity transmission and distribution sector. Even if NVE had the power to dictate mergers, this would probably not lead to the most efficient solutions."

5.4 *The Source and Extent of Distribution Ineffiencies in Ontario*

Our subsequent research on the technology frontier and factor allocation has revealed that the source of inefficiency in the LDC sector is: a sub-optimal factor input mix and significant allocative inefficiency resulting from previous regulatory incentives. Each of these practices created significant agency problems.[36]

Under-priced Capital

First, in the past, Ontario LDCs treated capital as though it were almost costless, employing extremely low hurdle rates for capital. Significant factor mix distortions resulted from under priced capital.

Second, a significant proportion of the rate base of some of the larger, high growth suburban utilities is made up of costless *contributed capital*, i.e., infrastructure contributed or paid for by customers or other third parties. In fact, in some cases, over 70 percent of an LDCs' equity was contributed by third parties.

Third, LDCs were not accountable for system losses (i.e., line loses). Line loses were treated by many utilities as a cost pass through, rather than as an input to the distribution production function. These practices presented a significant incentive for these utilities to substitute costless or almost costless capital for other inputs.

Rate Basing Contributed Capital

Increasingly in the 1970s and 1980s, capital requirements for some LDCs were being met with capital "contributed" from end users. Other LDCs used hardly any contributed capital and some only for expansions in excess of average system costs. Eventually, some

[36] This material comes from Cronin, F.J., S.A. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," forthcoming, *Annals of Public and Cooperative Economics.*

LDCs began charging for much larger proportions of costs, including provision of standard service. Among the utilities in our sample, the share of net fixed assets from contributed capital range from 1 percent to 77 percent. However, when the OEB took over the regulatory authority over the LDCs it prohibited contributed capital from entering the rate base and thus, from earning a return.

Electric distribution by the LDCs evolved under a power at cost philosophy reflected in low rates of return on capital. While LDCs were permitted to earn 6.5 percent - 8.0 percent, returns for the vast majority generally ranged from zero to 3 percent. Low costs of capital and an aversion to debt meant that utilities maintained sizeable cash or cash equivalents to fund operations. In the mid 1990s, cash and cash equivalents exceeded 60 percent of net fixed assets for the average LDC.

Between 1988 and 1993, the wholesale price of power increased about 45 percent. Many LDCs also maintained robust annual distribution rate increases during this period. By 1993, growing concerns over the price of electricity led to a government proclaimed freeze on wholesale power rates. The LDCs followed with self-imposed freezes on retail distribution rates. This action transformed the *de facto* regulatory framework from cost of service to performance based regulation since the freeze was equivalent to a price cap with a variable productivity target equal to the rate of input price inflation. This bifurcation in regulatory approaches provides an opportunity to examine the effects of alternative regulatory frameworks.

For some LDCs, contributed capital came to comprise 40, 50 or even 60 percent of net fixed assets. Supporting infrastructure requirements increasingly with contributed capital presented the classic principle-agent problem. Furthermore, increments to contributed "capital" could displace equity-financed investments and labour requirements funded from service revenues. Over time, the rate base supporting revenue requirements shrunk proportionately as more capital was contributed. By 1993, the combination of a proportionally smaller rate base and/or annual robust rate increases resulted in many LDCs' return on equity (ROE) rising dramatically: in some cases exceeding 7, 8, and even, 9 percent. These returns collided with regulatory ROE caps; at the same time, the exclusion of contributed capital from the rate base constrained the revenues.

In response to these complex pressures, Ontario Hydro altered its regulatory treatment of contributed capital. In 1994 the regulator implicitly condoned the use of contributed capital to fund standard operational requirements by allowing the rate basing of contributed capital. Since contributed capital now comprised a large portion of many LDCs' assets, its inclusion substantially lowered regulatory returns.

Stakeholder Concerns During the First Generation PBR Process

Consistent with the legislative requirements of the *Energy Competition Act*, the OEB initiated a process in the fall of 1998 to restructure the electricity distribution sector and examine the efficacy of developing, *de jure*, performance based regulation for the LDC in the Province. Board-sponsored Task Forces made significant progress on a myriad of issues but met opposition or failed to reach consensus on what to do about contributed capital and how to structure the productivity target(s).

Board staff consultants (1999 Staff report) had found some utilities to have operated under a notably more capital-intensive cost structure: in some cases, the share of capital exceeded 65 percent of costs, notably higher than the mean share of 45 percent. It was observed that utilities with high capital input ratios were also those with high contributed capital ratios and raised concerns that historical contribution policies had led to sub-optimal input choices (e.g., the 1994 rate base change exacerbated this inefficiency).[37]

For Ontario LDCs, this constraint would be even weaker: funding in excess of market or internal constraints could be provided by capital contributed by end-users. Some stakeholders noted that such excess capital, if present and included in the restructured rate

[37] The corporate finance literature finds that companies funding investments with excess cash (i.e., free cash flow) are often found to perform worse than companies using debt or external equity which are subject to third party scrutiny and review for prudent use of generated funds.

base, would cause distortions in post-restructured rates, profits and utility valuations and pressed for contributed capital to be excluded from the post restructured rate base.

5.5 *Third-Party Capital and Allocative Efficiency*

DEA is a non-parametric approach to estimating production frontiers using linear programming techniques, and has been increasingly adopted over the past ten years in regulatory applications to estimate technical efficiency. This approach estimates a production frontier by constructing a non-parametric piecewise linear convex hull around data on outputs and inputs, and then calculating efficiencies relative to the frontier. Advocates point to the ease of incorporating multiple outputs and inputs, no requirement to specify a functional form for the production function, and the ability to calculate efficiency measures without the incorporation of prices.

Using an input-oriented DEA model, the extent of inefficiencies among a sample of Ontario distributors has been examined. [38] Exhibit 5.2 presents the mean results for the calculated technical, allocative and total efficiencies.

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[38] Much of this analysis examines the effects of changed regulatory incentives on inefficiencies. Some research on utility benchmarking has included environmental characteristics to control for differences in operating circumstances. Since we are comparing the results from changing incentives with fixed environments, the absence of environmental characteristics in each instance will net out. In addition, there is no standard, accepted practice on how environmental characteristics should be specified within DEA models; researchers have employed at least four different approaches and these alternative approaches produce different rankings within DEA models. In the DEA applications on partial cost benchmarking below, environmental characteristics were examined and found not to have a significant effect on either the mean or individual utility results.

Exhibit 5.2: Ontario Distributors Mean Efficiency Results: 1988, 1993, and 1997

Year	Technical Efficiency	Allocative Efficiency	Total Efficiency
1988	.818	.738	.604
1993	.861	.760	.659
1997	.926	.704	.652

Source: Cronin, F.J., S.A. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," forthcoming, *Annals of Public and Cooperative Economics.*

To examine the concerns raised by some stakeholders that utilities employing higher proportions of contributed capital were over capitalised, we have collected data on contributed capital by utility. Exhibit 5.3 ranks utilities by the ratio of contributed capital to net fixed assets and groups them into two sets: those below the median (i.e., low-contributed capital group) and those above the median ranked utility (i.e., high-contributed capital group). The two groups vary markedly in the use of contributed capital. The group below the median has ratios of contributed capital to net fixed assets ranging from 1.3 percent to 13.4 percent; the group above the median have ratios ranging from 21.7 percent to 77.3 percent.

Exhibit 5.3: Mean Allocative Efficiency Score by Share of Contributed Capital

Mean CC/Net Assets	1988	1993	1997
Below Avg. Share	.809	.837	.783
Above Avg. Share	.663	.671	.603
Range CC/Net Assets			
Below Avg. Share	.644 to 1.000	.704 to 1.000	.532 to 1.000
Above Avg. Share	.486 to .933	.507 to .895	.454 to .761

Source: Cronin, F.J., S.A. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," forthcoming, *Annals of Public and Cooperative Economics.*

What does Exhibit 5.3 show? Throughout the period, utilities with contributed capital use above the median (i.e., high contributed capital) have markedly lower allocative efficiency than those below the median. For example, in 1988 utilities with a lower share of contributed capital have efficiency scores that average .809 versus .663 for utilities with higher ratios. In both groups, efficiency scores rise between 1988 and 1993, although the rise is greater in absolute and percentage terms for lower ratio utilities. Between 1993 and 1997, both groups have efficiency declines; the decline for utilities with a higher ratio of contributed capital is greater in absolute and percentage terms than for utilities with a lower share. The distribution of scores for the low-contributed capital group dominates that for the high-contributed capital group. In 1997 five out of 9 utilities in the low-contributed capital group have efficiency scores higher than the maximum score of .761 for the high-contributed capital group. Only 1 utility in the low-contributed capital group has a score below the average of .603 for the high group. All utilities in the high-contributed capital group have scores below the average in the low group.

What do we know about factor-input usage in the two groups? As Exhibit 5.4 notes, in 1988, both groups use about 3.1 employees per 1000 customers; however, the high-contributed capital group uses about 41 percent more capital per employee. By 1997, both groups have reduced their labour per customer ratio. For the high-contributed capital group the decline averages about 23 percent versus about 9 percent for the low-contributed capital group.

Thus, by 1997, the high-contributed capital group uses about 17 percent less labour per customer than the low-contributed capital group. While labour is decreasing, capital per full time equivalent (FTE), especially for the high-contributed capital group, is increasing. From 1988 to 1997, capital per employee of the low-contributed capital group grows by 10 percent; that of the high-contributed capital group by almost 31 percent. The high-contributed capital group goes from using 41 percent more capital per employee to 68 percent more.

Exhibit 5.4: Factor-input Usage by Contributed Capital

	1988	1993	1997
Low Contributed Capital			
FTEs/Customers (1000)	3.2	3.3	2.9
Mean Capital Input per FTE ($1000)	382.9	380.8	421.6
High Contributed Capital			
FTEs/Customers (1000)	3.1	2.8	2.4
Mean Capital Input per FTE ($1000)	541.0	636.2	707.3

Source: Cronin, F.J., S.A. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," forthcoming, *Annals of Public and Cooperative Economics.*

Regulatory Changes and Factor Mix

What can we say about the changes in efficiency noted above? Between 1988 and 1993, capital increases more than 15 percent and labour decreases over 10 percent. Capital per customer increases 4.3 percent between 1988 and 1993, while labour per customer decreases about 2.8 percent. Since capital represents about 45 percent of costs and labour about 30 percent, these opposing changes imply a net fall in mean productivity during the first half of the period. Offsetting this negative balance is a substantial improvement in distribution system losses. Losses average about 12 percent to 15 percent of costs and many utilities respond aggressively to the 40 percent increase in wholesale commodity prices by reducing kWh losses per customer by 27.6 percent.

The adoption of incentive regulation should increase efficiency. Indeed, during the second half of the period, total capital per utility is flat and labour falls over 10 percent. Capital per customer falls about 5 percent (returning to about its 1988 level); labour per customer falls almost 14 percent. Reinforcing these positive impacts on productivity, mean system losses continue to fall. Thus, consistent with the regulatory incentives embedded in the 1993 rate freeze, over the second half of our period, total productivity increases substantially.

What about the 1994 changes in rate base for third party contributed capital? Regulatory guidelines in 1994 explicitly condoned funding "standard" as well as "above standard service" with third party financing. The utility had discretion over what infrastructure to fund with contributed capital and what specifications to set. Thus, contributed "capital" could displace other investments and labour requirements that had to be funded from capped prices. In the vast majority of cases, third-party payers (i.e., developers) would be bearing the initial cost and recouping these from the buyers of these homes: the classic principle-agent problem.

From 1988 to 1993, contributed capital grew more slowly than non-contributed capital (e.g., 9.3 percent versus 12.7 percent). However, following the decision to include contributed capital in returnable base, contributed capital grew faster than non-contributed capital (e.g., 15.1 percent to 10.4 percent). Indeed, the annual growth in contributed capital escalated four fold from 1.9 percent in 1993 to 7.6 percent in 1997.

Thus, after 1994, capital increasingly replaced labour and contributed capital is increasingly replacing non-contributed capital. Exhibit 5.5 indicates the capital-labour ratio increases at about 7 percent in the first half and about 10 percent in the second half. Individual utilities employing contributed capital become significantly more capital intensive. While the average cost share of capital is 45 percent, some utilities increase their share by as much as 25 percent, raising their end of period share to over 60 percent. The output-labour ratio increases about 3 percent in the first half but almost 16 percent in the second half. The end result: between 1988 and 1993, two and a half times the number of firms improved their factor mix relative to those that experience degradation. However, between 1993 and 1997, fives times as many firms experience a less efficient mix relative to those that experience an improvement; and, among the former, over half experience a degradation of at least 10 percent. These results are consistent with the 1994 change in rate base.

Exhibit 5.5: Mean Labour Ratios

	1988	1993	1997
Mean Capital Input per FTE ($1000	$467.7	$516.9	$570.0
Mean cust. per FTE	329.6	350.3	400.4

Source: Cronin, F.J., S.A. Motluk, "Agency Costs of Third-Party Financing and the Effects of Regulatory Change on Utility Costs and Factor Choices," forthcoming, *Annals of Public and Cooperative Economics.*

The regulatory changes introduced in 1993 (rate freeze) and 1994 (rate basing) had a significant effect on the factor mix and efficiency of LDCs. Over the succeeding four-year period, utilities realised substantial improvements in technical efficiency from the freeze. Within this period, as well as the preceding five-year period, utilities evidenced an ability to affect both improvements and degradations in allocative efficiency consistent with the incentive structures provided by either the market (1988 – 1993) or the regulator (1994 – 1997). With these results in mind, it seems clear, that properly structured regulatory incentives could prompt notable improvements in both technical as well as allocative efficiency.[39]

The sub-optimal factor mix was further exacerbated by the inclusion of contributed capital in the rate base: following the 1994 decision, allocative inefficiency increased 23.3 percent relative to the benchmark. These results are consistent with the inadvertent incentives embedded in this financing arrangement. Markets discipline both pricing and investment performance. For some LDCs, even the weakened free cash constraint was not binding; the latter threshold was lowered by a reliance on third parties to fund

[39] Recall however, that by 1997, Ontario LDCs were on average at a 93 percent level of technical efficiency with minimal room for improvement until the frontier is shifted by the best practice LDCs.

investments. For these LDCs, rates, profits and valuations are indeed higher than they would be with the least cost factor mix. Regulators must recognize the potential efficiency and equity implications of such traditional "cost recovery" mechanisms.

Recommendation: Due to the distortions caused by non-market prices for capital, it is essential that benchmarking cost measures reflect the full set of factor input choices and their associated costs. Conventional measures of capital costs must be calculated and included for efficient and equitable cost comparisons among Ontario LDCs.

5.6 *Benchmarking with Partial Costs or Incorrect Capital Measures*

Rather than the endogenous, tournament-type regulation based on mean costs proposed by Shleifer almost twenty years ago, regulators have opted for market designs based on exogenously determined efficiency comparisons reflected in fixed productivity adjustments. These productivity assessments are based only on estimates of technical efficiency improvements derived from estimated production frontiers. Utilities' prices and potential profits are driven by this externally determined market. A recent paper examines the impacts on utility efficiency rankings from variations in peer group regulation in Europe and Australia as well as in its use in the U.S.[40]

Despite the potential for distortions caused by long periods with non-market prices, these regulatory applications measure only technical efficiency, leaving moot the assessment of optimal input selection. We examine both technical and allocative efficiency variations among firms from the different cost specifications employed by regulators involving output, factor inputs, and costs.[41] How are rankings impacted when only subsets of total

[40] Cronin, F. and S. Motluk, "Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks," forthcoming.

[41] Our interest is in examining the extent of potential biases from peer-group benchmarking with incomplete specifications and inadequate data. Some research on utility benchmarking has included environmental characteristics to control for differences in operating circumstances. Since we are comparing the results from alternative economic models and data to the results from our preferred Base Case, i.e., our interest is in the difference between the Base Case and each alternative not the absolute ranking, the absence of environmental characteristics in each instance will net out. In addition, there is no standard, accepted practice on how environmental characteristics should be specified within DEA models; researchers have employed at least four different approaches and these alternative approaches produce different rankings within DEA Footnote continued on next page.

costs (e.g., OM&A, not capital or system losses) are used to gauge efficiency?[42] Does the use of partial measures of capital relying on physical specifications impact efficiency rankings? Are rankings affected when comparisons are made independently one input at a time? Is the efficiency frontier stable? Finally, we compare alternative yardstick measures to a simple ranking on relative (total) cost per unit.

Few regulators have relied on Shleifer's version of yardstick regulation. On the contrary, as part of electricity sector restructuring over the past decade, a number of regulators have employed production frontier techniques like data envelopment analysis (DEA) or other peer-based techniques to externally establish fixed performance benchmarks for distribution utilities. Such benchmarking in New South Wales, the United Kingdom and the Netherlands, among other jurisdictions, has "uncovered" wide divergences in efficiency among individual firms. In some cases, these "laggard" firms have been assigned substantial targets for improved productivity, i.e., their rates must decrease each year by the external benchmark established by the regulator.

A number of studies have used DEA to estimate the relative efficiency of electricity

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models. Since our interest is in the biases from mis-specifying underlying economic relationships, we do not include alternative specifications of environmental characteristics since these could add to the confusion.

[42] An anonymous referee suggested that differences in environmental characteristics such as density or age of assets may explain differences in costs between electric utilities. The electric utilities that comprise this sample are urban or suburban utilities distinct from other LDCs operating in more extreme circumstances as defined by topography, geology, or remoteness. However, in order to test whether age of assets or service area density has a significant effect, these variables were incorporated into the DEA specification. Area density (the number of customers per square mile of service territory) and relative **a**ge of infrastructure were added to the base case specification separately and together. Results show a highly stable comparison to the base case. In each of the alternative specifications, the average efficiency scores were quite similar to the base case with TE going to .896 from .871, AE going to .698 from .704, and EE going to .627 from .614. In each of the alternative specifications, all utilities that defined the frontier remained on the frontier. In addition, the bottom 7 LDCs (37 percent) remained in the same exact ranking with nearly identical scores. One of the larger utilities did show some improved performance with the introduction of the density characteristic: however, although it moved up several places in the ranking, it was still far from the frontier and did not cause a substantive change in the overall results.

distribution systems (Weyman-Jones, 1991[43] and 1992,[44] Førsund and Kittelsen, 1998,[45] and Kumbhaker and Hjalmarsson, 1998[46]). Such yardstick approaches have also been employed by regulators in the design of regulatory mechanisms. The Norwegian regulator NVE (Grasto, 1997),[47] the Dutch regulator DTe (DTe, 2000)[48] and the NSW Australia regulator (IPART, 1999)[49] have all employed DEA to benchmark electricity distribution utilities and establish parameters of alternative regulatory frameworks. The California Public Utility Commission relied upon a DEA benchmarking to evaluate Pacific Gas and Electric's (PG&E) efficiency. The U.K. regulator OFFER employed less formal cost standardizations/comparisons and limited regression analysis to rank LDCs in its price reviews. However, these prior studies and regulatory applications suffer from several serious shortcomings.

First, these studies often employ model specifications that make the interpretation of the results difficult. For example, such applications often ignore capital and line losses relying on measures of operating cost representing less than half of a utility's total costs, employ physical measures of capital (e.g., number of transformers, line miles), and at times, even define output to include what most researchers would consider inputs (e.g., line miles, transformers). Some DEA/Malmquist analyses have produced implausibly large estimates of productivity changes by distribution utilities, e.g., as much as +/- 20 to

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[43] Weyman-Jones, 1991, "Productive Efficiency in a Regulated Industry: The Area Electricity Boards of England and Wales," *Energy Economics*, April: 116-122.
[44] Weyman-Jones, 1992, "Problems of Yardstick Regulation in Electricity Distribution", in Bishop, M. et al, editors, *Privatisation and Regulation II*, Oxford University Press.
[45] Førsund, F.R., and S. Kittelsen, 1998, "Productivity Development of Norwegian Electricity Distribution Utilities," *Resource and Energy Economics* 20: 207-224.
[46] Kumbhakar, S.C., and L. Hjalmarsson, 1998, "Relative Performance of Public and Private Ownership under Yardstick Regulation: Swedish Electricity Retail Distribution 1970-1990," *European Economic Review* 42 (1): 97-122.
[47] Grasto, K., 1997, "Incentive-Based Regulation of Electricity Monopolies in Norway," NVE working paper.
[48] DTe, February 2000, "Choice of Model and Availability of Data for the Efficiency Analysis of Dutch Network and Supply Businesses in the Electricity Sector." Accompanying "Guidelines for Price Cap Regulation in the Dutch Electricity Sector", prepared for DTe by Frontier Economics.
[49] IPART, February 1999, Technical Annex – Efficiency and Benchmarking Study of the NSW Distribution Businesses, prepared for IPART by London Economics.

30 percent per year (IPART/London Economics, 1999).[50] Second, in some cases, utilities are compared sequentially one input at a time. Yet, it is clear that input choices are interrelated, just as are utility operations. Third, the failure to calculate factor input prices restricts the research to examining technical efficiency. Thus, the potentially critical issue of optimal input selection is unexplored. Yet, earlier research (Fare, et al., 1985)[51] concluded that allocative inefficiency is especially important for regulated utilities facing non-market price signals. Finally, little research has examined the question of benchmarking stability: over time does the set of "efficient" firms exhibit stability?

Our comparison or base case uses an output measure of customer connections and kWh and four inputs representing capital, labour, system losses and material, which comprehensively span a utility's costs.[52] Our alternative cases are grouped into two sets. The first set varies output (e.g., customers only, kWh only) with inputs specified as in the base case. The second set varies input specifications with output defined as in the base case. These variations include inputs defined as (1) base case minus system losses, (2) capital and system losses only, (3) OM&A only, and (4) OM&A with physical counts of capital.

Using alternative production specifications employed in recent regulatory applications, we find mean total efficiency ranges from 58.2 percent to 74.6 percent. Frontier firms and their influence on the global frontier are found to vary substantially between the base and altenative cases for both technical and allocative efficiency. Correspondingly, among the alternative specifications, we find substantial diverenge from the base case efficiency scores for many individual utilities, often exceeding 10, 20 or even 30 percent. Such

[50]IPART, February 1999, Technical Annex – Efficiency and Benchmarking Study of the NSW Distribution Businesses, prepared for IPART by London Economics.
[51] Fare, R., S. Grosskopf, and J. Logan, 1985, "The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities," *Journal of Public Economics* 26: 89-106.
[52] Cronin, F. and S. Motluk, Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks, forthcoming.

differences may not be surprising since cost comparisons by regulators are not typically based on total costs. Similar to Fare, et al. (1985),[53] we find the vast majority of this ineffiency is due to factor mix (i.e., allocative) and a small minority to less efficient operations (i.e., technical). This may be due to shadow prices varying significantly from market prices over long periods and institutional incentives favoring internal over external funds. The use of a simple relative ranking on total cost per customer produces "scores" that are closer to the base case, and absent the extreme deviations found for individual firms in alternative DEA specifications employed by some regulators.

In addition, unlike earlier research that found benchmarking highly unstable with firms cycling on and off the frontier (Weyman-Jones, 1992),[54] we find that over a ten-year period "efficiency" in the base case (i.e., benchmark on total costs) is defined by a stable set of firms. Attributing cause to our stability is somewhat subjective, but our use of a comprehensive cost benchmark likely contributes significantly to this stability. Eighteen of nineteen firms have one or more peers that were their peers in 1988. Eleven of the 18 firms have as their 1997 peers only firms that were their peers in 1988. In 1997, seven firms have 1988 peers as well as some new 1997 peers. It is important to note that even for these latter seven, their new peers in 1997 were also frontier firms in 1988, but for other firms.[55] Only one firm has a peer in 1997 that was not a frontier firm in 1988. And, the only new frontier firm in 1997 has a capital share that increased from about 13 percent higher than the norm to about 50 percent higher.

Exhibit 5.6 presents technical efficiency results for the base case and seven alternative specifications. Firms on the efficiency frontier are assigned a score of 1.00; firms not on the frontier are assigned a score of less than 1.00 based on the percentage reduction in total inputs that could be made while holding output constant. In the base case, we find a

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[53]Fare, R., S. Grosskopf, and J. Logan, 1985, "The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities," *Journal of Public Economics* 26: 89-106.
[54] Weyman-Jones, 1992, "Problems of Yardstick Regulation in Electricity Distribution", in Bishop, M. et al, editors, *Privatisation and Regulation II*, Oxford University Press.
[55] That is the new frontier firms for these 7 were frontier firms in previous periods but for other firms.

mean technical efficiency of 87.1 percent. That is, on average, firms in our sample in 1997 could reduce their inputs by almost 13 percent and produce the same level of distribution services if all firms operated similarly to their peers on the frontier. The least efficient firm has a score of 58.8 percent . Four firms score in the 70s and five in the 80s. Alternative output definitions result in average efficiency scores of 74.8 to 85.0 percent and individual scores in many cases are found to differ by 10, 20, 30 or even 40 points from those of the base case. Among alternative output specifications we ran a customers only case and a kWh only case. While the customer only case has two firms with differences between 10 and 20 points from the base case, the kWh only scores for nine firms differerence by more then 10 points. Indeed, note firm 6 which is on the base case frontier scores only a 60.5 in the energy only case.

Alternative input specifications result in mean efficiency scores ranging from 72.37 to 87.8 with individual efficiency scores deviating substantially from the base case. With system losses omitted from the base case, one quarter of efficiency scores deviate by more than 10 percent. With only OM&A costs as the benchmark, we find four firms with deviations of more then 20 percent. Recall that firm 8 which is one of the two frontier firms in this case has one of the highest capital shares in the sample and thus one of the lowest OM&A shares. Indeed, firm 10 which is on the base case frontier has a score of only 83.6 with rankings based on OM&A. Note that firm 10 is the dominant influence firm in the CK (i.e., costs of capital), SL (i.e, system losses) case. In that case, we find 10 firms with deviations greater then 10 percent, some substantially higher. Indeed, the firm with the lowest score, firm 8 with 51.7, also has the largest deviation from the base case. One explanation for the differing results between the OM&A case and the CK, SL may be that many firms reported operating results in terms of OM&A to the former Municipal Electric Association which published the numbers annually. Similar statistics were not available for capital. Thus, utilities may have focused to a much greater degree on OM&A benchmarks. Finally, in the NK (i.e., physical counts of capital) and OM&A case more than half the sample scores deviate by more than 10 points.

Exhibit 5.7 presents allocative efficiency scores. Note that the base case averages 70.4. That is, on average, firms in our sample in 1997 could reduce their input costs by almost 30 percent if all firms' input mixes were consistent with those for firms operating on the frontier. This result is consistent with Fare, et al, (1985)[56] who also find allocative ineffiency to be more than twice as large as technical inefficiency. Two firms (4 and 6) define the frontier and interestingly one, firm 4, has an internal rate of return closest to the market based rate of return. The three other firms that were on the technical efficiency frontier have allocative scores of 45.7, 58.8 and 86.5. Among the three firms with scores below 50.0 percent, firms 7 and 8 have very high capital-labour ratios and both have over half of their capital from enduser "contributed capital."

Alternative output definitions result in average efficiency scores of 64.6 percent to 69.5 percent. Generally, firms are found to have similar scores on the alternative output definitions relative to the base case. However, individual scores in some cases are found to differ by 10 and even 20 points from those of the base case. In one case, firm 10 has a score that is 20.5 less then its score in the base case. Alternative input specifications result in efficiency scores ranging from 75.6 percent to 91.7 percent. Note that in the OM&A case, we are assessing factor input selections for only two inputs (i.e., labour and materials). Similarly, in the case of capital and system losses, we again are assessing factor input mix for two inputs. In the first two alternative cases, firms 4 and 6 still define the frontier of allocative efficiency. However, in the last two cases, firm 8 now defines the benchmark. In the case of NK with OM&A we find a high degree of divergence with the base case: nine firms have deviations of more then 10 points, many greater then 30.

[56] Fare, R., S. Grosskopf, and J. Logan, 1985, "The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities," *Journal of Public Economics* 26: 89-106.

Exhibit 5.6: Base Case and Alternative Regulatory Benchmarking Results for Technical Efficiency

Base Case Inputs				Base Case Outputs			
Firm	**Total Energy Only**	**Total Customers Only**	**Base Case**	**Base Case no SL**	**CK, SL**	**O&M**	**NK, O&M**
1	0.588	0.444	**0.588**	0.389	0.588	0.331	1.000
2	0.806	0.906	**0.906**	0.870	0.622	0.862	0.870
3	0.806	0.899	**0.899**	0.899	0.637	0.899	1.000
4	1.000	1.000	**1.000**	1.000	1.000	1.000	1.000
5	0.740	0.924	**0.924**	0.880	0.742	0.857	0.866
6	0.605	1.000	**1.000**	1.000	1.000	0.952	0.971
7	0.914	0.982	**0.982**	0.972	0.756	0.972	0.977
8	1.000	1.000	**1.000**	1.000	0.517	1.000	1.000
9	0.882	0.696	**0.882**	0.684	0.781	0.684	0.899
10	1.000	1.000	**1.000**	0.874	1.000	0.836	0.836
11	0.719	0.856	**0.856**	0.856	0.695	0.831	0.938
12	0.516	0.778	**0.778**	0.688	0.778	0.629	0.651
13	0.408	0.717	**0.717**	0.669	0.615	0.669	-
14	0.716	0.738	**0.738**	0.738	0.519	0.738	0.739
15	0.526	0.803	**0.803**	0.803	0.613	0.803	0.804
16	0.725	0.929	**0.930**	0.885	0.761	0.884	-
17	0.508	0.724	**0.724**	0.685	0.682	0.656	0.657
18	0.825	0.746	**0.825**	0.732	0.696	0.732	0.733
19	0.931	1.000	**1.000**	0.980	1.000	0.980	0.981
Mean	**0.748**	**0.850**	**0.871**	**0.821**	**0.737**	**0.806**	**0.878**

Source: Cronin, F. and S. Motluk, Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks, forthcoming.

Exhibit 5.7: Base Case and Alternative Regulatory Benchmarking Results for Allocative Efficiency

Base Case Inputs				Base Case Outputs			
Firm	**Total Energy Only**	**Total Customers Only**	**Base Case**	**Base Case no SL**	**CK, SL**	**O&M**	**NK, O&M**
1	0.583	0.746	**0.613**	0.925	0.663	0.860	0.282
2	0.468	0.467	**0.495**	0.514	0.600	0.996	0.991
3	0.728	0.661	**0.713**	0.713	0.967	0.780	0.697
4	1.000	0.909	**1.000**	1.000	1.000	0.978	0.976
5	0.554	0.665	**0.676**	0.709	0.753	0.998	0.989
6	0.960	1.000	**1.000**	1.000	1.000	0.999	0.981
7	0.374	0.436	**0.454**	0.458	0.488	0.902	0.983
8	0.453	0.417	**0.457**	0.456	0.735	1.000	1.000
9	0.484	0.625	**0.532**	0.684	0.571	0.778	0.587
10	0.660	0.831	**0.865**	0.988	0.868	0.984	0.983
11	0.856	0.778	**0.830**	0.830	0.967	0.992	0.885
12	0.677	0.816	**0.816**	0.922	0.846	0.879	0.846
13	0.691	0.761	**0.761**	0.815	0.857	0.859	-
14	0.539	0.491	**0.536**	0.535	0.658	0.889	0.884
15	0.798	0.725	**0.745**	0.745	0.954	0.758	0.751
16	0.582	0.704	**0.712**	0.748	0.786	0.975	-
17	0.843	0.872	**0.888**	0.938	0.940	0.945	0.941
18	0.613	0.708	**0.687**	0.773	0.764	0.919	0.913
19	0.369	0.587	**0.588**	0.599	0.505	0.927	0.923
Mean	**0.644**	**0.695**	**0.704**	**0.756**	**0.785**	**0.917**	**0.854**

Source: Cronin, F. and S. Motluk, Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks, forthcoming.

5.7 *Examining the PEG Proposal to see if it is Based on a Breadth of Methodologies to Test for Robustness in Results and whether it Encompasses Model Specifications, Data, and Estimation Techniques that Appropriately Reflect Electricity Distribution*

Clearly there are many steps in a benchmarking study, each with a set of choices that can influence the final results. Having the appropriate data, of course, is of paramount importance. But so to are the choices that are made with respect to analytical methodology (e.g., DEA); Stochastic Frontier Analysis (SFA) Cost or Production; Regression Analysis with its many variants), estimation technique (e.g., ordinary least squares (OLS), two stage least squares (TSLS), or system), and the specification of the model with all the variants possible. Each of these permutations can drastically impact such final results as estimated costs, efficiency score or, efficiency ranking. Indeed, researchers examining the sensitivity of such results have found them to be sensitive to methodologies, specifications environmental variables, and data.[57]

My comments are divided into four areas. First, I examine the proposal to see if it spans a range of methodological approaches and sensitivity tests. Second I review the proposed approach for the appropriateness of estimation techniques within the limited span of methodologies actually employed. Third I review the model(s) to see whether their specifications appropriately reflect electricity distribution. Finally, I examine the robustness and appropriateness of the data used in the proposed models.

Does PEG's Proposed Approach Cover a Sufficiently Wide Range of Methodologies to See if LDC Costs/Rankings are Sensitive to Different Approaches?

In his survey of benchmarking methodologies, Berg cautions (p 2),[58]

> "A single index of utility performance has the same problem of any indicator: it will be neither comprehensive nor fully diagnostic."… (p 10)

[57] See for example, Cronin, F. J. and Motluk, S. A., forthcoming, "Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks,"forthcoming, Originally, *The (Mis)Specification of Efficiency Benchmarks among Electric Utility Peer Groups*. Presented at the North American Productivity Workshop II, Union College, NY, 2002.

[58] Berg, S. "Survey of Benchmarking Methodologies: Executive Summary", Public Utility Research Center, March 1, 2006.

> "in most cases there is no 'ideal' model among the set of potential models."
>
> (p 10) "Thus to check for robustness of performance rankings, researchers have begun to compare results from different methodologies….verifying whether models identified the same set of utilities as the most efficient and least efficient. Clearly, if efficiency scores are to have any use for managerial incentive or as elements in regulatory mechanisms, stakeholders need to be confident that the scores reflect reality, and not just artifacts of model specification, sample selection, treatment of outliers, or other steps in the analytical process."

Berg (2006) presents 11 analytical methodologies techniques available to researchers for benchmarking purposes.[59] PEG chooses to use one technique (i.e., a variant of regression analysis) and two variants of that (i.e., translog versus double log). These two sets of results are closely associated and only differ in their functional form. No analysis is undertaken with other major forms of benchmarking methodologies to examine how sensitive results are to their narrowly chosen approach. This failure to examine widely employed benchmarking methodologies severely limits the confidence we can place in the results.

Does PEG's Proposed Approach Rely on Appropriate Estimation Techniques?

For the cost functions estimated by PEG, right hand side (i.e., explanatory) variables are required to be outside the control of the firms whose costs are being estimated, i.e., they are exogenous to the behavior under investigation. Yet, despite this requirement, PEG includes such variables as (1) the percent of wires placed underground, (2) the circuit miles of wire, and (3) the number of transformers. Number (1) is clearly under the control of LDC management or policymakers. This is determined by the LDC or shareholders and is implemented as such. Numbers (2) and (3) are to varying degrees under LDC discretion based on topology, system design and prices. All of these are not truly exogenous, and as such their inclusion on the right hand side of the model means

[59] Samuli, H. et al, "Effects of Benchmarking of Electricity Distribution Companies in Nordic Countries-Comparison Between Different Benchmarking Methods," present yet another methodology that has been employed for benchmarking in Sweden, the Network Performance Assessment Model.

that a more appropriate estimation technique such as TSLS should have been employed to correct for endogeneity effects. The inclusion of endogenous variables on the right hand side of the model seriously compromises PEG's statistical results,

Does PEG's Proposed Approach Rely on Appropriate Model Specifications?

Presumably for the purposes of benchmarking total LDC performance one would employ a properly specified total cost function, with **total cost** on the left-hand side and on the right-hand side to explain differences in costs, the model would include **all input prices** (i.e., capital, labour, line losses) and **measures of output.** Presumably, because PEG is under the impression that it does not have a measure of the cost of capital, the quantity of capital, nor the price of capital, PEG specifies their model as a short-run cost function and employs several **expedient short cuts** to cover critical gaps in their data. As such, to be properly specified, the short-run cost function should have **properly defined variable costs** on the left-hand side of the model, the **quantity** of the "fixed" input on the right-hand side, together with **all other input** prices.

What does PEG include in their estimated short-run cost function?

First, PEG employs a seriously biased left-hand side variable which does not consistently reflect the variations across the LDCs in labour capitalization and expenditures for reliability. That means, and, this is acknowledged by PEG, that we are comparing "apples to oranges": we can simply not make any sense out of a comparison that starts out with data of such a highly inconsistent nature. Second, PEG does not include the quantity of capital on the right-hand side but a proxy (GBV) that we have seen above, bears no resemblance to an individual LDC's actual quantity of capital. Worse, it actually shows some LDCs to use more capital than other LDCs when in fact they use less. The effect of such data errors would likely cause the model to produce dramatically inaccurate results. Third, PEG does not include a critical input price: the price of power losses. This statistical problem, called the problem of left out variables, would result in the wrong estimated impacts associated with the included variables.

Fourth, PEG mis-specifies the LDC output variable by including km of circuit wire as an output and leaving out the level of reliability achieved by each LDC. We have discussed above the biases engendered by including reliability-related costs within OM&A but not including the reliability associated with such costs as an output. On circuit km of wires, PEG had begun their discussion dealing with the issue of varying density among LDCs. Fair enough. But then PEG shifts its discussion to extensiveness. From there PEG jumps to including km of wires. Kilometers of wires are an investment input used by LDCs with other pieces of equipment, e.g., transformers, and other inputs to deliver power to customers. But, the specification is even more peculiar: fifth, PEG then defines the number of transformers as an "Other Business Condition" and includes it as well on the right-hand side. So, in one case we have PEG calling one category of investment (e.g., km of wires) an output, and on the other hand, we have PEG calling an associated investment category, an "Other Business Condition." PEG's arbitrary specification defies explanation and certainly causes significant errors on the modeled LDCs costs.

Finally, PEG estimates a poorly specified short-cost function with inadequate and missing data. However, even if the specification and data issues could have been overcome, the specification employed by PEG assumes that capital is fixed, i.e., that it does not respond to changes in such important determinants as price. But, my research on Ontario LDCs , discussed in section 4 indicates that capital does respond to altered circumstances, e.g., price or regulatory changes, and does so, even partially, within a 3 - 5 year period. In order to get a better handle on the cost/efficiency issues PEG is examining, PEG should estimate a properly specified short-run function with the appropriate data. In addition, PEG should estimate a properly specified long-run cost function with correct data. This would allow a full range of input substitution-complementary relationships to be observed with their associated cost impacts. Properly done, both models have something to offer in improving our understanding of these LDC costs issues.

Does PEG's Proposed Approach Rely on Appropriate Data Definitions?

As we have discussed in previous sections as well as in this section above, PEG has employed variables which have serious deficiencies when it comes to accurately representing the item they purportedly represent. First, PEG employs a cost variable

(OM&A) which does not consistently reflect the variations across the LDCs in labour capitalization and expenditures for reliability, the "apples to oranges" comparison.

Second, PEG includes a quantity of capital variable (GBV) that, they acknowledge, is a proxy not employed in rigorous, conventional, nor scholarly research, rather then the cost of capital variable "rigorous" research employs.

Third, PEG defines output to include an LDC's investment in circuit wires (the more the investment, the higher the output, even if no one is connected to the wires), but fails to include an LDC's achieved reliability whose costs are partially reflected in OM&A. As discussed in section 6, electricity distributors produce and sell a multi-dimensional output to their customers, and this output includes reliability and other aspects of power quality. PEG acknowledges that reliability varies widely across LDCs, and that higher reliability generally comes at a higher cost. Yet, having admitted such a critical difference among LDCs in output and costs, PEG fails to reflect these in their benchmark model. Without such fundamental features of electricity distribution reflected, it would not be possible for a model to accurately reflect an LDC's costs.

6 Service Quality/Reliability must be included in any Quantified Multivariate Output Variable used as a Benchmark to Assess a Utility's Production Integrating Utility Cost Benchmarking with Service Quality and Reliability Regulation.

Electricity distributors produce and sell a multi-dimensional output to their customers. Clearly, the customer service, reliability and voltage quality, among others, can vary substantially, producing different products depending on the mix of characteristics delivered to the customers. Many/most energy regulators have a dual responsibility toward consumers: they must ensure that prices are just and reasonable and they must ensure the appropriate level of service/reliability is delivered. Without the latter, there can be no assurance that the prices being paid are in fact just and reasonable. However, as PEG notes, and I agree with, (pp 30 - 31):

> The reliability of distribution services provided by utilities varies widely. Better reliability generally comes at a higher cost. The cost impact of quality is thus a valid issue in distribution benchmarking. There are special challenges in the estimation of the cost impact of quality. Despite its importance, empirical research on this topic is not well advanced.

Therefore, since reliability varies so "widely" among LDCs, and those LDCs with higher reliability will generally have higher costs, we must structure the LDC benchmarking to account for these differences. If not, and such different cost causation situations are simply observed through the LDCs' OM&A costs, we may mistakenly identify "higher cost" LDCs as less efficient than lower cost LDCs providing lower reliability.

If this is so, the benchmarking approach proposed by PEG and Board staff will penalize the high-reliability LDCs and reward the low-reliability LDCs.[60] Such a backwards reward/penalty scheme could then incent the high-reliability LDCs to reduce their OM&A expenses to improve their benchmarking scores; reliability would most likely decline as well. This is not the result we would expect from a well-structured benchmarking scheme.

[60] We are using the terms "high" and "low" in a relative context.

Imprudent curtailments in OM&A have been shown to significantly lower LDC reliability (see below for a discussion). Regulators in both North America and Europe have recently responded to profit-driven OM&A cuts with new regulatory initiatives Below, we examine some of the critical interlocking relationships among IR incentives, profit motives, cost impacts, reliability, and benchmarking and the steps that regulators in other jurisdictions, particularly the path breaking work on power supply (or service quality regulation) in Europe.

Given the Board's stated potential use of benchmarking as "informing the development of incentive regulation, and in particular the issue of variable, or utility-specific, productivity factors, in this section, I examine the differences between cost of service regulation and IR in terms of how each deals with service quality, the differing incentives faced by utilities operating under each, and the process employed in reviewing firm performance.

I examine the theoretical relationships among IR, incentives to under- maintain and under-invest, and the degradation of reliability. I also examine the empirical findings relating to the increased profit motives under IR, the resulting imprudent cost reductions, and the consequences for lowered reliability. I also discuss the role of service standards in the initial PBR adopted by the OEB in 2000 and the Board's process related to service standards since then.

Both the experiences among North American as well as European energy regulators to this potential IR-induced, service degradation phenomenon are discussed. Among the former, following a series of significant outages often caused by imprudent reductions in OM&A expenses, regulators have increasingly imposed on the utilities mandates covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing necessary to fulfill the regulations.

In Europe, regulators such as the Council of European Energy Regulators (CEER) have documented and encouraged the adoption of service/reliability quality regulation (SQR) which combines system-wide standards with incentive/penalty schemes as well as single-customer guarantees with monetary payments for nonperformance. Some regulators have used willingness to pay (WTP) studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements or interruption avoidance.

Indeed, some regulators have taken this WTP information and explicitly incorporated the customer interruption values into their distribution price regulation. In one case, the regulator has specified a goal of achieving a socially optimal level of reliability by recognizing that customer interruption costs must be considered equally with a utility's capital and OM&A costs in utility planning and regulatory benchmarking.

6.1 *The Multi-Dimensional Nature of Electric Distribution Output and Just and Reasonable Prices*

As mentioned above, electric distributors produce and sell a multi-dimensional output to their customers. Clearly, the customer service, reliability and voltage quality, among others, can vary substantially, producing different products depending on the mix of characteristics delivered to the customers. These different bundles of characteristics would likely have different costs associated with them and thus different prices. In evaluating the reasonableness of a distributor's price, we need the context of the "whole package(s)" being delivered to its customers.

Regulators usually have responsibility to ensure that regulated prices such as electric distribution are just and reasonable. Regulators also often have responsibility to ensure that distribution service and reliability meet certain standards associated with some of these non-price features of the distributor's output. Determining if distribution prices are just and reasonable requires that we evaluate the other non-price features of their product.

OEB Initiation of Working Group on the Review of Service Quality Regulation

Indeed, the OEB has noted its responsibility with respect to service/reliability as well as the necessity to evaluate prices hand-in-hand with the actual service/reliability delivered to customers. On August 29, 2003 the Board notified "All Licensed Electricity Distributors and Registered Parties," of its intent to commence an "**Initiation of Working Group on the Review of Service Quality Regulation" Board File No. RP-2003-0190.** The letter acknowledged that:

> Section 1 of the Ontario Energy Board Act, 1998 states, in part, that: The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives: ... 3. To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

Furthermore, the Board noted that the issues of distribution prices and service quality are integrally linked together. As the August 29, 2003 Board letter also states referring to an earlier, March 14, 2003 Board letter to electricity distributors and other stakeholders, the Board noted that "… a determination of just and reasonable rates must take into account the adequacy and level of service quality….". That is, we can only evaluate the justness and reasonableness of distribution prices in relation with the associated quality of service and reliability received by customers. To ignore the latter, especially for an extended period of time would, of necessity, raise the question of whether the prices being paid were just and reasonable.

OEB Staff Report on Service Quality Regulation for Ontario Electricity Distribution Companies

On September 15, 2003, Ontario Energy Board staff released paper, "Service Quality Regulation for Ontario Electricity Distribution Companies" (2003 Staff report). Section 2 of the 2003 Staff report dealt with the principles of service quality regulation, notably the inherent link between service quality and just and reasonable prices. As noted:

> In this section, we detail various principles that underlie service quality regulation. These principles are taken from research into both the theory and practice of service quality regulation. These principles are generic in nature, although comments are provided, in some instances, on how they

> relate specifically to electricity distribution. A reason for dealing with these principles up front is that an understanding of these issues aids in understanding the service quality reporting currently being done by electricity distributors – as part of the first-generation PBR plan – as well as to understand the issues that should be explored as part of the review of Service Quality Regulation.

Importantly, the Staff Discussion Paper stated: ***"A consideration of just and reasonable rates must take into account the quality of the product or service to be provided."***

> This basic premise underlies the concept and application of quality of service regulation. …In a competitive market, where customers have choices, including the option of forgoing purchase and consumption, customers will indicate their quality preferences, along with the prices that they are willing to pay to receive certain levels of quality. Firms must jockey to meet customers' needs and expectations with respect to acceptable price/quality offerings. Those who succeed in offering the levels of quality that meet (and even exceed) customers' requirements at prices that they are willing to pay for will attract customers; those who do not will lose customers and market share. In a monopoly market, there is only one supplier. Frequently, there are more limited choices for quality/price combinations. However, even here customers will express their satisfaction with the quality of the product or service relative to their needs and expectations and relative to the offered price by their willingness to buy, and how much. If the product or service is unsatisfactory, they may forego it or seek a substitute. … However, the ability of customers to alter their consumption, even going so far as to replace the service with a substitute, lessens for utility services. Many of these services are "essential", or nearly so, for modern living. Just as cars and trucks share the road, customers share the electricity grid for the transportation of electricity.

Commenting on COS regulation, the Staff Discussion Paper noted that under COS regulation the review process was ussualy annual, and had embedded in it a review of service quality and reliability.

> Traditionally, Cost-of-Service ("COS") regulation has been used for setting rates for economically-regulated firms. This involves reviewing capital investments and operating expenses, with respect to necessity and prudence, and factoring in debt servicing and a reasonable return on shareholders' equity given the business risk of the firm. Such reviews occurred periodically – often annually. Service quality could be reviewed as part of the revenue requirement and rate application, with consideration of how existing operational expenses and planned capital investments

> would contribute to the maintenance or improvement of service quality. Poor service quality could also be a factor considered by the regulator in reducing the allowed revenue requirement (without exacerbating the situation by the utility cutting costs and services in response to reduced revenues).
>
> While service quality was a factor considered in CoS regulation, this often did not entail formal reporting and monitoring. The relative often annual – frequency of rate applications meant that service was reviewed without long lags. Service quality measurement was also evolving since the 1970s in light of technical improvements and management approaches. Also, the "rate base" concept of CoS regulation, some argue, provides an incentive for the firm to overinvest and provide "gold-plated" service, and so service degradation is thus seen as less of a risk under CoS regulation.

The 2003 Staff report also noted that under COS regulation the firm's incentives were not at odds with service quality since they earned a return on investments, including capitalized labour, and prudent and necessary cost were passed along to the customers.

Commenting on, "*Quality of service as part of economic regulation,*" the 2003 Staff report stated:

> Service quality regulation is integral to economic rate regulation, to setting "just and reasonable" rates. From the perspective of the users or customers of the service, there must be a consideration of the "value" of the product or service, where value is defined as the product or service meeting or exceeding the needs and expectations of customers relative to the price charged. From the perspective of the regulated firm supplying the product or service, the regulated price must be sufficient to cover the costs of providing the product or service at least at the minimum acceptable level of quality, including the opportunity, if applicable, to earn a reasonable rate of return on its shareholders' investments, to cover its debt obligations, and to raise further capital as needed.

Commenting on PBR, the 2003 Staff report noted that the firm's differing incentives might result "in cost containment that results in degraded service" and that "Service quality monitoring serves as a counterbalance to ensure that adequate service is maintained." Unlike COS regulation, the Board staff noted "an increased need for on going monitoring of service performance" under PBR "to ensure that any problems that do occur are addressed in an effective and timely manner."

Beginning in the 1980s, there has been a migration to PBR forms of rate regulation, including price and revenue caps. PBR differs from CoS in that it provides incentives for a firm to improve its productivity, with an opportunity to share the gains from productivity improvement with both customers, through service improvements and service cuts, and with investors, through increased profits. Theoretically, PBR acts as a closer proxy to the market forces that firms in competitive markets face. Typical PBR rate setting mechanisms are more formulaic, allowing for upward pressures from input price inflation but offset, at least in part, but productivity gains. Other factors, such as growth or exogenous factors (tax rates, etc.) may also be factored in. Another advantage to PBR is that the formulaic approach to rate adjustments under PBR should also contribute to more efficient regulation, with less frequent detailed reviews to reset plan parameters. With less frequent detailed reviews, there is an increased need for ongoing monitoring of service performance, to ensure that any problems that do occur are addressed in an effective and timely manner. Also, the incentives inherent in PBR for the utility to seek productivity improvements could result in cost containment that results in degraded service. Service quality monitoring serves as a counterbalance to ensure that adequate service is maintained.

In some PBR plans, either explicitly or implicitly, the service performance of the firm may be a parameter affecting rates or revenues. A Q-factor … affects the price or revenue cap explicitly. In other plans, aggregate penalties, or the existence of service guarantees and rebates, link the firm's financial performance to its service performance, but do this separately from the PBR mechanism….

A consideration of service quality is thus integral to regulatory rate setting. However, service quality regulation can, to some degree be separate from rate-setting. While appropriate indicators and standards must be consistent with the needs and expectations of customers, these may be determined, or at least heavily influenced by technical considerations – engineering standards, technology choice. While different customers may have differing needs and expectations, the commonality of the network places constraints as to the extent that the utility can "differentiate" the core business of electricity transportation and distribution for different customers. The firm's management and engineers will seek to design, construct and operate the network, economically, to meet customers needs adequately. While customer needs and expectations are a key input for the design and operation of the network, the availability, capabilities and costs of the technology, and the commonality of the network will also influence operating standards.

The Council of European Regulators' Electricity Working Group, Quality of Supply Task Force

The CEER Electricity Working Group, Quality of Supply Task Force, Third Benchmarking Report on Quality of Electricity Supply 2005 also examined the reasons behind the need for service quality regulation.

The CEER task force report notes that quality may have a "long recovery time after deterioration." and that "quality of service is usually regulated over more than one regulatory period." (p 31)

> In recent years, a growing number of countries have adopted price-cap as the form of regulation for electricity distribution, and sometimes also transmission, services. Price-cap regulation without any quality standards or incentive/penalty regimes for quality may provide unintended and misleading incentives to reduce quality levels. Incentive regulation for quality can ensure that cost cuts required by price-cap regimes are not achieved at the expense quality. The increased attention to quality incentive regulation is rooted not only in the risk of deteriorating quality deriving from the pressure to reduce costs under price-cap, but also in the increasing demand for higher quality services on the part of consumers. For these reasons, a growing number of European regulators have adopted some form of quality incentive regulation over the last few years. Moreover, quality is multidimensional and some aspects of quality have a long recovery time after deterioration. Hence, quality of service is usually regulated over more than one regulatory period to address numerous issues, including continuous monitoring of actual levels of performance.

6.2 *An Empirical Examination of IR, OM&A Expenditures and Utility Reliability: IR without Standards Leads to Reduced O&M and Lowered Reliability*

One study examined the effects of incentive regulation on OM&A expenses and service results. Ter-Martirosyan (2002) examined the effects of IR on electricity distributors' OM&A and quality of service.[61] The author uses data from 1993 – 1999 from 78 major US electric utilities from 23 states. Ter-Martirosyan finds that IR is associated with a reduction in OM&A expenditures. The author finds that such reduced OM&A activities are associated with an increase in the average duration of outages per customer, System

[61] Ter-Martirosyan, A., "The Effects of Incentive Regulation on Quality of Service in Electricity Markets," Working Paper, 2002.

Average Interruption Duration Index (SAIDI). Importantly Ter-Martirosyan's analysis concludes that the incorporation of strict reliability standards with associated financial penalties into IR can offset the tendency of IR plans with out standards and penalties to imprudently cut critical OM&A activities.

Ter-Martirosyan finds that utilities with IR but without standards reduce their expenditures throughout the time period of the analysis, falling by 37 percent. On the other hand, utilities with IR and with standards and penalties increased their expenditures in every year of the analysis, rising by 17 percent. The former utilities were found to have had a 64 percent increase in SAIDI and a 13 percent increase in System Average Interruption Frequency Index (SAIFI). The latter utilities were found to have had a 26 percent decrease in SAIDI and a 23 percent decrease in SAIFI.

The author finds a statistically significant relationship between IR without standards and the decline in SAIDI. The author posits that the potentially different pathway through which OM&A reductions are reflected in the network and SAIFI means that we would require a longer period than the study had to statistically confirm the lagged effects of OM&A reductions on SAIFI. The statistical model finds that an 18 percent reduction in O expenditures together with an 8 percent reduction in M expenditures would imply an associated 30 percent increase in the average duration of outages per customer.

Possibly for these perverse quality services results, it is common for utilities under IR to have explicit and strict service quality standards, often with penalties for violations. Indeed, Ter-Martirosyan finds that 70 percent of the utilities in that sample with IR had such penalties. Third generation plans continue to apply and refine such service-penalty features as more is learned about the implications of IR on cost costs, OM&A practices and service quality.

However, some regulators in the US have begun a more direct approach to correcting reliability failures: instituting inspection, maintenance, and in some cases, investment mandates directing utilities what, when and how to perform critical operations. In

Europe, many regulators have instituted system-wide performance standards with significant financial consequences for the regulated utilities. In addition, many of these regulators have structured single-customer guarantees with penalty payments for non-performance (e.g., restoration of within a certain period or customer is eligible for a specific payment). These efforts are discussed in more detail below as well as very recent developments to set service performance planning within a more rational approach that considers and values the costs of customer interruptions.

6.3 *Service Standards with Financial Consequences are Needed to Counter the Incentive to Maximize Profit through Excessive Cuts in Service Quality and Reliability.*

It is clear that incentive regulation alters the motivations of utilities. Rather than focusing on higher ROE through increases in the rate base, for example, IR encourages utilities to reduce costs. Under COS, increases in OM&A expenses, if judged prudent, would not be in conflict with the goal of maximizing ROE since such OM&A expenses would be recouped through higher rates.

However, the shift to IR can put OM&A costs directly in conflict with the pursuit of profit during the plan's term. Cost reductions experienced earlier in a plan's term are worth more to a utility than cost reductions achieved in later years. Since capital may not be subject to significant changes within the earliest years of a plan's term, the utility could be incented to cut OM&A expenses beyond what is prudent for the quality and reliability of the network.

This tendency is reinforced by the fact that near term reductions in OM&A expenses may only be apparent over a longer time period. As PEG notes (p 11):

> In the long run, utilities that defer maintenance will experience service quality deterioration.

Activities such as tree trimming might be exceptions to this relationship, but even in this case, utilities have been found to have excessively reduced tree-trimming operations under IR, with increased outages following such reductions. For example, in the US, regulators at both the federal as well state levels have concluded that profit-incented utilities imprudently cut critical OM&A activities.

Firms will only optimize those costs internal to its cost structure, generally capital and OM&A. The costs borne by customers due to the utility's non-performance, i.e., interruptions for example, are not factored into the calculations made by a utility when deciding how much to spend on capital and OM&A. Under these circumstances, it would generally be the case that the utility's failure to recognize such customer interruption costs would lead it to spend too little on reliability. Three approaches have evolved to alter the utility's natural tendency to under-maintain/invest.

First, both federal and state regulators in the US have responded by mandating specific and detailed actions on the part of utilities regarding what OM&A or investment needs to be undertaken. Second, regulators in a number of European countries have spelled out system-wide incentives and single-customer mandates with penalties regarding service quality and reliability. A third approach is identified in section 6.4 below.

While the efforts in the first and second approach are a significant improvement over the cases of no/weak SQR, the fact is that these incentives and penalties are not grounded in a vision of what the socially optimal level of reliability for electricity distribution is: that is, the monetary values associated with the penalties are usually ultimately selected to get the distributors' attention. Over the short run, these approaches should improve reliability and, in many cases the society's welfare. Over the medium to longer run, however, we need to develop a framework that moves the network's quality performance toward that level that maximizes the welfare of its stakeholders. That is what regulators adopting the third approach have strived to move toward.

6.4 *Reliability Needs to be Viewed in the Context of an Optimal Level by Integrating Costs of Customer Interruptions with Distributors' Capital and OM&A Costs*

Thus, a third preferred approach would be to determine what the socially optimal level of reliability is and then put in place a plan for distribution utilities to achieve this level of service quality performance. To do this, however, we would need to know the incremental costs of improved reliability as well as the associated incremental benefits. While the former information could be provided by the distribution utilities and regulators, we would still have to determine a schedule of benefits. In fact, some regulators have developed a third approach using monetary estimates of what reliability means in terms of customers costs/values.

That is, what would a customer pay to avoid an outage or improve service often called WTP studies. Ofgem in the UK has set the penalties for its single-customer guarantee standards based on WTP surveys of residential and commercial/industrial customers. This is a beginning step in attempting the distributors to factor into their operational decisions the costs borne by customers.

NVE in Norway has gone even further. NVE's goal is not necessarily to improve system-wide reliability, but to find the socially optimum level, i.e., the level of reliability where marginal benefits from improvements equal the marginal costs of implementation. To attain this goal, NVE must estimate what the customer costs of interruptions are and get the distributors to treat customer interruption costs just as they would treat capital or OM&A costs in their planning process: to "internalize" the externally borne customer costs.

Appendix B presents information from NVE on its power quality regulation.

To that end, NVE has undertaken WTP studies of customer interruption costs. NVE has examined the impact of short interruptions, long interruptions, and voltage dips on the breadth of distribution customers (e.g., residential, agricultural, commercial, industrial). NVE finds that the annual costs of customer interruptions are larger than the amount spent annually by distributors on OM&A and about 60 percent – 75 percent of the amount spent on investments.[62] Given the magnitude and importance of these interruption costs, starting in 2000-2001 NVE structured its IR to explicitly account for costs of energy not supplied (CENS) by benchmarking individual distributors on the amount of energy not supplied (ENS).

Approach 1: The US Response---Mandates on Utility Operations

In the US, the response which has been increasingly adopted is for the regulator to impose on their utilities mandates covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing to be associated with these mandates and necessary to fulfill the regulations. Below, we examine in some detail the specific responses of some North American regulators to the IR-induced cuts to necessary operational expenditures.

Approach 2: In Europe---System-Wide Standards, Incentive/Penalty Schemes, and Single-Customer Guarantees

In Europe, regulators such as the CEER have encouraged the adoption of SQR which combines distribution continuity (i.e., reliability) standards with incentive/penalty schemes on revenues as well as single-customer guarantees with monetary payments for nonperformance.[63] In fact, CEER has been publishing a benchmarking report on SQR among its constituent members since 2002; the 2005 report covered regulators from 19 member countries.

CEER published in September 2003 the "2nd Benchmarking Report on quality of supply." This report was presented at 2nd World Forum on Energy Regulation (Rome, October 2003), debated in several conferences and raised, according to CEER, the interest of energy regulators, energy market operators and stakeholders. Meanwhile, with the enlargement of the EU, the number of CEER members significantly increased making a broader comparison possible within the framework of SQR benchmarking analysis.

[62] Sand, et al, Quality of Supply Regulation – Status and Trends

[63] Council of European Energy Regulators (CEER), Third Benchmarking Report on Quality of Electricity Supply – 2005, Ref: C05-QOS-01-03, December, 2005.

As noted by CEER:

> The General Assembly of CEER requested the Electricity Working Group to establish a Task Force for Quality of Supply (CEER QoS TF) and gave it the task of updating the previous data, widening the participation in the data collection and analysis, showing trends in various elements of Quality of Service, suggesting common indicators for the CEER members who are at the stage of introduceting quality regulation and for those who would like to harmonize their existing practices with others. Practically all CEER members participated in the work of the CEER QoS TF to-date.
>
> When starting to work on the 3rd Benchmarking Report CEER QoS TF members…have extended the scope … In addition to the two topics (Continuity of Supply and Commercial Quality) which were addressed in the previous report, information was asked on the use of standards and incentives for quality regulation, especially with regard to continuity of supply.
>
> Colleagues from Austria, Belgium, the Czech Republic, Estonia, Finland, France, Great Britain, Greece, Hungary, Italy, Ireland, Latvia, Lithuania, Norway, Poland, Portugal, Slovenia, Spain and Sweden actively participated in the work of the Task Force and supplied valuable information on their own country's quality levels and standards, so that the analysis in this Report was based on the information obtained from these nineteen countries.
>
> The main chapters…focused on the…most important standards, the requirements, the indicators, the factors influencing the measured quality levels and on those schemes,…recommendable to be introduced in practice.

According to the CEER task force on electricity quality benchmarking, incentive regulation for quality comprises three aspects:

> **measuring actual and perceived levels of quality –** a necessary and preliminary step, since setting continuity standards and/or incentive/penalty regimes requires robust and reliable data on the service actually provided and on customers' perception. …customer surveys, through which regulators can collect …information on quality as perceived by customers, which is extremely valuable for regulatory decision-making;

> **promoting continuity improvement**, which means giving utilities signals and incentives to evaluate their investment and management decisions not only in light of their costs but also taking into account the effects on actual quality levels. Regulators can promote continuity improvement especially by introducing incentive/penalty schemes, generally based on system-level quality standards that refer to the average quality level in a geographical area…
>
> **ensuring good continuity levels to consumers**, especially worst-served ones; regulators can do this through guaranteed standards that refer to the quality level experienced by each single customer connected to the network. Single-customer guaranteed standards are associated with the payment of compensations to the affected customers where the company fails to meet the standard.

In Appendix C, more detail is provided on the standards, incentive schemes, and guarantees in the CEER benchmarking report.

Approach 3: In Europe---Willingness to Pay Valuations, Costs of Energy Not Delivered, and Analyzing the Full Societal Costs of Distribution for Benchmarking Performance

In Europe, regulators in Great Britain, Norway, Italy and Sweden have conducted various studies to ascertain customers' satisfaction with distribution performance or the value placed on reliability. These regulators have used WTP studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements. Some of these regulators have taken this WTP information and explicitly incorporated the values into their distribution price regulation.

In Great Britain, earlier data from 1999 was used to set some of the initial values for penalty payments. More recently (Ofgem, 2004) updates on customer reliability valuations were used to revalue the payments. Below in Exhibit 6.1 we present Ofgem's table of guaranteed standards with their associated payments to customers for non-performance. For example, under standard GS2, a distributor who failed to restore power within 18 hours under normal conditions would face a penalty of 50 pounds for residential customers and 100 pounds for nonresidential customers. This penalty would increase by 25 pounds for each additional 12 hours of non-service. Similarly for standard

GS2A, a customer that experiences four or more interruptions each lasting 3 or more hours that occur in any single year (1 April – 31 March) , would be eligible for a penalty payment of 50 pounds. In this way, the regulator tries to induce the distributor to factor in the customers costs and consequences from lessened reliability.

Exhibit 6.1: Ofgem Penalty Payments Associated with Guaranteed Distributors' Standards

Table A2.1 Guaranteed Standards of Performance

Reporting code	Service	Performance Level	Penalty Payment
GS1	Respond to failure of distributors fuse (Regulation 10)	All DNOs to respond within 3 hours on a working day (at least) 7 am to 7 pm, and within 4 hours on other days between (at least) 9 am to 5 pm , otherwise a payment must be made	£20 for domestic and non-domestic customers
GS2*	Supply restoration: normal conditions (Regulation 5)	Supply must be restored within 18 hours, otherwise a payment must be made	£50 for domestic customers and £100 for non-domestic customers, plus £25 for each further 12 hours
GS2A*	Supply restoration: multiple interruptions (Regulation 9)	If four or more interruptions each lasting 3 or more hours occur in any single year (1 April – 31 March) , a payment must be made	£50 for domestic and non-domestic customers
GS3	Estimate of charges for connection (Regulation 11)	5 working days for simple work and 15 working days for significant work, otherwise a payment must be made	£40 for domestic and non-domestic customers
GS4*	Notice of planned interruption to supply (Regulation 12)	Customers must be given at least 2 days notice, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS5	Investigation of voltage complaints (Regulation 13)	Visit customer's premises within 7 working days or dispatch an explanation of the probable reason for the complaint within 5 working days, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS8	Making and keeping appointments (Regulation 17)	Companies must offer and keep a timed appointment, or offer and keep a timed appointment where requested by the customer, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS9	Payments owed under the standards (Regulation 19)	Payment to be made within 10 working days, otherwise a payment must be made	£20 for domestic and non-domestic customers
GS11A*	Supply restoration: Category 1 severe weather conditions (Regulation 6)	Supplies must be restored within 24 hours (see table 2.2 below), otherwise a payment must be made	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer
GS11B*	Supply restoration: Category 2 severe weather conditions (Regulation 6)	Supplies must be restored within 48 hours, otherwise a payment must be made	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer
GS11C*	Supply restoration: Category 3 severe weather conditions (Regulation 6)	Supplies must be restored within the period calculated using the following formula: $48 \times \left(\frac{\text{total number of customers interrupted}}{\text{category 3 threshold number of customers}} \right)^2$	£25 for domestic and non domestic customers, plus £25 for each further 12 hours up to a cap of £200 per customer

GS12*	Supply restoration: Highlands and Islands (Regulation 7)	Supply must be restored within 18 hours, otherwise a payment must be made	£50 for domestic customers and £100 for non-domestic customers, plus £25 for each further 12 hours

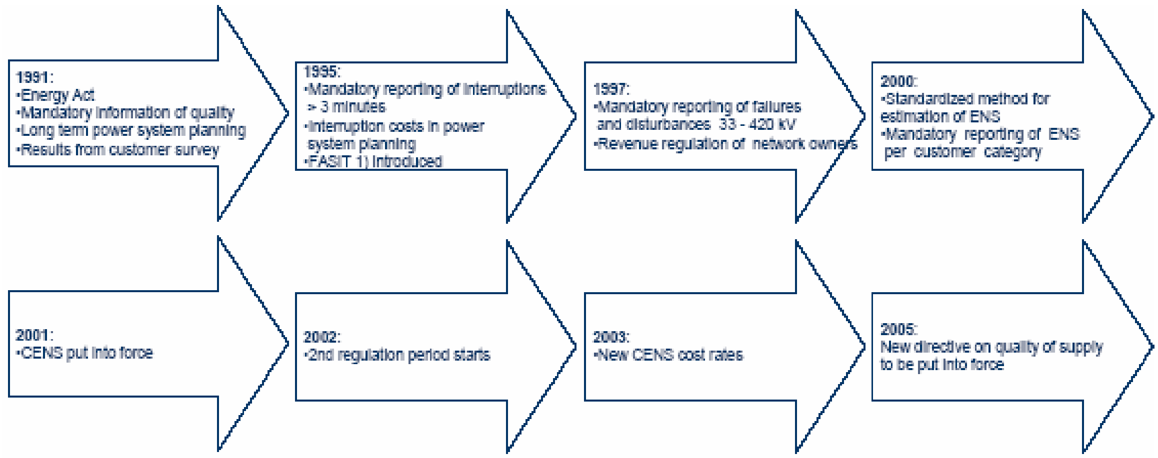
* Customers need to claim under these standards, for the remaining standards payments are automatic
Source: Ofgem website.

NVE recent developments with its supply quality benchmarking are discussed in "Quality of Supply Regulation – Status and Trends," Kjell Sand, Knut Samdal, Helge Seljeseth, SINTEF Energy Research. The authors note:

> Recent deregulation of electricity markets around the world and subjection of electricity networks to economic Performance-Based- Regulation regimes pose a challenge to assure efficient provision of quality of supply by the regulated network monopolies. Absence of explicit regulatory framework for assuring quality of supply creates perverse incentives for the regulated network monopolies to reduce quality to meet the budgetary constraints implicit in the performance based regulatory regimes. This can over time lead to declined quality of supply.
>
> To counteract such consequences, the network companies are being increasingly subjected to regulatory regimes that explicitly take into account the quality of supply to the consumers. One example is the Norwegian regulation scheme CENS (Quality adjusted revenue caps), where the network companies' revenue caps are adjusted in accordance with the customers' interruption costs… (Sand, et al, p 1)

Introduction of regulation of quality of supply in its present form in Norway, has been introduced through step-wise evolution, rather than a crash-test revolution. This is illustrated in Figure 6.1 (Sand, et al, p 5)

Figure 6.1: Development of Quality of Supply Regulation in Norway



Sand, et al, Quality of Supply Regulation – Status and Trends

Sand, et al, note:

> The CENS-arrangement [1] (Quality adjusted revenue caps by means of Energy Not Supplied) regulates only long interruptions (> 3 min). The regulator, the Norwegian Water Resources and Energy Directorate (NVE), gave the following evaluation of the CENS-arrangement at the 2003 CIRED – conference in Barcelona, May 2003:
>
> - *"The CENS arrangement has a positive effect on the network companies' behavior and attitude related to the customers' interruption costs.*
> - *There is a need for additional regulation dealing with other quality parameters than long interruptions.*
> - *Future development to extend the CENS arrangement is possible."*
>
> The experience with the arrangement so far, have mostly been positive, taking into account the clear limitations of the arrangement; namely to impose economical incentives for long interruptions. However, new research has proven that long interruptions only count for approx. half of the customers total costs related to interruptions and voltage dips… (Sand, et al, p.5)

The authors present NVE estimates of CENS by source (Exhibit 6.2 below).

Exhibit 6.2: Norway Customers' Costs Associated with Interruptions and Voltage Dips

Table 1: Customers' costs associated with interruptions and voltage dips – total for Norway

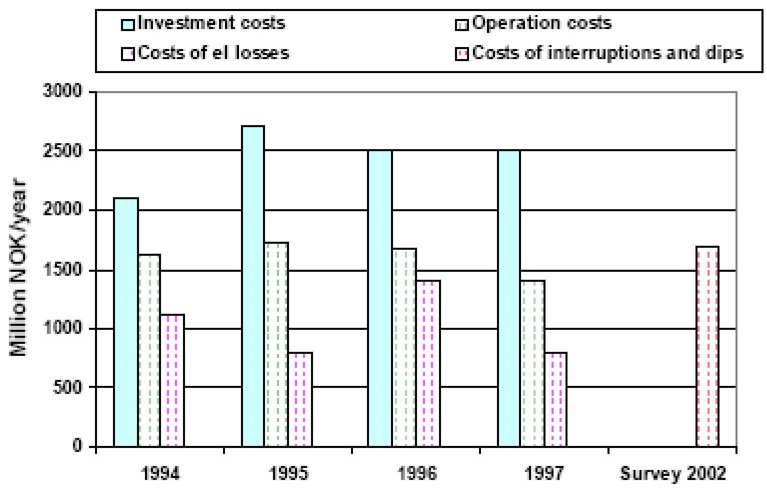
Long interruptions (> 3 min)	850 MNOK/year
Short interruptions (≤ 3 min)	600 MNOK/year
Voltage dips	170-330 MNOK/year
Total	**1 600- 1 800 MNOK[2]/year**

Sand, et al, Quality of Supply Regulation – Status and Trends

Sand, et al, also present NVE CENS estimates relative to capital investment, OM&A costs, and line loses. CENS is larger than OM&A costs as well as power loses and represent about 60 percent – 75 percent of investment costs per year.

> These figures are compared to the network companies' internal costs related to investments, operation and maintenance and electrical losses in Figure 6.2. The customers' costs associated with interruptions and voltage dips (the "*Survey 2002*"-bar) actually exceed the total costs that the Norwegian network companies in sum has on operation and maintenance on a yearly basis. (Sand, et al, p.6)

Figure 6.2: Norway Utilities Internal investment and OM&A costs and Electrical Losses



Sand, et al, Quality of Supply Regulation – Status and Trends

6.5 *Yardsticking Service Quality Regulation in Practice*

Commenting on, the possible approaches to SQR, the 2003 Staff report noted that "Yardstick comparisons" were an option for consideration.

> A second method is to compare performance against that of other firms. With around 100 licensed electricity distributors currently operating in Ontario, "yardsticking" of service performance is conceptually possible. However, yardsticking appears to be little used (at least for regulatory purposes) in other jurisdictions and industries. There are a number of reasons for this. First, in most other jurisdictions, the number of regulatees is small, and so there are few firms to compare performance against. Second, these firms are, with few exceptions, local monopolies and hence operate in different areas. Geographic and environmental differences are legitimate sources of variation in performance. Finally, there are many differences in how various utilities measure their performance – even if the indicator is industry-wide.

But, in fact, there have been a number of applications of yardstick benchmarking of service quality performance. The CEER report on service quality benchmarking notes that Italy, Great Britain, Hungary, Norway, Portugal, Spain, and Sweden have all incorporated some form of service performance yardstick benchmarking into their regulatory framework.

As the CEER report noted for Great Britain:

> In Great Britain there is no territorial classification, but the regulator developed a methodology for benchmarking company performance that is used also to set targets for the interruption incentive scheme. Ofgem collects physical characteristics and performance information for each MV circuit for each distribution company. These circuits are then divided into 22 circuit groups with physically similar characteristics. The groups are defined so that differences in the percentage of overhead line, circuit length and number of connected customers are minimised and that no group is dominated by a single company. Performance is compared and benchmarked within each circuit group. Ofgem then establishes an overall benchmark for each company based on its mix of circuits and compares actual performance with these benchmarks. (CEER p 8)

As the CEER report noted for Italy, there a concern was converging the worst performing distributors toward the better performing utilities:

> Incentive/penalty schemes have been implemented in European countries with the general objective of improving/maintaining continuity levels at a socio-economically acceptable level, in particular under price- or revenue-cap types of regulation. In one case only (Italy) has the regulator designed the mechanism specifically around a country-specific objective: the convergence of continuity levels towards unique targets (for districts having the same territorial characteristics). Prior assessment of current continuity levels can, in fact, show the need to address specific issues (Table 2.6). (CEER, p 39)

In terms of Portugal, Spain, and Sweden, the CEER report noted:

> In all cases surveyed, the scheme includes both penalties and rewards and, since it is designed to address system-average continuity levels, is or will be complemented by some form of protection for the worst-served consumers. In general this is done by introducing Guaranteed Standards (GS) on duration and number of long interruptions (maximum restoration time being the most common, see section 2.4). Sometimes this assumes the form of observation of the worst-performing areas (Sweden) or, as in Portugal and Spain, of a quality improvement plan financed through tariffs (See Additional information 2.3). (CEER, p 40)
>
> Spain does not have an incentive/penalty regime yet, but it has set system- level continuity standards, which are not only evaluated as average levels in a given territory but aimed at identifying worst-served areas in that region. Standards are set on TIEPI, 80th percentile TIEPI, and NIEPI, and differentiated by density areas. Distribution companies experiencing difficulties in maintaining the quality required in certain areas are given the opportunity to submit, to the competent administration, a temporary action programme describing the problems that need to be corrected. Those programmes will be included in a quality improvement plan financed through the tariff. Special plans have been implemented since 2004 and the amount of expenses recovered through this mechanism has been quite large so far: for 2004 special plans received a budget of 50 million, increased to 80 million for 2005.

The CEER report also noted for Italy, Great Britain, and Hungary:

> In Italy, Great Britain, and Hungary the worst performing companies have larger improvements to make: this choice enables a convergence of continuity levels for the entire country. Continuity targets are set in all cases by company. The only exception is Italy, where targets are given by territorial district. Historical performance and structural differences in network layouts must be taken into account when setting the standards, in order to set targets that are achievable for the company and valuable for consumers. Differentiating targets by density area, as in Italy, or by company, as in other countries, does just that.

For Norway, the CEER report noted the regulator's use of reliability data for all utilities to benchmark the expected performance of each individual utility after adjusting for the effects of certain structural variables:

> In Norway a regression model is used to calculate "expected total interruption costs" for each company using historical data and various structural variables (energy supplied, network extension, number of transformers, wind, geographical dummies). (CEER, p 44)

6.6 *The Ontario Energy Board's Experience with Service/Reliability Quality Regulation*

The OEB's experience with SQR of electric distributors has its origins in the OEB's 2000 Electricity Distribution Rate Handbook (Rate Handbook). In terms of SQR, this document was largely based on the Implementation Task Force Report's [64] recommendations. This report, was itself, based largely on the task force's work which roughly covered the middle/end of January to May. And, indeed, SQR was just one of numerous issues assigned to this task force. This task force and the others convened by the OEB did yeoman's work on many difficult issues.

In the end, for a variety of reasons the task force recommended that only minimum customer contact standards be applied to the LDCs during the first generation. The levels of the minimum standards were determined through a survey of the LDCs. For reliability, the "standards" were actually weaker: for those LDCs with historical data, those LDCs should keep their performance within the range of whatever it had been during the

[64] Report of the Ontario Energy Board Performance Based Regulation Implementation Task Force. May 18, 1999,

preceding three years. Those LDCs without data on reliability performance should begin to collect it.

However, despite the reluctant acceptance of the "lowest common denominator" for SQR by the Implementation Task Force, the general expectation was that the Board would move quickly, possibly even early in the first generation but no later than the beginning of the second generation following the initial three-year PBR term, to set reliability performance targets based on a more reasoned and judicious rationale than "just do whatever it was that you were doing."

Indeed, the principles of just and reasonable rates would require that service quality and reliability standards be explicitly formulated as part of the sale of access by distributors to customers. And, the Board itself stated its intent to move expeditiously: "upon review of the first year's results, the Board will determine whether there is sufficient data to set thresholds to determine service degradation for years 2 and 3."[65] Unfortunately, it is now 2007 and the same standards that applied in 2000 still apply today.

The Initial Rate Handbook, Chapter 7, Service Quality

As laid out in Chapter 7, Service Quality, of the 2000 Rate Handbook, the Board spelled out the reasons for regulating service/reliability performance and what monitoring and reporting requirements were expected of the utilities.

> PBR provides the electricity distribution utilities with incentives for economic efficiency gains. To discourage utilities from sacrificing service quality in pursuing these economic incentives, service quality performance measures are included in the PBR plan. Utilities will be expected to monitor and report on all of the service quality indicators included in the plan. The performance of individual electricity distribution utilities will be made publicly available to customers and the general public.
>
> The service quality indicators, their associated monitoring and reporting requirements, and the minimum standard guidelines (where applicable) are

[65] Ontario Energy Board, Service Quality, 2000 Electric Distribution Rate Handbook, March 9, 2000, p 7-10.

> described in this chapter. These standards represent the minimum acceptable performance standards. An electricity distribution utility should continue to establish its operating performance at any levels better than the minimum standards, taking into consideration needs and expectations of their customers. (7-1)

The Board also discussed what surveys and customer research it might undertake in setting standards for the second PBR, i.e., after the initial 3 year PBR term:

> In addition to imposing service quality performance standards, the Board may conduct surveys to determine customer satisfaction with the electricity distribution service quality. The Board may also conduct customer research to identify those elements of service quality most important to customers for use in setting standards for the second PBR term. (7-2)

The Board explained the reasoning behind the standards selected as follows:

> PBR task force survey results indicate that the degree of service quality monitoring that the electricity distribution utilities currently carry out varies. Therefore the Board's approach to encourage the maintenance of service quality during the first generation PBR plan is to apply minimum standard guidelines for customer service indicators, and to apply a utility's historic performance as its specific service reliability standards. Where a utility has not monitored service reliability in the past, it is required to initiate monitoring and reporting of the indices. (7-2)

Thus for the system reliability indicators SAIDI and SAIFI, "All planned and unplanned interruptions of one minute or more should be used to calculate this index. Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance." (7-6, 7-7)

With respect to service degradation and remedial action, the Board noted:

> In the absence of historical service quality data, it is not possible to identify service degradation during the first year of the PBR plan. However, upon review of the first year's results, the Board will determine whether there is sufficient data to set thresholds to determine service degradation for years 2 and 3. When established, the Board will issue these thresholds and any utility whose performance falls below these thresholds will be required to file a remedial action plan. (7-10)

Finally, the Board noted its intent to set industry service standards by the advent of the second generation; financial consequences would be tied into the standards.

> It is anticipated that by the second generation PBR plan, there will be sufficient data collected to set industry service quality performance standards. Once these standards have been established, PBR incentive mechanisms with economic consequences will be introduced around the service quality indicators. (7-10)

In fact, the Board seems not to have reviewed the PBR first year's result "to set thresholds to determine service degradation." Nearly 3 years later, about the time that the second generation PBR would have been about to commence, the Board was still not in a position "to set industry service quality performance standards… with economic consequences." Indeed, in the late summer of 2003, the Board initiated a process which, if completed, should have provided the information necessary to set thresholds and financial consequences.

OEB Notice on Initiation of Working Group on the Review of Service Quality Regulation Board File No. RP-2003-0190

The August 29, 2003 notice (the notice) on "**Initiation of Working Group on the Review of Service Quality Regulation" Board File No. RP-2003-0190,** reviewed the Board's initial PBR decision and specification of service/reliability indicators. Speaking of the initial standards set in the 2000 Rate Handbook, the notice said:

> For most SQIs, the Board approved initial minimum standards. The Board determined that other aspects of service quality regulation, including remedial action and/or financial consequences of service degradation, should be considered, but that a proper assessment of these issues required experience with the measurement and reporting of the SQIs.

The notice also discussed subsequent developments regarding second generation PBR:

> On October 28, 2002, the Board advised stakeholders of the planned phased development of a second-generation PBR ("PBR II") plan. A review of currently reported service quality indicators and associated standards, as well as consideration of other indicators and elements of service quality regulation, were identified as one of the components of PBR II plan development. ….As electricity distributors have been reporting their service performance for three years now, the Board considered it timely to review the SQIs and to further develop service

> quality regulation applicable to electricity distributors, and indicated that Board staff would be commencing consultations by mid-2003.

The notice then explained the forthcoming process.

> Board staff are starting a working group to consider service quality regulation ("SQR"). Staff will also shortly be issuing a discussion paper on service quality regulation that will help to start informed consideration of pertinent issues in this area. The Board has assigned file number RP-2003-0190 to this matter. The Appendix to this letter provides a generic, but not necessarily exhaustive, list of issues to be considered by the SQR working group.
>
> The consultations are targeted to conclude by the fall of 2003. Board directions on a public regulatory process to consider the proposed service quality regulation will be issued in due course.

The notice listed the following issues for review:

1. Review of the existing service quality indicators ("SQIs").
2. Review of SQI standards to assess whether these standards are appropriate…Where appropriate, standards for the reliability indicators should be established.
3. The consideration of additional or replacement indicators... Other operational indicators, or measures of customer complaints or customer satisfaction, could also be investigated.
4. The frequency of reporting and the periodicity of reported performance should be considered.
5. The criteria for defining degraded service need to established. Regulatory responses to service degradation (remedial action reports, possible financial consequences) should be considered.
6. Other matters - e.g. should there be a distinction in terms of reporting or standards for urban/rural or large/small utilities?
7. What should be the form and purpose of service quality audits and investigations? The role of SQ audits increases in a comprehensive SQR plan, where there are regulatory impacts (remedial action plans and/or financial rewards and/or penalties).

OEB Staff Report on Service Quality Regulation for Ontario Electricity Distribution Companies

On September 15, 2003, Ontario Energy Board staff released paper, *Service Quality Regulation for Ontario Electricity Distribution Companies.* As we noted above, Section 2 of the paper dealt with the principles of SQR, notably the inherent link between service quality and just and reasonable prices. Section 2 of the report gave an overview of PBR in Ontario. Section 4 reviewed the SQR in the first generation PBR. Section 5 discussed issues that might be considered for second generation SQR. The report also reviewed SQR in some other jurisdictions and industries.

Recommendation: Service quality/reliability must be included in any quantified multivariate output variable used as a benchmark to assess a utility's production integrating utility cost benchmarking with service quality and reliability regulation. Although the Board's work to establish meaningful service quality standards was prematurely curtailed, it is abundantly clear that a substantial amount of work has already been accomplished. We should not now be debating the need to implement meaningful standards, nor their integration into an IR framework, but rather the manner in which this should be done. European regulators have made substantial progress in the area of service quality standard implementation. The Board can use these standards, presented in Appendix B, to help guide its efforts.

7 Overview, Primary Conclusions and Recommendations

In this section I provide an overview of my key findings and conclusions, and a compilation of the recommendations made throughout my report (see section 7.10 below).

7.1 *Intent of PEG's Benchmarking*

PEG's report recommends the use of econometric modeling and multivariate indexing "to compare relative distributor performance and also recommends that for the current analysis only aggregated OM&A costs be benchmarked." PEG also appraised Staff's distributor peer grouping and cost benchmarking and recommended upgrades to Staff's approach.

PEG recommends that these benchmarking approaches be used in the upcoming 2008 electricity distribution rate to identify LDCs that "merit expedited processing" or should receive "especially thorough prudence reviews" based on their "favorable" or "poor scores" (p vi). PEG notes that with more and better data, benchmarking may play a larger role, and encourages "the Board to consider awards for superior performance in addition to penalties for inferior performance" (p vii). The Board also noted that, depending on the robustness of the techniques, potential uses of the comparative analysis could include: benchmarking expense levels; informing the development of IR; and, in particular, in addressing the issue of variable, or utility-specific, productivity factors.

7.2 *A Sufficiency Test on PEG's Proposals: Examining the PEG Proposal to see if it is Based on a Breadth of Methodologies to Test for Robustness in Results and whether it Encompasses Model Specifications, Data, and Estimation Techniques that Appropriately Reflect Electric Distribution*

Clearly there are many steps in a benchmarking study, each with a set of choices that can influence the final results. Having the appropriate data, of course, is of paramount importance. But so to are the choices that are made with respect to analytical methodology (e.g., DEA; SFA; Cost or Production; Regression Analysis with its many variants), estimation technique (e.g., OLS, TSLS, or system), and the model specification with all the variants possible. Each of these permutations can drastically impact such final results as estimated costs, efficiency score or, efficiency ranking. Indeed, researchers examining the sensitivity of such results have found them to be sensitive to methodologies, specifications environmental variables, and data definitions.[66]

Given the intended ultimate use of these benchmarking techniques and their potential impact on an LDCs revenues, I believe the benchmarking proposals must pass a two-part sufficiency test: first, in terms of whether or not the proposals are based on the precepts of accepted, rigorous, academic research; and, second, whether or not they are analytically structured to reflect an LDC's distribution business. In light of these considerations, in my review below, the PEG report's analysis and proposals are examined from the perspective of the following requirements that, they:

- reflect the full extent and integrated nature of a utility's distribution business,
- encompass cost measures reflective of a distributor's actual and total cost comparison, i.e., do PEG's proposed cost benchmarks accurately depict the state of each utility's costs and relative efficiency,
- specify cost measures that actually represent a consistently defined activity across LDCs in terms of their underlying costs, burdens and allocations,
- employ a breadth of methodologies to test for robustness in results,
- utilize specifications and sensitivity tests of inputs, outputs and cost/production relations that appropriately reflect the electric distribution business sensitivity.
- specify that any quantified multivariate output variable used as a benchmark to assess a utility's production must include service quality/reliability, and
- require that the analytical work underpinnings of these requirements be based on conventional, scholarly, rigorous research.

[66] See for example, Cronin, F. J. and Motluk, S. A., forthcoming, "Flawed Competition Policies: Designing 'Markets' with Biased Costs and Efficiency Benchmarks,"forthcoming, Originally, *The (Mis)Specification of Efficiency Benchmarks among Electric Utility Peer Groups*. Presented at the North American Productivity Workshop II, Union College, NY, 2002.

In this report I examined:

1. the proposal to see if it spans a range of methodological approaches and sensitivity tests.
2. the proposed approach for the appropriateness of estimation techniques within the limited span of methodologies actually employed.
3. the model(s) to see whether their specifications appropriately reflect electricity distribution.
4. the robustness and appropriateness of the data used in the proposed models.
5. the role of reliability in PEG's proposal.
6. and, finally, based on recent advances in SQR particularly in Europe, I discuss how the Board should integrate SQR into utility benchmarking.

7.3 *Does PEG's Proposed Approach Cover a Sufficiently Wide Range of Methodologies to See if LDC Costs/Rankings are Sensitive to Different Approaches?*

In his survey of benchmarking methodologies, Berg cautions (p 2),[67]

> "A single index of utility performance has the same problem of any indicator: it will be neither comprehensive nor fully diagnostic."…(p 10) "in most cases there is no 'ideal' model among the set of potential models."
>
> (p 10) "Thus to check for robustness of performance rankings, researchers have begun to compare results from different methodologies….verifying whether models identified the same set of utilities as the most efficient and least efficient. Clearly, if efficiency scores are to have any use for managerial incentive or as elements in regulatory mechanisms, stakeholders need to be confident that the scores reflect reality, and not just artifacts of model specification, sample selection, treatment of outliers, or other steps in the analytical process."

Berg (2006) presents 11 analytical methodologies available to researchers for benchmarking purposes.[68] PEG chooses to use one method (i.e., a variant of regression

[67] Berg, S. "Survey of Benchmarking Methodologies: Executive Summary", Public Utility Research Center, March 1, 2006.

analysis) and two variants of that method (i.e., translog versus double log). These two sets of results are closely associated and only differ in their functional form. No analysis is undertaken with other major forms of benchmarking methods to examine how sensitive results are to their narrowly chosen approach. This failure to examine widely employed benchmarking methodologies severely limits the confidence we can place in the results.

7.4 *Does PEG's Proposed Approach Rely on Appropriate Estimation Techniques?*

For the cost functions estimated by PEG, right-hand side (i.e., explanatory) variables are required to be outside the control of the firms' whose costs are being estimated, i.e., they are supposed to be exogenous to the behavior under investigation. Yet, despite this requirement, PEG includes such variables as (1) the percent of wires placed underground, (2) the circuit miles of wire, and (3) the number of transformers. Number (1) is clearly under the control of LDC management or policymakers. This is determined by the LDC or shareholders and is implemented as such. Numbers (2) and (3) are to varying degrees under LDC discretion based on topology, system design and prices. All of these are not truly exogenous, and as such their inclusion on the right hand side of the model means that a more appropriate estimation technique such as TSLS should have been employed to correct for endogeneity effects. The inclusion of endogenous variables on the right hand side of the model seriously compromises PEG's statistical results.

7.5 *Does PEG's Proposed Approach Rely on Appropriate Model Specifications?*

Presumably for the purposes of benchmarking total LDC performance one would employ a properly specified total cost function, with **total cost** as the dependent (left- hand side) variable and on the right hand side to explain differences in costs, the model would include **all input prices** (i.e., capital, labour, line losses) and **measures of output** (i.e., number of customers and kWh and reliability). With this specification, all the inter-

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[68] Samuli, H. et al, "Effects of Benchmarking of Electricity Distribution Companies in Nordic Countries-Comparison Between Different Benchmarking Methods," present yet another methodology that has been employed for benchmarking in Sweden, the Network Performance Assessment Model.

related input demands are estimated together (e.g., the demand for capital by an LDCs and how changes in the price of capital and other inputs like power losses and labour affect this demand). With such a specification one obtains a complete picture of an LDCs' cost structure and all the associated complementary and substitute relationships among inputs.[69]

This information is critical: we know that input substitution has permitted widely different labour-capital cost shares among Ontario LDCs. Furthermore, I have examined the marked changes in cost shares for line loses following the price of power increases in the early 1990s and the regulatory changes to capital and rate basing contributed capital in 1994 which for some LDCs significantly increased the share of capital among some Ontario LDCs (and reduced the share of labour).

Presumably, because PEG assumes there to be a lack of data to provide a measure of the cost of capital, the quantity of capital, nor the price of capital, PEG specifies their model as a short-run cost function and employs several **expedient short cuts** to cover critical gaps in their data. As such, to be properly specified, the short-run cost function should have **properly defined variable costs** on the left-hand side of the model, and the **quantity** of the "fixed" input on the right-hand side, together with **all other input** prices.

What does PEG include in their estimated short-run cost function?

First, PEG employs a seriously biased left-hand side variable which does not consistently reflect the variations across the LDCs in labour capitalization and expenditures for reliability. That means, and, this is acknowledged by PEG, that we are comparing "apples to oranges"…we can simply not make any sense out of a comparison that starts out with data of such a highly inconsistent nature.

Importantly, the use of OM&A as the benchmark means that, by definition, we can not examine the size and extent of allocative inefficiency (i.e., the cost of using say capital

[69] When two inputs are substitutes, an LDC could use different combinations of the two inputs and produce the same level of output.

and labour in non-optimal proportions due generally to one input, say capital, having a non-market price for extended periods of time or receiving other regulatory, preferential treatment like rate basing contributed capital).

Historically, the Ontario distributors had achieved a robust rate of productivity growth (i.e. efficiency improvement), reaching 2 percent a year over the 1993 to 1997 period among a large cohort of utilities. In fact, across the industry the level of associated technical efficiency (which is the result of productivity change) had already achieved a superior level before the 2000 restructuring. Research found that by 1997, the average LDC had an almost 93 percent score on technical efficiency (meaning that on average the LDCs were only 7 percent less efficient then the most technically efficient distributor).[70] Therefore, by 1999, it would appear that the LDCs had already achieved a superior level of efficiency with respect to OM&A and that, at that time, efforts to raise technical efficiency would be like raising a math grade from "A" to "A+." Maybe a better approach would be to identify areas where more effort might raise a grade from "C" to "B" or "B+."

What about allocative (in) efficiency? That research, however, also found that some utilities had a non-optimal mix of inputs (i.e., had become too capital intensive) and that these utilities could achieve significant allocative efficiency gains, (i.e., the cost savings from using inputs in more optimal combinations, usually in ratios of use that better track market input prices rather than the price of regulated inputs like capital).[71] In terms of our grades above, this would receive a "C." *Non-optimal factor mixes, and the associated excess costs, are not reflected in productivity or technical efficiency statistics.*

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[70] This research has its genesis in a paper originally prepared as a kickoff to a potential research program for the OEB for a yardstick regulation regime for Ontario LDCs, presented at the Canadian Economics Association 35th Annual Meeting at McGill University, Montreal, Quebec in June 2001: Frank J. Cronin and Stephen A. Motluk, "Inter-Utility Differences in Technical and Allocative Efficiency." This presentation is reproduced in Appendix E.

[71] Potential allocative efficiency gains have been documented by numerous utility research studies because utilities often are faced with non-market price for capital. Furthermore, allocative inefficiency has been found to be a substantially more significant problem among utilities in numerous jurisdictions (e.g., US, Canada, and Japan).

In fact, the PEG report, like other recent Board staff and staff consultants reports seems to consider operational efficiencies as being synonymous with technical efficiency (i.e., achieving the maximum output to input ratio) while ignoring allocative inefficiency, traditionally a larger source of inefficiency. Researchers in other jurisdictions have found allocative inefficiency can be two to three times as large as technical ineffeciency. My research on Ontario LDCs also finds that to be true for some LDCs. Unfortunately, focusing attention on OM&A and ignoring capital costs would preclude any possibility of correcting the existent capital cost problem.

In order to correct the non-optimal input mix among some Ontario distributors, consideration of capital costs in the benchmarking approach is an essential requirement. Without information on the magnitude of both measures of inefficiency, we are flying blind in setting meaningful regulatory parameters.

Second, PEG does not include the quantity of capital on the right-hand side but a proxy (i.e., GBV) that bears no resemblance to an individual LDC's actual quantity of capital. *Worse, it actually shows some LDCs to use more capital than other LDCs when in fact they use less.* The effect of such data errors would likely cause the model to produce dramatically inaccurate results. Peculiarly, PEG does not refer to GBV in the context of a fixed capital variable but rather as an "Other Business Conditions" variable, as though the gross stock of capital were completely set exogenously. But, we have seen that LDCs can operate with different capital shares and respond differently to factors influencing input decisions. Thus GBV is not exogenous and is certainly not an "Other Business Condition."

Third, while PEG admits that power losses are a key distribution input, PEG does not include a critical input price, the price of power losses. This statistical problem, called "the problem of left out variables," would result in wrong estimated impacts associated with the included variables. In addition, the lack of this price term (i.e., the price of line loses) means that we are not capturing key input relationships among input prices, including line loses, labour and capital, i.e., among the actual substitute-complementary relationships that actually exist for distribution utilities.

Fourth, PEG mis-specifies the LDC output variable by including km of circuit wire as an output. On circuit km of wires, PEG had begun their discussion with the issue of varying density among LDCs. Fair enough. But then PEG shifts its discussion to extensiveness. From there PEG jumps to including km of wires. *Kilometers of wires is an investment input used by LDCs with other pieces of equipment, e.g., transformers, and other inputs (labour, materials, other capital) to deliver power to customers.* Why is this LDC input picked out and labeled as an "output." Why not labour? Why not trucks? But, the specification is even more peculiar.

Fifth, PEG then defines the number of transformers as an "Other Business Condition" and includes it as well on the right-hand side. So, in one case we have PEG calling one category of investment (e.g., km of wires) an *output*, and on the other hand, we have PEG calling an associated investment category, an "*Other Business Condition*." PEG's arbitrary specification defies explanation and certainly causes significant errors on the modeled LDCs costs.

Sixth, PEG also mis-specifies the LDC output variable by leaving out the level of reliability achieved by each LDC. We have discussed above the biases engendered by including reliability-related costs within OM&A but not including the reliability associated with such costs as an output. This is the "apples to oranges" comparison. But regulatory requirements regarding a just and reasonable rate also raise concerns here.

Finally, PEG estimates a poorly specified short-cost function with inadequate and missing data. However, even if the specification and data issues could have been overcome, the specification employed by PEG assumes that capital is fixed, i.e., that it does not respond to changes in such important determinants as price. But, my research on Ontario LDCs, discussed in section 5 indicates that capital does respond to altered circumstances, e.g., price or regulatory changes, and does so, even partially, within a 3 - 5 year period.[72]

PEG should estimate a properly specified long-run cost function.

In order to get a better handle on the cost/efficiency issues PEG is examining, PEG should estimate a properly specified short-run function with the appropriate data. In addition, PEG should estimate a properly specified long-run cost function with correct data. This would allow a full range of input substitution-complementary relationships to be observed with their associated cost impacts. Estimating some form of frontier analysis based on properly specified total costs would also prove useful in developing appropriate regulatory benchmarks. Properly done, both models have something to offer in improving our understanding of these LDC costs issues and in answering key questions related to developing an appropriate regulatory framework. For example, given the distribution of estimated inefficiencies in the late 1990s, rate freezes or productivity targets would not necessarily be a productive framework for improving LDCs efficiencies.

7.6 *Does PEG's Proposed Approach Rely on Appropriate Data Definitions?*

First, PEG defines output to include an LDC's investment in circuit wires (presumably, the more the investment, the higher the output, even if no one is connected to the wires), but fails to include an LDC's achieved reliability whose costs are partially reflected in OM&A. As discussed in section 6, electricity distributors produce and sell a multi-dimensional output to their customers, and this output includes reliability and other aspects of power quality. PEG acknowledges that reliability varies widely across LDCs, and that higher reliability generally comes at a higher cost. Yet, having admitted such a critical difference among LDCs in output and costs, PEG fails to reflect these in their benchmark model. Without such fundamental features of electricity distribution reflected, it would not be possible for such a model to accurately reflect an LDC's costs.

[72] Capital also responds to changes in prices of other inputs such as the price of power loses, which itself, is not included.

Second, PEG includes as a "Business Condition quantity of capital variable (GBV) that, they acknowledge, is a proxy not employed in "rigorous," "conventional," nor "scholarly" research, rather then the cost of capital variable "rigorous" research employs.

Third, as we have discussed in previous sections as well as in this section above, PEG has employed variables which have serious deficiencies when it comes to accurately representing the item they purportedly represent. For example, PEG employs a cost variable (OM&A) which does not consistently reflect the variations across the LDCs in labour capitalization and expenditures for reliability: the "apples to oranges" comparison.

7.7 *Service Quality/Reliability must be included in any Quantified Multivariate Output Variable used as a Benchmark to Assess a Utility's Production*

Finally, evaluating whether a rate is just and reasonable requires that we consider the associated distribution service quality/reliability. Service quality/reliability varies among electricity distributors and those utilities providing higher levels of quality/reliability can be expected to have higher costs. Therefore, since service quality/reliability is part of distribution output that entails costs on the part of a utility, and reliability and its associated costs vary across utilities, service quality/reliability must be included in any quantified multivariate output variable used as a benchmark to assess a utility's production

7.8 *Integrating Utility Cost Benchmarking with Service Quality and Reliability Regulation.*

Electric distributors produce and sell a multi-dimensional output to their customers. Clearly, the customer service, reliability and voltage quality, among others, can vary substantially, producing different products depending on the mix of characteristics delivered to the customers. Many/most energy regulators have a dual responsibility toward consumers: they must ensure that prices are just and reasonable and they must ensure the appropriate level of service/reliability is delivered. Without the latter, there can be no assurance that the prices being paid are in fact just and reasonable. However, as PEG notes, and we agree with, (pp 30 - 31):

> The reliability of distribution services provided by utilities varies widely. Better reliability generally comes at a higher cost. The cost impact of quality is thus a valid issue in distribution benchmarking. There are special challenges in the estimation of the cost impact of quality. Despite its importance, empirical research on this topic is not well advanced.

Therefore, since reliability varies so "widely" among LDCs, and those LDCs with higher reliability will generally have higher costs, we must structure the LDC benchmarking to account for these differences. If not, and such different cost causation situations are simply observed through the LDCs' OM&A costs, we may mistakenly identify "higher cost" LDCs as less efficient then lower cost LDCs providing lower reliability.

OEB Initiation of Working Group on the Review of Service Quality Regulation

Indeed, the OEB has noted its responsibility with respect to service/reliability as well as the necessity to evaluate prices hand-in-hand with the actual service/reliability delivered to customers. In an August 29, 2003 Notice of the Board (2003 Board Notice) on an "**Initiation of Working Group on the Review of Service Quality Regulation" Board File No. RP-2003-0190**, the Board acknowledged that:

> Section 1 of the Ontario Energy Board Act, 1998 states, in part, that: The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives: ... 3. To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

Furthermore, the Board noted that the issues of distribution prices and service quality are integrally linked together. As the 2003 Board Notice also states in referring to an earlier, March 14, 2003 Board communication," … a determination of just and reasonable rates must take into account the adequacy and level of service quality….". That is, we can only evaluate the justness and reasonableness of distribution prices in relation with the associated quality of service and reliability received by customers. To ignore the latter, especially for an extended period of time would, of necessity, raise the question of whether the prices being paid were just and reasonable.

OEB Staff Report on Service Quality Regulation for Ontario Electricity Distribution Companies

Section 2 of the 2003 Staff report dealt with the principles of SQR, notably the inherent link between service quality and just and reasonable prices. As noted:

> In this section, we detail various principles that underlie service quality regulation. These principles are taken from research into both the theory and practice of service quality regulation. These principles are generic in nature, although comments are provided, in some instances, on how they relate specifically to electricity distribution. A reason for dealing with these principles up front is that an understanding of these issues aids in understanding the service quality reporting currently being done by electricity distributors – as part of the first-generation PBR plan – as well as to understand the issues that should be explored as part of the review of Service Quality Regulation.

Inappropriate Incentive Schemes

Therefore, the benchmarking approach proposed by PEG in ignoring service quality/reliability will likely penalize the high-reliability LDCs and reward the low-reliability LDCs.[73] Such a backwards reward/penalty scheme could then incent the high-reliability LDCs to reduce their OM&A expenses to improve their benchmarking scores; reliability would most likely decline as well. This is not the result we would expect from a well-structured benchmarking scheme.

Imprudent curtailments in OM&A have been shown to significantly lower LDC reliability. Regulators in both North America and Europe have recently responded to profit-driven OM&A cuts with new regulatory initiatives (these are discussed). Below, we examine some of the critical interlocking relationships among IR incentives, profit motives, cost impacts, reliability, and benchmarking and the steps that regulators in other jurisdictions, particularly the path breaking work on power supply (or service quality regulation) in Europe.

[73] We are using the terms "high" and "low" in a relative context.

North American and European Regulators' Response to Service Degradation

Both the experiences among North American as well as European energy regulators to this potential IR-induced, service degradation phenomenon are discussed. Among the former, following a series of significant outages often caused by imprudent reductions in OM&A expenses, regulators have increasingly imposed on their utilities mandates covering inspection and maintenance, and sometimes investment, which specify the nature, timing and, in some cases, the money and/or staffing necessary to fulfill the regulations.

In Europe, regulators such as the CEER have documented and encouraged the adoption of SQR which combines system-wide standards with incentive/penalty schemes as well as single-customer guarantees with monetary payments for nonperformance. Some regulators have used WTP studies to gauge the value customers place on reliability and the amount they would be willing to pay for service improvements or interruption avoidance.

7.9 *Incorporating Customer Interruption Costs to Achieve a Socially Optimal Level of Reliability*

Indeed, some regulators have taken this WTP information and explicitly incorporated the customer interruption values into their distribution price regulation. In one case, the regulator has specified a goal of achieving a socially optimal level of reliability by recognizing that customer interruption costs must be considered equally with a utility's capital and OM&A costs in utility planning and regulatory benchmarking.

Given the substantial, excellent work on SQR in Europe, particularly the incorporation of WTP and customer interruption costs into the process of determining the correct level of reliability and power quality, I recommend that the Board review this experience and consider applying its best features to the regulation of Ontario LDCs.

In Europe---System-Wide Standards, Incentive/Penalty Schemes, and Single-Customer Guarantees

CEER's benchmarking report on SQR which relied on information from 19 member countries' regulators, notes that quality may have a "long recovery time after deterioration." and that "quality of service is usually regulated over more than one regulatory period."[74] (p 31)

Willingness to Pay Valuations, Costs of Energy Not Delivered, and Analyzing the Full Societal Costs of Distribution for Benchmarking Performance

NVE, in Norway has gone even further with a goal that is not necessarily to improve system-wide reliability, but to find the socially optimum level, i.e., the level of reliability where marginal benefits from improvements equal the marginal costs of implementation. To attain this goal, NVE must estimate what the customer costs of interruptions are and bring these into the planning process by treating customer interruption costs along with capital or O&M costs in their planning process.

For example, NVE has undertaken WTP studies of customer interruption costs. NVE has examined the impact of short interruptions, long interruptions, and voltage dips on the breadth of distribution customers. NVE finds that the annual costs of customer interruptions are larger than the amount spent annually by distributors on OM&A and about 60 percent – 75 percent of the amount spent on investments.[75] Given the magnitude and importance of these interruption costs, starting in 2000-2001 NVE structured its IR to explicitly account for CENS by benchmarking individual distributors on the amount of ENS.

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[74] Council of European Energy Regulators (CEER), Third Benchmarking Report on Quality of Electricity Supply – 2005, Ref: C05-QOS-01-03, December, 2005.

[75] Sand, et al, Quality of Supply Regulation – Status and Trends

7.10 *Compilation of Recommendations*

The following is a compilation of my recommendations:

- The original purpose of the baseline and annual PBR filings can, and should, still be fulfilled. The Board should move to update the initial PBR submissions with the subsequent annual and distributors' submissions. This would provide the Board a world-class resource capable of more than adequately handling cost analysis, cost comparisons, and benchmarking among Ontario distributors.

- Given the risks to customers, shareholders, and LDCs associated with inadequate benchmarking regimes, the Board should not implement any benchmarking of Ontario LDCs until this can be done correctly, i.e., with the full, properly specified costs of distribution together with each LDCs reliability level as a foundation of the framework. Total cost benchmarking better reflects an LDC's cost structure and input choices, is more equitable, permits an evaluation of societal resource usage, and limits inappropriate regulatory incentive. The Board should develop the appropriate capital cost information necessary to properly benchmark Ontario electric utilities. A very good starting point is the 1999 PBR Baseline Surveys which covered decades of capital components and, as of that time, had calculated the total costs of distribution, including capital costs, for those LDCs in the 1999 Staff report as well as others. Even with the subsequent substantial mergers and amalgamations since 1999, the Board could update the initial PBR submissions with the subsequent annual PBR filings and other distributors' submissions.

- Proper benchmarking needs to include the correct measure of capital as described by PEG for "rigorous" analysis, but which PEG did not employ in the benchmarking approach recommended in their report. Capital is a critical infrastructure resource. The Board should not lay out inappropriate precedents inconsistent with proper cost analyses and benchmarking because the correct approach is time consuming and difficult. A past effort collected PBR capital data from the 1970s to 1997 and PBR operating/financial/demand data from 1988 to 1997, including "environmental" factors potentially affecting an LDC's performance. This effort was augmented by directed PBR filings among Ontario LDCs for at least the years 2001 and 2002. It is possible as well as preferable to update this data as must surely have been the intent in collecting the data from the LDCs on an on going basis. These critical data and what must mount up to thousands of man hours of effort expended collectively to compile, process and analyze this wealth of information should not be ignored. Updating the 1999 data would cost no more, and probably less, than efforts to start in 2007 and work backward. It is not even clear if the latter approach is even feasible, would most certainly produce less robust data and almost certainly take longer to complete.

- Benchmarking for regulatory incentives/penalties should be done on a utility's total costs. Use of partial cost measures whether it be OM&A or capital suffers from the fact that some inputs are substitutes and LDCs combine them in different ways. Without a correct measure of capital to examine, OM&A costs can and do present biased results of LDC performances since they reflect inconsistent approaches to labour burdens and capitalization. Even adjusting the reported OM&A for allocations differences will still not present a plausible efficiency result since many combinations of capital and labour can be employed by equally efficient utilities. In addition, LDCs have different levels of reliability and different levels of associated costs, i.e., higher reliability costs more. When we observe different OM&A costs among Ontario LDCs without the associated reliability information, we can not assume that an LDC with higher OM&A is less efficient, it may simply be providing a higher-valued output for its customers. This difference among LDCs with respect to reliability needs to be accounted for just as does the differing labour capitalization rate.

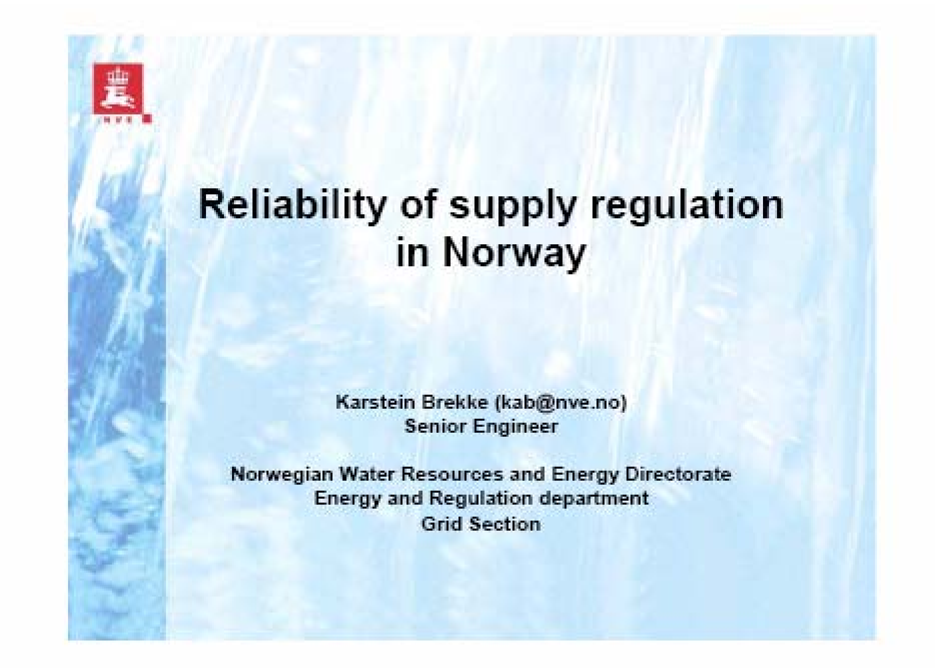
- The issue of scale economies seems to have become an unnecessary preoccupation by policy makers and regulators. Research supports the conclusion that there are no substantial unrealized economies of scale in the Ontario distribution sector; rather, there may be diseconomies. A market-based, policy-neutral merger framework should be adopted. NVE's conclusion appears reasonable for Ontario as well: "As far as NVE is aware, there are as yet no scientific studies of unrealized efficiency gains related to economies of scale within the Norwegian electricity transmission and distribution sector. Even if NVE had the power to dictate mergers, this would probably not lead to the most efficient solutions."

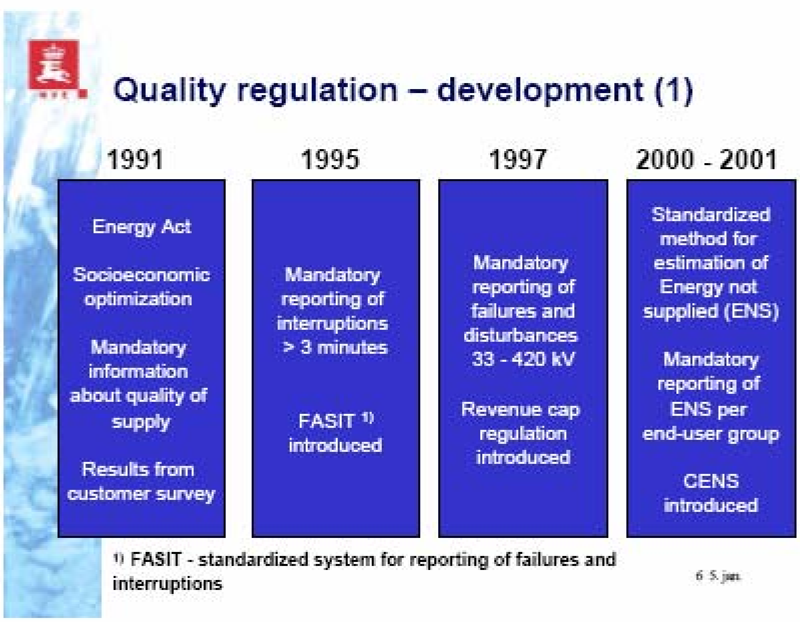
- Due to the distortions caused by non-market prices for capital, it is essential that benchmarking cost measures reflect the full set of factor input choices and their associated costs. Conventional measures of capital costs must be calculated and included for efficient and equitable cost comparisons among Ontario LDCs.

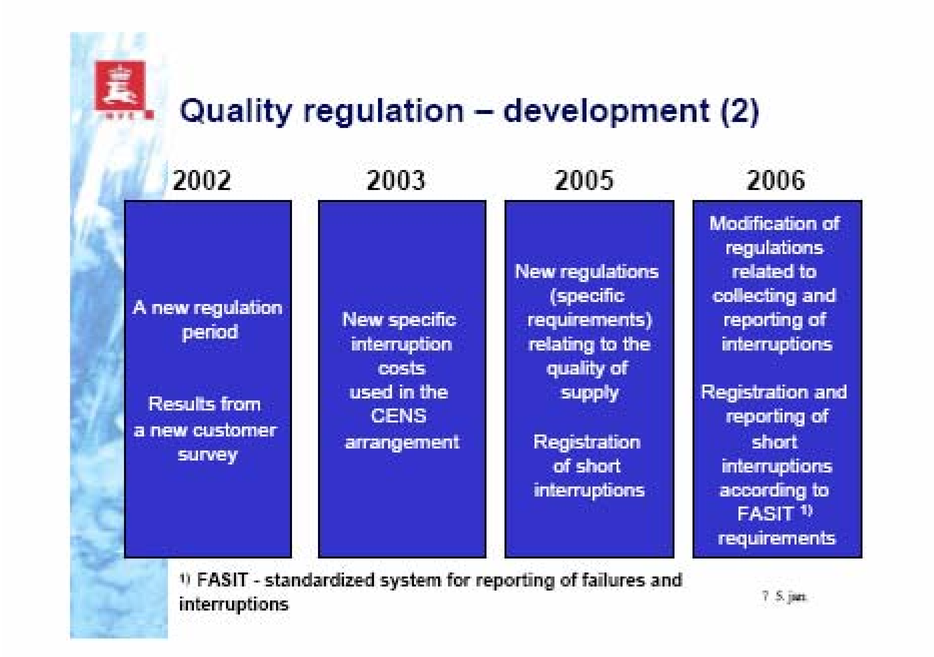
- Service quality/reliability must be included in any quantified multivariate output variable used as a benchmark to assess a utility's production integrating utility cost benchmarking with service quality and reliability regulation. Although the Board's work to establish meaningful service quality standards was prematurely curtailed, it is abundantly clear that a substantial amount of work has already been accomplished. We should not now be debating the need to implement meaningful standards, nor their integration into an IR framework, but rather the manner in which this should be done. European regulators have made substantial progress in the area of service quality standard implementation. The Board can use these standards, presented in Appendix B, to help guide its efforts.

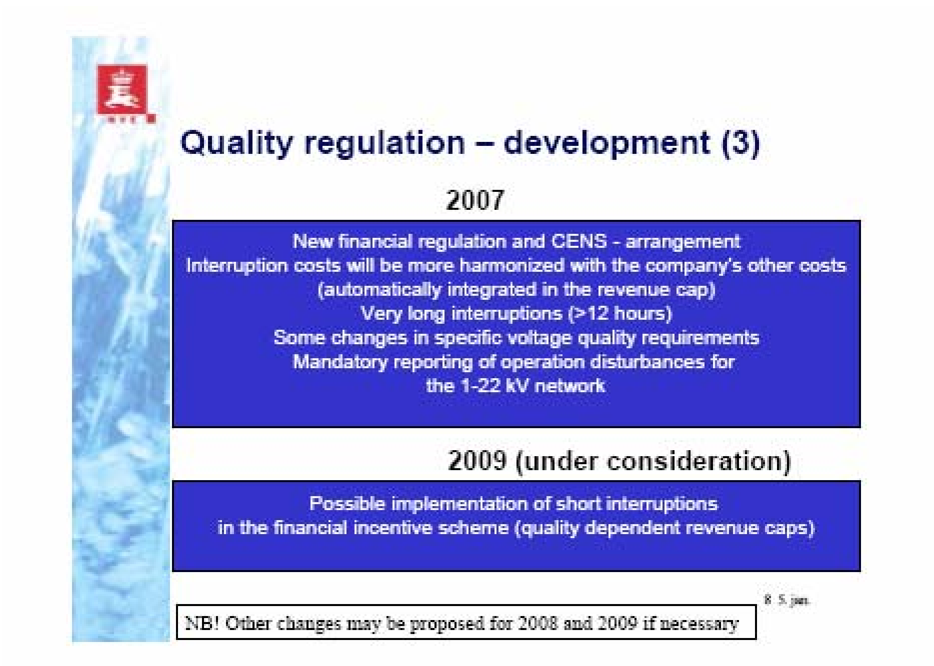
APPENDIX A: NVE'S Reliability of Supply Regulation in Norway

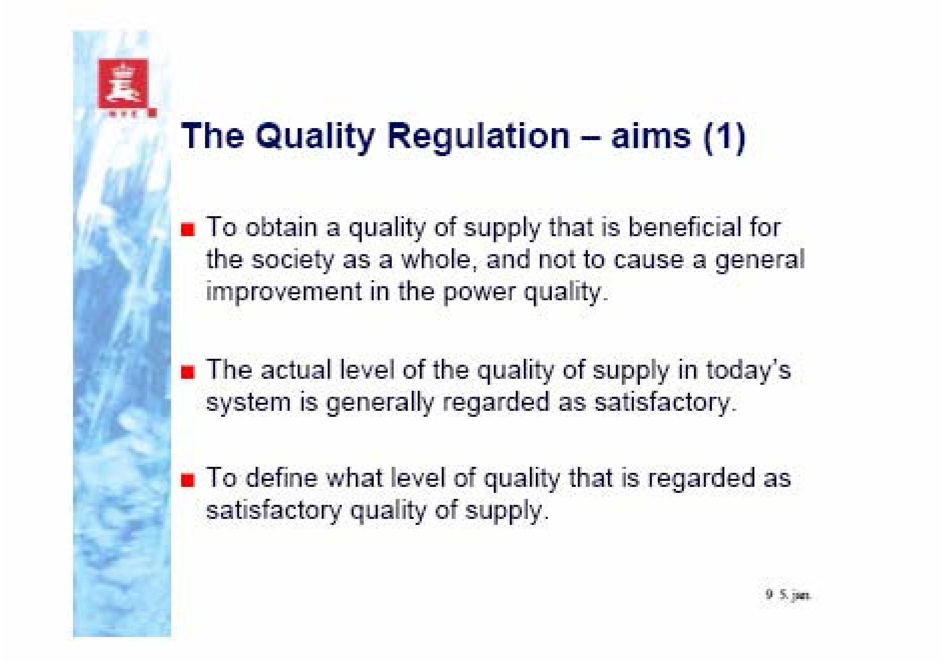
Selected slides from the Norwegian regulator, NVE, on power reliability regulation.

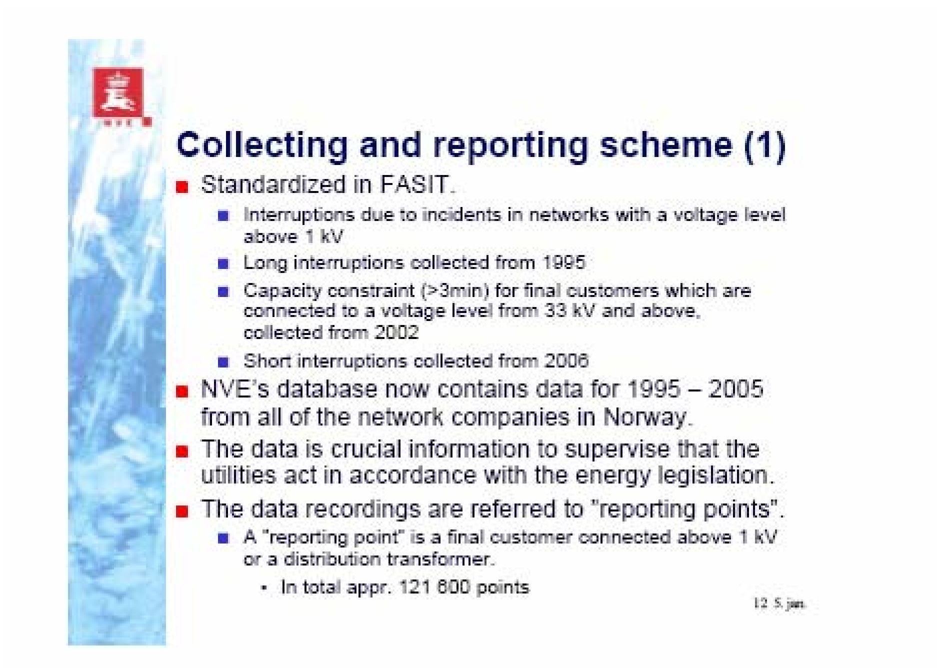


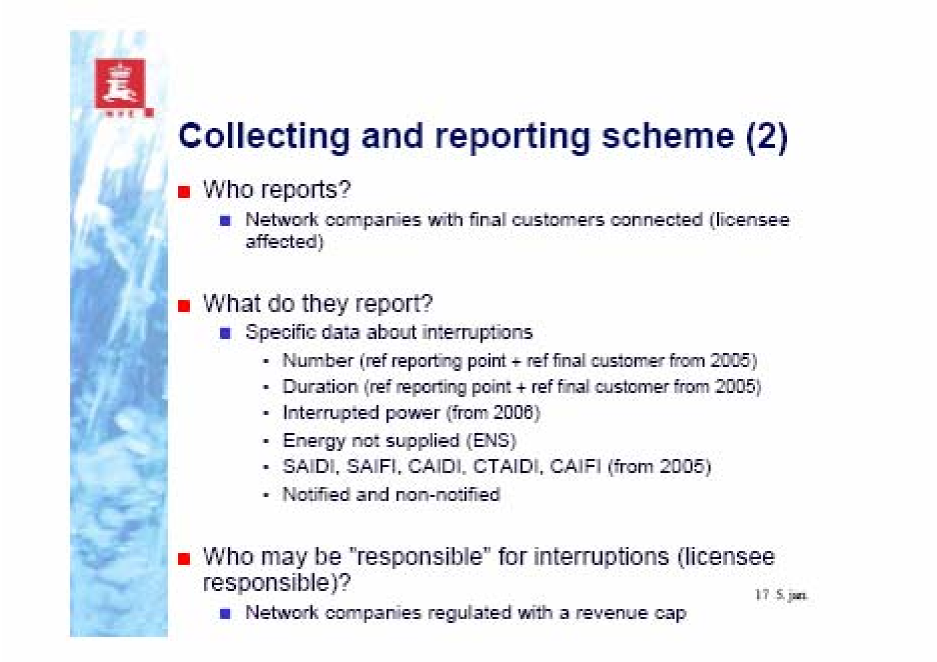



Quality regulation – development (2)
2002
A new regulation period
Results from a new customer survey
2003
New specific interruption costs used in the CENS arrangement
2005
New regulations (specific requirements) relating to the quality of supply
Registration of short interruptions
2006
Modification of regulations related to collecting and reporting of interruptions
Registration and reporting of short interruptions according to FASIT [1)] requirements
1) FASIT - standardized system for reporting of failures and interruptions
7 5. jan.

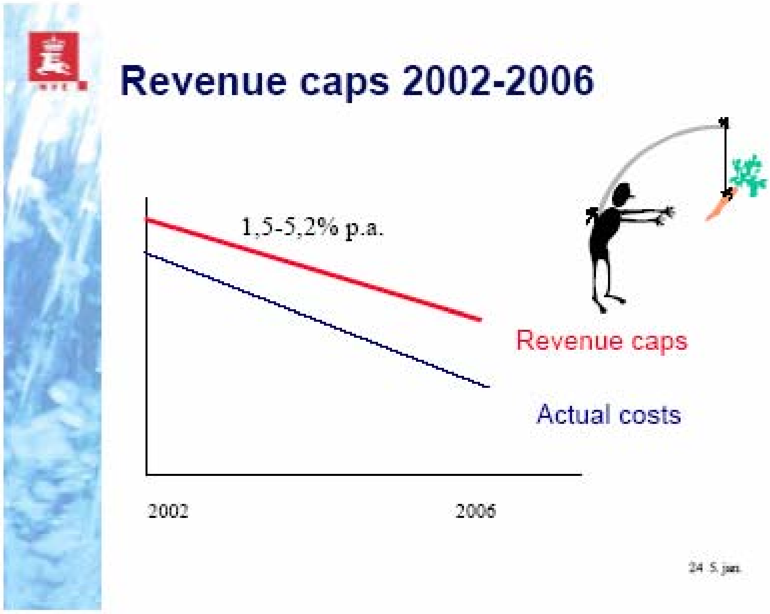

Quality regulation – development (3)
2007
New financial regulation and CENS - arrangement
Interruption costs will be more harmonized with the company's other costs (automatically integrated in the revenue cap)
Very long interruptions (>12 hours)
Some changes in specific voltage quality requirements
Mandatory reporting of operation disturbances for the 1-22 kV network
2009 (under consideration)
Possible implementation of short interruptions in the financial incentive scheme (quality dependent revenue caps)
NB! Other changes may be proposed for 2008 and 2009 if necessary
8 5. jan.


The Quality Regulation – aims (1)
To obtain a quality of supply that is beneficial for the society as a whole, and not to cause a general improvement in the power quality.
The actual level of the quality of supply in today's system is generally regarded as satisfactory.
To define what level of quality that is regarded as satisfactory quality of supply.
9 5.jan.


Collecting and reporting scheme (1)
Standardized in FASIT.
Interruptions due to incidents in networks with a voltage level above 1 kV
Long interruptions collected from 1995
Capacity constraint (>3min) for final customers which are connected to a voltage level from 33 kV and above, collected from 2002
Short interruptions collected from 2006
NVE's database now contains data for 1995 – 2005 from all of the network companies in Norway.
The data is crucial information to supervise that the utilities act in accordance with the energy legislation.
The data recordings are referred to "reporting points".
A "reporting point" is a final customer connected above 1 kV or a distribution transformer.
In total appr. 121 600 points
12 5.jan.

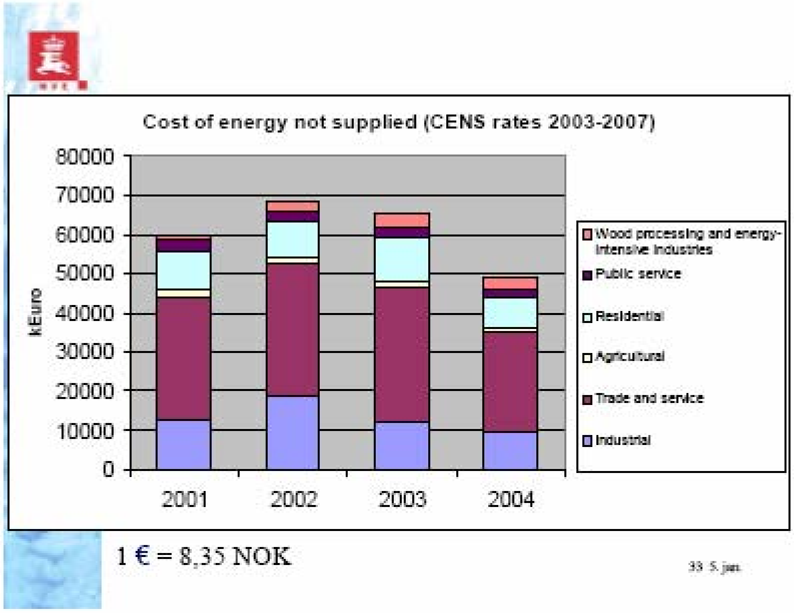

Collecting and reporting scheme (2)
Who reports?
Network companies with final customers connected (licensee affected)
What do they report?
Specific data about interruptions
Number (ref reporting point + ref final customer from 2005)
Duration (ref reporting point + ref final customer from 2005)
Interrupted power (from 2006)
Energy not supplied (ENS)
SAIDI, SAIFI, CAIDI, CTAIDI, CAIFI (from 2005)
Notified and non-notified
Who may be "responsible" for interruptions (licensee responsible)?
Network companies regulated with a revenue cap
17 S. jan.


Incentive regulation until 2006
23 S. jan.



Quality dependent revenue caps (CENS - Cost of Energy Not Supplied.) (1)

- Introduced 2001
- The main objective of the CENS-arrangement is to give the network owners incentives to plan, operate and maintain their networks in a socio-economic optimal way and thereby provide a socio-economic optimal level of reliability. The utilities internalizes the customers interruption costs (it's a part of their accounts).
- CENS includes today interruptions > 3 minutes and ENS because of capacity constraint (> 3 minutes) in networks from 33 kV and above.
- A standardised method is used to estimate energy not supplied.
  - based on load profiles and calibration techniques.
- A change in the revenue cap: ΔR = E(IC) - IC, => may result in tariff changes.



Experiences after 5 years with CENS

- It has been some initial difficulties related to the mandatory reporting routines, communication between involved parties, understanding the set of rules and deciding who is responsible for the interruptions
- The utilities are more attentive to the customers economic expenses as a result of energy not supplied, and they have changed their behaviour in relation to building, operating and maintaining their transmission- and distribution networks.
- The CENS-arrangement brings more attention to and clarifies the responsibilities in the grid. This is important to improve performance.
- Need for further development of CENS
  - Better harmonization of CENS and income cap regulation (from 2007)
  - Other quality aspects, i.e. short term interruptions – will probably be included in 2009.

35 5. jan.

- Incentive regulation from 2007

39 5. jan.

Incentive scheme reliability - Principles changes

- Include the incentive scheme for reliability directly in the calculation of the revenue caps.
- Interruption costs will be more harmonised with the companies other costs.
- The actual level of interruptions will influence on the allowed revenue each year.

42 5. jan.


Very long interruptions > 12 hours (1)
Decision made December 2005 – introducing a new regulation on direct payment to affected consumers.
Regulation will enter into force 1st January 2007
Customers that experience very long interruptions, can claim from the network company:
>12 – 24 hours 600 NOK;
>24 – 48 hours 1400 NOK;
>48 – 72 hours 2700 NOK;
additional NOK 1300 per new 24-hour period
Claim must be put forward within reasonable time
Certain constraints for holiday cottages. Payment can not exceed annual tariff-payment
1 NOK is appr. 0,125 €
46 5. jan.

APPENDIX B: The European Regulators' Response: Standards, Incentive/Penalties, and Guarantees

Electricity Working Group
Quality of Supply Task Force

THIRD BENCHMARKING REPORT ON QUALITY OF ELECTRICITY SUPPLY 2005

Ref: C05-QOS-01-03
Final Version: 6-December-2005

Issued by
Council of European Energy Regulators ASBL
28 rue le Titien, 1000 Bruxelles
Arrondissement judiciaire de Bruxelles
RPM 0861.035.445

The Council of European Regulators' (CEER) Electricity Working Group, Quality of Supply Task Force, Third Benchmarking Report On Quality of Electricity Supply 2005 undertakes a through and rigorous review and analysis of the operating standards adopted for SQR, the incentive/penalty schemes associated with performance/non performance, and the single-customer guarantees that ensure that even poor performing circuits or elements of the network receive the quality of service associated with the standard for "average" performance. The report also examines the standards in place or about to be adopted for 19 member countries. Their results were based on data provided by 19 countries: Austria (AT), Belgium (BE)13, Czech Republic (CZ), Estonia (EE), Finland (FI), France (FR), Great Britain (GB), Greece (GR), Hungary (HU), Ireland (IE) Italy (IT), Latvia (LV), Lithuania (LT), Norway (NO), Poland (PL), Portugal (PT), Slovenia (SI), Spain (ES) and Sweden (SE).

As stated by the task force: (p.vi)

> The Report compares both actual levels and standards of several aspects of quality of service and various practices in terms of regulatory methods, and analyses the factors influencing the levels of service. This could be useful for those regulators, who would like to harmonise their activity with that of others, as well as for those who are in the stage of introducing new elements of quality regulation.

Chapter 1 of the CEER report discusses the use of continuity (i.e., reliability) standards by member countries. Chapter 2 of the CEER report, "The Use of Standards and Incentives in Quality Regulation" is an extensive analysis of past, current and proposed service quality regulation.

> The objective of this chapter is to provide relevant and comparable information on the regulation of quality in the electricity distribution and transmission services, as enforced in CEER-member countries. This chapter deals with standards and incentive/penalty regimes related to continuity of supply... It is the first time that the CEER's Quality of Electricity Supply Benchmarking report reviews existing incentive regulations for quality. Therefore, this chapter should be regarded as a first and general-purpose comparison, while more focused comparisons could be developed in future.

MATERIAL BELOW IS TAKEN STRAIGHT FROM THE CEER REPORT.

TABLE 1.2	CONTINUITY INDICATORS FOR DISTRIBUTION: unplanned interruptions
SAIDI, SAIFI and MAIFI per voltage level (H, M, L)	GB, HU, IT, NO (from 2006)
SAIDI and SAIFI per voltage level (H, M, L)	CZ, GR, PT, FR, LT, NO (from 2006)
SAIDI and SAIFI per voltage level (H, M)	SI (some data only), BE_Wallonia
SAIDI and SAIFI all voltages	SE, EE, IE (SAIFI from 2006)
Average duration (D) and frequency (F) per contracted power or other	AT (average D and F weighted on MV power affected, MV/MV, MV/LV), ES (average D and F weighted on MV power affected: TIEPI, NIEPI) FI (Average D and F weighted on yearly energy consumption) FI (Interruptions are weighted by the yearly energy consumption of the distribution area that one distribution transformer feeds). PT (TIEPI, ENS, excluding LV) NO (ENS, excluding LV: ≤1kV)
Other/No indicators	LV (number of interruptions), PL (no indicators)

Third Benchmarking Report on Quality of Electricity Supply – 2005 · Chapter 1

THE USE OF STANDARDS AND INCENTIVES IN QUALITY REGULATION

2.1 Introduction: what is quality regulation and why is it needed?

2.2.1 Continuity measurement systems

As described in Chapter 1, there is a widespread commitment by regulators to regularly monitor actual levels of continuity of supply, by collecting data from distribution and transmission companies, and to publish the data for benchmarking (Table 2.1). The most common indicators are SAIDI and SAIFI for long interruptions (duration > 3 minutes) for distribution and ENS and AIT for transmission. Usually both planned and unplanned interruptions are monitored separately. Concern for planned interruptions on the part of the regulator is motivated by the fact that even planned interruptions have a cost for consumers. As long as they are informed in advance, however, they will be able to reduce their outage costs and inconvenience. At present, very few regulators have data on the number of short interruptions (duration < 3 minutes).

However, it is clear that regulators are increasingly concerned about short interruptions as they become increasingly relevant to business customers. Monitoring short interruptions requires attention to technical details and is, naturally, the prerequisite for setting regulatory standards. It was rather clear from the survey that significant differences exist with regard to accuracy and completeness in the measurement and registration of the data. This diversity makes it difficult, even today, to fairly compare numerical values. One example for all is the measurement of interruptions originated on LV circuits. Where these are not measured (more than half of the countries surveyed), the number and duration of interruptions actually experienced by consumers will be worse than indicated in the reported data. (CEER, p.33)

TABLE 2.1 MONITORING AND COMMUNICATION OF CONTINUITY INDICATORS

	Measure long interruptions	Measure short int's	Measure separately planned/unplanned	Voltage level	Information to regulator	Publication
AT	✓		✓	HV, MV	Yearly	✓
BE	✓(>15' in LV)		✓	HV, LV	Yearly	
CZ	✓		✓	HV, MV, LV	Yearly	✓
EE	✓		✓	HV, MV	Yearly	✓
ES	✓		✓	HV, MV	Yearly	✓
FI	✓	✓	✓	HV, MV, LV	Yearly	✓
FR	✓	✓	✓	HV, MV, LV	Yearly	✓
GB	✓	✓	✓	HV, MV, LV	Yearly	✓
GR	✓		✓	HV, MV, LV	Yearly	✓
HU	✓	✓	✓	HV, MV, LV	Yearly	✓
IE	✓(>1')	✓(>1')	✓	HV, MV	Yearly	✓
IT	✓	✓	✓	HV, MV, LV	Yearly	✓
LT	✓		✓	HV, MV, LV	Quarterly	✓
LV	✓			HV, MV	Yearly	✓
NO	✓		✓	HV, MV	Yearly	✓
PO						
PT	✓		✓	HV, MV, LV	Quarterly	✓
SI	some data available	some data available	some data available	HV, MV	upon request	✓
SE	✓		✓	HV, MV	Yearly	✓

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Comparison of data across countries is made inherently difficult by the fact that performances vary substantially even among companies and within the same company. As suggested by Ofgem, factors that influence performance can be grouped into three classes:

Inherent factors such as weather conditions, geography and population density of a particular area;

Inherited factors such as the design of the network at the starting moment of incentive regulation and/or privatisation (e.g. some companies or areas may have long, predominantly overhead circuits, whilst others may have more underground lines). It takes a long time and significant capital expenditure to fundamentally alter network design;

Incurred factors such as managerial performance, how well assets are maintained, and how effectively resources are used.

Reliable and robust data is crucial for incentive regulation on continuity. On the one side, it clearly emerged from the survey that the majority of regulators have not established or approved rules for recording interruptions (see Table 2.2). On the other hand, measurement protocols are generally found in almost all of the eight countries where an incentive/penalty regime is implemented (not in all countries that have set continuity standards at system- or customer-level). These protocols require companies to measure and analyse data in a manner that is consistent with regulatory purposes, enable the regulator to control the registration process, and give credibility and fairness to financial incentive regimes. The most critical issues in measurement protocols that affect the implementation of incentive/penalty regimes are classification of causes (in particular force majeure: this is defined in the great majority of countries, see Annex 2.1), and identification of the number of consumers affected by the interruptions (or its estimate). (CEER, p34)

Almost all countries having adopted incentive/penalty schemes regularly audit data provided by companies. The variety of auditing systems (audits can be carried out by regulators themselves, by consultants, or even by the companies according to procedures set by the regulator) should facilitate the diffusion of such important measures in other countries, especially those interested in implementing a financial incentive scheme. It is important that audits be carried out more frequently when the incentive/penalty regime is first introduced. Frequency of audits can then be relaxed over time. (CEER, p 35)

TABLE 2.2 RECORDING, AUDITS, AND QUALITY REGULATION

	Rules for recording long interruptions	Classify interruptions with causes	Definition of Force Majeure	Audits	Continuity standards*	Incentive/penalty regime
AT	✓	✓	✓			
BE		✓	✓		✓	
CZ	✓	✓	✓		✓	
EE			✓		✓	✓
ES	✓	✓	✓	✓	✓	
FI		✓			✓	
FR		✓	✓	✓	✓	
GB	✓		✓	✓	✓	✓
GR						
HU	✓	✓	✓	✓	✓	✓
IE		Not regularly			✓	✓
IT	✓	✓	✓	✓	✓	✓
LT		✓	✓		✓	
LV						
NO	✓			✓	Proposal	✓
PO						
PT	✓	✓	✓	✓	✓	✓
SI		✓				
SE	✓				✓	✓

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2.2.2 Customer surveys

Customer surveys are an additional, important form of "measuring" quality, complementary to continuity measurement systems. Even if customer surveys are not widely used by regulators, customer research can provide useful information on customer satisfaction, expectations and Willingness To Pay (WTP) for quality. This information is useful in regulatory decisions regarding the choice of quality factors and services to be monitored and given the presence of incentives. For this reason, regulators who do carry out customer research usually find them extremely important and use the results in various matters of regulation.

The most frequent issues explored through customer research are (see Table 2.3):

Customer satisfaction: this is the typical subject of customer research, either occasionally (like in Portugal) or periodically (like in Hungary, Italy, Great Britain); acccording to the separation between network operator and energy supplier, the common quality factors on which customers are requested to express their satisfaction are:

regarding the network operator: continuity of supply, troubleshooting, voltage fluctuation, staff behaviour, information provided;

regarding the supplier: punctuality of bills, details of bills, complaints handling, information provided, billing adjustments in case of errors.

Customer expectations and importance of quality factors: this is a more sophisticated matter that can provide regulators with useful information for standard setting and for identifying new areas of regulatory intervention. Often, continuity of supply is felt as the most important quality factor (for instance in Portugal and in Italy), but more focused research can uncover new areas of great interest to consumers. For instance, Ofgem's latest study, published on Ofgem's website in June 2004, suggests that British customers' main priorities are:

- improving restoration times following storms;
- receiving accurate information during power cuts;
- reducing the number and frequency of power cuts;
- carrying out some degree of undergrounding in national parks and areas of outstanding natural beauty.

Customer willingness to pay: this type of quantitative research is done by many of the regulators that introduced incentive regulation for continuity of supply and is used by them, together with cost and performance information, to get information on incentive rates and cost allowances of the incentive schemes. This kind of research is based on "contingent valuation": this means that, in order to quantify the valuation of economic damage ensuing from interruptions, generally one or more "interruption scenarios" are proposed to the interviewee. WTP (CEER, p. 35) research is the most difficult to carry out and can lead to results that are hard to interpret; for instance, both in Italy and in Great Britain, WTP studies have shown higher than expected willingness to pay, even if the vast majority of both household and business consumers feel that the price they pay to electricity suppliers is consistent with the value they receive…(CEER, p.36)

The case of Great Britain is probably the most innovative as regards the use of customer surveys. Results from customer satisfaction become, in fact, an indicator in the incentive/penalty regime, even if with a weight that is largely lower than the continuity-based indicators. The regulator (Ofgem) carries out monthly surveys of the quality of telephone response. The regulator commissions market research consultants to call back customers who have contacted their distribution business in relation to an emergency or power cut. The customers are asked to rank the company from 1 to 5 where 1 is very dissatisfied and 5 is satisfied in four key areas:

- politeness of staff;
- willingness of staff to help;

· accuracy of information provided;
· usefulness of information provided.

Nine hundred customers are interviewed each year for each distribution company. Companies are then incentivised on the basis of their annual mean score. Companies are subject to a sliding-scale penalty if their annual mean performance deteriorates below 4.1. If their annual mean scores fall below 3.6, companies will be liable for the full penalty of 0.25 per cent of revenue. There will be a small reward of 0.05 per cent of revenue for those companies with annual mean scores greater than 4.5. (CEER, p. 36)

TABLE 2.3	CUSTOMER SURVEYS CONDUCTED BY REGULATORS
Other specific matters	GB (quality of telephone response, monthly)
Customer surveys on willingness to pay (WTP)	NO (2001), IT (2003), GB (2004), SE (2003)
Customer surveys on expectations and importance of quality factors	HU (annually), IT (1998)
Customer surveys on satisfaction	HU (annually), IT (annually), GB (every 5 years), PT (occasionally)
Customer surveys under preparation	GR
None	AT, BE, CZ, EE, ES, FI, FR, IE, LV, LT, PL, SI

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2.3 Continuity standards at system-level and incentive/penalty regimes

In the past five years regulators have developed incentive/penalty regimes for continuity that are linked to continuity standards at the system level. As far as the distribution service is concerned, incentive/penalty regimes are in place in eight countries out of 19 surveyed: Italy (from 2000), Norway and Ireland (from 2001), Great Britain (from 2002), Hungary and Portugal (from 2003), Sweden (from 2004), and Estonia (from 2005). Note that in Estonia the incentive/penalty regime, introduced on both distribution and transmission, is too recent to be described in the present report. Other countries expressed interest in introducing an incentive scheme in the future: Finland (from 2008), France, Lithuania (from 2008), Poland, Spain, and Slovenia (see Table 2.4). (CEER, p. 37)

TABLE 2.4	SYSTEM-LEVEL STANDARDS OF CONTINUITY: DISTRIBUTION
System-level continuity standards	GB (SAIDI, SAIFI), HU (Outage rate, faults/km, average repair time (MV), average number of grouped faults (LV), SAIDI, SAIFI, Percentage of interr. restored within 3 and 24 hrs). IE (SAIDI and losses until 2005; SAIDI, SAIFI and losses from 2006), IT (SAIDI), NO (ENS), PT (ENS), SE (SAIDI, SAIFI), ES (TIEPI-MV, NIEPI-MV, 80 percentile TIEPI-MV), EE (not available)
Special plans	ES, PT, SE
Incentive/penalty regime	EE, GB, HU, IE, IT, NO, PT, SE
Interest or intention	ES, FI, FR, LT, PL, SI

Third Benchmarking Report on Quality of Electricity Supply – 2005 · Chapter 2

This section illustrates the regulatory mechanisms adopted in the surveyed countries. The incentive schemes implemented are all based on the same principle: the revenues of the company are modified upward or downward depending on its performance in terms of continuity of supply, measured as the distance between actual system-level continuity standards and a predefined target. Although the principle is the same, the mechanisms adopted in European countries are quite different in numerous respects, as will be explained below. In order to facilitate understanding of the comparison the Portuguese mechanism, chosen for its simplicity, is described in detail (Additional Information 2.2).

ADDITIONAL INFORMATION 2.2 – PORTUGAL: INCENTIVE/PENALTY REGIME

The Tariff Code, published by the Portuguese regulator (ERSE) establishes an incentive scheme to improve continuity of service. The financial measures affect the annual adjustment of the allowed revenues for the activity of electricity distribution in MV and results in a penalty or a reward, depending on the results of continuity of service performance. The continuity indicators considered in the incentive scheme is the Energy Not Supplied (ENS). (CEER, p. 38)

2.3.1 Incentive/penalty schemes adopted in European countries

Incentive/penalty schemes have been implemented in European countries with the general objective of improving/maintaining continuity levels at a socio-economically acceptable level, in particular under price- or revenue-cap types of regulation. In one case only (Italy) has the regulator designed the mechanism specifically around a country-specific objective: the convergence of continuity levels towards unique targets (for districts having the same territorial characteristics). Prior assessment of current continuity levels can, in fact, show the need to address specific issues (Table 2.6). (CEER, p.39)

TABLE 2.6 TYPE OF INCENTIVE/PENALTY REGIMES ADOPTED IN EUROPEAN COUNTRIES

	Objectives	Incentive and/or penalty	Other schemes	Duration
GB	Improve continuity levels	both	Guaranteed Standards (GS) on maximum restoration time: GS on maximum yearly number of long unplanned interruptions	5 years (as price control period)
HU	Improve continuity levels Compensate drawbacks of price cap regulation	both	GS on maximum restoration time	No predetermined duration. From 1 January 2006 a new regime will be introduced for 3 years. No correlation with the price control period (4 years).
IE	Improve continuity levels	both	GS on maximum restoration time	5 years (as price control period)
IT	Improve continuity levels and reduce regional gaps in continuity through a "convergence" mechanism	both	GS on maximum yearly number of long unplanned interruptions per HV and MV customer GS on maximum restoration time under consultation	4 years (as price control period)
NO	Achieve a socio- economically acceptable level of continuity (rather than to improve it)	both	None	No predetermined duration until now. From 2007 there will be some small changes in the scheme.
PT	Improve continuity of service levels	both	GS on Maximum yearly cumulative duration of unplanned interruption (all voltage levels), GS on Maximum yearly number of long unplanned interruptions (all voltage levels), Special Plans for improving Quality of Supply	No predetermined duration
SE	Achieve a socio-economically acceptable level of continuity	both	GS on maximum restoration time under evaluationObservation of the worst performing areas	No predetermined duration (ex-post regulation, year by year)

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In all cases surveyed, the scheme includes both penalties and rewards and, since it is designed to address system-average continuity levels, is or will be complemented by some form of protection for the worst-served consumers. In general this is done by introducing Guaranteed Standards (GS) on duration and number of long interruptions (maximum restoration time being the most common, see section 2.4). Sometimes this assumes the form of observation of the worst-performing areas (Sweden) or, as in Portugal and Spain, of a quality improvement plan financed through tariffs (See Additional information 2.3).

ADDITIONAL INFORMATION 2.3 – WORST PERFORMING AREAS

In Portugal, a distributor experiencing difficulties in meeting quality standards can submit a temporary action program aimed at improving its performance in a specific location. The program, with a maximum duration of 2 years, must be approved by the Ministry after consultation with the regulator. Special plans are financed through tariffs. (CEER, p.40)

In Sweden, a quality of supply index is calculated for every company using a network performance assessment model (see Additional Information 2.4). The regulator observes the change in this index from year to year and investigates any companies that present a persistently low quality of supply over a period of few years. Companies below the lower quality boundary can be checked for quality issues, regardless of the company's performance from a tariff regulation point of view.

Spain does not have an incentive/penalty regime yet, but it has set system-level continuity standards, which are not only evaluated as average levels in a given territory but aimed at identifying worst-served areas in that region. Standards are set on TIEPI, 80th percentile TIEPI, and NIEPI, and differentiated by density areas. Distribution companies experiencing difficulties in maintaining the quality required in certain areas are given the opportunity to submit, to the competent administration, a temporary action programme describing the problems that need to be corrected. Those programmes will be included in a quality improvement plan financed through the tariff. Special plans have been implemented since 2004 and the amount of expenses recovered through this mechanism has been quite large so far: for 2004 special plans received a budget of 50 million, increased to 80 million for 2005.

Incentive/penalty schemes have in most cases the same duration as the price control period (4 or 5 years) and in a few cases have no predetermined duration. All schemes are periodically reviewed: in the first case, with the same frequency as the tariff, in the second at the regulator's discretion. When the review is performed at the same time as the tariff adjustment it should be easier to separate the expected level of continuity (remunerated via the base tariff) from the improvements, financed via the incentive scheme.

2.3.2 Indicators used for incentive/penalty regimes

The indicators included in the incentive schemes are usually one or two (in some cases SAIDI only; in other cases both SAIDI and SAIFI; occasionally ENS, Energy Not Supplied) and concern long interruptions. Until 2005, Hungary monitored several indicators, but it is planning to use only three starting in 2006 (Table 2.7).

In some cases the indicator includes only unplanned interruptions, in others also planned ones. In the latter case, planned interruptions are usually not given the same weight as unplanned ones. In Great Britain, where the regulator found evidence from a customer survey that their impact is about half that of unplanned interruptions, they have been counted with a 0.5 discount factor since 2005. In Norway their reduced impact on consumers is taken into account in the incentive rate, which is lower than the incentive rate for unplanned outages (but more than half of it). Planned interruptions in Norway were evaluated using data from a customer survey (i.e. in the same manner as unplanned interruptions, see paragraph 2.3.4). In any case is important to be aware of the fact that a scheme that allows companies to gain higher revenues by reducing planned interruptions, on the one hand, can induce companies to adopt a more efficient maintenance program or, on the other hand, may create a long term risk due to insufficient maintenance of the network. This may be especially true if the company is close to its target halfway or three quarters of the way through the year: the company may choose to defer planned work. (CEER, p. 41)

TABLE 2.7 INDICATORS USED FOR INCENTIVE/PENALTY SCHEMES

	Indicators	Planned	Exclusions	Rolling average
GB	CIs: number of customers interrupted per 100 customers, CML: average number of customer minutes lost per customer	Included in CML and CIs with 50% weighting from 2005	exceptional events; separate regulatory mechanism (see Additional information 2.6)	No
HU	Network Security (NS) indicators: *Outage rate*, Number of MV faults per grid length, Average repair time of MV network, Average number of LV grouped faults. Continuity of Supply (CS) indicators, *SAIDI, SAIFI*, Percentage of interruptions restored within 3 and within 24 hrs	Excluded	NS: no CS: yes	Yes: three year rolling average
IE	SAIDI and Losses (SAIFI being added from 2006)	Included	days with daily SAIDI with deviation larger than twice the standard deviation from the mean	No
IT	SAIDI	Excluded	force majeure and external causes; Statistical method	Yes: two year rolling average
NO	ENS Energy Not Supplied	Included in the incentive regulation (evaluated separately)	Yes (exceptional events can be evaluated upon request by the company)	No
PT	ENS Energy Not Supplied, which is determined on the basis of TIEPI (indicator of frequency of interruption weighted with the installed power in MV)	Excluded	force majeure, public interest, service reasons, safety reasons, agreements with the customer, facts attributable to the customer.	No
SE	SAIDI, SAIFI	Included in the incentive (evaluated separately)	Force majeure	No

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2.3.3 Standards used for the incentive/penalty scheme

Five out of eight regulators require distribution companies to improve their performance over time. In other words, they set continuity targets that decrease with time (Table 2.8). In Sweden the continuity target can theoretically vary from year to year. Is important to notice that Sweden offers an implicit incentive to improve quality, since the benchmark used in the performance assessment model is based on 100% underground cables at LV and MV levels (see Additional Information 2.4). In Norway no improvement is required by the regulator, whose aim is to achieve a socio-economically acceptable level of continuity and not necessarily to improve it. The Norwegian regulator (CEER, p. 43) calculates a benchmark for company performance using a regression model: this benchmark is adjusted in order to give companies incentives to provide a socio-economically optimal level of reliability; to this end, utilities are forced to internalise consumer interruption costs.

In Italy, Great Britain, and Hungary the worst performing companies have larger improvements to make: this choice enables a convergence of continuity levels for the entire country. Continuity targets are set in all cases by company. The only exception is Italy, where targets are given by territorial district. Historical performance and structural differences in network layouts must be taken into account when setting the standards, in order to set targets that are achievable for the company and valuable for consumers. Differentiating targets by density area, as in Italy, or by company, as in other countries, does just that.

Some regulators try to avoid tariff changes for performances that are "close enough" to the target. This reduces the administrative burden of regulation. To this end, Italy Hungary, and Portugal have defined dead bands around the target. The width of the dead band varies from a minimum of +/- 5% to a maximum of +/- 12%. Note that there is a risk of diluting incentives if the band is too wide. In Norway there is no dead band, but the regulator requires companies not to introduce changes in the tariff unless long-lasting changes in continuity have been achieved.

ADDITIONAL INFORMATION 2.4 – NETWORK PERFORMANCE ASSESSMENT

Network performance assessment methodologies enable regulators to compare company performance in a objective and fair manner, taking into account differences in structural variables across distribution companies.

The Swedish regulator employs a network tariff regulation model, the so-called Network Performance Assessment Model ("PAM"). Long planned and unplanned SAIDI and SAIFI reported for a whole year by the companies, for every network concession, are converted to a total cost of interruptions for that particular concession. The calculation is based on a study of customers' estimated interruption costs conducted by Swedenergy (the branch organization) in 1994 and updated in 2003, where both planned and unplanned interruptions were considered.

This amount, called the "reported total interruption cost", is compared for every concession with the "expected total interruption cost" calculated from the PAM. If the company's reported total interruption cost is higher than the calculated one, the difference between the reported and expected interruption cost will correspond to the penalty due to poor quality of supply for that concession.

Therefore, there is a target level of continuity that is defined, in terms of cost of interruption, by the "expected normal interruption cost" calculated by the PAM. There is also an implicit incentive to improve quality as costs computed from the performance assessment model are based on 100% underground cables at LV and MV levels.

The effect of quality performance on the tariff is limited by upper and lower "boundaries". The upper boundary is the limit for over-quality and the lower boundary corresponds to the performance from a pure radial network.

In Norway a regression model is used to calculate "expected total interruption costs" for each company using historical data and various structural variables (energy supplied, network extension, number of transformers, wind, geographical dummies). (CEER, p. 44)

In Great Britain the regulator (Ofgem) collects physical characteristics and performance information for each MV circuit for each distribution company. These circuits are then divided into 22 circuit groups with physically similar characteristics. The groups are defined so that differences in the percentage of overhead line, circuit length and number of connected customers are minimised and that no group is dominated by a single company. Ofgem compares and benchmarks performance within each circuit group. A benchmark is then built for each company based on its mix of circuits. (CEER, p. 45)

TABLE 2.8 STANDARDS USED FOR INCENTIVE/PENALTY SCHEME

	Baseline	Scope (number of companies)	Dead band
GB	Flat or minimum level of improvement. Convergence mechanism.	Per distribution company (14 ex-PES), excluding the new smaller ones	No
HU	SAIDI decreases yearly. All other indicators are constant. Convergence mechanism.	Per distribution company (6)	Yes: 5% for penalties; 10% for incentives
IE	Yearly decreasing	Per distribution company (1)	No
IT	Yearly improvement required. Convergence mechanisms.	Per territorial district (more than 300). Each district is formed by all the municipalities of the same province with the same density (inhabitants) and served by the same distribution company (24 major companies).	Yes: ±5% from target
NO	Target can vary from year to year.	Per distribution company (137); the same incentive regime is applied to the transmission company.	No dead band but until 2006 regulator requires companies to adjust tariff changes only if long-lasting changes in continuity have been achieved
PT	Only one target, ENSRef = 0,0004 x ES (Energy supplied in the year), has been published by the regulator so far. The target can be recalculated every year	Per distribution company, only in MV (1)	Yes: ± 12% from target
SE	Target can vary from year to year. Implicitly decreasing.	Per distribution company (193)	No

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2.3.4 Economic effects

Incentive/penalty schemes, in one form or another, affect revenues earned by distribution companies. With the exception of Hungary (and Great Britain from 2002 to 2004), such economic effects are directly proportional to the difference between the actual value of the regulated indicator(s) and the target and symmetry. Symmetry means that for the same deviation in absolute value (positive or negative) from the target there is the same amount of incentive (for positive deviation, i.e. actual quality better than standard) or penalty (for negative deviation, i.e. actual quality worse than standard). Indeed, the degree of symmetry of the whole incentive/penalty regime should be regarded not only in the light of the proportionality between deviation from the standard and economic effects, but also looking at the standard setting system, and in particular at the existence of a required minimum improvement (see Table 2.9).

Rewards are ultimately paid by consumers in all cases. In Great Britain, as well as in other countries, these costs are shared only among consumers of the company that earned incentives. Differentiating the distribution tariff across different areas of the same country can be an issue in some countries, where a higher-level principle prevents such tariff differentiation. In Italy, for instance, the constraint of the single distribution tariff across the national territory requires that all consumers in the country share the costs of quality improvements above the target: it is the single national tariff that increases. The problem does not apply to countries where there is only one distributor (for example Ireland and Portugal).

> The most interesting aspects are the following: In the case of Great Britain and Ireland, respectively ±3% and ±2% of price control revenue is exposed to the continuity incentives (note that the amount of revenues exposed to the scheme is boundaried). In Ireland the percentage of revenues exposed will be increased to ±2.5% in 2006 and ±4% from 2007. There are four incentives, 3 of which refer to quality of supply and network performance (SAIDI, SAIFI and losses). In Great Britain 1.2% of this relates to SAIFI and 1.8% relates to SAIDI. Rewards (penalties) are proportional to the difference between the actual performance level and the target. Such difference is valued using a fixed incentive rate. In the case of Norway and Sweden the difference between expected interruption costs and actual interruption costs (using respectively actual ENS and actual SAIDI and SAIFI), is calculated annually for each company and added to the company's revenue cap if positive or subtracted if negative. In Sweden the tariff for each company is adjusted accordingly (network tariff and quality are evaluated *ex post* through a reference network model). Upper and lower boundaries are used, respectively corresponding to the quality of a totally undergrounded net-

TABLE 2.9 ECONOMIC EFFECTS

	Incentive/penalty	Incentive rate	Symmetry
GB	±3% of price control revenue is exposed to the continuity incentives	Average value of energy not supplied implicitly used in the scheme: 4.18 €/kWh not served	Yes (but minimum improvement required)
HU	Tariff-related incentives and penalties apply to 3 indices out of NS & CS: outage rate; SAIDI, and SAIFI; Fines apply to all NS and CS indicators	Not applicable	No
IE	±2% of price control revenue is exposed to the incentives (2001-2005)±4% of price control revenue is exposed to the incentives (2006-2010)	Average value of energy not supplied used in the scheme: 7.2 €/kWh-not-supplied (year 2000)	Yes (but minimum improvement required)
IT	The price-cap formula contains a Q factor that funds the net difference between incentives and penalties.	Differentiated according to type of consumers (domestic and business); respectively 10.8 and 21.6 €/kWh-not-supplied	Yes (but minimum improvement required)
NO	The difference between expected interruption costs and actual interruption costs (using actual ENS) is calculated annually for each company and added to the company's revenue cap if positive and subtracted if negative. From 2007 companies will have to adjust tariffs yearly on the basis of the incentive/penalty effect	Costs of energy not supplied, differentiated according to type of consumers (unplanned - planned in €/kWh-not-supplied); Industrial: 7.90 - 5.51; Trade/Service: 11.86 - 8.14; Agricultural: 1.80 -1.20; Residential: 0.96 - 0.84; Public service 1.56 - 1.20; Wood processing/ energy intensive industry: 1.56 - 1.32	Yes
PT	Rewards (penalties) are proportional to the difference between the actual performance level and the target (excluding the dead band)	Fixed incentive rate for any deviation from the targetValue of energy not supplied used in the scheme: 1.5 €/kWh-not-supplied.	Yes
SE	The difference between "expected interruption costs" and actual interruption costs (using reported SAIDI and SAIFI) is calculated annually for each company. The tariff for the company is adjusted accordingly. An upper boundary (totally underground network) and a lower boundary (quality of a pure radial network) are used.	Costs of energy not supplied and cost of power interrupted, differentiated according to density of line, i.e., meter line per number of customers. €/kWh-not-supplied (unplanned/planned) Urban: 12 / 8.6; Suburban: 8.8 /6.3; Rural: 7.4 /5.2; €/kW-interrupted (unplanned/ planned); Urban 2.5 /0.4 Suburban 1.9 /0.3; Rural 1.6 / 0.2	Yes

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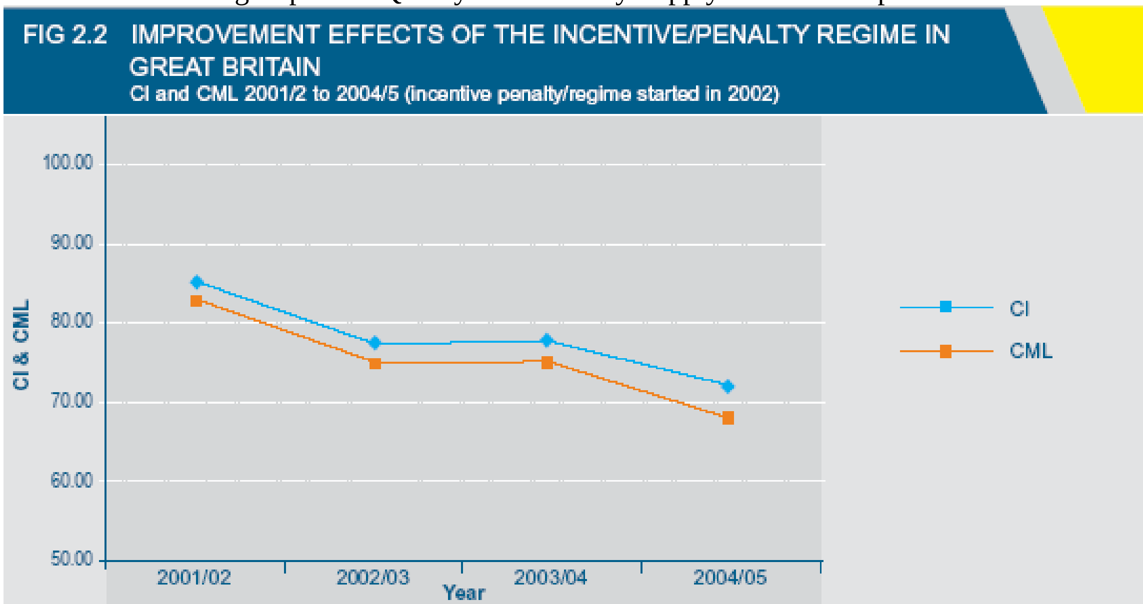

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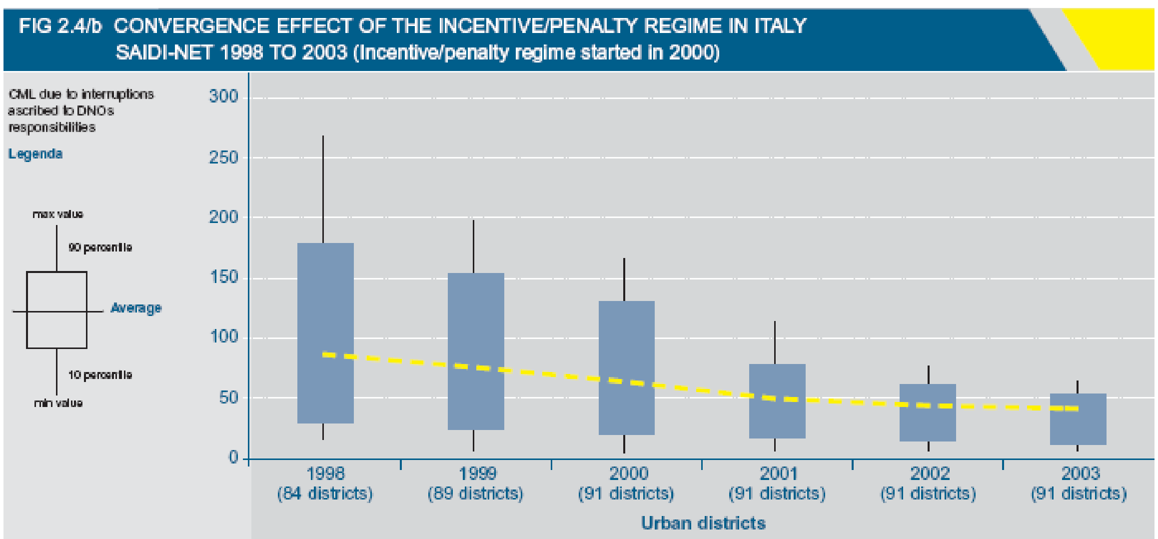

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TABLE 2.10	VERY LONG INTERRUPTION STANDARDS FOR SINGLE CUSTOMERS
Standards on maximum duration of each unplanned interruption	BE, CZ, EE, FI, FR, GB, HU, LT
Standards on maximum yearly duration of unplanned interruption for the same connection point	ES, PL, PT
Proposal stage	IT, SE
None	AT, GR, IE, LV

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TABLE 2.11 CONTINUITY SINGLE-CUSTOMER STANDARDS: maximum duration of each unplanned interruption

Country	Standard	Conditions	Compensation	Amount
BE (Wall.)	4 hours	Exceptional events (force majeure) excluded	Economic compensation on request. After 4 hours provisional production has to be installed.	Damages only if interruptions are distributor's fault
CZ	LV cust: 18 hrs HV cust: 12 hrs	Exceptional events (force majeure) excluded	On request; must be claimed by the customer within 5 working days	10% from yearly payments for distribution, max. €150 for LV and €300 for HV
EE	20 hours (in the summertime) 24 hours (in the wintertime); stricter standards will apply from 2008	Exceptional events (force majeure) excluded	Automatic for the three biggest distribution companies; on request for the other companies	LV <63A: from 8€ (excess up to 48 hours) to 24 (excess more than 96 hours) MV: from 0.77 €/kW to 2,3 €/kW according to the excess time
FI	12 hours	Exceptional events excluded (see list in Annex 1); moreover, in case of risk for workers' safety, the distributor can delay the starting time for counting the duration	Customer has to ask for compensation, but the DSO should make it as easy as possible. Many companies pay compensation automatically	interruption 12-24 h: compensation 10% of customer's annual network charges; interruption 24-72 h: compensation 25% interruption 72-120 h: compensation 50%; beyond 120 h: 100% Max 350€/interruption
FR	6 hours	Exceptional events excluded (see list in Annex 1, Force majeure)	Automatic	For each range of 6 hours interruption, 2% of the fixed tariff component depending on the subscribed power (4% after 12 hours, ...).
GB	18 hours (normal weather conditions) 24 up to 141 hours for exceptional events	Severe weather events excluded Severe weather events classification (see additional information 2.6). Some exceptional events excluded	On customer's request On customer's request	£50 domestic customers £100 non-domestic, plus £25 for each further 12 hours £25 (around €36) plus £25 for each further 12 hours up to maximum of £200 (all types of customers)
HU	12 hours (in case of single disturbance); 18 hours (in case of several disturbances)	Exceptional events excluded (see list in Annex 1)	Automatic in the case of 1 company out of 6, on customer's request for the other 5 companies	Household consumers: automatic payment around €8, on request €20. Non domestic consumers: from €12 (LV, automatic) up to €120 (MV on request).
LT	24 hours (stricter standards apply under specific contractual conditions only to some categories of customers)	Exceptional events excluded	On customer's request	Not defined

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TABLE 2.12 CONTINUITY SINGLE-CUSTOMER STANDARDS: maximum yearly duration of unplanned interruptions

Country	Standard	Conditions	Compensation	Amount
ES	MV CUST.: Urban: 4h/year; Suburban: 8h/yr; Conc. rural: 12h/yr; Scat. rural: 16h/yr; LV CUST.: Urban: 6h/year Suburban: 10h/yr; Conc. rural: 15h/yr; Scat. rural: 20h/yr HV (>36KV) CUST.: 6h/yr	Exceptional events excluded (see list in Annex 1)	Automatic	Discount=PW*DH*5*P PW = billed annual average power DH = difference between the number of consumer interruption hours and the hours fixed in the required standards; P = kWh price for non eligible customers, or P = pool kWh annual average hourly final price for eligibles
PL	LV customers: 60 hours/year	Only applicable to interruptions due to the transmission service; Exceptional events excluded (see list in Annex 1)	On customer's request	For each undelivered unit of electric energy, the customer shall be entitled to a discount equal to five times the electric energy price for the period of the interruption
PT	MV CUST.: Urban: 4h/year; Suburban: 8h/yr; Rural: 16h/yr; LV CUST.: Urban: 6h/year; Suburban: 10h/yr; Rural: 20h/yr HV (>36KV) CUST.: 4h/yr	Excluding all interruption due to fortuitous reasons or force majeure, public interest, service reasons, safety reasons, agreements with the customer and circumstances attributable to the customer.	Automatic	Compensation depends on the standard, the actual duration of the interruptions registered for each costumer, the voltage level and the contracted power

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Category of weather	Definition	Standard
Normal weather	< 8 times daily mean faults at higher voltage.	Supply must be restored within 18 hours, subject to certain exemptions, otherwise a payment must be made
Category 1 (medium events)	Lightning events (≥8 times daily mean faults at higher voltage and less than 35% of exposed customers affected) Non-lightning events (≥8 times and < 13 daily mean faults at higher voltage and less than 35% of exposed customers affected)	Supply must be restored within 24 hours, subject to certain exemptions, otherwise a payment must be made
Category 2 (large events)	Non-lightning events (≥13 times daily mean faults at higher voltage and less than 35% of exposed customers affected)	Supply must be restored within 48 hours, subject to certain exemptions, otherwise a payment must be made
Category 3 (very large events)	Any severe weather events where ≥35% of exposed customers are affected	Supply must be restored within the period calculated using the following formula: $48 \times \left(\frac{\text{total number of customers interrupted}}{\text{category 3 threshold number of customers}}\right)^2$

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TABLE 2.13 MULTIPLE INTERRUPTION STANDARDS

Country	Standard (interr/year)	Conditions	Compensation	Amount
ES	Long interruptions: MV CUST.: urban: 8; Suburban: 12; Concentrated rural: 15; Scatterd rural: 20; LV CUST: urban: 12; Suburban: 15; Conc. rural: 18; Scat. rural: 24; HV (>36kV): 8	Exceptional events excluded	Automatic	Discount=PW*H*P*DN/8; H = number of interruption hours; DN= difference between the actual number of interruptions and the applicable standard; PW: contractual power; P: see table.2.12
FR	Long interruptions: MV CUST: urban: 2; suburban: 3; rural: 3; rural scattered: 6; LV CUST: no standard Short interruptions: MV CUST.: urban: 2; suburban: 3; rural: 10; rural scattered: 30; LV CUST.: no standard; Long+short interruptions: MV CUST.: on request, customised standard	Exceptional events excluded	On request and only if there are damages	Amount of claimed damages
GB	Interruptions longer than 3 hours All customers: 3	Exceptional events excluded; interruptions with more than 0,5 Mill.; customers interrupted; transmission interr. excluded	On request	£50 (not differentiated)
IT	Long interruptions; HV CUST.: 1 interr./yr; MV CUST.: high density: 3; medium density 4; low density 5; LV CUST.: no standard	Exceptional events excluded;reinterruptions within 1 hour excluded; transmission interr. excluded	Automatic, subject to conditions (technical requirements for selectivity of customer's protections)	Compensation = 0,7*PW*DN*Vp;PW contractual power, DN difference between actual number of interruptions and standard; Vp= 2,5€/kW for MV up to 500 kW; 2€/kW over 500 kW
PT	Long interruptions; HV CUST.: 8; MV CUST.: zone A: 8; zone B: 18; zone C: 30; LV CUST.: zone A: 12; zone B: 23; zone C: 36	Same exclusion as for maximum yearly duration of unplanned interruptions (see table 2.12).	Automatic	Compensation depends on applicable standard, actual number of interruptions and contracted power

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2.5 Conclusions: recommendations for future work on Quality Regulation

The following recommendations are made to regulators who want to introduce quality regulation with an incentive/penalty mechanism. It is important to consider that setting such a mechanism for distribution or transmission companies is delicate, for economic, technical and political reasons. This advice comes from experienced countries which already have set up an incentive system for quality regulation and which know the consequences, advantages and disadvantages of such a mechanism. The following recommendations also take into account the different regulators' points of views toward electricity service quality, what they expect for the future and how they want to manage it, as collected through questionnaires. Although this advice is important to follow in order to prevent unintended effects, the quality regulation system adopted in one specific country might not be applicable in others, because of many different conditions (electricity network features, meteorological conditions, economic situation, degree of companies' privatisation, customers' willingness to pay for better quality, customer satisfaction, and so on). Indeed, a quality regulation system needs to be set up by the country itself, considering all its country-specific factors.

1. Continuity measurement rules: It is absolutely necessary to collect reliable and robust data for due time before introducing any type of continuity standards or incentive regime. It is strongly recommended to set measurement rules that can assess *separately* the different types of interruptions, monitoring at least planned and unplanned interruptions, the latter at least divided between long and short ones. It is also highly recommended that regulators define their own guidelines for recording interruptions, or approve the procedures of the regulated companies, at least with respect to the definition of *force majeure* and the assessment of customers affected by each interruption. It is known that once recording protocols are introduced, the indicators can worsen due to the fact that all interruptions are taken into account.

2. Audits on continuity data: The guidance for recording interruptions should be regarded as a preliminary step towards more diffuse regulatory auditing on the continuity data provided by distribution and transmission companies. Measurement rules and audit procedures become more important when some kind of economic incentive or disincentive is used to promote continuity of supply enhancement. It is strongly recommended that regulators who introduce incentive/penalty regimes and/or guaranteed standards on continuity of supply set obligations for auditing and actually do audits in order to check that all interruptions are taken into account in continuity indicators and that there is no abuse of exclusions.

3. Complete continuity indicators: As interruptions can originate at all voltage levels, only continuity indicators that contain all voltage levels wholly represent the situation from the customer viewpoint. Regulators are advised to move towards continuity indicators where all voltage levels are included. In order to introduce incentives, it is necessary to include at least medium and higher voltage levels, even if LV interruptions can be a major issue in urban areas. In order to introduce single-customer standards, it's strongly recommended to measure continuity of supply according to the customer's viewpoint, which means that interruptions at every voltage level should be recorded.

4. Incentive/penalty regimes for continuity: Regulators have a strong interest in introducing incentive/penalty regimes that counterbalance the cost cutting trend of price-cap regulation in order to avoid unintended effects on quality of service, especially continuity of supply. The

examples of incentive/penalty regimes already enforced for several years show that extremely good results can be obtained. It is recommended that each country develop its own incentive/penalty regime taking into account its specific conditions as regards, for instance, network development, investment levels, regional differences and automation projects. It is highly advisable for incentive/penalty regimes to be subject to regular periodic review and for results to be evaluated in light of the benefits and costs for final consumers.

5. Customer research: The introduction of incentive/penalty regimes will require more customer research, especially on the customers’ willingness to pay for continuity improvement. Country specific issues are very relevant to customer research, but it would be best to follow common research methodologies or at least share ideas about how such research can be improved.

6. Multiple interruption standards: Standards related to the maximum yearly number of unplanned interruptions can be seen as a very useful regulatory signal for structural investment on the distribution networks, and can also have potential benefits for LV customers even if the standards apply only to MV customers, as the MV network is generally responsible for most interruptions per customer. This type of standard requires a measurement system with indicators evaluated for each customer subject to the standards; it is therefore advisable to adopt a gradual approach, for instance starting with HV and MV customers.

7. Very long interruption standards and severe weather conditions: As most of the “very long” interruptions are due to the impact of atmospheric phenomena on overhead circuits, it is strongly recommended that regulators establish a precise definition of “*force majeure*” or set up mechanisms (like the British one) for differentiating maximum duration standards according to the severity of weather conditions. It is worth mentioning that, due the different objectives of the two regulatory regimes, different approaches can be used for treating exceptional events for the incentive/penalty regimes and for Guaranteed Standards.

APPENDIX C: All Ontario Electricity Distributors – PBR Data Request

Ontario Energy Board | Commission de l'Énergie de l'Ontario

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January 22, 1999

All Ontario Electricity Distributors

PBR Data Request

As indicated in the Ontario Energy Board Staff report distributed to you on December 17, 1998, Board Staff has proposed the adoption of a two-pronged PBR Framework with (1) a cap mechanism for the largest utilities and (2) a yardstick mechanism for the remaining utilities. In addition, Board Staff identified the need for four task forces to be formed as soon as possible to develop the following PBR details: cap mechanism; yardstick mechanism; implementation issues; and initial rates.

The Yardstick Mechanism Task Force had its first meeting on January 11, 1999. At this meeting data that could potentially be used to group similar electricity distribution utilities for yardstick regulation were identified. A list of 1998 data required by the Yardstick Mechanism Task Force is shown in part A of the attachment. It is essential that the task force obtain this data for all electricity distributors in the Province in order to determine reasonable yardstick groupings of utilities.

In addition to the data identified by the Yardstick Task Force to be used for peer grouping, the task force members also discussed the need for consistency between the cap and yardstick mechanisms in the consideration of productivity. In order to be able to address this issue, Board Staff have designed a second data request, listed in part B of the attachment. This information on labour/compensation and capital will allow the task force to directly examine the issue of productivity performance across the distribution industry. In addition, the information on capital will be useful in gauging the age distribution of infrastructure among utilities. Unlike the information requested in part A, the information requested on labour/compensation must cover a ten-year period, retroactive to 1988, and the requested information on capital needs to span a 20 to 25-year period, retroactive to the early 1970's, if possible.

0761JN (06/94)

The success of this task force will simplify the regulatory process for the distributors under the yardstick mechanism. However, availability of the subject data is paramount to this success.

The data requested is for the use of the task force purposes only. While the task force will identify the general basis for the yardstick groupings of utilities, to ensure confidentiality of the data provided, it will not include utility specific data in its recommendations. Further, the identity of specific utility data will be held in confidence by Board staff and its consultants.

The Task Force's goal is to provide Board Staff with recommendations on yardstick mechanisms by mid-March. To this end we would appreciate it if you could provide us with the data by February 5, 1999. Please forward your information to Christiane Wong, Administrative Assistant, Regulatory Affairs, by fax at (416) 440-7656 or by e-mail to wongch@oeb.gov.on.ca.

If you have any questions regarding the data listed please call Judy Kwik at (416)440-7661.

On behalf of the OEB Task Force on Yardstick Mechanisms, I thank you in advance for your cooperation.

Robert Cappadocia

Robert Cappadocia
Director
Regulatory Affairs

Attachments

Ontario Energy Board | Commission de l'Énergie de l'Ontario

A. Yardstick Mechanism Data Requirement

Please provide the following information for your utility for 1998:

1. Total Service Area (square km)
2. Rural Service Area (square km) as Defined by Municipality
3. Urban Service Area (square km) as Defined by Municipality
4. Service Area Population
5. Municipal Population
6. Number of Seasonal Occupancy Customers (at least four months at minimum bill)
7. Number of Total Customers, kWh, kW and Revenues
8. Number of Residential Customers, kWh and Revenues
9. Number of General Service Customers, kWh, kW and Revenues
10. Number of Large Use Customers, kWh, kW and Revenues
11. Utility Annual Peak Load (kW) and Average Peak Load (kW)
12. Utility Average Annual Load Factor
13. Distribution System Losses (all losses) and Line Losses.
14. System Voltage Level (kV)
15. Total Kilometres of Line
16. OH/UG Kilometres of Line
17. Circuit Kilometres of Line by Type :

    3 phase

    Single phase

18. Number of Distribution and Transmission Stations and Voltages
19. Number of Transformers by type:
    - Transmission
    - Subtransmission
    - Distribution
20. Does your Utility have a Control Centre
21. Description of Generation Assets within your Utility
22. Description of Utility-owned Transmission System
23. Contributed Capital Policy
24. Does your Utility have Shared Services with other Municipal Departments?
25. Is your Utility a Multiple-use Utility (e.g. electricity, water and sewer)
26. Special Circumstances/Unique Attributes of your Utility (e.g. rock substrate)

Ontario Energy Board
Commission de l'Énergie de l'Ontario

B. Labour/Compensation and Capital Additions

The following information is required by year for a ten-year period (1988-1998)

Labour/Compensation

1. Number of own full-time employees
2. Number of own part-time employees
3. Number of own FTE employees
4. Number of contract or outsourced "employees"
5. Total labour compensation (e.g. wages, salaries, pension, fringe, bonuses, etc.)
6. Total contract and outsourced labour expenses

The following information is required by year for a 25-period if possible, 1972-1998, but at minimum for the period 1977-1998.

Capital

6. Gross book value
7. Depreciation expense
8. Amortization expense

APPENDIX D1: LDC PBR Yardstick Information Collected in 1999

Area		
(Sq. km.)	Total Service	
	Rural	
	Urban	
Population		
	Municipal	
	Svc Area	
Customers		
(numbers, kW, kWh and revenue)	Total	
	Seasonal	
	Gen Svc	
	Large Use	
	Residential	
Peak Load		
	kW annual	
	Winter/summer	
	Load Factor	
System Volt By kv level		
Line Miles		
	Total	
	Undergrnd	
	Overhead	
Line Type		
(km)	Phase 1	
	Phase 2	
	Phase3	
Transformers		Number
	Transmission	

	Subtransmission	
	Distribution	
Facilities		
	Control Room	
	Generation Assets	
	Transmission Assets	
	Shared Svcs	
	Multiple Use	
	Contributed Capital	
Special Circumstances		

APPENDIX D2: PBR Data Collected in 1999 Capital Stock, Additions, Depreciation, and Retirements 1980 to 1997

A	B	C	D	E	F	G	H
	Stock* (nominal) [start of year]	Stock (real, 1986$) [start of year]	Capital Additions (nominal)	Capital Additions (real, 1986$)	Depreciation** (real, 1986$) 0.054	Retirements*** (real, 1986$)	Constant $ Stock of Capital
1980	14,771,522	37,291,508	1,152,953	1,608,024	2,076,697	368,607	36,454,228
1981		36,454,228	2,206,708	2,821,877	2,106,242	197,006	36,972,858
1982		36,972,858	2,681,409	3,136,150	2,160,426	24,576	37,924,006
1983		37,924,006	2,869,945	3,224,658	2,197,024	385,200	38,566,440
1984		38,566,440	3,376,477	3,634,529	2,259,256	282,854	39,658,859
1985		39,658,859	3,347,925	3,426,740	2,301,726	379,494	40,404,378
1986		40,404,378	4,134,544	4,134,544	2,297,522	1,910,818	40,330,582
1987		40,330,582	6,847,487	6,641,597	2,495,663	667,784	43,808,732
1988		43,808,732	5,004,364	4,574,373	2,560,310	879,252	44,943,543
1989		44,943,543	4,431,650	3,901,101	2,602,538	557,290	45,684,815
1990		45,684,815	5,896,339	5,031,006	2,688,820	827,597	47,199,403
1991		47,199,403	4,426,905	3,806,453	2,727,665	396,905	47,881,287
1992		47,881,287	5,047,639	4,241,714	2,762,936	859,647	48,500,418
1993		48,500,418	5,233,207	4,289,514	2,828,130	316,968	49,644,834
1994		49,644,834	6,269,085	4,971,519	2,927,176	305,687	51,383,490
1995		51,383,490	4,111,928	3,101,001	2,917,104	360,704	51,206,683
1996		51,206,683	5,078,801	3,810,053	2,750,209	3,989,507	48,277,020
1997		48,277,020	5,065,487	3,797,217	2,780,972	476,227	48,817,038

Appendix D2: PBR Data Collected in 1999 Capital Equipment price, Stock, Depreciation Rate, Bond Rate, Capital Expense and Capital Price, 1980 to 1997

	D696101 (1986=100)	Capital Stock Nominal	Average Depreciation Rate	Bond Rate Opportunity Cost of Capital	P_k =(L+M)*J/100	Capital Price Index (1988=1)	Capital Expense
1980	71.7	50,842,717	5.390%				
1981	78.2	47,279,869	5.390%				
1982	85.5	44,355,563	5.390%				
1983	89	43,333,079	5.390%				
1984	92.9	42,689,837	5.390%				
1985	97.7	41,355,556	5.390%				
1986	100	40,330,582	5.390%				
1987	103.1	42,491,496	5.390%	9.950%	0.158		
1988	109.4	41,081,849	5.390%	10.230%	0.171	1.000	7,679,926
1989	113.6	40,215,506	5.390%	9.920%	0.174	1.018	7,945,415
1990	117.2	40,272,529	5.390%	10.810%	0.190	1.111	8,961,296
1991	116.3	41,170,496	5.390%	9.820%	0.177	1.035	8,469,658
1992	119	40,756,654	5.390%	8.770%	0.169	0.986	8,172,335
1993	122	40,692,487	5.390%	7.860%	0.162	0.946	8,024,899
1994	126.1	40,748,208	5.390%	8.600%	0.176	1.032	9,064,561
1995	132.6	38,617,408	5.390%	8.350%	0.182	1.066	9,329,258
1996	133.3	36,216,819	5.390%	7.540%	0.172	1.009	8,320,678
1997	133.4	36,594,481	5.390%	6.460%	0.158	0.925	7,716,746

APPENDIX D3: PBR Data Collected in 1999. Gross Book Value, Depreciation, Amortization, Retirements, and Additions; Capital Investment Category 1973 to 1995

	Gross Book	Depreciation Expense	Amortization Expense	Retirements	Additions Total	Land	Land Rights	Buildings & Fixtures
1973	11,417,589	348,783	0	14,873	2,619,551	0	683	1,248
1974	12,233,949	344,925	0	35,570	852,591	51,513	3,060	3,215
1975	13,672,265	395,944	0	89,662	1,523,535	0	338	0
1976	15,024,513	440,246	0	71,761	1,420,294	224,651	2,480	1,364
1977	16,626,641	474,121	0	57,090	1,656,658	0	1,929	59,893
1978	17,770,160	527,032	0	92,097	1,231,245	0	0	3,128
1979	19,345,711	575,737	0	61,612	1,638,875	297,500	0	16,383
1980	20,627,190	650,144	8,341	87,360	1,152,953	0	778	26,283
1981	22,983,668	741,026	8,341	49,054	2,206,708	0	20,720	137,262
1982	25,895,792	820,403	10,431	6,341	2,681,409	0	2,351	90,689
1983	28,619,942	887,720	13,558	98,611	2,869,945	0	1,670	9,390
1984	31,997,007	997,873	26,014	75,522	3,376,477	0	5,742	9,374
1985	35,366,143	1,230,252	25,800	108,915	3,347,925	0	9,181	174,576
1986	39,458,513	1,384,718	26,225	567,513	4,134,544	0	6,841	155,379
1987	45,136,098	1,775,844	13,724	207,013	6,847,487	0	3,372	1,623,693
1988	49,850,394	2,015,104	15,133	298,067	5,004,364	0	2,156	150,474
1989	54,054,671	2,200,122	14,063	227,374	4,431,650	0	3,820	0
1990	59,377,504	2,417,166	13,638	379,039	5,896,339	0	3,252	88,580
1991	63,612,306	2,587,872	13,483	192,102	4,426,905	0	2,441	173,342
1992	68,414,499	2,752,063	30,412	443,578	5,047,639	0	4,355	227,911
1993	73,424,879	2,913,898	9,112	175,600	5,233,207	0	5,019	159,871
1994	79,334,612	3,167,534	7,641	192,277	6,269,085	0	4,277	254,381
1995	83,212,806	3,140,656	6,333	258,625	4,111,928	0	1,082	267,661
1996	84,866,834	3,261,923	6,012	3,119,795	5,078,801	0	3,366	218,145
1997	89,525,090	3,443,318	6,012	407,174	5,065,487	0	643	112,651
1998	94,625,434	3,613,457		359,548	5,099,024	0	973	156,279

APPENDIX D3: PBR Data Collected in 1999. Gross Book Value, Depreciation, Amortization, Retirements, and Additions; Capital Investment Category 1973 to 1995

	Generating Assets	Transmission Line	Transmission Station Equipment	Distribution Station Equipment	Sub Feeder Overhead	Sub Feeder Underground	Distribution Lines Overhead	Distribution Lines Underground
1973	0	0	173,954	0	64,476	0	100,952	191,048
1974	0	0	29,717	0	19,002	0	122,195	176,094
1975	0	0	239,067	0	25,995	0	320,098	371,041
1976	0	0	390,504	0	6,670	0	217,297	254,682
1977	0	0	286,272	0	27,939	0	318,955	292,733
1978	0	0	3,876	0	5,232	0	248,185	437,489
1979	0	0	134,727	0	0	0	187,688	385,176
1980	0	0	4,490	439	70,815	0	424,744	365,163
1981	0	0	104,404	314,629	102,486	0	548,617	112,436
1982	0	0	(382)	284,801	254,475	239,280	463,875	396,673
1983	0	0	0	193,755	152,179	3,611	647,033	762,905
1984	0	0	0	493,349	75,861	0	601,891	843,150
1985	0	0	0	496,591	269,317	0	705,049	524,811
1986	0	0	206,870	289,414	224,692	0	441,862	1,122,644
1987	0	0	556,411	484,909	325,162	0	579,694	1,277,224
1988	0	0	6,330	21,563	328,899	0	1,053,445	1,422,467
1989	0	0	0	0	445,770	0	779,923	1,188,866
1990	0	0	627,794	776,540	333,069	0	1,048,782	1,035,137
1991	0	0	157,273	463,637	489,765	0	878,279	1,050,937
1992	0	0	68,641	201,136	664,524	0	1,185,656	1,158,222
1993	0		86,088	243,008	828,218	111,761	851,227	1,882,835
1994	0		19,794	50,631	692,539	1,255,724	1,011,874	1,043,031
1995	0	0	48,078	97,623	292,528	(47,320)	1,470,526	930,978
1996	0	0	352,477	67,557	968,615	17,868	1,037,106	1,105,334
1997	0	0	94,290	158,531	778,818	74,746	1,072,859	1,594,943
1998	0	0	301,439	173,074	340,847	(2,816)	992,125	1,734,107

APPENDIX D3: PBR Data Collected in 1999. Capital Investment Category 1973 to 1995

	Distribution Transformers	Distribution Meters	Sentinel Light Equipment	Office Equipment	Computer	Stores
1973						
1974	105,401	1,853,070	0	3,188	0	0
1975	213,105	25,917	0	1,291	0	0
1976	294,345	60,323	0	3,326	0	0
1977	104,255	75,132	0	11,521	0	0
1978	367,628	131,096	0	20,170	0	0
1979	274,397	64,824	0	9,915	0	0
1980	296,387	75,478	0	16,441	0	0
1981	(120,232)	(45,770)	0	11,832	0	493
1982	344,308	73,390	0	27,916	0	0
1983	614,566	104,474	0	16,494	0	859
1984	499,286	176,635	0	15,512	0	0
1985	532,332	234,217	0	26,062	239,793	0
1986	558,626	172,882	0	82,369	19,508	280
1987	846,123	153,783	0	15,095	40,456	35,293
1988	856,789	370,634	0	26,531	30,588	0
1989	848,075	320,464	0	40,963	189,909	1,393
1990	675,106	498,077	0	50,087	22,042	5,068
1991	555,547	310,806	0	223,341	11,929	0
1992	563,205	245,792	0	57,931	17,145	39,261
1993	592,448	252,151	0	15,989	23,074	1,888
1994	379,987	293,701		11,524	7,948	0
1995	704,846	340,814	0	18,641	73,087	205
1996	324,292	108,801	0	110,221	4,642	0
1997	379,807	253,025	0	36,460	47,632	0
1998	421,778	205,369	0	22,082	32,918	0
	611,869	242,684	0	10,119	55,666	0

APPENDIX D3: PBR Data Collected in 1999. Gross Book Value, Depreciation, Amortization, Retirements, and Additions; Capital Investment Category 1973 to 1995

	Leasehold Improve	Rolling Stock	Misc Equipment (Tools, Meter read)	Water Heaters	Load Management Control	System Supervisory Equipment (SCADA)	Sentinel Lights	Contributed Capital/Develop Charges
1973	0	46,103	2,264	76,518	0	0	647	0
1974	0	96,389	24,168	86,925	0	0	0	0
1975	0	70,748	22,657	115,597	0	0	0	0
1976	0	20,766	12,696	98,276	0	0	0	0
1977	0	58,605	6,440	84,999	0	0	0	0
1978	0	64,615	12,530	107,054	0	0	0	0
1979	0	49,145	8,878	171,072	0	0	0	0
1980	0	160,304	70,818	148,233	0	34,564	0	366,611
1981	0	51,670	6,765	125,971	0	236,133	0	314,361
1982	0	1,244	14,091	170,450	0	27,469	0	626,508
1983	0	157,965	22,884	175,600	0	51,520	0	994,361
1984	0	109,962	11,466	192,277	0	1,000	0	1,365,451
1985	0	122,920	12,126	199,688	0	0	0	823,802
1986	0	170,397	108,569	317,127	0	0	0	1,507,215
1987	0	351,373	47,045	314,064	0	0	0	2,631,028
1988	0	336,705	37,923	230,239	0	13,358	0	1,949,676
1989	0	156,568	205,090	305,963	0	95,272	0	2,002,340
1990	0	312,023	60,835	224,294	0	284,410	0	1,591,274
1991	0	74,350	34,399	140,374	0	38,774	0	1,612,890
1992	0	337,698	94,851	176,889	0	42,207	0	2,399,251
1993	0	46,811	43,158	191,663	36,062	54,327		3,779,578
1994	0	479,805	47,179	189,111	34,591	48,554	0	3,783,128
1995	0	228,096	26,740	215,325	22,793	9,861	0	875,851
1996	0	333,910	27,263	192,740	852	36,643	0	2,454,551
1997	0	167,779	28,829	179,208	0	120,043	0	2,621,295
1998	0	263,314	44,796	174,547	0	0	0	

APPENDIX E: Inter-Utility Cost and Efficiency Differences Among Electric Distribution Utilities in Ontario

Inter-Utility Cost and Efficiency Differences Among Electric Distribution Utilities in Ontario

Francis J. Cronin* and Stephen A. Motluk**

Abstract

The province of Ontario (Canada) recently undertook electricity restructuring and performance based regulation for the municipal electric distribution utilities (MEUs). Until 1993, the MEUs operated under an administrative form of Cost-Of-Service regulation. Since 1993, the MEUs have been operating under a price freeze (i.e., a price cap with variable productivity targets). Prior to restructuring, there were upwards of 300 MEUs operating in the province, ranging from large urban systems with hundreds of thousands of customers, to small rural systems with a few hundred customers. While restructuring has reduced the number of utilities through mergers and acquisitions, there are still over 200 utilities in the province (end of 1999). The parameters of the first term PBR were based in part on analyses of the growth in productivity of 48 utilities over the 1988-1997 period (see Cronin et al, 1999). This research also noted wide variations in average costs and returns to capital.

In order to evaluate second term PBR alternatives which are potentially more appropriate for utilities operating in varying circumstances, as well as to assess the long-term payoff from restructuring, it is necessary to refine the analysis of productivity performance and potential. The large number of utilities operating in the province of Ontario intuitively suggests yardstick competition as a possible regulatory approach. We require an analysis that permits comparisons of absolute efficiency among the utilities. This specification should also permit a comparison of allocative as well as technical efficiency. How do technical and allocative efficiencies vary among the utilities? How many utilities are at the frontier and what is the size distribution of potential efficiency gains from movements toward the frontier? Ultimately, we may require a specification of performance that accounts for the impacts of non-controllable, inter-utility differences in "environmental" factors. Prior studies based on non-North American utilities include little if any reported effort to control for environmental factors. Furthermore, these studies are conducted on utilities operating under traditional Cost-Of-Service regulation. This first paper examines absolute inter-utility differences among distribution utilities in Ontario and the effects certain regulatory and institutional factors have had.

Key Words: utility regulation, productivity, electric distribution utilities, Ontario, Canada

JEL Classification: ***D24 - Production; Capital and Total Factor Productivity; Capacity***
L32 - Public Enterprises
L51 - Economics of Regulation
L94 - Industry Studies: Electric Utilities

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Note: Views and conclusions expressed are the authors' and not necessarily those of the Ontario Energy Board.

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1.0 Introduction

This paper analyses the inter-utility differences in efficiency among nineteen electric distribution utilities in the Province of Ontario. Other studies of distribution efficiency have tended to employ data for utilities operating under cost of service (COS) regulation and to examine technical efficiency only. This paper examines utilities operating under COS as well as subsequent performance based regulation. In addition, we calculate a total measure of efficiency based on both technical and allocative variations among the firms. Finally, we examine the implications for efficiency rankings from alternative measures of output, input costs, capital, and time.

1.1 Background

In the Fall of 1998, the Ontario Energy Board (OEB) initiated a process to examine the efficacy of developing, de jure, performance based regulation (PBR) for the more than 250 electric distribution utilities in the Province.[1] Over a year later, this examination culminated in the Board's adoption of a "first generation" PBR. During this initial term, (2001-2003), local distribution companies (LDCs), which in the vast number of cases are municipal electric utilities (MEUs), will operate under a price cap formula. This formula bases distribution price adjustments on changes in distribution input prices offset by a single, fixed productivity factor.[2]

Research by Cronin et al (1999) examined the productivity growth and input price performance for 48 MEUs covering small (i.e., less then 10,000 customers), medium (i.e., 10,000-50,000 customers) and large (i.e., greater then 50,000 customers) utilities over the 1988 to 1997 period. Relatively similar productivity growth and input price changes were found on average across the three size classes – particularly following the self imposed distribution price freeze in 1993.[3] Wide variations were found for individual firms in all three size-classes. In addition, this research documented large differences in costs per customer across individual firms in each size class and systematic differences in mean costs among the size classes.

Based in part on these findings of substantial variations across individual utilities in costs per customer, a small minority of LDCs strongly urged during the Board's hearing that a pure yardstick form of PBR be implemented in the first term.[4] These intervenors contended that LDCs had, in fact, attained substantially different levels of efficiency. They maintained that the proposed price cap plan would therefore disadvantage more efficient utilities by requiring them to make the same percentage improvement in productivity as less efficient utilities.

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1 These utilities had in fact been operating since 1993 with a variant of PBR due to their self imposed distribution rate freeze.
2 OEB Decision With Reasons RP-1999-0034, Jan. 18, 2000.
3 For example, Cronin et al (1999) found mean productivity growth of 2 percent between 1993 and 1997.
4 Since the input price term is computed based on the actions of the 250 LDCs, this formula embeds an annual yardstick competition within this term.

The remaining majority of LDCs and industry stakeholders as well as Board staff and consultants, conceded that differences in initial efficiency might in fact exist but could not be substantiated by cost data alone. This majority, noting time and resources constraints which precluded the analyses necessary to properly operationalize a pure yardstick approach, concluded that such a framework could not be implemented at the current time. Rather, this group strongly supported the adoption of yardstick competition in the second term after the requisite analyses had been completed.

1.2 Prior Research

A number of studies have used DEA to estimate the efficiency of electricity distribution systems (for example, Førsund and Kittelsen (1998), Hjalmarsson and Veiderpass (1992), Weyman-Jones (1991)). Several regulators have also performed studies using the DEA approach and have used the results to guide the design of regulatory mechanisms (for example, the Norwegian regulator NVE (Grasto, 1997), the Dutch regulator DTe (DTe, 2000) and the NSW Australia regulator (IPART, 1999). However, the authors are unaware of any such study using DEA techniques to estimate efficiency of electricity distribution systems in a Canadian jurisdiction.

In fact, these prior studies suffer from several shortcomings when evaluated for their insights into the case of Ontario. First, the research is restricted generally to examining technical efficiency. Due to a number of factors discussed below, the issue of allocation efficiency may be particularly important for the MEUs serving Ontario. Second, this prior research tends to examine LDCs operating under COS regulation. In the case of Ontario, MEUs operated under an administrative form of COS until 1993. In 1993, MEUs instituted a self-imposed price freeze for distribution services. Such a rate freeze acts as a price cap with a variable productivity factor. Thus, for the last five years of our data, MEUs operated under a variant of PBR. And, third, these studies often employ model specifications that make their applicability uncertain.

1.3 Findings

We find that the MEUs examined increased their gross technical efficiency from a mean of 81.8 in 1988 to 82.5 in 1993 and to 87.1 in 1997.[5] Eleven of the fifteen non-frontier LDCs improved their technical efficiency relative to the frontier. On the other hand, the mean gross allocative efficiency rises from 73.8 in 1988 to 76.0 in 1993 and but then falls to 70.4 in 1997. In fact, 13 of the eighteen non-frontier MEUs moved further from the frontier, particularly from 1993 to 1997. As a result total, gross efficiency rises from 60.4 to 63.2 from 1988 to 1993 but falls to 61.4 by 1997. Despite the steady and relatively sizeable improvement in gross technical efficiency over the whole period, total gross efficiency in 1997 is only marginally higher than in 1988 due to the substantial worsening of gross allocative efficiency in the second half of the period.

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5 Our analysis is based on distribution output (i.e., customers and kilowatt hours) unadjusted for electricity quality. Similarly, distribution inputs are unadjusted for the varying requirements "environmental" characteristic differences might impose. The former might lead to overestimates of potential frontiers while the latter might lead to overestimates of potential inefficiencies. Thus we use the term "gross" efficiency to signify that such adjustments might result in lowered or small net efficiency gains.

1.4 Outline

Section 2 overviews the electric distribution industry in Ontario and key institutional and regulatory developments potentially affecting our results. Prior research is reviewed in section 3. Data and methodology are presented in section 4. Section 5 lays out our results and examines some of their implications.

2.0 Electric Distribution in Ontario

The electric distribution industry in Ontario evolved along two related but highly dissimilar parts.[6] One sector (Ontario Hydro) operated as a traditional, vertically integrated utility including generation, transmission and rural distribution. A second part consisted of hundreds of MEUs providing distribution services to more populated areas. The overwhelming amount of electricity distributed by the MEUs was purchased from Ontario Hydro.

Both parts of the electric industry were considered to be publicly owned, although ultimate ownership of the MEUs was somewhat in dispute. Despite the public nature of ownership, the two parts differed in important ways. First, while Ontario Hydro had a more traditional capital structure with significant debt, the MEUs operated with little to no long-term debt. Capital requirements were funded by equity; capital expansions for many MEUs were often undertaken with capital "contributed" from developers or end users. Second, over the course of history, Ontario Hydro assumed administrative regulatory oversight for the more than 300 MEUs. This combination of financing, ownership and oversight was to have potentially important consequences.

First, electric distribution by MEUs has evolved under a power at cost philosophy. In Ontario this was reflected in the very low rates of return on capital employed. While utilities were permitted under Ontario Hydro regulation to earn up to 6.5-8.0 percent, returns for the vast majority generally ranged from zero (or even less) to 3 percent for most recent years, with one notable exception which is discussed below. Second, low opportunity costs on capital and an aversion to debt meant that many utilities maintained sizeable cash or cash equivalents to fund operations.[7] Third, the ability to fund capital expansions from customer-contributed capital which was not considered part of the rate base. Before 1994 Ontario Hydro regulation prohibited such contributed capital from entering the rate base and thus, earning a return. However, in this year, regulatory policy was changed to allow utilities to earn a return on such customer-contributed capital.

6 A small number of LDCs (4) are privately owned.
7 For example, in the mid 1990s, cash and cash equivalents exceeded 60 percent of net fixed assets for the average MEU.

Between 1988 and 1993, the wholesale price of power charged to MEUs by Ontario Hydro increased about 45 percent. By 1993, growing concerns led to a government proclaimed freeze on wholesale power rates. MEUs followed with self-imposed freezes on retail distribution rates. While not recognized at the time, this action essentially transformed the de facto regulatory framework from COS to performance based regulation. In effect, the freeze acted as a price cap with a variable productivity target equal to the rate of input price inflation. From our perspective, the bifurcation in regulatory approaches provides an interesting opportunity to examine the effects of alternative incentives among the regulated utilities.

In addition, many MEUs were supporting growing infrastructure requirements with contributed capital; for some MEUs, such contributed capital came to comprise 40, 50 or even 60 percent of net fixed assets.[8] Consequently, by 1993 many MEUs' return on equity had risen dramatically: in some cases exceeding 7, 8, or even 9 percent. These returns collided with ROE caps while at the same time the regulatory treatment of contributed capital constrained the MEUs' revenues. Noting the "distortions" engendered in the application of rate of return regulation to rate bases excluding contributed capital and depreciation from revenue requirements, in 1994, MEU regulation was modified to permit the inclusion of contributed capital previously excluded from the rate base.[9] Since contributed capital comprised a large portion of many MEUs assets, its inclusion substantially lowered regulatory returns for many MEUs. Table 1 presents ROEs from 1993-1995 for our sample.[10]

Table 1. Return on Equity, 1993 - 1995.

1993 ROE	1994 ROE	1995 ROE
5.14%	3.28%	2.46%
1.43%	0.63%	0.98%
7.24%	5.99%	4.24%
9.10%	8.66%	6.94%
6.38%	4.97%	5.13%
5.83%	3.64%	3.12%
6.59%	3.51%	3.39%
5.45%	0.68%	1.94%
7.28%	4.80%	4.15%
1.82%	1.08%	-0.68%
9.10%	5.34%	4.77%
6.97%	4.13%	0.57%
7.38%	3.90%	4.29%
5.76%	-0.40%	1.03%
7.76%	5.57%	5.68%
2.30%	3.08%	0.10%
5.34%	4.52%	3.41%
7.32%	4.35%	4.25%
8.76%	4.12%	5.35%

8 Contributed capital policies varied widely across MEUs. Some did not utilise such capital at all or in small amounts; some only for expansions in excess of average system costs; some would appear to have charged for larger proportions of costs.
9 See *Ontario Hydro Accounting For Municipal Electric Utilities In Ontario*, Subject No. 5710.
10 Note: utilities have been reordered in this table to prevent subsequent identification of individual utilities later in the paper.

Eventually, over 300 MEUs varying in size from several hundred to over 200,000 customers operated in the Province. Some critics maintained that mergers among the MEUs would create efficiencies due to increased scale.[11] Following years of debate, Government studies, and an Advisory Committee (chaired by former federal cabinet minister Donald S. Macdonald), the Ontario legislature passed the *Energy Competition Act*. This legislation affected a restructuring of the entire electricity sector in Ontario, not just distribution. With respect to the latter, this Act provided for the privatization and recapitalization of the MEUs, the transfer of oversight under alternative regulatory frameworks to the OEB, and the opening of the retail market. Indeed some observers hoped that this legislation would prompt so called "rationalization" of the MEU sector by inducing substantial merger or amalgamation activity.

3.0 Prior Research

During the past decade, a number of studies have used DEA to estimate the efficiency of electricity distribution systems. These studies have been done primarily in Europe. More recently, DEA has been employed by a few regulators to establish PBR parameters.

For example, Weyman-Jones (1991) examined the technical efficiency of the area electricity boards in England and Wales prior to privatization, and found wide divergences in performance. Inputs included the number of employees and two measures of capital: (1) the total value of assets and (2) the number of circuit-kilometres of distribution lines in service. Output was measured using annual kilowatt-hours sold in each area board by customer class. The study finds five of the twelve area boards to be on the frontier. The least efficient board is approximately 80 percent as efficient as those on the frontier; the second least efficient about 85 percent. The remaining non-frontier utilities are about 95 percent as efficient. The study finds the inefficient utilities to be operating with too many kilometres of distribution lines, too much labour and too few commercial energy sales. Viewing network capital as fixed, the study recommends increasing efficiency through manpower reductions and increased energy sales to commercial customers.

Hjalmarsson and Veiderpass (1992a,b) examined productivity growth of electricity retail distribution in Sweden. The input variables included the hours worked by all employees, the kilometres of low-voltage (LV) and high-voltage (HV) power lines, and total transformer capacity (kVA). Outputs included both HV and LV throughput received by customers and the number of HV and LV customers. While they found a relatively rapid increase in productivity over a 17 year period from 1970 to 1986, the level of structural input saving efficiency was rather low. In addition, the authors report significant productivity growth from increased usage per customer, but negative productivity growth in terms of number of customers.

Kumbhaker and Hjalmarsson (1998) focus on differences in technical efficiency among Swedish distributors during the 1970-1990 period. Two models are presented. The first includes HV and LV throughput and the number of HV and LV customers as output; the input variables include the number of full time equivalent employees, the kilometres of low-voltage (LV) and high-

11 As discussed in Cronin (2000), the literature covering the potential for economies of scale in distribution is generally indeterminate with respect to existence or magnitude. On the other hand, potential economies stemming from scope or energy density appear to be more generally supported by the literature.

voltage (HV) power lines, and total transformer capacity (kVA). The second model is the same as the first except for the inclusion of the kilometres of lines as an output rather than as an input. The authors offer their opinion that in electric distribution, productivity is "mainly determined by management and efficient labour use…. The amount of capital in the form of network reflects geographical dispersion… rather than differences in productive efficiency. …Therefore, and somewhat paradoxically, … network capital should be referred to the output side,… leaving labour as the dominant input…" since the authors view transformer capacity as fixed.

Bagdadioglu et al. (1996) examined technical efficiency in 70 electricity distribution organizations in Turkey using data for 1991 and found wide variation in individual technical efficiency scores. Outputs included number of customers, energy supplied (MWh), demand (MW), and service area (km^2). Inputs include manpower, transformer capacity, network size (km), general expenses and network losses (MWh).

Førsund and Kittelsen (1998) examined the productivity performance of electricity distribution in Norway for the period 1983 to 1989. Inputs included a measure of capital, materials, energy losses and labour (measured in hours). Outputs included number of customers, total energy delivered, and a distance index (representing average travelling time to municipal centres, and other topographical peculiarities). They found average annual productivity growth of about 1.5 to 2 per cent per year, with frontier production shift as the driving force.

Several regulators have also performed studies using the DEA approach and have used the results to guide the design of regulatory mechanisms. For example, the Norwegian regulator NVE (Grasto, 1997), the Dutch regulator DTe (DTe, 2000) and the NSW Australia regulator (IPART, 1999) have all employed variously specification models in a DEA framework.

The DTe study employs 1996 data to examine the technical efficiency of 20 distribution utilities. A range of output specifications are employed including: energy delivered, customers, transformers, network length, and density. In four of the five specifications presented inputs are defined as operating costs (i.e., wages, materials, services and other); in the sixth specification, tangible depreciation is also included. The study finds a wide range of technical efficiency among
Dutch distributors with nearly two-thirds off the frontier. Among non-frontier utilities, some are found to be only 40 percent as efficient as utilities on the frontier.

The IPART study measures technical efficiency for 6 New South Wales distributors. Output is specified as energy delivered, peak demand and customers. Inputs are network length, transformer capacity, and operating and maintenance expenditure. The study benchmarks NSW utilities against utilities in the US, the UK, New Zealand and other Australian states over various periods in the 1990s. The study reports mean productivity growth 3.5 percent in the UK, 0.7 percent in the US, and 1.4 percent in NZ. The study also reports minimum and maximum yearly productivity changes among utilities. For the UK these changes are –11.0 and 20.6 percent; for the US these are –28.7 and 28.9 percent; for NZ these are –22.2 and 35.1 percent. Among NSW distributors the minimum and maximum changes are –11.2 and 5.4 percent.

These studies may have limited applicability to the Ontario MEUs. For example, these studies

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have typically been done on utilities operating under traditional cost of service regulation. Second, in many instances the specification employed restricts the interpretation of the results (e.g., less then a comprehensive set of factor inputs, output definition, capital definition). Third, due to a lack of factor input prices, these studies tend to focus on technical efficiency. In fact, little has been published on the extent of allocative inefficiency among electric distribution utilities.

With respect to the potential importance of allocative efficiency, we cite Fare, Grosskopf and Logan (1985). The authors employ 1970 data on 153 U.S. electric utilities. While their focus is on generation (i.e., output is kilowatt hours supplied and capital is generation), it is significant to note that the authors find technical efficiency to average about 75 percent but allocative efficiency to average only 29. The authors conjecture that their use of proxies for market prices would seem to imply that the utilities are minimizing with respect to shadow rather then market prices. Note that in Ontario, the MEUs return on equity was typically below the market cost of capital, utilities were almost entirely financed through equity, and, for some, the proportion of capital financed through customer contributions exceeded 30, 40, or even 50 percent.

4.0 Methodology and Data

In this section, we present the approach and data employed in our analysis.

4.1 The Methodology: Data Envelopment Analysis (DEA)

DEA is a non-parametric approach to estimating production frontiers using linear programming techniques, and has been increasingly adopted in industry studies to estimate technical efficiency over the past ten years. The DEA approach estimates a production frontier by constructing a non-parametric piecewise linear convex hull around data on outputs and inputs, and then calculating efficiencies relative to the frontier. The advantage of this approach is the ease of incorporating multiple outputs and inputs, no requirement to specify a functional form for the production function, and the ability to calculate efficiency measures without the incorporation of prices.

The approach was originally suggested by Farrell (1957), and subsequently developed by Charnes et al. (1978), Fare et al. (1994) and others. The empirical analysis presented here has made use of the DEAP computer program developed by Coelli (1996) based on its ease of availability and its use by other analysts.

An input-oriented constant returns to scale (CRS) DEA model for N firms with data on K inputs and M outputs can be defined[12] as:

$$\begin{aligned} &\min_{\theta,\lambda} \theta, \\ \text{s.t.}\quad & -\mathbf{y_i} + \mathbf{Y}\lambda \geq 0, \\ & \theta\mathbf{x_i} - \mathbf{X}\lambda \geq 0, \\ & \lambda \geq 0, \end{aligned}$$

where $\mathbf{y_i}$ is vector of outputs for the i-th firm, $\mathbf{x_i}$ is a vector of inputs for the i-th firm, θ is the efficiency score for the i-th firm where $\theta \leq 1$, and λ is an Nx1 vector of constants. This linear program is solved N times for each firm in the sample, obtaining an efficiency score, θ, for each firm. Solution of the LP essentially radially contracts the input vector $\mathbf{x_i}$ as much as possible while remaining within the production possibility set. The radial contraction of the input vector $\mathbf{x_i}$ produces a projected point on the surface of the estimated efficient frontier (the efficient technology) which is a linear combination of the observed data points ($\mathbf{X}\lambda$, $\mathbf{Y}\lambda$).

Once the technical efficiency scores have been obtained through the solution of the above LPs, a cost minimizing input oriented DEA model can be solved to obtain cost DEA results. The cost min DEA can be defined as follows:

$$\begin{aligned} &\min_{\lambda,\mathbf{x_i*}} \mathbf{w_i}'\mathbf{x_i}^*, \\ \text{s.t.}\quad & -\mathbf{y_i} + \mathbf{Y}\lambda \geq 0, \\ & \theta\mathbf{x_i}^* - \mathbf{X}\lambda \geq 0, \\ & \lambda \geq 0, \end{aligned}$$

12 This section follows Coelli (1996) and Coelli et al. (1999).

where $\mathbf{w_i}$ is a vector of input prices for the i-th firm and $\mathbf{x_i}$* is the cost-minimizing vector of input quantities for the i-th firm, calculated by the LP given the input prices $\mathbf{w_i}$ and the output levels $\mathbf{y_i}$. Total economic efficiency (EE) of the i-th firm is calculated as

$$EE = \mathbf{w_i}'\mathbf{x_i}^* / \mathbf{w_i}'\mathbf{x_i}$$

or EE is the ratio of minimum cost to observed cost for the i-th firm. Allocative efficiency can then be calculated residually as

$$AE = EE/TE.$$

Input-Oriented Technical and Allocative Efficiency

Following the example used by Farrell, suppose we have an industry which uses two inputs, x_1 and x_2, to produce one output, y, under the assumption of CRS. If the unit isoquant of the efficient firm is known, technical or productive efficiency (TE) can be determined. In Diagram 1, SS′ represents the unit isoquant of the efficient firm, which can be estimated from a sample of firms in the industry using DEA.

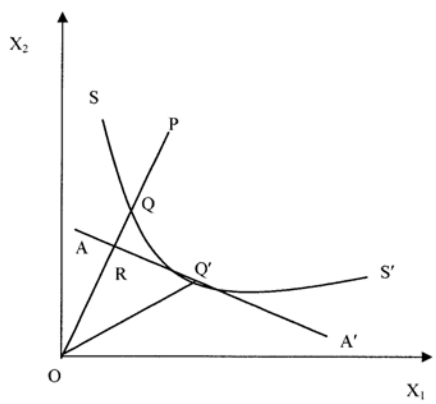

Diagram 1 – Farrell Efficiency Measures

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If a firm produces a unit of output using quantities of inputs x_1 and x_2 defined by point P, the distance QP represents the technical inefficiency of that firm (i.e., both inputs could be reduced proportionately by QP without a reduction in output). In percentage terms, the firm's technical efficiency can be represented by the ratio OQ/OP and the firm's technical inefficiency is the ratio QP/OP (1 – OQ/OP). If TE = 1, the firm is fully technically efficient and is producing on the isoquant SS′ (for example, point Q).

Allocative or price efficiency (AE) can also be measured if the input price ratio is known, as represented by the slope of the isocost line AA′ in Diagram 1. Allocative efficiency of the firm operating at point P can be represented by the ratio OR/OQ, and the allocative inefficiency represented by the distance RQ, which is the savings the firm could realize if it produced at point Q′. The firm is both allocatively and technically efficient, if it produces at point Q′.

Total economic efficiency (EE) of the firm producing at point P can be represented by the ratio OR/OP = (OQ/OP)·(OR/OQ) = TE·AE.

4.2 Data

Our data comes from the sample of Ontario MEUs reported in Cronin (1999). Originally, this sample included 40 utilities. Subsequently, this sample was expanded to cover 48 MEUs. This data includes information on output (i.e., customers and usage) quantities and prices as well as input (i.e., labour, materials, line losses and capital) quantities and prices. Data spanning the 1988 to 1997 period was employed in the analysis. In addition, data on capital including stock, additions, retirements and depreciation was typically collected for a twenty-year period. Variable definitions are discussed below.

OUTPUTS

Output is defined two ways. First, we define output as the total number of customers. In fact, the OEB Cap Mechanism Task Force recommended number of customers since it reflects a "wires" only business. We also analyze a second measure that includes total kilowatt-hours delivered as well as customers. Over history, MEUs employed a split-rate design which included both fixed, as well as per kilowatt charges, for the recovery of distribution costs in class revenues. Therefore, individual utilities' distribution revenues and earnings were a function of customers' kilowatt usage.

INPUTS

We employ a four-factor model of inputs that comprehensively covers distribution costs.[13] These factors are capital, labour, materials, and line losses. For each input, we develop measures of quantity and price.

13 The authors are examining the implications of using partial cost measures for efficiency rankings.

Capital. We employ a service price approach to capital costs. Thus, the cost of capital can be expressed as a function of a capital service price index and a capital quantity index:

$$CK_t = PK_t \bullet QK_t$$

CK is the cost of capital, PK is the capital service price index, and QK is the capital quantity index.

Standard utility accounting of capital costs is based on book valuation (i.e., historical prices) and fails to reflect changing assets prices over time. Our capital quantity index is constructed using inflation – adjusted values for historical capital stock deployed before a benchmark year, as well as for subsequent additions and retirements. Real stock in 1980, our benchmark year, is estimated by deflating undepreciated capital by a capital asset price constructed by "triangularizing" the pre-benchmark asset prices. The capital asset price index, CAP, is the electric utility distribution system construction price index published by Statistics Canada.

The standard treatment of capital in productivity research expresses subsequent values of the capital quantity index as a perpetual inventory model:

$$QK_t = (1-d) \bullet (QK_{t-1}) + \frac{AK_t}{CAP_t} - \frac{R_t}{CAP_{t-n}}$$

where d is the annual depreciation rate, AK is the addition to capital book value, and R is retired capital.[14] The annual depreciation rate is calculated as the average annual share of depreciation to gross book value. Retirements are assumed to have aged 15 years. The share of capital in total distribution costs ranges between approximately 40 and 60 percent.

The capital service price index, PK is:

$$PK_t = (r_t + d)\, CAP_t$$

r is the Canadian long bond rate, a measure of opportunity cost.

Labour. We measure the quantity of labour by the number of full-time equivalent employees. The price of labour is represented for each utility by its line crew wage rate.

Material. Material inputs are all inputs excluding capital, utility labor and line losses. Differences between MEUs in the extent of outsourcing will be picked up in materials. Material costs are calculated as the non-labor cost portion of three operating accounts: operating and

14 Recent historical examinations of individual components of utility infrastructure by one of the authors indicate that network assets very often provided undiminished service levels over long lives. Such components may be better represented by undepreciated capital measures spanning the service life of the assets. A number of studies have also employed physical units rather than values to represent capital. The authors are investigating the use of such alternative measures of capital compared with the perpetual inventory approach.

maintenance, billing and collecting, and administration. We found that about 35 percent of expenditures in these accounts represent materials (e.g., services, materials expensed purchases, contract labor). The price of materials is represented by the Industrial Producer Price Index (IPPI) published by Statistics Canada. Material inputs are obtained by calculating the constant dollar expenditure derived by deflating nominal material expenses by the IPPI.

Line Losses. The cost of line losses is calculated based on reported line losses and the price of purchased power. Line loss rates range from approximately 2 to 7 percent across our sample. For some firms, such losses are relatively steady year after year; for other utilities, line loss rates can change substantially from one year to the next. As a share of total distribution costs, line losses range from approximately 6-8 up to 20-22 percent.

5.0 Results and Conclusions

Table 2 presents some summary measures for our sample of 19 MEUs in 1997. In terms of outputs, customers range from a low of 35,368 to a high of 222,026. The sample mean is 84,551. Similar descriptive statistics are presented for inputs. The number of employees ranges from 72 to 1,305 with a mean of 245. The 19 MEUs contained in this sample are among the largest in the Province.[15]

Table 2. Mean Outputs and Inputs, 1997

	Mean	Max	Min
Output			
No.of customers	84,551	222,026	35,368
kWhs	2,940,733,971	9,067,730,199	830,278,047
Inputs			
Capital ($1000Cdn)	124,343	454,936	43,693
Line Losses MWh	76,959	235,033	13,747
FTE Employees	245	1,305	72
Materials ($1000Cdn)	4,424	25,361	1,292

As discussed in section 2, the regulatory treatment of contributed capital changed in 1994 to permit this capital to enter the rate base. Table 3 presents some summary measures of capital usage over our ten- year time frame. Note that the definition of capital used in Cronin (1999) includes all capital employed by the utility whether or not it was in the rate base. Therefore, the time series of capital includes contributed capital if it was used by the utility at any time. Table 3 does indicate that the amount of capital input increased, particularly during the first half of period. Capital increased 15 percent per customer between 1988 and 1993; over the second half of the period, capital per customer returned to approximately its 1988 level. In terms of labour

15 In 1995, the Province had approximately 300 MEUs. These ranged in size from hundreds of customers to hundreds of thousands of customers. Sixteen utilities had less then 200 customers; 120 or 40 percent had less then 1,000. The average MEU had 9,500 customers. By 1999, the number of MEUs had fallen to about 250; by 2001 this number was probably below a hundred. See, PBR Options for Ontario (1998).

13

however, capital increased in both periods: about 10 percent in the first half and another 10 percent in the second.

Table 3. Mean Capital Input

	1988	1993	1997
Mean Capital Input ($1000 Cdn)	106,263	124,915	124,343
Mean Capital Input per FTE ($1000Cdn)	467.7	516.9	570.0
Mean Capital Input per customer ($Cdn)	$1,452	$1,514	$1,443

For our DEA we employ an input-oriented, constant returns to scale framework. Our output measure includes total number of customers as well as total kilowatt hours of usage.[16] The program minimises inputs subject to output. Table 4 presents aggregated results for technical, allocative, and total efficiency for 1988, 1993, and 1997.

Table 4. Mean Efficiency Results, 1998, 1993, 1997

	TE	AE	EE
1988	0.818	0.738	0.604
1993	0.825	0.760	0.632
1997	0.871	0.704	0.614

Four utilities define the frontier of technical efficiency in 1988. We find that MEUs increased their gross technical efficiency slightly relative to the frontier from a mean of 81.8 in 1988 to 82.5 in 1993; by 1997 however, the mean increased to 87.1.[17] By 1997, eleven of the 15 non-frontier LDCs in 1988 improved their technical efficiency relative to the terminal year frontier. This seems consistent with the incentives provided by the price freeze. A utility's earnings will fall by the rate of input price inflation unless offset by increased productivity.

Mean allocative efficiency is substantially lower than technical efficiency across the whole period. In addition, while allocative efficiency initially increases from 73.8 in 1988 to 76.0 in 1993, it declines to 70.4 in 1997. In fact, 13 MEUs moved further from the frontier, particularly from 1993 to 1997. The 1988 frontier is defined by one utility; the 1997 frontier by two. This

16 We also examined alternative definitions of output including only number of customers.
17 Our analysis is based on distribution output (i.e. number of customers and kWhs) unadjusted for electricity quality. Similarly, distribution inputs are unadjusted for the varying requirements "environmental" characteristic differences might impose. The former might lead to overestimates of potential frontiers while the latter might lead to overestimates of potential inefficiencies. Thus we use the term "gross" efficiency to signify that such adjustments might result in lowered or small net efficiency gains.

seems consistent with our earlier observations about the low implied price of capital for MEUs, the treatment of contributed capital, and the clear substitution of capital for labour among many utilities.

Thus, while mean technical efficiency is increasing from 81.8 to 87.1, mean allocative efficiency is falling from 73.8 to 70.4. As a result, total gross efficiency relative to the frontier rises from a mean of 60.4 in 1988 to 63.2 in 1993 before falling to 61.4 in 1997. That is, despite the steady and relatively sizeable improvement in gross technical efficiency over the whole period, total gross efficiency is only marginally higher in 1997 than in 1988 due to the substantial worsening of gross allocative efficiency in the second half of the period.

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Appendix 1 – Alternative Specifications of Inputs and Outputs.

The base case specification of outputs and inputs that generated the preceding results was varied to test the robustness of the results. Several alternatives were considered, including restriction of output to total number of customers, stepwise addition of inputs to the specification, and three alternative definitions of capital.

The following alternative specifications of outputs and inputs were tested in addition to the base case:

	Inputs	Outputs
Base Case	capital ($1986) line losses (kWhs) FTE employees Materials ($1986)	# of total customers energy delivered (kWhs)
Alt #1	capital ($1986) line losses (kWhs) FTE employees Materials ($1986)	# of total customers
Alt #2	capital ($1986) line losses (kWhs) FTE employees	# of total customers energy delivered (kWhs)
Alt #3	capital ($1986) line losses (kWhs)	# of total customers energy delivered (kWhs)
Alt #4	FTE employees Materials ($1986)	# of total customers energy delivered (kWhs)
Alt #5	alt capital #1 ($1986) line losses (kWhs) FTE employees Materials ($1986)	# of total customers energy delivered (kWhs)
Alt #6	alt capital #2 ($1986) line losses (kWhs) FTE employees Materials ($1986)	# of total customers energy delivered (kWhs)
Alt #7	alt capital #3 ($1986) line losses (kWhs) FTE employees Materials ($1986)	# of total customers energy delivered (kWhs)

The base case capital input quantity was calculated based on a perpetual inventory model approach. The alternative capital input quantities are variant measures of the gross capital stock.

Table A1.1. Base Case

Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

	1988				1993				1997		
Utility	TE	AE	EE	Utility	TE	AE	EE	Utility	TE	AE	EE
1	0.604	0.816	0.493	1	0.499	0.704	0.352	1	0.588	0.613	0.360
2	0.776	0.588	0.456	2	0.625	0.653	0.408	2	0.906	0.495	0.448
3	0.825	0.850	0.701	3	0.778	0.854	0.664	3	0.899	0.713	0.641
4	1.000	1.000	1.000	4	1.000	1.000	1.000	4	1.000	1.000	1.000
5	0.867	0.653	0.566	5	0.924	0.714	0.660	5	0.924	0.676	0.625
6	1.000	0.737	0.737	6	0.980	0.862	0.845	6	1.000	1.000	1.000
7	0.767	0.509	0.391	7	0.827	0.525	0.434	7	0.982	0.454	0.446
8	0.763	0.570	0.435	8	0.813	0.507	0.412	8	1.000	0.457	0.457
9	0.695	0.644	0.448	9	0.661	0.734	0.485	9	0.882	0.532	0.469
10	1.000	0.726	0.726	10	1.000	0.847	0.847	10	1.000	0.865	0.865
11	0.784	0.882	0.691	11	0.925	0.976	0.902	11	0.856	0.830	0.711
12	0.756	0.975	0.737	12	0.900	0.840	0.756	12	0.778	0.816	0.635
13	0.773	0.933	0.721	13	0.787	0.895	0.704	13	0.717	0.761	0.546
14	0.773	0.486	0.376	14	0.792	0.544	0.431	14	0.738	0.536	0.396
15	0.770	0.775	0.597	15	0.790	0.752	0.594	15	0.803	0.745	0.598
16	0.859	0.738	0.633	16	0.948	0.730	0.692	16	0.930	0.712	0.662
17	0.735	0.766	0.564	17	0.701	0.864	0.606	17	0.724	0.888	0.643
18	0.793	0.772	0.613	18	0.730	0.819	0.598	18	0.825	0.687	0.567
19	1.000	0.596	0.596	19	1.000	0.617	0.617	19	1.000	0.588	0.588
mean	0.818	0.738	0.604	mean	0.825	0.760	0.632	Mean	0.871	0.704	0.614

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Table A1.2. Alt #1

Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

	1988				1993				1997		
Utility	TE	AE	EE	Utility	TE	AE	EE	Utility	TE	AE	EE
1	0.604	0.816	0.493	1	0.445	0.790	0.352	1	0.444	0.746	0.331
2	0.729	0.625	0.456	2	0.625	0.653	0.408	2	0.906	0.467	0.423
3	0.825	0.850	0.701	3	0.778	0.854	0.664	3	0.899	0.661	0.594
4	1.000	1.000	1.000	4	1.000	1.000	1.000	4	1.000	0.909	0.909
5	0.844	0.671	0.566	5	0.924	0.714	0.660	5	0.924	0.665	0.615
6	1.000	0.737	0.737	6	0.980	0.862	0.845	6	1.000	1.000	1.000
7	0.743	0.526	0.391	7	0.827	0.525	0.434	7	0.982	0.436	0.428
8	0.688	0.633	0.435	8	0.813	0.507	0.412	8	1.000	0.417	0.417
9	0.695	0.644	0.448	9	0.661	0.734	0.485	9	0.696	0.625	0.435
10	1.000	0.726	0.726	10	1.000	0.847	0.847	10	1.000	0.831	0.831
11	0.784	0.882	0.691	11	0.925	0.976	0.902	11	0.856	0.778	0.666
12	0.756	0.975	0.737	12	0.900	0.840	0.756	12	0.778	0.816	0.635
13	0.773	0.933	0.721	13	0.787	0.895	0.704	13	0.717	0.761	0.546
14	0.701	0.536	0.376	14	0.792	0.544	0.431	14	0.738	0.491	0.362
15	0.770	0.775	0.597	15	0.790	0.752	0.594	15	0.803	0.725	0.582
16	0.859	0.738	0.633	16	0.948	0.730	0.692	16	0.929	0.704	0.654
17	0.731	0.771	0.564	17	0.701	0.864	0.606	17	0.724	0.872	0.632
18	0.793	0.772	0.613	18	0.730	0.819	0.598	18	0.746	0.708	0.528
19	1.000	0.596	0.596	19	1.000	0.617	0.617	19	1.000	0.587	0.587
mean	0.805	0.748	0.604	mean	0.822	0.764	0.632	Mean	0.850	0.695	0.588

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Table A1.3. Alt #2
Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

	1988				1993				1997		
Utility	TE	AE	EE	Utility	TE	AE	EE	Utility	TE	AE	EE
1	0.604	0.903	0.546	1	0.499	0.792	0.396	1	0.588	0.662	0.389
2	0.676	0.593	0.401	2	0.625	0.586	0.367	2	0.774	0.486	0.376
3	0.825	0.852	0.702	3	0.778	0.849	0.661	3	0.899	0.687	0.618
4	1.000	1.000	1.000	4	1.000	1.000	1.000	4	1.000	1.000	1.000
5	0.825	0.614	0.506	5	0.814	0.740	0.603	5	0.839	0.668	0.560
6	1.000	0.672	0.672	6	0.920	0.880	0.809	6	1.000	1.000	1.000
7	0.730	0.460	0.335	7	0.788	0.471	0.372	7	0.982	0.379	0.372
8	0.621	0.619	0.384	8	0.813	0.441	0.358	8	0.956	0.400	0.382
9	0.695	0.597	0.415	9	0.661	0.707	0.467	9	0.882	0.507	0.447
10	1.000	0.699	0.699	10	1.000	0.841	0.841	10	1.000	0.868	0.868
11	0.696	0.954	0.664	11	0.925	0.981	0.907	11	0.707	0.951	0.672
12	0.753	0.973	0.733	12	0.900	0.880	0.792	12	0.778	0.846	0.659
13	0.773	0.926	0.716	13	0.787	0.901	0.708	13	0.717	0.738	0.529
14	0.668	0.484	0.323	14	0.728	0.510	0.371	14	0.738	0.465	0.343
15	0.770	0.734	0.565	15	0.790	0.722	0.570	15	0.803	0.731	0.587
16	0.859	0.681	0.585	16	0.898	0.709	0.636	16	0.921	0.653	0.601
17	0.617	0.844	0.521	17	0.648	0.898	0.581	17	0.724	0.886	0.642
18	0.793	0.729	0.578	18	0.689	0.822	0.566	18	0.825	0.646	0.533
19	1.000	0.521	0.521	19	1.000	0.550	0.550	19	1.000	0.508	0.508
mean	0.784	0.729	0.572	mean	0.803	0.752	0.608	Mean	0.849	0.688	0.583

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Table A1.4. Alt #3

Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

	1988				1993				1997		
Utility	TE	AE	EE	Utility	TE	AE	EE	Utility	TE	AE	EE
1	0.604	0.906	0.548	1	0.499	0.796	0.397	1	0.588	0.663	0.390
2	0.426	0.936	0.399	2	0.410	0.891	0.365	2	0.622	0.600	0.373
3	0.703	0.999	0.702	3	0.660	1.000	0.660	3	0.637	0.967	0.616
4	1.000	1.000	1.000	4	1.000	1.000	1.000	4	1.000	1.000	1.000
5	0.636	0.794	0.505	5	0.681	0.884	0.602	5	0.742	0.753	0.558
6	0.781	0.859	0.671	6	0.809	1.000	0.809	6	1.000	1.000	1.000
7	0.626	0.533	0.334	7	0.463	0.789	0.370	7	0.756	0.488	0.369
8	0.401	0.956	0.383	8	0.501	0.711	0.356	8	0.517	0.735	0.380
9	0.527	0.785	0.414	9	0.549	0.849	0.466	9	0.781	0.571	0.446
10	1.000	0.698	0.698	10	1.000	0.842	0.842	10	1.000	0.868	0.868
11	0.664	1.000	0.664	11	0.925	0.984	0.910	11	0.695	0.967	0.672
12	0.753	0.974	0.734	12	0.900	0.882	0.794	12	0.778	0.846	0.658
13	0.773	0.927	0.717	13	0.762	0.930	0.708	13	0.615	0.857	0.527
14	0.620	0.519	0.322	14	0.588	0.629	0.370	14	0.519	0.658	0.342
15	0.564	1.000	0.564	15	0.604	0.941	0.569	15	0.613	0.954	0.584
16	0.611	0.955	0.583	16	0.732	0.867	0.635	16	0.761	0.786	0.598
17	0.520	1.000	0.520	17	0.619	0.938	0.581	17	0.682	0.940	0.641
18	0.737	0.783	0.577	18	0.632	0.896	0.566	18	0.696	0.764	0.531
19	0.948	0.548	0.519	19	1.000	0.548	0.548	19	1.000	0.505	0.505
mean	0.679	0.851	0.571	mean	0.702	0.862	0.608	Mean	0.737	0.785	0.582

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Table A1.5. Alt #4

Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

	1988				1993				1997		
Utility	TE	AE	EE	Utility	TE	AE	EE	Utility	TE	AE	EE
1	0.402	0.882	0.354	1	0.277	0.940	0.260	1	0.331	0.860	0.284
2	0.776	0.997	0.773	2	0.625	0.958	0.599	2	0.862	0.996	0.859
3	0.825	0.805	0.664	3	0.778	0.870	0.677	3	0.899	0.780	0.701
4	1.000	1.000	1.000	4	1.000	1.000	1.000	4	1.000	0.978	0.978
5	0.867	1.000	0.867	5	0.920	0.997	0.917	5	0.857	0.998	0.856
6	1.000	1.000	1.000	6	0.980	0.998	0.978	6	0.952	0.999	0.951
7	0.767	0.999	0.766	7	0.826	0.999	0.825	7	0.972	0.902	0.877
8	0.763	0.995	0.759	8	0.813	0.902	0.733	8	1.000	1.000	1.000
9	0.695	0.856	0.595	9	0.650	0.853	0.555	9	0.684	0.778	0.532
10	0.780	1.000	0.779	10	0.867	0.996	0.863	10	0.836	0.984	0.822
11	0.783	0.998	0.781	11	0.888	0.990	0.879	11	0.831	0.992	0.824
12	0.662	1.000	0.662	12	0.659	0.999	0.658	12	0.629	0.879	0.553
13	0.657	0.981	0.644	13	0.727	0.952	0.692	13	0.669	0.859	0.574
14	0.773	0.995	0.770	14	0.783	0.997	0.780	14	0.738	0.889	0.656
15	0.770	0.868	0.669	15	0.790	0.865	0.683	15	0.803	0.758	0.609
16	0.859	0.927	0.796	16	0.936	0.998	0.934	16	0.884	0.975	0.862
17	0.734	0.997	0.731	17	0.699	0.997	0.697	17	0.656	0.945	0.620
18	0.732	0.997	0.730	18	0.721	0.997	0.718	18	0.732	0.919	0.672
19	1.000	1.000	1.000	19	0.951	0.999	0.951	19	0.980	0.927	0.908
mean	0.781	0.963	0.755	mean	0.784	0.964	0.758	Mean	0.806	0.917	0.744

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Table A1.6. Alt #5
Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

1997 Utility	TE	AE	EE
1	0.588	0.533	0.313
2	0.906	0.524	0.474
3	0.899	0.700	0.629
4	1.000	1.000	1.000
5	0.924	0.625	0.578
6	0.997	0.727	0.724
7	0.982	0.398	0.391
8	1.000	0.474	0.474
9	0.882	0.466	0.411
10	1.000	1.000	1.000
11	0.856	0.753	0.645
12	0.728	0.853	0.621
13	0.693	0.737	0.511
14	0.738	0.585	0.431
15	0.827	0.811	0.670
16	0.928	0.689	0.639
17	0.667	0.741	0.495
18	0.825	0.660	0.544
19	1.000	0.642	0.642
mean	0.865	0.680	0.589

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Table A1.7. Alt #6
Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

1997 Utility	TE	AE	EE
1	0.588	0.607	0.357
2	0.906	0.426	0.386
3	0.899	0.741	0.666
4	1.000	1.000	1.000
5	0.924	0.571	0.528
6	1.000	0.729	0.729
7	0.982	0.317	0.311
8	1.000	0.445	0.445
9	0.882	0.503	0.443
10	1.000	1.000	1.000
11	0.860	0.841	0.723
12	0.746	0.879	0.656
13	0.729	0.758	0.553
14	0.738	0.506	0.373
15	0.803	0.633	0.508
16	0.934	0.618	0.577
17	0.694	0.726	0.504
18	0.825	0.676	0.558
19	1.000	0.535	0.535
mean	0.869	0.658	0.571

Table A1.8. Alt #7
Efficiency score results, by utility: cost DEA, Scale Assumption = CRS

1997 Utility	TE	AE	EE
1	0.588	0.515	0.303
2	0.906	0.850	0.770
3	0.899	0.790	0.710
4	1.000	1.000	1.000
5	0.924	0.899	0.831
6	0.997	0.956	0.953
7	0.982	0.757	0.744
8	1.000	0.808	0.808
9	0.882	0.590	0.520
10	1.000	0.920	0.920
11	0.856	0.948	0.811
12	0.728	0.838	0.610
13	0.693	0.866	0.600
14	0.738	0.817	0.603
15	0.803	0.790	0.634
16	0.928	0.926	0.859
17	0.667	0.943	0.629
18	0.825	0.809	0.667
19	1.000	0.896	0.896
mean	0.864	0.838	0.730

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Appendix 2 – Malmquist Productivity Index Results

Table A2.1

Total Factor Productivity Change, 1988-1997.
Total Customers & Total kWhs as Outputs

firm	Malmquist Index TFPCH	Technology Change TECHCH	Efficiency Change EFFCH	Pure Efficiency Change PEFFCH	Scale Change SCH
1	0.980	0.983	0.997	1.000	0.997
2	1.012	0.995	1.017	1.018	1.000
3	1.030	1.020	1.010	1.009	1.001
4	0.999	0.999	1.000	1.000	1.000
5	1.008	1.001	1.007	1.010	0.997
6	1.021	1.021	1.000	1.000	1.000
7	1.041	1.013	1.028	1.028	1.000
8	1.039	1.009	1.030	1.030	1.000
9	1.075	1.047	1.027	1.000	1.027
10	0.984	0.984	1.000	1.000	1.000
11	1.014	1.004	1.010	1.008	1.002
12	1.021	1.018	1.003	1.005	0.998
13	0.991	0.999	0.992	0.984	1.007
14	1.056	1.061	0.995	1.003	0.992
15	1.023	1.018	1.005	1.002	1.003
16	1.030	1.021	1.009	1.000	1.009
17	1.000	1.002	0.998	1.010	0.988
18	1.019	1.015	1.004	1.000	1.004
19	1.029	1.029	1.000	1.000	1.000
mean	**1.019**	**1.012**	**1.007**	**1.006**	**1.001**

Table A2.2

Total Factor Productivity Change, 1988-1997.
Total Customers as Outputs (Alt #1)

firm	Malmquist Index TFPCH	Technology Change TECHCH	Efficiency Change EFFCH	Pure Efficiency Change PEFFCH	Scale Change SCH
1	0.984	1.018	0.996	1.000	0.996
2	1.029	1.004	1.024	1.024	1.001
3	1.029	1.020	1.010	1.009	1.001
4	1.010	1.010	1.000	1.000	1.000
5	1.012	1.002	1.010	1.011	0.999
6	1.021	1.021	1.000	1.000	1.000
7	1.053	1.021	1.031	1.028	1.004
8	1.048	1.005	1.042	1.034	1.009
9	1.090	1.090	1.000	0.992	1.008
10	0.990	0.990	1.000	1.000	1.000
11	1.024	1.014	1.010	1.008	1.002
12	1.021	1.018	1.003	1.005	0.998
13	0.991	0.999	0.992	0.984	1.007
14	1.063	1.056	1.006	1.007	0.999
15	1.023	1.018	1.005	1.002	1.003
16	1.030	1.021	1.009	1.000	1.009
17	1.002	1.003	0.999	1.010	0.989
18	1.014	1.021	0.993	0.992	1.002
19	1.029	1.029	1.000	1.000	1.000
mean	**1.024**	**1.019**	**1.005**	**1.005**	**1.000**

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