



Australian  
Competition &  
Consumer  
Commission

**Regulatory Practices in Other Countries**  
**Benchmarking opex and capex in energy networks**

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# 1 Introduction

## 1.1 Purpose of report

This report, titled *Regulatory Practices in Other Countries*, has been prepared by staff from the Australian Energy Regulator (AER) and the Regulatory Development Branch (RDB) of the Australian Competition and Consumer Commission (ACCC). The report is intended as a background resource and forms part of a RDB/AER joint project on cost benchmarking. The other components of the research which make up the joint project are:

- ACCC/AER Working Paper 6, *Benchmarking Opex and Capex in Energy Networks*, May 2012
- WIK-Consult, *Cost Benchmarking in Energy Regulation in European Countries*, December 2011
- Utility Regulation Services was also engaged to review Regulatory Practices in Australia
- An extensive review of the relevant literature has also been undertaken internally.

The purpose of this report is to provide some background on the approaches used by a selected group of international energy regulators to benchmark the costs of regulated utilities. The report provides an overview of the practices that have been employed by international energy regulators to benchmark operational expenditure (opex) and capital expenditure (capex) and the extent to which cost benchmarking has contributed to the regulatory decision on revenue or price setting.

The report presents a factual account of opex and capex benchmarking approaches that have been employed by international regulators. It does not discuss the relative merits or appropriateness of the different approaches and it does not make any recommendations on the appropriateness of the reviewed benchmarking methods in the Australian context.

The information provided in this report has been drawn from the relevant energy regulator's website, discussion and decision documents, and from related consultants' reports. It should be noted that, in some cases, limited re-writing of source material has taken place.

The seven international regulators covered in this report include:<sup>1</sup>

- The Office of Gas and Electricity Markets (OFGEM), the United Kingdom
- The Commission for Energy Regulation (CER), Ireland

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<sup>1</sup> The choice of countries covered in this report was based on the availability of regulatory documents and consultants reports that are written in English or have been able to be translated to English by available ACCC/AER staff. WIK-Consult was commissioned to review European countries where insufficient information was available in English. Utility Regulation Services was commissioned to review Australian jurisdictional regulators.

- The Commerce Commission (NZCC), New Zealand
- The Office of the Energy Regulator (DTe), Netherlands Competition Authority, the Netherlands
- The Ontario Energy Board (OEB), Ontario, Canada<sup>2</sup>
- The California Public Utilities Commission (CPUC), California, United States of America<sup>3</sup>
- The Agency for Natural Resources and Energy (ANRE), Ministry of Economy, Trade and Industry (METI), Japan.

This report reviews regulatory applications of cost benchmarking to the electricity and gas distribution sub-sectors.<sup>4</sup> A review of the electricity and gas transmission sub-sectors has not been undertaken due to time constraints.<sup>5</sup>

The report is organised as follows. For each of the seven energy regulators covered, background information is provided on the market structure, the regulator's role and the regulatory framework. Detailed information is then provided on the application of cost benchmarking to recent regulatory decisions for electricity distribution and gas distribution respectively.

## ***1.2 Overview of report findings***

There is a range of cost benchmarking methods employed by the seven international regulators reviewed in this report, including:

- Partial Performance Indicators (PPI), including unit-cost analysis
- Econometric methods such as Ordinary Least Squares (OLS) and variants such as Corrected OLS (COLS)
- Data Envelopment Analysis (DEA)
- Index-number-based Total Factor Productivity (TFP) analysis and variants.

The choice of method employed by the seven international regulators appears to be related to:

- the intended application to the regulatory decision. For example, an index-number-based TFP approach may be preferred when the objective is to estimate

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<sup>2</sup> Ontario has been chosen as an example of a Canadian province where cost benchmarking has been employed as part of a regulatory decision process.

<sup>3</sup> California has been chosen as an example of a state in the US where cost benchmarking has been considered as part of a regulatory decision process.

<sup>4</sup> A review of regulatory practices in relation to the Netherlands gas distribution has not been completed due to language constraints.

<sup>5</sup> A review of regulatory practices in relation to gas transmission in New Zealand has been undertaken and is included in this report.

the long-term productivity improvement of the sub-sector as a whole. Econometric or DEA methods may be preferred when the objective is to estimate the efficiency differences between businesses

- the quantity and quality of data available over time and across regulated businesses. For example, a bottom-up engineering approach or PPI method may be preferred where data are not comparable between businesses or there are few comparable businesses. DEA or econometric methods may be preferred when more data observations are available. None of the seven international regulators covered in this report has undertaken Stochastic Frontier Analysis (SFA), possibly due to the intensive data requirements of the technique.<sup>6</sup>

Statistical techniques, such as DEA and OLS (or its variants), appear to be more commonly applied for opex benchmarking, while capex benchmarking is generally assessed by cost category using methods such as historical cost trends, PPI and engineering-based analysis.<sup>7</sup> PPI, including unit-cost analysis, also appears to be more common for benchmarking of individual opex categories where there are few data observations; i.e., small number of businesses and/or time periods.

In most cases, opex and capex have been benchmarked separately; however, in 2000 the DTe in the Netherlands employed a DEA model that benchmarked total costs,<sup>8</sup> and, from 2013, the Ofgem intends to employ total cost benchmarking under its new Revenue, Incentives, Innovation and Outputs (RIIO) regulatory framework.

In most cases quality of service has not been included in the cost benchmarking model. The inclusion of quality of service, and similarly capital costs, is noted by some regulators and/or their consultants as being desirable, but difficult in practice, due to either data limitations or technical model estimation issues.

The number of cost drivers included in the model specification appears to be related to the number of data observations available to support the inclusion of more cost drivers. In some cases, the regulator has estimated multiple models with different cost drivers and weighted the outcomes (e.g., the Ofgem weighted 40 different regression models) or the regulator has created a single cost driver, a composite scale variable, by taking a weighted average of multiple cost drivers (e.g., following the Ofgem's approach in prior price reviews, the CER developed a composite scale variable by weighting three output variables: customer numbers, network length and throughput).

Some regulators have considered multiple benchmarking methods, either to compare the robustness of the results from their primary method or to combine the results of the different methods (e.g., the OEB combined the results from unit-cost and econometric benchmarking methods to group electricity distribution networks based on relative performance).

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<sup>6</sup> SFA techniques have been used by three regulators that are reviewed in WIK-Consult, *Cost Benchmarking in Energy Regulation in European Countries*, December 2011.

<sup>7</sup> Less detail is provided on the benchmarking of capex where engineering, historical cost or PPI analysis has been undertaken.

<sup>8</sup> Where total cost is the sum of opex plus depreciation plus a standardised cost of capital.

The seven international regulators have applied the results of benchmarking analysis in varying ways, including:

- the results may be used to group businesses based on relative performance and assign group-specific stretch factors that feed into the revenue or price cap formula (e.g., the OEB, the NZCC (pre-2008) and the METI)
- the results may be used to assess the efficient costs of the business and then used to adjust the allowed costs of the businesses' for the regulatory period (e.g., the Ofgem and the CER)
- the results may be directly applied through the price cap or revenue setting formula (e.g., the DTe's relative efficiency factor and the NZCC's industry-wide efficiency factor)
- the results may form the starting point for a settlement process between the regulated business and the customer advocate group, where the process and outcomes of the settlement are to be approved by the regulator (e.g., the CPUC).

The methods of opex benchmarking for electricity and gas distributors, the data used and the regulatory applications for each of the seven international regulators are summarised in the table below.

#### Summary of cost benchmarking applications of by seven international regulators

Regulator	Sub-sector	Technique	Data used <sup>9</sup>	Application
Ofgem, UK	ED	Econometric (COLS)	14 DNOs 5 years	Determine base year efficient opex and adjust forecast costs
	GD	Econometric and PPI	8 DNOs (4 companies) 2 years	Determine base year efficient opex and adjust forecast costs
CER, Ireland	ED	Econometric (COLS)	13 DNOs (1 Irish + 12 UK) 1 year	Adjust forecast opex
	GD	PPI/historical trend analysis	1 Irish DNO + various US, UK and Australian comparators 4 years	Assess forecast costs

<sup>9</sup> The data used in the analysis may not necessarily correspond to the size of the sub-sector in the respective jurisdiction.

Regulator	Sub-sector	Technique	Data used <sup>9</sup>	Application
NZCC, New Zealand	ED	TFP index number	28 DNOs 13 years	Determine industry-wide productivity growth for X factor in price path
	GD	TFP index number	3 DNOs 4 years	Determine industry-wide productivity growth for X factor in price path
DTe, Netherlands	ED	1) DEA 2) Unit cost	1) 20 incl. DNOs and retail suppliers 2) Efficient DNOs only	Determine X factor components: 1) firm-specific 2) industry-wide
OEB, Ontario, Canada	ED	1) Unit cost and Econometric 2) TFP index	1) 86 DNOs 2) 69 US DNOs	Determine X factor components: 1) firm-specific 2) industry-wide
	GD	TFP index	36 US DNOs	Basis of negotiation between regulated businesses and regulator to determine X factor
CPUC, California, US	ED	1) TFP index	1) 71 EDNs, 37 GDNs	Basis of negotiation for settlement process between regulated business and customer advocate
	& GD	2) Econometric	2) 44 GDNs	
METI, Japan	ED	Econometric (Regression)	231 GDNs	For each cost category, group businesses and assign stretch factor. Multiply stretch factor by forecast costs to determine allowed costs for revenue determination
	& GD		Approximately 10 EDNs	

## 2 United Kingdom: Office of the Gas and Electricity Markets

### 2.1 Overview of the UK energy market

The gas and electricity transmission and distribution sectors in the UK primarily consist of regional monopoly businesses, including four energy transmission networks, eight local gas distribution networks (GDNs) and 14 licensed regional electricity distribution networks (EDNs).

Electricity retail supply is legally separated from distribution and there are over seventy licensed retailers of electricity and gas. However six vertically-integrated businesses have 99 per cent of the retail market and are also active in electricity generation.<sup>10</sup>

#### *Electricity*

The three electricity transmission operators are:

- National Grid Electricity Transmission (NGET), which owns the network in England and Wales
- Scottish Hydro-Electric Transmission Limited (SHETL), which owns the northern Scotland networks
- Scottish Power Transmission Limited (SPTL), which owns the southern Scotland network

There are seven companies operating the 14 major EDNs in the UK, there are also four smaller independent network operators.<sup>11</sup> The two Scottish EDNs are operated by the same businesses that operate the transmission network, as above. In England and Wales, the transmission and distribution systems remain fully separated through independent ownership. Each distribution company holds a licence for each distribution network they operate.<sup>12</sup>

#### *Gas*

The single gas transmission operator is National Grid Gas (NGG), which owns and operates the national gas transmission network. The gas distribution sub-sector was restructured on 1 June 2005, following the sale of four GDNs by NGG. There are presently four gas businesses that operate the eight gas distribution networks — NGG, Soctia Gas Network, Northern Gas Networks and Wales & West Utilities. Each

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<sup>10</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, pp. 311-312.

<sup>11</sup> Ofgem, *Electricity Distribution Price Control Review, Initial consultation document*, 28 March 2008, pp. 4-5.

<sup>12</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, p. 311.

business operates in a separate geographical region. There are also a number of smaller, independent networks.<sup>13</sup>

### *Regulator*

The Office of Gas and Electricity Markets (Ofgem) is responsible for the economic regulation of gas and electricity networks in the UK (excluding Northern Ireland). The Ofgem's regulatory powers are primarily derived from the *Gas Act 1986*, the *Electricity Act 1989* and the *Utilities Act 2000*. The Ofgem is also responsible for introducing competition in the wholesale and retail parts of the electricity and gas markets. The Ofgem's functions include administering a price control regime for network operators, monitoring the quality of services by setting guaranteed standards of performance and deciding upon proposed industry code changes.<sup>14</sup>

### *Appeal Process*

The Ofgem's decisions on price controls are not binding without the agreement of the regulated businesses, which can otherwise make an appeal to the Competition Commission. Any such appeal would be on the substance as well as the process of the Ofgem's decision. There have been no appeals of the Ofgem's price control decisions since 1995.<sup>15</sup>

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<sup>13</sup> Ibid.

<sup>14</sup> Ibid, p. 312.

<sup>15</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice*, prepared for the AEMC, 2008, p. 24, footnote 41.

## 2.2 Regulatory framework

For the past 20 years, the Ofgem has used a price cap regime, where the price cap sets the maximum base revenue the regulated businesses may earn for each year of the regulatory period. The price cap takes the form:

$$P = P_0 + \text{Retail Price Index (RPI)} - X$$

where  $P_0$  is the base year level of efficient costs (that is the year preceding the start of the regulatory period; e.g., the base year is 2008-09 for the regulatory period 2009-10 to 2014-15 for EDNs), RPI is the economy wide measure of retail price inflation and  $X$  is a price smoothing factor.<sup>16</sup>

The maximum base revenue of a regulated business is capped at an annual growth rate of RPI-X for the five five-year regulatory period. The Ofgem then provides additional financial incentives relating to other factors, such as service quality, electricity losses during transportation and/ or environmental impacts.<sup>17</sup>

The Ofgem determines the price cap for 14 electricity distribution networks, eight gas distribution networks, and four transmission networks.<sup>18</sup> The regulatory control period is generally five years and all businesses within a sub-sector are assessed at the same time (for example, the latest regulatory control period for electricity distribution networks is 2010 to 2015).<sup>19</sup>

The Ofgem has employed the building block model to estimate the costs of each regulated business over the regulatory period. Each regulated business is required to submit detailed forward-looking business plans to the Ofgem. The business plans form the basis of the Ofgem's analysis and a bottom-up review of the business plans is undertaken by technical experts. Where possible, the Ofgem also employs cost benchmarking methods to assess the relative efficiency of costs between regulated businesses in a sub-sector. There is no direct (i.e., mathematical) link between the results of any particular analysis and the choice of  $P_0$  and the  $X$  factor. The Ofgem takes into account various quantitative and qualitative analysis in making its determination.<sup>20</sup>

From 2013, the Ofgem will begin to implement its new Revenue = Incentives + Innovation + Outputs (RIIO) regulatory framework. The RIIO framework was designed to promote greater innovation and investment in smarter networks for a low carbon future and to deliver lower costs to consumers.<sup>21</sup>

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<sup>16</sup> Ofgem, *Electricity Distribution Price Control Review, Initial Consultation Document*, 28 March 2008, pp. 5-6, 9-13.

<sup>17</sup> Ibid.

<sup>18</sup> Ofgem, *Networks*; available at: <http://www.ofgem.gov.uk/Networks/Pages/Ntwrks.aspx> [accessed on 21 March 2012].

<sup>19</sup> Ofgem, *Electricity Distribution*; available at: <http://www.ofgem.gov.uk/Networks/ElecDist/Pages/ElecDist.aspx> [accessed on 21 March 2012].

<sup>20</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice*, prepared for the AEMC, 2008, p.23.

<sup>21</sup> Ofgem, *RIIO, A New Way to Regulate Energy Networks*, Final Decision, October 2010, p. 3.

## 2.3 Electricity distribution

The following information is drawn from the Ofgem's fifth Electricity Distribution Price Control Review (DCPR5) which applied from 2009-10 to 2014-15.

### 2.3.1 Overview of approach to cost assessment<sup>22</sup>

To determine the price cap for DCPR5, the Ofgem assessed the following key components:

- efficient operating costs (including network opex, indirect opex and non-operational capex)
- efficient network investment costs (i.e., capex)
- real price effects (i.e., input price inflation) and ongoing efficiency assumptions (i.e., general sector-wide productivity gains).

The Ofgem applied a different process for assessing each of these key components. Its general approach involved:

- reviewing the businesses' forecasts
- undertaking modelling and benchmarking work
- considering evidence for differences between businesses' forecasts and the benchmarks
- consultation with stakeholders.

Based on the above analysis and wider evidence, the Ofgem formed a view on the appropriate baseline level of total costs for each EDN. The Ofgem cross-checked the results by comparing historical forecasts provided by EDNs under previous price control reviews with the actual costs incurred and by considering the quality of information provided by EDN's for both the past and present price control reviews.

### *Determining efficient opex<sup>23</sup>*

In DPCR5, the Ofgem used benchmarking analysis based on four years of historical cost data to inform its view of the 'base year efficient costs' for operational costs (network operating costs, indirect costs and non-operational capex). The Ofgem's view was also informed by the EDNs' forecasts, engineering-based analysis (i.e., analysing the work required and the unit cost of inputs) and stakeholder consultation.

The Ofgem set the benchmarks at the upper third for network operating costs, and at the upper quartile for indirect costs and non-network costs. The benchmark costs were

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<sup>22</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment*, 7 December 2009, pp. 3-6.

<sup>23</sup> Ibid, pp. 10-13.

used to derive efficiency scores and determine the ‘base year efficient costs’ for each EDN. The base year was 2008-09 for the regulatory period 2009-10 to 2014-15.

The ‘base year efficient costs’ were then rolled forward into each year of the regulatory period, using the Ofgem’s views on input price inflation and general productivity growth during the regulatory period.

The benchmark costs applied from the first year of the DPCR5 period and therefore the Ofgem did not provide any time allowance for inefficient EDNs to ‘catch-up’ to the more efficient EDNs. Where an inefficient EDN was unable to catch-up to the benchmark within the first year, shareholders, not customers, carried the cost of the inefficiency.

Benchmarking was not considered appropriate for some cost categories such as lumpy or business-specific costs that may not be sufficiently comparable.

#### *Determining efficient capex<sup>24</sup>*

In DCPR5, the Ofgem assessed the EDNs forecasts of network investment using network investment models. These models are audited by specialist engineering consultants, PB Power.

In summary:

- asset replacement was assessed by comparing each EDN's forecasts against its own asset replacement policies in the past, and against the expenditure forecasts of other EDNs, taking into account the age profile of assets in the individual networks
- the network reinforcement model assessed capacity added against the additional capacity each EDN needed to meet demand growth in the past, and compared the forecast unit cost of adding new capacity with long-run average costs
- the volume and unit cost of investment each EDN planned to undertake were also assessed.

#### *Ongoing efficiency and real price effects<sup>25</sup>*

The Ofgem made assumptions regarding:

- ‘ongoing efficiency’, that is, the general productivity or efficiency improvements expected of the sub-sector as a whole over the regulatory period. (This is additional to any efficiency ‘catch up’ identified in the cost benchmarking analysis). An ongoing efficiency assumption was determined for each of operational costs and network investment costs (refer to section 2.3.4)

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<sup>24</sup> Ibid, pp. 6-9.

<sup>25</sup> Ibid, pp. 80-87.

- ‘real price effects’, that is, changes in input prices over the regulatory period. The Ofgem’s assumptions on the real price effects over the regulatory period were based on forecasts of economy-wide price effects prepared by Cambridge Economic Policy Associates.

The Ofgem’s assumptions for ongoing efficiency and real price effects were used to roll forward the base year efficient costs into the regulatory period.

### 2.3.2 Benchmarking opex

#### *Summary*<sup>26</sup>

In DCPR5, the Ofgem took the following general approach to benchmarking EDNs’ operational costs:

- collate the base cost data for all operational activities for the four years 2005-06 to 2008-09
- exclude costs that were not suitable for benchmarking
- normalise the costs to take account of factors outside the control of the EDNs which have an impact on cost performance
- apply appropriate drivers and run regressions using a four-year panel of data and estimate the efficient costs in 2008-09 (‘base year efficient costs’)
- compare the estimated efficient costs with the EDN’s actual costs in 2008-09 and determine the overall efficiency scores, using the following formula:

$$EfficiencyScore = \frac{ActualEDN\ Costs_{2008-09}}{Estimated\ Efficient\ Costs_{2008-09}}$$

- set each EDN’s base year efficient costs for 2008-09 as the statistical upper third of the ranked actual EDN costs for network operating costs, and as the statistical upper quartile for indirect costs and non-network capex
- scale up each EDN’s base year efficient costs by applying annual network growth and efficiency saving estimates to determine forward opex estimates for each EDN for the five years of DPCR5.

#### *Data used*

The Ofgem primarily used the data from the Forecast Business Plan Questionnaires (FBPQs) that were submitted by the EDNs. The FBPQ data included historical and forecast data at both aggregate and disaggregated levels (split by activities and by cost types). Other information was collected from the annual Regulatory Reporting Packs

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<sup>26</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, p. 59.

(RRPs) submitted by the EDNs to the Ofgem and through supplementary questions posed by the Ofgem to the EDNs.<sup>27</sup>

The Ofgem provided detailed guidance to the EDNs on how to report data in the FBPs and RRs. This was to improve the consistency of reporting and ensure that the cost base and normalisation adjustments eliminated non-comparable costs. The standardised reporting allowed the Ofgem to collect data from each EDN on a largely consistent basis.<sup>28</sup>

### *Benchmarking technique*

The Ofgem applied panel data regression techniques as the core of its comparative benchmarking analysis. The Ofgem choose these techniques to:

make use of multi-period data and provide better estimates of the impact of cost drivers on costs than is possible with only a single year's data.<sup>29</sup>

### *Inputs*

The Ofgem used operating costs, including network operating costs, indirect costs and non-operational capex, as the dependent variable in each of the regression models.<sup>30</sup> The Ofgem used three different levels of disaggregation of operating costs, as follows:

- top down – all operational costs were included in a single regression
- single group – regression analysis was conducted for each of the following five groups of costs:
  - indirect costs
  - LV and HV underground faults
  - LV and HV overhead faults
  - inspections and maintenance
  - tree cutting
- groups – indirect costs were further disaggregated, and regression analysis was conducted for each of the following seven cost groups:
  - LV and HV underground faults
  - LV and HV overhead faults
  - inspections and maintenance
  - tree cutting
  - group 1 – network design, project management and system mapping

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<sup>27</sup> Ibid, p. 60.

<sup>28</sup> Ibid, p. 76.

<sup>29</sup> Ibid, p. 74.

<sup>30</sup> Ibid, pp. 69-70.

- group 2 – engineering management, control centre, call centre, stores, H&S and operational training
- group 3 – HR and non-operational training, network policy, CEO, finance and regulation, IT and property management. Group 3 costs are assessed both per EDN and on a per EDN ownership group basis, as the Ofgem found that these costs were organised by EDNs within an ownership group.<sup>31</sup>

The Ofgem undertook the regression analysis at the different levels of disaggregation to ensure the results would not be skewed by a particular choice of aggregation or disaggregation. The Ofgem noted that more disaggregation would allow the cost drivers to be more relevant to the costs being assessed, whereas more aggregation reduced the influence of potential inconsistencies in the EDNs' reporting of costs by categories.<sup>32</sup>

The Ofgem determined the costs to be included in the regression analysis based on whether they met the following criteria:<sup>33</sup>

- costs could be influenced or controlled by EDNs
- the activity was undertaken by most EDNs
- costs are material for all EDNs and the activity occurs frequently
- costs are relatively stable, rather than being one-off or 'lumpy'
- the relationship between costs and associated cost drivers are well understood
- costs are reported on a consistent basis across EDNs.

Costs that failed to meet one or more of the above criteria and were unable to be adjusted to compensate were excluded from some or all of the benchmarking analysis. The following costs were excluded:<sup>34</sup>

- traffic management costs
- wayleaves (costs to gain access or right of way)
- terrorism insurance
- unmetered electricity
- submarine cable repairs
- low volume high vault faults
- remote location generation

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<sup>31</sup> Ibid, pp. 69-70.

<sup>32</sup> Ibid, p. 69.

<sup>33</sup> Ibid, p. 62.

<sup>34</sup> Ibid.

- specific urban costs
- pressure assisted cables
- non-quality of service (QoS) faults
- third party damage recovery
- dismantlement
- property operating costs
- IT and telecoms
- pensions and related costs
- EDFE LPN high value projects
- atypical costs.

#### *Outputs*<sup>35</sup>

For each of cost categories or groups to be included as dependent variables in the regression, the Ofgem, in consultation with the Electricity Networks Association, identified the most material cost drivers (outputs) and assigned these as either primary or secondary cost drivers, as shown in the table below.

The Ofgem was not able to include all possible cost drivers as explanatory variables in a regression due to data limitations. The Ofgem only included secondary cost drivers when the cost driver had a material impact on the cost category or group and would improve the regression model.

Where the Ofgem included both primary and secondary cost drivers, the cost drivers were combined to form a composite scale variable which was used as the single explanatory variable in the regression.

In short, the Ofgem determined the weights to apply to each cost driver in the composite scale variable by:

- estimating a multivariate regression model
- assigning weights based on the ratio of the coefficient on cost driver to the sum of the two coefficients on the cost drivers
- imposing the constraint that primary cost drivers have a minimum weight of 0.5.

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<sup>35</sup> Ibid, pp. 71-73, 79-80.

**The primary and secondary cost drivers and weightings used in the Ofgem's regression analysis<sup>36</sup>**

Regression cost group	Primary driver	Secondary driver
LV & HV Underground Faults	LV & HV Underground faults 78%	Length of cable replaced 22%
LV and HV Overhead Faults	LV & HV Overhead faults 100%	
Inspection & Maintenance	Asset Hours Work driver for Inspection & Maintenance 100%	
Tree Cutting	Spans cut 100%	Spans affected 0%
Group 1 Network Design, Project Management, System Mapping	Load & Non-load costs 100%	MEAV 0%
Group 2 Engineering Management & Clerical Support, Control Centre, Customer Call centre, Stores, Health & Safety	Total Direct Costs (less non-operational capex) 50%	MEAV 50%
Group 3 Network Policy, HR & Non-operational Training, Finance & Regulation, CEO, IT & property	MEAV 66%	Total Direct Costs (less non-operational capex) 34%
Single Group As for Groups but amalgamating the three groups of costs into a single regression	Total Direct Costs (less non-operational capex) 52%	MEAV 48%
Top Down Single regression of all of the above costs	MEAV 63%	Load & Non-load costs 37%

<sup>36</sup> Source: Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, p. 73.

### *Normalisation adjustments*<sup>37</sup>

The Ofgem applied normalisation adjustments to the raw historical-cost data provided by the EDNs to ensure that the benchmarking analysis was undertaken on an equitable basis and would not produce biased results. Normalisation adjustments were made as per the table below.

### **The Ofgem's opex normalisation adjustments**<sup>38</sup>

<b>Opex category</b>	<b>Adjustment</b>
Labour and contractor rates	To account for regional differences
Vehicles and small tools & equipment	Excluded from regression then added back after regressions, taking into account efficiency adjustments from the Network Investment analysis
Non-operational capex	The Ofgem took the average costs over the period because these costs were considered to be lumpy
Indirect costs reported within direct activity contractors	The Ofgem adjusted indirect costs to normalise them to an average level of outsourcing to reflect the extent to which contractors undertook indirect activities as part of contracts for working on the network
Cable replacement (non-load cable, including rising mains and laterals)	The Ofgem made adjustments to these costs to correct for inconsistencies in the reporting of cable faults and replacement
Interconnected network costs in the SP Manweb area	The Ofgem considered that the interconnected network in SP's area increases its costs and made a normalisation adjustment to account for this
Sparsity issues in the SSE Hydro area	The Ofgem considered that additional operational costs were incurred to service the SSE Hydro area and therefore made an adjustment to normalise costs
Urban working environment	The Ofgem considered there were additional costs of working in an urban environment and therefore made adjustments to total costs based on population densities in local authorities/areas
EDFE Alliance contracting start-up costs	EDFE moved to a new contracting model and incurred significant set-up costs which were excluded from the regression
Average non-load costs	The Ofgem included a network investment cost in the analysis to ensure that lumpiness of connections and other load-related investment would not impact on the results

### *Model specification*

The Ofgem adopted a time fixed-effects approach that allowed for average costs to differ between years, as a result of factors such as input prices, industry-wide efficiency improvements and industry-wide shocks. This approach involved adding a time-

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<sup>37</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, pp. 65-68.

<sup>38</sup> Source information in: Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, pp. 65-68.

specific variable to the regression equations, which could be used to estimate the expected costs for each year.<sup>39</sup>

The Ofgem used the log-log functional form. This meant that the regression results could be interpreted as a one per cent increase in the cost driver will lead to a constant percentage increase in costs. The Ofgem suggested that this makes economic sense and did not consider it appropriate to deviate from that assumed relationship.<sup>40</sup>

The model specification is as follows:

$$\log(\text{adjusted costs}) = a + \beta \cdot \log(\text{cost driver}) + \varepsilon$$

where,  $a = a_{2005-06}$  in 2005-06,  $a_{2006-07}$  in 2006-07,  $a_{2007-08}$  in 2007-08 and  $a_{2008-09}$  in 2008-09 and  $\varepsilon$  is the error term.<sup>41</sup>

### *Model testing*

For each level of cost disaggregation (top down, single group and groups), the Ofgem identified a particular combination of costs (dependent variable) and cost drivers (explanatory variables) that would form the 'core' model. The core models provided the baseline against which the Ofgem could assess the impact of changes in the costs and cost drivers.<sup>42</sup> The core models are shown in the table below as model numbers 1, 9 and 11.

For each level of disaggregation, the Ofgem then identified alternative models. The alternative models were arrived at by either changing the dependent variable by taking a single cost item and adding or excluding it, or changing the cost drivers (explanatory variables).<sup>43</sup> The alternative models are shown in the table below as model numbers 2-8, 10 and 12-19.

The Ofgem then re-ran some of the regression models to ensure that the presence of outliers and the choice of weightings did not bias the results.<sup>44</sup> The regression models were re-estimated to:

- exclude outliers where the initial regression had outliers
- allow free-weighting of cost drivers where composite scale variables were used
- remove outliers for regressions where free-weighting of cost drivers were used.

In total, the Ofgem estimated 40 regression models covering the three different levels of disaggregation, the core and alternative models, and the models re-estimated to

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<sup>39</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, pp. 74–76.

<sup>40</sup> Ibid, pp. 86–87.

<sup>41</sup> Ibid, p. 87.

<sup>42</sup> Ibid, pp. 70–71.

<sup>43</sup> Ibid, p. 71.

<sup>44</sup> Ibid, pp. 76–79.

remove outliers and/or allow for free-weightings. The 40 models are shown in the table below.

**Models estimated by the Ofgem<sup>45</sup>**

	Level of Disaggregation	Costs	Driver Alternatives	Cost Base alternatives	Rerun for:		
					Outlier	Free weights	Outlier for free weights
1	Top Down – CORE	Operational Costs	Modern Equivalent Asset Value (MEAV) /Load & Non-load	Base Operational	Yes		
2	Top Down	Operational Costs	MEAV		Yes		
3	Top Down	Operational Costs	MEAV/Load & Non-load	Add Average Non-load Capex		Yes	
4	Top Down	Operational Costs	MEAV/Load & Non-load	Exclude Property	Yes	Yes	Yes
5	Top Down	Operational Costs	MEAV/Load & Non-load	Exclude property and IT	Yes	Yes	Yes
6	Top Down	Operational Costs	MEAV/Load & Non-load	Regional Adjustment only applied to LPN		Yes	
7	Top Down	Operational Costs	MEAV/Load & Non-load	Excluding Contractor adjustments	Yes	Yes	Yes
8	Top Down	Operational Costs	MEAV/Load & Non-load	Exclude tree cutting		Yes	

<sup>45</sup> Source: Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, Tables 4 and 5.

	Level of Disaggregation	Costs	Driver Alternatives	Cost Base alternatives	Rerun for:		
					Outlier	Free weights	Outlier for free weights
9	Single Group – CORE	Indirects LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting	Direct/MEAV No. of faults/cable replaced No of faults Asset Manhours Spans Cut/Spans Affected				
10	Single Group	Indirects LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting	MEAV No. of faults/cable replaced No of faults Asset Manhours Spans Cut/Spans Affected				
11	Groups – CORE	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Group 1 Group 2 Group 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load Direct/MEAV MEAV/Direct		Yes	Yes	Yes

Level of Disaggregation	Costs	Driver Alternatives	Cost Base alternatives	Rerun for:		
				Outlier	Free weights	Outlier for free weights
12 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Group 1 Group 2 Group 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected Load & Non-load Direct/MEAV MEAV/Direct				
13 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Group 1 Group 2 Group 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected MEAV Direct/MEAV MEAV/Direct				

Level of Disaggregation	Costs	Driver Alternatives	Cost Base alternatives	Rerun for:		
				Outlier	Free weights	Outlier for free weights
14 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Groups 1, 2 & 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load Direct MEAV/Direct		Yes		
15 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Groups 1, 2 & 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load MEAV MEAV/Direct		Yes		

Level of Disaggregation	Costs	Driver Alternatives	Cost Base alternatives	Rerun for:		
				Outlier	Free weights	Outlier for free weights
16 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Groups 1, 2 & 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load Direct/MEAV MEAV				
17 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Groups 1, 2 & 3	No of faults No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load Direct/MEAV MEAV/Direct		Yes		

Level of Disaggregation	Costs	Driver Alternatives	Cost Base alternatives	Rerun for:		
				Outlier	Free weights	Outlier for free weights
18 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Groups 1, 2 & 3	No of faults No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load Direct/MEAV MEAV/Direct	Excluding Non-load Cable			
19 Groups	LV&HV Underground Faults HV&LV Overhead Faults Inspections & Maintenance Tree Cutting Groups 1, 2 & 3	No of faults/cable replaced No of faults Asset Man hours Spans Cut/Spans Affected MEAV/Load & Non-load Direct/MEAV MEAV/Direct	Method Change – On per EDN Group basis		Yes	

The Ofgem also conducted a series of statistical tests on the regression models. These included:<sup>46</sup>

- White test for heteroscedasticity - to provide an indication of a general model misspecification
- F-test - to examine whether the slope coefficients were constant over time
- Ramsey RESET type Wald test - to test if the model was mis-specified
- Jarque-Bera test for whether the data are normally distributed
- Standardised residuals test for outliers.

The Ofgem undertook these tests to:

provide an indication of the robustness of the modelling results and also indicate where some of the outputs from the regressions might be biased and require an adjustment to avoid misleading results.<sup>47</sup>

The Ofgem drew a number of conclusions from the results of these statistical tests:<sup>48</sup>

- No problems were found with the distribution of the residuals from the model
- There was no statistical evidence to suggest that the slopes of the cost drivers were not constant over time (therefore the data could be pooled over the given years)
- Heteroscedasticity was detected in a number of models, which affected the standard errors and the use of F-tests. The Ofgem corrected the standard errors using a robust estimator and noted that the estimated coefficients on which it relied for the efficiency assessment were unbiased
- The standardised residuals test found some outliers; however, this did not affect the robustness of the models as the Ofgem had no strong expectation for the residuals to follow a particular distribution
- The Ramsey RESET type Wald test indicated that the squared fitted values from some of the regressions were statistically significant, which suggested that there might have been an issue with the specification of some the models. However, the Ofgem considered that the results of its analysis remained robust and unbiased, as the results of all the models (including the alternative approaches considered) broadly supported each other.

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<sup>46</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, pp. 82–84.

<sup>47</sup> Ibid, p. 82.

<sup>48</sup> Ibid, p. 86.

### *Analysis of model outputs*<sup>49</sup>

From each of the regression results, the Ofgem calculated the average and efficient costs of performing an activity in a given year. Where an individual EDN's actual costs lie relative to the average level provides an indication of their efficiency relative to the industry average.

The Ofgem estimated an EDN's efficient costs from the regression results using the following formula:

$$Efficientadjusted\ Cost_{2008-09} = \exp[a_{2008-09} + b \times \log(Driver)]$$

The Ofgem considered that the use of the logarithmic transformation of the cost data could lead to underestimation of the expected costs for a given cost driver. The Ofgem corrected for this by multiplying each efficient adjusted cost by an estimate of the expected value of the exponential ( $\epsilon$ ), this correction is known as the 'alpha factor'. The correction is only made if the alpha factor ( $\alpha$ ) is greater than one, otherwise no correction is made.

The corrected efficient adjusted cost is calculated using the following formula:

$$Correctedefficientadjusted\ Costs_{EDN} = Efficientadjusted\ Costs_{EDN} \times \alpha$$

The Ofgem then compared each EDN's actual costs to the efficient costs calculated from the regressions to determine a relative efficiency score for each EDN for each set of analysis.

$$EfficiencyScore = \frac{ActualAdjustedCosts_{2008-09}}{Corrected\ Efficient\ Adjusted\ Costs_{2008-09}}$$

The Ofgem adjusted the efficiency scores for each EDN to ensure that the average efficiency score across the EDNs was equal to 100 per cent for each set of analysis. This was to ensure that the scores were calculated on a comparable basis.

$$AdjustedEfficiencyScore(DNO) = \frac{EfficiencyScore(DNO)}{IndustryAverageEfficiencyScore}$$

The Ofgem then determined the weighting to give each set of the 40 regression models. The weights were determined based on the Ofgem's judgement of the relative merits of each analysis, including consideration of the different data sets, the cost drivers used, and the Ofgem's understanding of the EDNs' businesses.<sup>50</sup> In aggregate, the Ofgem applied the following weightings to the models at each of the following levels of disaggregation:<sup>51</sup>

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<sup>49</sup> Ibid, pp. 87-93.

<sup>50</sup> A table of the weightings applied to each set of analysis is available on page 92 of: Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009.

<sup>51</sup> Ibid, p. 92.

- Top Down—9.09 per cent
- Single Group—45.45 per cent
- Groups—45.45 per cent

The Ofgem applied less weight to the top-down models, because it was concerned that the limited number of cost drivers used in the regressions were not sufficient to adequately explain the costs reported by the EDNs.<sup>52</sup>

Based on the weightings, the Ofgem determined a final efficiency score for each EDN for network operating costs and indirect costs separately. To do this, the Ofgem used a weighted average of the network operating costs and indirect costs scores for the single group and group sets of models, and an implied efficiency score for the network operating costs and indirect costs scores from the overall score for the top down models.<sup>53</sup>

#### *Application to regulatory decision*

##### Efficient costs for 2008-09<sup>54</sup>

The Ofgem set the benchmark for indirect costs and non-operational capex at the upper quartile and the benchmark for network operating costs at the upper third of the efficiency scores. The Ofgem applied a lower benchmark for network operating costs because the range of efficiency scores was significantly larger.

The Ofgem noted that econometric models cannot provide robust efficiency assessments in isolation. It therefore used its judgement to make adjustments to ensure that the data were comparable and that EDN specific factors were taken into account. The Ofgem also noted that unexplained costs in the regression results might not all be due to inefficiency and for this reason the Ofgem set the benchmark at the upper quartile or below rather than at the frontier.

The Ofgem calculated the efficient costs for 2008-09 for each EDN using the following steps:

1. it made an efficiency adjustment to each EDN's actual costs to take the costs to the benchmark using the following formula:

$$\text{Adjustment to Actual Costs} = \text{Actual Costs} \times (\text{Actual Efficiency Score} - \text{Benchmark Score})$$

2. it calculated the efficient costs for each EDN for 2008-09 using the following formula:

$$\text{Efficient Costs}_{2008-09} = \text{Actual Costs} + \text{Adjustment to Actual Costs}$$

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<sup>52</sup> Ibid, p. 90.

<sup>53</sup> Ibid, p.93.

<sup>54</sup> Ibid, pp. 96-97.

### Rolling Efficient 2008-09 costs into DPCR5<sup>55</sup>

The Ofgem rolled forward the efficient costs for EDNs for 2008-09 into DPCR5 by applying annual growth terms and an annual efficiency saving.

The Ofgem applied a one per cent annual efficiency saving to the operational costs for EDNs from 2009-10 to 2014-15.<sup>56</sup> The Ofgem chose one per cent as it made an assumption that the EDNs' network operational costs and indirect costs would increase between 0.9 per cent and 1.4 per cent faster than the general rate of inflation from 2008-09 to 2014-15.

Based on an analysis of the relationship between the changes in network investment costs and in indirect costs, the Ofgem also applied a one per cent growth factor to indirect costs for each three per cent change in the network investment costs.

The Ofgem also included a one per cent annual growth factor to LV and HV underground cable faults and a one per cent annual growth factor to Inspections and Maintenance costs.

### Cost baselines for costs excluded from the regression analysis<sup>57</sup>

The Ofgem determined the cost baselines for costs excluded from the regression analysis independently. Generally, it used the lower of the average actual costs for 2005-06 to 2009-10 or the EDNs' own forecasts for DPCR5. The following cost baselines were calculated differently:

- Wayleaves—cost baselines were set at the levels forecast by the EDNs
- Terrorism Insurance—cost baselines were set, only for some EDNs, at the minimum of the costs reported in 2008-09 and the average of the costs reported for the years 2005-06 to 2008-09
- Unmetered Electricity—the EDNs' forecasts were accepted with an adjustment to the calculations of the DPCR5 loss targets
- Specific Urban Costs—cost baselines were allowed for only one of the EDNs and was calculated as the minimum of the EDN's forecasts and the average of the costs reported for the years 2005-06 to 2009-10
- Property Operating Costs—benchmarks were provided by consultants (the Ofgem did not report how these costs were calculated)
- IT and Telecoms—IT consultants provided percentage adjustments to the EDNs' forecasts

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<sup>55</sup> Ibid, pp. 97-98.

<sup>56</sup> Refer to the detailed description of the 'ongoing efficiency factors' section 2.3.4.

<sup>57</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix*, 7 December 2009, pp. 98-101.

- Atypical costs—no cost baseline was allowed, except for those costs that were included in the benchmarking regression analysis.

#### *Alternative techniques considered*<sup>58</sup>

The Ofgem considered alternative benchmarking methods to determine the comparative efficiency scores for the EDNs.

The Ofgem undertook a Data Envelopment Analysis (DEA) based on the same model as the core Top Down model estimated by OLS. The DEA method used cost data from 2008-09 and assumed a Variable Returns to Scale (VRS) functional form. The Ofgem compared the rankings of EDNs resulting from the DEA and the OLS methods. This comparison indicated small differences in the rankings for most EDNs.

The Ofgem did not adjust the comparative efficiency scores from the OLS method as they considered that DEA had the following limitations:

- The DEA frontier could be sensitive to a small number of observations
- Some EDNs will always lie on the DEA frontier
- DEA does not have statistical tests that can help select the general functional form or the cost drivers
- DEA assumes no measurement error or noise.

The Ofgem also considered Stochastic Frontier Analysis (SFA); however, the academic advisors' initial analysis indicated that the method might be inappropriate due to data limitations.

### 2.3.3 Benchmarking capex

#### *Connections*

The Ofgem considers connections capex falls into two high-level categories: sole-use connections and shared-use connections. Only net shared-use connections are included in the price control revenue allowance.<sup>59</sup> Sole-use connections directly funded by customers are treated as excluded (unregulated) services by the Ofgem (EDNs are allowed to earn a margin, which is unregulated if the connection passes a contestability test).<sup>60</sup>

Shared-use connections expenditure is split into volumes and unit costs. Unit costs are benchmarked. Shared-use connections are categorised as:<sup>61</sup>

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<sup>58</sup> Ibid, pp. 93-96.

<sup>59</sup> Net shared-use connection is shared-use connection net of customer contributions.

<sup>60</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment – Ref. 146/09*, 7 December 2009, p. 92.

<sup>61</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix – Ref. 146a/09*, 7 December 2009, p. 1.

- high volume low cost (HVLC)
- low volume high cost (LVHC).

HVLC connections are further categorised into:<sup>62</sup>

- small-scale low-voltage domestic and one-off commercial connections ('small scale')
- all other low-voltage connections with only low-voltage work ('all other')
- low-voltage end connections involving high-voltage work ('LV with HV').

Separate average gross unit costs<sup>63</sup> are calculated for each HVLC category.<sup>64</sup> The average gross unit cost is calculated excluding indirect costs, traffic management costs and EDN margins.<sup>65</sup>

The industry median value is used as the benchmark for 'small scale' and 'all other',<sup>66</sup> while the upper quartile is used as the benchmark for 'LV with HV'.<sup>67</sup> The median value was chosen as the benchmark for LV end connections that do not involve HV work because these connections are relatively homogeneous within their respective category. The upper quartile value was chosen as the benchmark for LV with HV connections because these connections are usually more heterogeneous than connections involving solely LV work. The lower of the EDN forecast unit cost and the benchmark unit cost is taken as the efficient gross unit cost.

Each EDN's forecast volume of energised Metering Point Administration Numbers (MPAN) connections in each category is multiplied by the efficient gross unit costs for that EDN. This results in a gross expenditure for each category of connection.<sup>68</sup>

The gross expenditure is then multiplied by the Ofgem's final view of the proportion of expenditure recovered through distribution use of system charges (DUoS) rather than upfront connection charges (the net to gross expenditure ratio). This establishes the net expenditure for each EDN for each category of connection.<sup>69</sup>

The net-to-gross ratio was set as the lower of the EDN's own net-to-gross ratio and the industry upper quartile.<sup>70</sup>

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<sup>62</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals - Allowed Revenue - Cost Assessment – Ref. 146/09*, 7 December 2009, p. 92.

<sup>63</sup> Gross connections capex (i.e., before netting off customer contributions) divided by number of connections.

<sup>64</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals - Allowed Revenue - Cost Assessment Appendix – Ref. 146a/09*, 7 December 2009, p. 1.

<sup>65</sup> Ibid, p. 3.

<sup>66</sup> Ibid, pp. 3-4.

<sup>67</sup> Ibid, p. 4.

<sup>68</sup> Ibid, p. 2.

<sup>69</sup> Ibid.

<sup>70</sup> Ibid, p. 6.

The Ofgem also committed to making a ‘true-up’ adjustment to future revenues in the next regulatory period (DPCR6) to reflect the difference between the actual number of connections made and the number assumed as part of the *ex ante* allowance. This true-up will take into account the workings of the Regulatory Asset Value (RAV) rolling incentive so that expenditure is not double counted.<sup>71</sup> The Ofgem also committed to apply a true-up for the actual proportion of gross shared connection costs that are funded upfront through connection charges so that EDNs do not make a significant windfall gain or loss from such movements. This true-up will be symmetrical and will apply to under-recoveries and over-recoveries relative to the assumed proportion of costs to be funded by connection charges.<sup>72</sup>

LVHC connections capex allowance is set based on historical trends analysis and selected detailed project analysis.

### *Reinforcements*

The Ofgem modelling considered separately:

- extra high voltage (EHV) and 132kV asset reinforcements
- high voltage and low voltage asset reinforcements.

### EHV and 132kV reinforcements<sup>73</sup>

The Ofgem looked at the efficient volume of reinforcement expenditure and the efficient cost of this expenditure. The table below outlines the Ofgem’s assessment and benchmarking approach in detail.

At a general level, the Ofgem’s approach is to determine EHV & 132kV reinforcement expenditure as the product of:<sup>74</sup>

- amount of capacity added in response to growth in maximum demand
- cost of the added capacity.

The Ofgem then benchmarked both:<sup>75</sup>

- the size of the capex response to demand growth (the ratio of added capacity to maximum demand growth)
- the average unit cost of adding capacity.

The revenue allowance then accounts for EDN-specific circumstances through:<sup>76</sup>

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<sup>71</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals - Allowed Revenue - Cost Assessment* – Ref. 146/09, 7 December 2009, pp. 92–93.

<sup>72</sup> Ibid.

<sup>73</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals - Allowed Revenue - Cost Assessment Appendix* – Ref. 146a/09, 7 December 2009, pp. 11-12.

<sup>74</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper* – Ref. 47/09, 8 May 2009, pp. 67-69.

<sup>75</sup> Ibid.

- different rates of growth in maximum demand
- the average unit cost of adding capacity being weighted by the modern equivalent asset value of the EHV & 132kV assets of the EDNs.

### The Ofgem's approach to setting reinforcement allowance<sup>77</sup>

Component	Formula
Amount of EHV and 132kV capacity added over the regulatory control period	A
Maximum demand growth on EHV and 132kV schemes listed for reinforcement	B
Ratio of added capacity to maximum demand growth	$C = A / B$
Industry mean ratio of added capacity to maximum demand growth	C#
Adopted ratio of added capacity to maximum demand growth	$C^{\wedge} = \min ( C , C\# )$
Adopted volume of reinforcements	$D = C^{\wedge} * B$
Total expenditure on additional EHV and 132kV capacity	E
Ratio of EHV and 132kV expenditure to added capacity (short-run average cost)	$F = E / A$
Modern equivalent asset value of EHV and 132kV assets	G
Total capacity of EHV and 132kV schemes	H
Ratio of EHV and 132kV asset value to total capacity (long-run average cost)	$I = G / H$
Ratio of short-run AC to long-run AC	$J = F / I$
Industry mean ratio of short-run AC to long-run AC	J#
Adopted ratio of short-run AC to long-run AC	$J^{\wedge} = \min ( J , J\# )$
Adopted reinforcements expenditure	$K = D * J^{\wedge}$

Maximum demand growth was defined as the gross increase in substations where reinforcement was forecast. The Ofgem only took into account growth driving expenditure and the model was therefore not affected by negative growth on other areas of the network.<sup>78</sup>

<sup>76</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper – Appendices – Ref. 47a/09*, 8 May 2009, pp. 28-37.

<sup>77</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper – Ref. 47/09*, 8 May 2009, pp. 68-69.

<sup>78</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper – Appendices – Ref. 47a/09*, 8 May 2009, p. 30.

The benchmark ratio of added capacity to maximum demand growth may be adjusted following consideration of EDN-specific issues, such as:<sup>79</sup>

- capacity being added in large chunks due to standard equipment sizes
- the five-year growth window not capturing historical growth which also drives the need for investment
- the marginal cost of capacity being very low, making it economic to add a relatively large amount of capacity once the decision to reinforce is made.

For the cost of capacity ratio, some reinforcement expenditure may extend outside the regulatory control period. Where this occurs, the capacity figure used to derive the ratio is adjusted *pro rata* based on expenditure proportions in the two regulatory control periods.<sup>80</sup>

### HV and LV reinforcements

The Ofgem considered there to be a high level correlation between economic growth and LV and HV general reinforcement. The Ofgem then considered that economic growth in DPCR5 would resemble that experienced in DPCR4, and hence the Ofgem provided an allowance for HV and LV reinforcements based on historical trends (of both total expenditure and connection volumes, and therefore implied unit costs).<sup>81</sup>

Benchmarking of HV and LV reinforcements was undertaken but only as a sense-check. Benchmarking was undertaken as follows:<sup>82</sup>

- a scaling factor was calculated based on each EDN's ratio of LV and HV MEAV to the industry median LV and HV MEAV
- the scaling factor was then multiplied by the industry median expenditure to produce a benchmark expenditure level for each EDN.

### *Replacements*

The Ofgem considered there to be two types of assets: those that are allowed to fail in service, and those that are replaced before failure. For the latter, the Ofgem considered that the EDN should assess replacement needs based on information on the asset's condition. The Ofgem used benchmarking to inform its analysis of both the expected asset lives and unit-costs of asset replacement.<sup>83</sup>

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<sup>79</sup> *Ibid*, pp. 28-37.

<sup>80</sup> *Ibid*, p. 31.

<sup>81</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper – Ref. 47/09*, 8 May 2009, p. 37.

<sup>82</sup> Ofgem, *Electricity Distribution Price Control Review, Initial Proposals – Allowed Revenue and Cost Assessment – Appendix – Ref. 94a/09*, 3 August 2009, p. 18.

<sup>83</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper – Appendices – Ref. 47a/09*, 8 May 2009, p. 39.

### Asset lives

The Ofgem's asset replacement model required information on mean asset lives and the standard deviation around this mean for each asset category.<sup>84</sup> The model applied a distribution curve, representing the probability of an asset requiring replacement, to each EDN's asset age profiles to derive forecast asset replacement volumes.<sup>85</sup>

In DPCR4, the Ofgem's age-based modelling was largely based on benchmarking of the mean asset lives and standard deviations reported by the EDNs. In DPCR5, the Ofgem calculated asset lives based on historical and forecast volumes of replacements by:<sup>86</sup>

- calculating the lives that, when entered into the model using the asset age profile at 2004-05, gave output volumes equal to those actually replaced by the EDNs in DPCR4 (2005-06 to 2009-10)
- calculating the lives that, when entered into the model using the asset age profile at 2007-08, gave output volumes equal to those forecast by the EDNs to be replaced in DPCR5 (2010-11 to 2014-15)
- using the poisson distribution to represent asset lives – where the standard deviation is defined as the square root of the mean life.

The figure below shows the approach adopted by the Ofgem to determine asset replacement volumes. The Ofgem assumed that, across the industry, asset lives can either be maintained at the levels achieved in DPCR4 or longer lives can be achieved in DPCR5 through improved asset management. The Ofgem therefore took the higher of the lives achieved across the industry in DPCR4 and those forecast for DPCR5. This new set of lives was then inputted into a model along with each EDN's individual asset-age profile to model EDN-specific volume. An EDN's forecast was accepted if it was less than or equal to the modelled volume for that EDN. If not, the modelled volume was adopted.<sup>87</sup>

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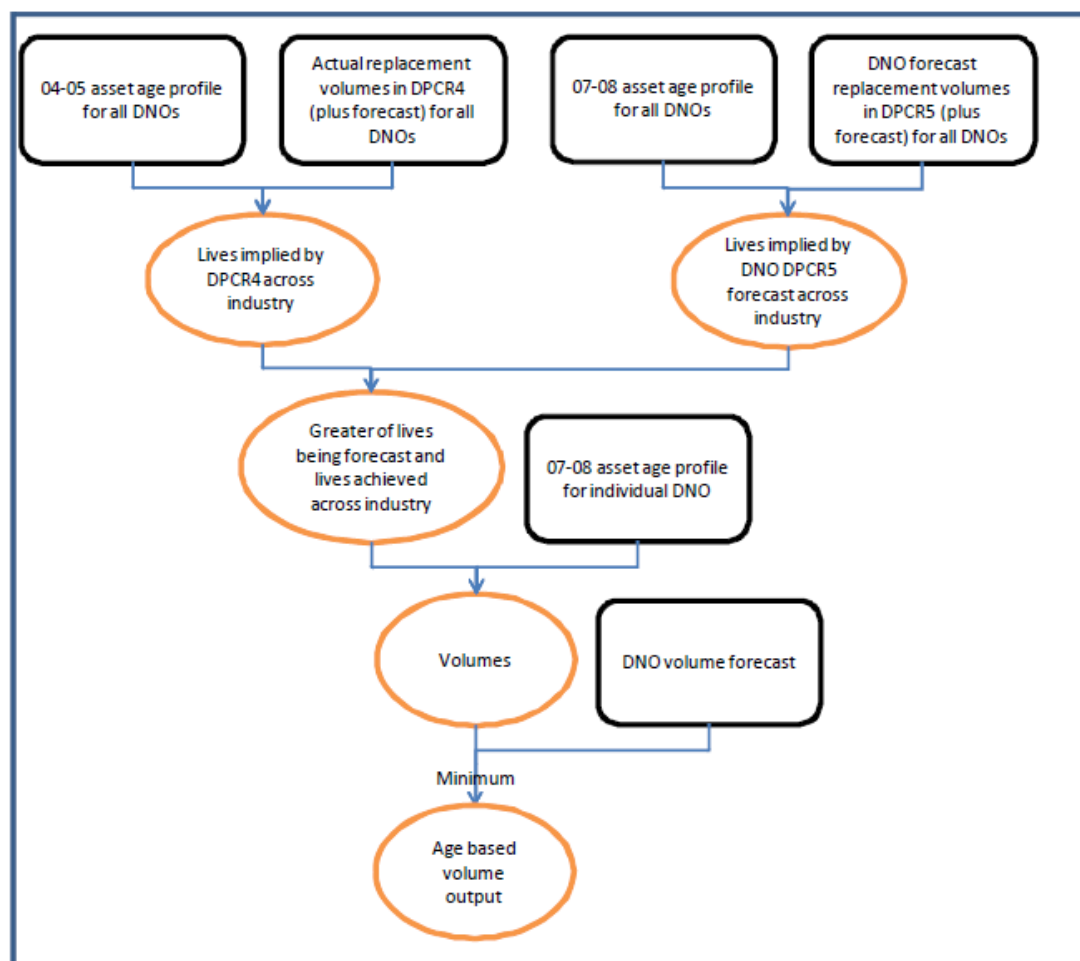
<sup>84</sup> The replacement expenditure (repex) model applied by the AER in its 2011-2015 Victorian electricity distribution determination is substantially similar to the Ofgem's asset replacement model.

<sup>85</sup> Ofgem, *Electricity Distribution Price Control Review – Methodology and Initial Results Paper – Ref. 47/09*, 8 May 2009, p. 70.

<sup>86</sup> Ibid, pp. 70-72.

<sup>87</sup> Ibid, pp. 70-72.

## The Ofgem's benchmarking of asset lives in replacement modelling<sup>88</sup>



### Asset replacement costs

The Ofgem noted that factors influencing replacement unit costs might differ across EDNs, making benchmarking complicated. Those factors included:<sup>89</sup>

- the scope of work including size and rating of equipment
- assumptions about site-specific costs (civil requirements, ground type, indoor/outdoor)
- assumptions in allocating project costs to individual component assets, including civil costs.

The Ofgem took the industry median values, corrected for factors such as differences in work scope, as the starting point for benchmarked unit-costs. The Ofgem used this approach to ensure that the median values reflected the scope of work being proposed by the majority of EDNs. The median value was based on the unit-cost schedules

<sup>88</sup> Ibid, p. 42.

<sup>89</sup> Ofgem, *Electricity Distribution Price Control Review – Initial Proposals – Allowed Revenue – Cost Assessment – Ref. 94/09*, 3 August 2009, pp. 46-47.

provided in the forecast business plan questionnaires (FBPQs), corrected for any differences identified through the calculation of the average/implied unit-cost (i.e., proposed capex spend divided by proposed capex volume).<sup>90</sup>

The industry-wide median unit-cost was then applied to all EDNs, except where specific issues resulting in departure from the benchmark were identified by individual EDNs and accepted by the Ofgem.<sup>91</sup>

#### Replacements outside the general replacement model

Substation asset repex was identified by the EDNs in their forecasts separately from other replacement expenditure that was subject to the replacement model. This covers general expenditure on substation assets and mostly consisted of spending on substation civils such as buildings and other infrastructure.<sup>92</sup>

The Ofgem assessed these costs by developing a benchmark that takes account of the industry-average cost per substation at each voltage level. Due to the high-level nature of the analysis and the wide range of different costs included by each EDN, there are some uncertainties with the benchmarked expenditure. In setting the baseline, the Ofgem therefore applied equal weightings to the historical level of expenditure, forecast expenditure and the results of the high-level benchmarking.<sup>93</sup>

Overhead pole lines were excluded from the replacement modelling and volumes were assessed via a detailed bottom-up build-up assessment. This was due to EDNs' concerns with the variety of activities included in the scope of works for LV, HV and EHV overhead pole lines (conductor and supports), and because the scope of work is different across EDNs, making a single volume comparison difficult. A benchmark unit replacement cost was determined for overhead pole lines.<sup>94</sup>

#### *Legal and safety*

The legal and safety building block included costs associated with the Electricity Safety Quality and Continuity of Supply Regulations (ESQCR), site security, asbestos clearance, safety equipment, and other areas specified by the EDNs.<sup>95</sup>

The Ofgem examined ESQCR safety clearance costs through a combination of assessment approaches including unit-cost comparisons and reviews of EDNs' contracting strategy, tendering process, contract incentives and contract structure.

ESQCR unit-costs were benchmarked relative to the mean.<sup>96</sup> Required volume of works was subject to a detailed survey and agreement with the UK Health and Safety Executive.

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<sup>90</sup> Ibid, p. 46.

<sup>91</sup> Ibid, pp. 46-47.

<sup>92</sup> Ibid, p. 48.

<sup>93</sup> Ibid.

<sup>94</sup> Ibid, p. 47.

<sup>95</sup> Ibid, pp. 49-51.

In response to the Ofgem's *Initial Proposals*,<sup>97</sup> a number of EDNs raised concerns about the impact on unit-costs of rebuilding and undergrounding a large number of short lengths (e.g. single spans) compared to a lower number of longer lengths (e.g. ten spans).

To address these concerns for Final Proposals, the Ofgem collected data at a greater level of detail (through a supplementary question to EDNs) to account for the type of work being undertaken. The EDNs were required to disaggregate work by replacement of a single service (LV), one/two/three spans of overhead line, and four or more spans of overhead line for:<sup>98</sup>

- undergrounding of LV and HV overhead lines with vertical clearance issues
- rebuilding of LV and HV overhead lines with vertical clearance issues
- undergrounding of LV and HV overhead lines with horizontal clearance issues
- reconductoring of LV and HV overhead lines with horizontal clearance issues.

The Ofgem's analysis of the information did not reveal a clear distinction between unit-costs of replacing a span of overhead line when the total length of replacement is one, two or three spans. The Ofgem therefore combined these categories in its benchmarking. For those EDNs replacing four or more spans of LV overhead line with covered conductors, the Ofgem's analysis showed that the unit-costs were broadly equivalent to the benchmarked unit-cost derived for asset replacement assuming 20 spans per km.<sup>99</sup>

The Ofgem initially considered setting the 'baseline' level of site security expenditure by developing a benchmarking based on the number of substations with EHV or 132kV primary voltage.<sup>100</sup> However, it considered that regionally dependent levels of criminal activity mean that the benchmarking carried out was inappropriate, and that the EDNs are best placed to assess trends in the level of such activity in their areas and their forecasts are more robust than simple benchmarking.

Other areas of legal and safety costs were subject to a 'high level review' of the EDN forecasts.<sup>101</sup>

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<sup>96</sup> Lower quartile was the benchmark in DPCR4. The Ofgem changed to the mean value after considering that increased amount of information available since DPCR4 had increased confidence in the robustness of the forecasts.

<sup>97</sup> The Ofgem's 'initial proposals' report is similar to an ACCC/AER draft decision report. Following industry consultation on the 'initial proposals', the Ofgem releases a 'final proposals' report which is similar to an ACCC/AER final decision report.

<sup>98</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix – Ref. 146a/09*, 7 December 2009, p. 30.

<sup>99</sup> Ibid.

<sup>100</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix – Ref. 146a/09*, 7 December 2009, p. 31.

<sup>101</sup> Ibid.

## *Other investment*

### Operational IT and telecoms

Expert review by PB Power focusing on three areas of investment:<sup>102</sup>

- substation RTUs, marshalling kiosks and receivers
- communications for switching and monitoring
- control centre hardware and software.

In each of these areas PB Power assessed both the scope of work proposed and the unit costs implied and provided an indication of EDNs that are outliers with respect to the industry. The Ofgem used this information to apply specific reductions to EDN proposals where indicated by PB Power, and a reduction of 25 per cent on areas where insufficient detail and/or justification was provided in response to further questions.<sup>103</sup>

### Diversions

This expenditure includes costs of:<sup>104</sup>

- conversion of wayleaves to easements, injurious affection and related costs
- diversions due to wayleave terminations
- diversions for highways funded as detailed in the National Roads and Street Works Act.

The Ofgem set allowances based on historical trends, and allowed deviations from trends only where justified by the EDNs.<sup>105</sup>

### Fault levels

This expenditure refers to spending on assets where the equipment fault rating is not adequate to meet system requirements. Because the EDNs did not forecast fault levels as part of their business planning, the Ofgem did not allow forecasts of fault levels to contribute to allowances. The Ofgem only provided allowances for fault-level issues that are currently present in the EDN networks. The Ofgem appeared to assess fault-level expenditure on a case-by-case assessment of current projects, and it is not clear if any benchmarking was used.<sup>106</sup>

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<sup>102</sup> Ibid, p. 28.

<sup>103</sup> Ibid, p. 28.

<sup>104</sup> Ofgem, *Electricity Distribution Price Control Review Final Proposals – Allowed Revenue – Cost Assessment Appendix – Ref. 146a/09*, 7 December 2009, p. 9.

<sup>105</sup> Ibid, pp. 9-10.

<sup>106</sup> Ibid, p. 14.

### 2.3.4 Ongoing efficiency factors

#### *Summary*

The ongoing efficiency factor is used to account for sector-wide productivity improvements.

The Ofgem determined an ongoing efficiency factor for each of operational costs and network investment costs which were then used to roll forward the 'base year efficient costs' into the regulatory period.

The Ofgem employed the method used by consultants Reckon LLP for the Gas Distribution Price Control Review. This approach involved examining the productivity of comparable industries in terms of labour, energy and material costs and other immediate inputs comprising operating expenditure. The Ofgem calculated a productivity trend and unit-cost trend for each of labour and labour plus intermediate inputs.

#### *Ongoing efficiency for operating costs<sup>107</sup>*

#### Data

The dataset used for calculating the productivity and unit-cost measures from other UK sectors is sourced from the EU KLEMS dataset published in March 2008. The EU KLEMS dataset has been produced by a European Commission-funded consortium that includes the National Institute of Economic and Social Research (NIESR). For the UK data, the EU KLEMS dataset covered the period 1970 to 2005.

The Ofgem chose to use the full period of available data and to review 36 sectors of the UK economy.

#### Technique

A TFP index-number-based approach was taken.

#### Outputs

The Ofgem chose to review two measures of industry output – Gross Output and Value Added.

#### Inputs

The inputs for the Gross Output measure were labour and intermediate inputs,

The input for the Value Added measure was labour.

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<sup>107</sup> Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper Appendix*, May 2009, pp. 51-55.

## Model

The Ofgem calculated the productivity trends assuming constant returns to capital by setting the growth rate of capital equal to the growth rate of the relevant output measure, Gross Output (GO) or Value added (VA), as shown below. This was done because the Ofgem considered that EDNs may not be able to undertake capital substitution which may have occurred in the comparator sectors.

These formulas are used to calculate the productivity trends.

<i>Growth in labour productivity (VA) at constant capital</i>	=	$\frac{\text{Growth in TFP (VA)}}{\text{Share of labour in VA}}$
<i>Growth in labour and intermediate input productivity (GO) at constant capital</i>	=	$\frac{\text{Growth in TFP (GO)}}{\text{Share of labour and intermediate inputs in GO}}$

The unit-cost productivity trends are then calculated by combining the productivity trend with a relevant input price trend.

<i>Growth in unit labour costs (VA) at constant capital (relative to the RPI)</i>	=	$\begin{aligned} &\text{Growth in wages} \\ &- \text{Growth in RPI} \\ &- \text{Growth in labour productivity (VA) at constant capital} \end{aligned}$
<i>Growth in unit labour and intermediate input costs (GO) at constant capital (relative to the RPI)</i>	=	$\begin{aligned} &\text{Growth in wages and price of intermediate inputs} \\ &- \text{Growth in RPI} \\ &- \text{Growth in labour and intermediate input productivity (GO) at constant capital} \end{aligned}$

## Application to regulatory decision

The Ofgem used this analysis along with analysis undertaken by First Economics (commissioned by EDNs) to determine an ongoing efficiency factor of one per cent. The chosen value sits within the range of values found by First Economics and the Ofgem for comparable sectors.

The ongoing efficiency factor was used by the Ofgem to roll forward the base year efficient operating costs into the five year regulatory period.

### *Ongoing efficiency of network investment costs<sup>108</sup>*

The Ofgem appears to have based its assessment of the ongoing efficiency costs for network investment costs on the results of a Frontier Economics report prepared for

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<sup>108</sup> Ofgem, *Electricity Distribution Price Control Review, Final Proposals, Allowed Revenue Costs Assessment*, 7 December 2009, p. 81.

EDNs. This report indicated an annual efficiency improvement of one per cent for the regulatory period.

## **2.4 Gas distribution**

### **2.4.1 Overview of approach to cost assessment**

The Ofgem's most recent price control review for gas distribution networks (GDNs) is for the five-year period from 1 April 2008 to 31 March 2013. This is the fourth gas price control review (GPCR4).

Similar to the process for the electricity distribution price control review, the Ofgem assessed the efficient operating costs and capital costs in the base year (2007-08) using benchmarking methods where possible. Assumptions regarding ongoing efficiency improvements and real price effects were used to roll forward the efficient base-year costs into the regulatory period.

#### *Determining efficient opex<sup>109</sup>*

The Ofgem assessed the efficient level of operating expenditure (opex) required by each GDN using a combination of 'bottom-up' benchmarking of specific activities and 'top-down' benchmarking of total opex. The price control review for 2008-2013 is the first time, following the sale of four of the GDNs by National Grid Gas in 2005, that the Ofgem had been able to make use of meaningful comparisons between GDNs.

The Ofgem did not consider it appropriate to benchmark total operating costs using regression methods as there are only eight GDNs (or four if ownership groups are used). In addition, given the timing of GDN sales, only two years of comparable data were available from which to determine any trend.

Given the limited data observations available, the Ofgem considered it most appropriate to employ benchmarking at the individual activity level as it allowed the use of more data points and more in-depth consideration of the cost drivers associated with each activity. However, the Ofgem noted that a potential weakness with benchmarking at the upper quartile level of costs for each individual activity was that it created a benchmark that was not currently achieved by any GDN. Therefore, the Ofgem applied an 'up-lift' to the estimated costs that were derived from the bottom-up benchmarking. The up-lift was based on the average difference between the bottom-up benchmarks and the top-down total opex benchmark (both the bottom-up and top down benchmarks were based on the upper quartile level of performance).

The Ofgem also carried out more specific analysis for business activities where benchmarking was not practicable or did not provide sufficiently robust results.

The Ofgem commissioned three consultants to undertake benchmarking work:

- Europe Economics carried out a top-down benchmarking exercise of total controllable opex and a Total Factor Productivity (TFP) analysis to estimate the scope for efficiency savings in the gas distribution sub-sector

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<sup>109</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals*, December 2007, pp. 8-11.

- PB Power reviewed direct operating activities and capex and replacement expenditure (repex)
- LECG reviewed indirect opex (support service) activities.

The Ofgem then appointed consultants Reckon LLP to carry out additional work on the scope for ongoing operating cost efficiencies, including updating the earlier Europe Economics work based on new data and reviewing the work that First Economics had carried out on behalf of the GDNs.

Information on the technique of each of these consultants and the Ofgem's application of each consultants benchmarking work is discussed below.

#### *Determining efficient capex*<sup>110</sup>

The Ofgem commissioned PB Power to review capex and repex for each GDN.

PB Power's work included:

- a high-level assessment of policies, procedures and forecasting processes associated with capex and repex
- a review of GDNs' forecast costs to understand whether these were based on appropriate assumptions, including the justification for workload forecasts and assumptions on real price increases and productivity
- an assessment of GDNs' efficiency for particular capex and repex activities by benchmarking costs across GDNs
- bottom-up analysis to consider the appropriate costs for particular activities based on information submitted by the GDNs and PB's own engineering experience.

The Ofgem based its decisions on the results of PB Power's studies but also made adjustments in response to submissions received from industry. More information on PB Power's approach is provided in section 2.4.5.

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<sup>110</sup> Ibid, pp. 27-28.

## 2.4.2 Europe Economics: Opex benchmarking and sector-wide productivity growth

Europe Economics undertook two types of benchmarking analysis:<sup>111</sup>

- an analysis of the relative efficiency of GDNs in terms of total controllable costs (opex benchmarking)
- an analysis of the sector-wide long-term productivity trend by assessing the productivity of the gas distribution sub-sector relative to other similar sectors. This included developing a partial productivity estimate for opex.

Using the relative efficiency analysis, the sector-wide opex partial productivity trend was decomposed into a frontier shift and a catch-up component. Each of the analyses is described in detail below.

### *Opex relative efficiency benchmarking*

#### Data<sup>112</sup>

The data were provided to Europe Economics by the Ofgem. The Ofgem sourced the information from the GDNs' Business Plan Questionnaires (BPQs). The data covered the eight GDN's (four ownership groups). Given significant changes in industry structure, only the 2005-06 historical data and 2006-07 estimated data were used in the analysis. The analysis was updated following updates to the 2006-07 data. The financial data were presented in 2005-06 prices.

Employment benchmarking analysis was not pursued due to inconsistency in the data across GDNs.

#### Technique<sup>113</sup>

The two main regression models were estimated using pooled Ordinary Least Squares (OLS) then the Corrected Ordinary Least Squares (COLS) procedure was applied. The two models are referred to as COLS1 and COLS2.

#### Level of disaggregation

Europe Economics was asked by the Ofgem to undertake a top-down analysis of total opex only. Therefore no further disaggregation of costs was undertaken.

#### Inputs<sup>114</sup>

The dependent variable in the regression models was total controllable operating costs, considered at both network and group ownership levels.

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<sup>111</sup>Europe Economics, *Top Down Benchmarking of UK Gas Distribution Network Operators*, A report by Europe Economics to Ofgem, April 2007, p. i.

<sup>112</sup> Ibid, p. 2.

<sup>113</sup> Ibid, p. 22.

<sup>114</sup> Ibid, p. 2.

## Outputs<sup>115</sup>

The choice of cost drivers to be included as explanatory variables in the regression models was based on a review of the academic literature that discussed work on econometric estimates of gas distribution network cost functions when constrained by data availability.

Europe Economics also undertook some exploratory regression analysis to explore the relationship between the total controllable opex (dependent variable) and the main cost drivers (explanatory variables).

The set of cost drivers included as explanatory variables were:

- the length of network (LEN)
- volume of gas distributed (VOL)
- total number of customers (CUST).

Other explanatory variables considered were:

- customer density (CD), i.e., total customers per network length
- number of customers per kilometre of network
- proportion of non-domestic customers to total customers (PNDC), which is a proxy for the importance of large users in the customer base.

## Normalisation adjustments

The Ofgem normalised the data on total controllable opex to ensure consistency, prior to providing the data to Europe Economics.

## Model specification<sup>116</sup>

The basic model estimated was of the form:

$$\ln(TC_{it}) = \alpha + \beta X_{it} + u_{it}$$

where  $TC$  is the total controllable opex costs for GDN  $i$  at time  $t$ ,  $X_{it}$  is a vector of cost drivers,  $u_{it}$  is the error term,  $\alpha$  is the constant,  $\beta$  is a vector of parameters to be estimated, and  $\ln$  is the natural logarithm.

All explanatory variables were entered in logarithmic form except the proportion of non-domestic customers (PNDC).

In the two main regression models, COLS1 and COLS2, the general-to-specific method<sup>117</sup> was applied for determining the significant cost drivers.<sup>118</sup> This resulted in the models shown in the table below.

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<sup>115</sup> Ibid, pp. 3, 22.

<sup>116</sup> Ibid, pp. 61-70.

## Two main COLS models estimated by Europe Economics

Model	Dependent variable	Explanatory variable/s
COLS1	Total controllable costs	VOL
COLS2	Total controllable costs	CUST

### Statistical testing of model

The following statistical tests were undertaken on the two models estimated and after each step of the general-to-specific method for determining significant cost drivers.<sup>119</sup>

- DFFITS, Welsh and Cook statistics for identifying influential observations and calculating Student's T-statistic
- Reset tests – for functional form misspecification
- The Brush Pagan and Cameron and Trivedi tests for heteroscedasticity
- Jarque-Bera test for normality of error terms.

Europe Economics also tested the model specification by estimating two additional COLS models. Both of these additional models included one output variable, which was a composite scale variable. The composite scale variable weighted together the cost drivers: VOL, CUST and LEN. The two additional models varied in the weights used to construct the composite scale variable.<sup>120</sup>

- COLS 3: 50 per cent weight to LEN and 25 per cent to each of CUST and VOL
- COLS 4: 86 per cent weight to CUST and 14 per cent to VOL. This weighting was based on econometric evidence from a US study of the gas distribution sector.<sup>121</sup>

The rationale provided for the consideration of including composite scale variables was the potential for multicollinearity between the explanatory variables CUST, LEN and VOL.

The four estimated models were compared using a rank correlation analysis, where each GDN was ranked according to the estimated efficiency derived from the model. This was also conducted at ownership group level.<sup>122</sup>

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<sup>117</sup> The general to specific method is when all the independent variables are included in the initial model estimation. Then an iterative process of removing one statistically insignificant independent variables and re-estimating the model is undertaken until only the independent variables to be included in the final model remain.

<sup>118</sup> Ibid, pp. 23-24.

<sup>119</sup> Ibid, pp. 61-70.

<sup>120</sup> Ibid, p. 67.

<sup>121</sup> Sourced by Europe Economic from Pacific Economics Group, *Envestra Gas Distribution Operations and Maintenance Cost Performance: Results from International Benchmarking*, Madison, Wisconsin, 2001.

As a further robustness test, a model including dummy variables for the ownership groups of the GDNs were estimated. This model identified the percentage difference in controllable opex for different ownership groups relative to the control ownership group.<sup>123</sup>

#### Analysis of model outputs<sup>124</sup>

The industry frontier was defined as the upper quartile. This definition was considered a pragmatic approach to dealing with the potential for measurement error and noise and the possibility that the COLS procedure overestimates the extent of inefficiency.

The COLS benchmarking method was preferred by the consultants due to the small sample size, the various drawbacks of the other models and the ability to statistically test the significance and robustness of the regression model results.

COLS 1 and COLS2 were the preferred model specifications and it was recommended that an equal weighting be applied by the Ofgem to the results of these two models.

#### Alternative methods considered by Europe Economics<sup>125</sup>

Europe Economics undertook the opex relative efficiency benchmarking using a number of different benchmarking methods, including COLS, unit-cost ratios, Data Envelopment Analysis (DEA) and multi-factor productivity indexes. Europe Economic considered that while no method can be considered as clearly superior to another, some methods provide more reliable estimates than others in certain circumstances, and confidence in the results is stronger when alternative methods provide similar results.

#### Unit-cost ratios<sup>126</sup>

Unit-cost ratios were used by Europe Economics only as preliminary analysis and results were compared with those from regression and DEA techniques. Partial ratios were calculated as total controllable costs over three different indicators: network length, volumes of gas distributed and total number of customers. These unit-costs were compared across GDNs. The analysis was undertaken at both the network level (eight GDNs) and the ownership group level (four groups).

#### DEA<sup>127</sup>

The DEA method was used based on an input-orientated variable returns-to-scale (VRS) model. VRS was chosen as it was considered that it is difficult for GDNs to change the scale of operation in the short run and DEA frontiers calculated with VRS would not penalise GDNs that are not operating at the efficient scale.

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<sup>122</sup> Europe Economics, *Top Down Benchmarking of UK Gas Distribution Network Operators*, A report by Europe Economics to Ofgem, April 2007, p. 25.

<sup>123</sup> Ibid, p. 69.

<sup>124</sup> Ibid, pp. 36-37.

<sup>125</sup> Refer to Ibid, pp. 9-15 for a general discussion on the relative merits of different techniques.

<sup>126</sup> Ibid, p. 15.

<sup>127</sup> Ibid, pp. 26-32.

The input variable was total controllable costs (opex). Three potential output variables were considered: volumes of gas delivered (VOL), total number of customers (CUST) and network length (LEN). Two additional environmental variables were considered: customer density (CD) and proportion of residential customers to total customers.

As shown in the table below, four DEA models were estimated, the input and output combinations were chosen to align with the COLS models.

#### DEA models estimated by Europe Economics

Model	Input	Output/s	Corresponding model
DEA1	Total controllable costs	VOL	COLS1
DEA2	Total controllable costs	CUST	COLS2
DEA3	Total controllable costs	CSV: $0.5LEN+0.25CUST+0.25VOL$	COLS3
DEA4	Total controllable costs	CSV: $0.86CUST+0.14VOL$	COLS4

A rank correlation analysis was undertaken comparing the efficiency of each GDN under the four different DEA models, and the efficiency of the ownership groups across the four different DEA models.

The small sample size was noted as a particular concern with using the DEA method.

#### MTFP Indices<sup>128</sup>

Multilateral TFP indices are a refinement of unit-cost ratios and were developed by Caves, Christensen and Diewert (1982a). The Europe Economics model was adapted for opex productivity only and therefore excludes capital costs. Total controllable costs are the input, and three same three output variables are considered: VOL, CUST and LEN.

The output variables are aggregated into an output index using weights. Given the limited data, the weights are based on cost elasticity shares derived from previous studies (rather than econometric analysis given the small sample size). Three models were developed as shown in the table below

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<sup>128</sup> Ibid, pp. 32-36.

### MTFP models estimated by Europe Economics

Model	Input	Output/s	Corresponding model
MP1	Total controllable costs	0.86 CUST, 0.14 VOL	COLS4
MP2	Total controllable costs	0.5LEN+0.25CUST+0.25VOL	COLS3
MP3	Total controllable costs	CUST/LEN and VOL/LEN	N/A

A rank correlation analysis between the results from each of the three MPI models for each GDN and each GDN ownership group was undertaken.

A Spearman rank correlation analysis was then undertaken across all of the models estimated using COLS, DEA and MPI. Europe Economic's rationale for this analysis was that conclusions drawn from the analysis would be stronger if the different methods yielded relatively similar results.

#### SFA Analysis<sup>129</sup>

The SFA model was not considered by Europe Economics as it would have required a large sample size (only 16 observations were available, eight GDNs over two years).

#### Application to regulatory decision

The Ofgem used the results of the top-down total opex benchmarking to give an up-lift to the results of the bottom-up opex benchmarking. The up-lift was based on the average difference between the bottom-up benchmarks, and the top-down opex benchmarks.

#### *Nature-of-work benchmarking – sector-wide long-term productivity trend*

#### Summary<sup>130</sup>

To estimate the long-term productivity trend for the UK gas distribution sector, Europe Economics undertook 'nature-of-work' benchmarking.

The nature-of-work benchmark combines various productivity estimates of other sectors in the UK economy that undertake similar types of work to gas distribution businesses. The various productivity estimates are combined in proportions that are intended to mirror the gas distribution sub-sector.

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<sup>129</sup> Ibid, p. 11.

<sup>130</sup> Ibid, p. 38.

### Data<sup>131</sup>

The data were sourced from the National Institute of Sectoral Productivity dataset NSIEC02<sup>132</sup>. The data cover 30 sub-sectors of the UK economy between 1950 and 1999. Data on labour productivity, capital stock and total factor productivity were available. No adjustment was made to different sectors for economies of scale.

### Technique

The nature-of-work benchmark was a weighted average of productivity estimates for the comparator industries. The analysis involved:

- the breakdown of gas distribution into separable business activities
- for each business activity, assign a share of the total workload for GDNs
- identifying comparator industries that undertake each business activity
- constructing the benchmark by weighting the productivity estimates for each comparator industries in accordance with share of the workload for the respective business activity
- where there is more than one comparator sector for a business activity, each comparator sector is given equal weight.

The table below sets out the business activities identified, the share of the work based on 2005-06 gas distribution data and the comparator sector/s identified:<sup>133</sup>

### **Components of UK gas distribution sub-sector and the comparator sectors identified by Europe Economics**

Components identified	Share of workload	Comparator sector/s identified
Capital and replacement expenditure	55.9%	Construction Engineering Utilities
Work management	12.5%	Business Services Engineering Communications
Emergency & repairs	11.6%	Utilities Construction
Support services and indirect opex	13%	Business services <sup>134</sup>

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<sup>131</sup> Ibid, pp.39-40.

<sup>132</sup> The productivity dataset published by the NIESR contains sectoral data for the UK economy as well as for Germany, France, Japan and the USA.

<sup>133</sup> Ibid, pp.42-44.

<sup>134</sup> Ibid, p. 44. As business services is a category on its own and is likely to be a sub category within other sectors, adjustments are made to weightings such that five per cent of a comparator sector is set to reflect productivity improvements in financial and business services, except communications sector where this is set at 15 per cent.

Components identified	Share of workload	Comparator sector/s identified
Maintenance and other	7%	Utilities Engineering Construction

### Index construction

Using the above weights and business sectors, an index of ‘overall TFP growth’ and an index of ‘TFP growth outperformance of the economy’ were constructed. The latter was defined such that the index changed from one period to the next according to the weighted average growth between those periods in each comparator sector.<sup>135</sup>

After comparing three different time periods, the period 1973 to 1999 was chosen to balance the need for a long time-series of data to identify the underlying trend against fundamental changes in the trend.

A regression method was then used to remove the effect of transitory trends such as privatisation of networks. The privatisation index is higher near privatisation and then decays until reaching 15 years after privatisation. The estimation method used for this was pooled COLS with the inclusion of dummy variables estimated as the coefficients of the comparator industries.<sup>136</sup>

The coefficients could therefore be used to calculate an average TFP outperformance for the comparator sectors with the effect of privatisation removed. These coefficients were then combined based on the weights in the table above.

### Analysis of model results

Opex partial TFP was estimated by adjusting the TFP estimates for capital substitution, real input price movements and economies of scale.<sup>137</sup>

Opex partial productivity was then decomposed into two components: frontier shift and catch up. The frontier shift represents the scope for cost reductions that is due to the movements in the industry efficiency frontier. The catch up refers to the scope for individual GDNs to catch up with the most efficient GDN over the next five years. The decomposition into two components is done by:<sup>138</sup>

- taking a weighted average of the scope for catching up with the industry frontier for each GDN to derive an estimate of the overall catching up. That is, the reduction in opex achievable by the sector
- the difference between the overall scope for efficiency saving and the overall catching up would give the rate of reduction in opex achievable by the businesses operating on the frontier; i.e., the frontier shift

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<sup>135</sup> Ibid, p. 46.

<sup>136</sup> Ibid, p. 47.

<sup>137</sup> Ibid, pp. 49-52.

<sup>138</sup> Ibid, pp. 53-60.

- for the remaining relatively inefficient GDNs, the expected reduction in opex could then be computed by adding their individual catch up factor on top of the frontier shift.

### Sensitivity Analysis<sup>139</sup>

To test the sensitivity of the results to the model specification, Europe Economics assessed the impact of a change in the relative weights of the business activities and a change in the choice of comparator sectors.

### Application to regulatory decision

The Ofgem commissioned consultants Reckon LLP to carry out additional work on the scope for efficiency savings and to update Europe Economics' analysis. The analysis by Reckon LLP did not change the Ofgem's assumptions regarding the ongoing efficiency factor for opex.<sup>140</sup>

### 2.4.3 LECG study: Opex indirect costs benchmarking<sup>141</sup>

#### *Summary*

LECG's indirect opex benchmarking focused on the following support functions: information systems; finance, audit and regulation; insurance; property management; corporate centre and communication; human resources; legal; and procurement and logistics. The eight GDNs were benchmarked in terms of their four ownership groups.

The LECG's indirect opex benchmarking was conducted on each indirect cost category. In general, the steps taken by LECG were:

- determining the level of benchmarking
- normalising support services costs
- calculating both low and high savings benchmarks
- selecting third party benchmarks
- calculating an efficiency score and potential efficiency savings
- calculating efficient cost forecasts.

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<sup>139</sup> Ibid, p. 48.

<sup>140</sup> Ofgem, *Gas Distribution Price Control Review, Updated Proposals, Main Supplementary Appendices*, September 2007, p. 5.

<sup>141</sup> LECG, *Benchmarking National Grid Gas Distribution's Business Support Services*, Draft April 2007 and LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007.

For each support service cost benchmark, the GDN groups were compared directly as it was considered that they operate in highly comparable environments. LECG then set:

- a low savings scenario, where the benchmark is the median GDN group
- a high savings scenario, where the benchmark is the top quartile GDN group.

LECG also considered external (third-party) benchmarks. These are benchmarks from independent studies of comparable businesses in terms of business size, industry type, and geographical region. Where a third-party benchmark presented a more challenging efficiency target than the upper quartile GDN group, LECG adopted the third party benchmark as the high saving scenario.

The application by the Ofgem is described below, following the description of the LECG analysis for each indirect cost category.

#### *Data<sup>142</sup>*

The data were sourced from the 2006 Business Plan Questionnaires submitted to the Ofgem by GDNs, GDN' responses to supplementary questions, site visits and other supplementary sources. The data included current costs for the 2006-07 financial year and forecast costs. 2006-07 was taken as the base year due to significant industry restructuring during 2005-06.

For the supplementary data requests, the Ofgem asked GDNs for a breakdown of support service costs by function and by activity. This information helped to ensure the consistency of cost category definitions across all of the GDNs. It also helped the Ofgem to identify atypical and one-off costs, problems with the data, and differences in the internal processes between GDNs.

#### *Normalisation*

Many of the metrics used by LECG were based on costs expressed as a function of revenue and LECG considered it necessary to adjust the revenue data. Revenue data was initially based on sculpted regulatory asset values (RAV).<sup>143</sup> LECG was concerned that sculpted RAV may not properly reflect the scale of the business and may lead to differences between GDNs reflecting margin differences rather than efficiency differences. LECG therefore adjusted the revenue data to reflect the absolute differences in the revenue calculated using the natural RAV and the sculpted RAV in 2002-03. This difference was then added or deducted from GDN revenues in 2006-07 to estimate revenues based on the actual RAV.

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<sup>142</sup> LECG, *Benchmarking National Grid Gas Distribution's Business Support Services*, Draft April 2007, p. 18.

<sup>143</sup> During the price control review for 2008-2013, the Ofgem decided to separate gas distribution into eight regional price controls. The original RAVs of each GDN were calculated based on physical asset values (i.e., the 'natural' or actual RAV). The Ofgem considered it was appropriate to minimise any unnecessary regional variations in distribution charges by adjusting (i.e., sculpting) the RAV of each GDN (see LECG (April 2007), pp. 20-21).

LECG normalised support services costs across the GDNs as they considered that comparing absolute costs levels may not be appropriate due to, for example, differences in operational scale. LECG identified revenue, operating costs and staff numbers as the suitable indicators of operational scale. In many cases, all three metrics were considered, but in general, they found that adjusted revenue was the most reliable and consistent indicator.

### *Technique*

LECG used unit-cost analysis and ratio analysis.

### *Level of disaggregation*

The level of disaggregation was determined by the scope of the work set by the Ofgem. LECG was asked to focus on the following support services: information systems; finance, audit and regulation; insurance; property management; corporate centre and communication; human resources; legal; and procurement and logistics.

Benchmarking was conducted for each of these cost categories. The benchmarking was not performed at a more granular level as it was considered that doing so would require more subjective cost allocations. GDNs also indicated difficulties with providing the information at a more granular level.

### *Total support costs*

LECG first conducted high-level benchmarking of total support service costs as a percentage of adjusted revenue.

### *Information systems*

LECG benchmarked GDN average Information Systems support costs as a percentage of adjusted revenue covering the period 2005-06 to 2012-13. These unit-costs were compared with third-party benchmarks obtained from independent studies. LECG set the benchmarks at the median and upper quartile.<sup>144</sup>

The Ofgem set the benchmark at the second lowest cost GDN group.<sup>145</sup>

### *Finance and Audit (F&A) and Regulation*

LECG benchmarked F&A costs and Regulation costs separately. F&A costs were normalised by total revenue. LECG set the benchmarks at the median and the third-party benchmark. Regulation costs were normalised by total operating costs. LECG set the benchmarks at the median and upper quartile of GDNs.<sup>146</sup>

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<sup>144</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 34-42.

<sup>145</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 38.

<sup>146</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 43-55.

The Ofgem set the benchmark for F&A costs based on the second lowest cost GDN and the benchmark for Regulation costs based on the upper quartile level of performance.<sup>147</sup>

### *Insurance*

LECG benchmarked controllable insurance costs as a percentage of adjusted revenue. The benchmark was set at the median and upper quartile. LECG considered benchmarking of insurance premium costs, uninsured costs and insurance coverage but concluded that it was inappropriate because of the trade-offs between risk and insurance costs.<sup>148</sup>

The Ofgem set the benchmark for controllable insurance costs at the second lowest cost GDN group. Other insurance costs were set at the base year actual costs.<sup>149</sup>

### *Property management*

LECG benchmarked the following<sup>150</sup>:

- Rental costs per square foot for each GDN property against market rent data prepared by GVA Grimley. The efficiency saving was calculated by comparing the actual property rent with the lower end of the market rent range and multiplying the difference by the floor size of the property
- Total facilities costs per square foot of GND floor space was benchmarked across GDNs. The benchmark was set at the median and upper quartile
- Total floor space per kilometre of pipeline was benchmarked across GDNs. The benchmark was set at the median and upper quartile.

LECG also reviewed the property management benchmarks used by the Drivers Jonas Report for comparing National Grids property-related costs for the transmission price control review for 2007 to 2012.<sup>151</sup>

The Ofgem set the benchmarks for property management at the upper quartile for total facilities costs per square foot and total floor space per kilometre of pipeline. The rental cost benchmark, based on market data, led to further adjustments for some GDNs.<sup>152</sup>

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<sup>147</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 39.

<sup>148</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 56-62.

<sup>149</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 39.

<sup>150</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 71-72.

<sup>151</sup> LECG, *Benchmarking National Grid Gas Distribution's Business Support Services*, Draft April 2007 p. 101.

<sup>152</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 40.

### *Corporate Centre and Communications*

LECG benchmarked Corporate and Communication costs as a percentage of total (controllable and non-controllable) operating costs. The benchmarks were set at the median and upper quartile. LECG also considered the benchmarks derived by Deloitte for National Grid for the Transmission price control review 2007 to 2012.<sup>153</sup>

The Ofgem set the benchmarked at the second lowest GDN group.<sup>154</sup>

### *Human Resources*

LECG benchmarked a subset of total HR costs to ensure consistency. The subset excluded learning and development, and apprentice/graduate training schemes. LECG benchmarked the adjusted HR costs as a percentage of total revenue and as a percentage of total operating costs. The benchmark was set at the median and upper quartile.

LECG compared their findings with the following comparable third-party benchmarks:

- Global Best Practices benchmark of HR as a percentage of total revenue. The benchmark was developed in 2006 based on HR costs from 40 comparable businesses (six utility businesses, with a further 20 from related industries)
- PricewaterhouseCoopers Saratoga benchmark of HR costs as a percentage of total operating costs. The benchmarking study was commissioned by National Grid Gas for the transmission price control review for 2007-2012.<sup>155</sup>

The Ofgem chose to set the benchmark based on adjusted HR costs per total full-time equivalent employees (FTEs). The benchmark was set at the second lowest GDN group. This was because the level of outsourcing affected the benchmarks applied in the updated proposals.<sup>156</sup>

### *Legal*

LECG benchmarked controllable legal costs as a percentage of adjusted revenue. GDNs were benchmarked against each other and the benchmark was set at the median and upper quartile. LECG also benchmarked the GDNs' costs against the results of a third party study by the Working Council for Chief Financial Officers in 2003, which

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<sup>153</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 78-85.

<sup>154</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 40.

<sup>155</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 86-95.

<sup>156</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 40.

contained legal cost metrics derived from a survey of over 300 of the world's largest corporations.<sup>157</sup>

The Ofgem set the benchmark of legal costs as a percentage of adjusted revenue at the second lowest GDN group.<sup>158</sup>

### *Procurement and Logistics*

LECG benchmarked procurement and logistics costs as a percentage of total operating costs. GDNs were benchmarked against each other and against a third-party benchmark. The third-party benchmark is from Deloitte's analysis of UK EDNs. LECG set the benchmarks at the median and upper quartile of the GDNs' benchmark.<sup>159</sup>

The Ofgem benchmarked GDNs procurement and logistics costs as a percentage of total opex and set the benchmark at the second lowest GDN group.<sup>160</sup>

### *Analysis of model outputs*

For most of the indirect cost categories, LECG calculated the GDNs' benchmark based on the median and the upper quartile normalised support services costs. Where an external benchmark was comparable and more challenging, this was presented to the Ofgem as an alternative benchmark.<sup>161</sup>

LECG derived an efficiency score for each GDN group for each indirect cost category. This was done by taking each of the two recommended benchmarks and dividing this value by the GDN's actual value. The efficiency saving was then calculated from the efficiency score by multiplying the efficiency score by the GDN's actual value (if the efficiency score was less than one).<sup>162</sup>

### *Application to regulatory decision*

The Ofgem decided to use the second best GDN as the benchmark for all indirect cost categories. This was to minimise any distortions arising from one of the GDNs use of a marginal cost method for the provision of some support services which is the frontier GDN for most indirect functions. The use of external benchmarks was not adopted by the Ofgem as the GDNs argued that the comparators were less appropriate.<sup>163</sup>

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<sup>157</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 96-102.

<sup>158</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 41.

<sup>159</sup> LECG, *Update Assessment of GDN Indirect Opex based upon 2006/07 Actual Performance*, September 2007, pp. 103-110.

<sup>160</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 41.

<sup>161</sup> LECG, *Benchmarking National Grid Gas Distribution's Business Support Costs*, Draft, April 2007, pp. 25-28.

<sup>162</sup> Ibid, p. 28-29 and example of calculation in Table 8 on p. 38.

<sup>163</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals*, December 2007, p. 17.

The Ofgem also applied an up-lift to the efficient costs (that were derived from the benchmarks set for indirect cost categories). The up-lift was based on the average difference between the disaggregated benchmarks for each cost category and the top-down total opex benchmark derived by Europe Economics (refer section 2.4.2).<sup>164</sup>

The Ofgem noted that:<sup>165</sup>

In practice our combined approach of making use of both disaggregated and top-down analysis means that the overall level of allowances is determined by the top-down analysis but the detailed benchmarking determines the allocation of allowances between the GDNs.

#### 2.4.4 PB Power study: Opex direct costs benchmarking<sup>166</sup>

##### *Summary*

PB Power employed two principal procedures to review the costs of each direct opex activity:

- comparative benchmarking between GDNs, where the workload was sufficiently well-defined to obtain reliable regression analysis
- forming a judgement on appropriate expenditure projections based on the information available.

The comparative benchmarking methods employed by PB Power and the application by the Ofgem are described by direct opex activity.

##### *Data*

Data were sourced from the Business Plan Questionnaires submitted to the Ofgem by the eight GDNs. The base-year costs to be benchmarked were generally for 2005-06, although 2006-07 costs were used for some activities due to variations in the 2005-06 data.

##### *Technique*

PB Power employed the following benchmarking methods, where appropriate for each direct cost category:<sup>167</sup>

- engineering-based bottom up analysis
- OLS regression analysis
- unit-cost analysis.

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<sup>164</sup> Ibid, p. 11.

<sup>165</sup> Ibid, p. 12.

<sup>166</sup> PB power prepared eight reports on direct opex, one for each gas distribution business. Available at: <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=175&refer=Networks/GasDistr/GDPC R7-13> [accessed on 20 December 2011].

<sup>167</sup> PB Power, *Gas Distribution Price Control Review Five Year Control (Opex), Report 5 East of England Network*, June 2007, pp. 13-14.

PB Power used the OLS regression analysis to set the benchmark when the R-squared value exceeded 0.7.

#### *Level of disaggregation*

The Ofgem tasked PB Power with undertaking the benchmarking of direct opex costs at the activity level. The direct opex categories/activities covered were:

- work management
- emergency services
- repair costs
- maintenance costs
- other direct costs.

The analysis was undertaken at the GDN level, rather than the group ownership level.

#### *Normalisation adjustments*

The following normalisation adjustments were carried out on the direct opex categories where appropriate:<sup>168</sup>

- accounting adjustments undertaken by the Ofgem
- the transfer of costs to bring the allocation of costs into the same category for all GDNs
- the re-allocation of costs by the GDNs to reflect the categories chosen for the analysis
- the removal of special or one-off costs prior to comparative analysis
- pension costs submitted by GDNs were replaced with an amount equal to 22 per cent of direct employee salary/wages to bring the direct opex on a consistent basis across GDNs.

#### *Model specification*

Where used, the regression model is of the form:

$$\ln(\text{cost}) = \ln(K) + a \ln(w)$$

where  $w$  is the work load driver and  $K$  and  $a$  are constants.<sup>169</sup>

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<sup>168</sup> Ibid, pp. 10-11.

<sup>169</sup> Ibid, p. 12.

### *Workload management*<sup>170</sup>

For the work management direct cost category, PB Power based its recommendations on regression analysis using a composite scale variable (CSV) as the explanatory variable.

The cost drivers were determined using a bottom-up engineering approach. To form the CSV, each cost driver was weighted based on the proportion of workload management costs driven by each of the activities emergency response, emergency repairs and other operational activities.

The composite cost driver (CSV) consisted of:

$$\begin{aligned} & \text{Average length of mains} \times \\ & (0.3 \times \text{no. Public Reported Escapes (PREs)} / \text{Average no. PREs} \\ & + 0.3 \times \text{No. repairs} / \text{Average no. repairs} \\ & + 0.4 \times \text{Length of main pipes less than 7-bar} / \text{Average length of main pipes}) \end{aligned}$$

The cost drivers included in the CSV were each scaled by the respective average GDN so that the balance between the cost drivers in the CSV was independent of the choice of units used to quantify each cost driver.

The derived CSV was then used in a regression analysis where workload management opex was the dependent variable and the CSV was the explanatory variable.

The regression was based on OLS method using eight data observations corresponding to each of the eight GDNs in 2005-06.

The regression line was then adjusted to set the benchmark at the upper quartile.

PB Power then used the regression results to forecast the appropriate costs for the regulatory period, taking into account planned growth of the network and variations in repairs and PREs as well as standard assumptions regarding productivity, real price effects, regional factors, and adjustments to pensions.

These results were compared with the forecast costs provided by the GDNs.

### Application to regulatory decision

The Ofgem applied PB Power's work load management regression analysis but made its own adjustments to the cost forecasts for factors such as regional labour cost adjustments, gap closure and real price effects.<sup>171</sup>

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<sup>170</sup> Ibid, pp. 23-32.

<sup>171</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 34.

### *Emergency services*<sup>172</sup>

PB Power's analysis for emergency service costs was based on regression analysis.

The dependent variable was the cost of emergency procedures. To ensure consistency, emergency service costs are determined on the basis of no loss of metering and a separate revenue driver is proposed to deal with the increased costs that will be caused by any such loss.

The explanatory variable was a composite scale variable (CSV) calculated as:

$$(0.8 \times \text{Total no. of PREs} / \text{Average no. of PREs} \\ + 0.2 \times \text{No. of repairs} / \text{Average no. of GDN repairs})$$

The cost driver included in the CSV were each scaled by their respective average GDN so that the balance between the cost drivers was independent of the choice of units used to quantify each cost driver.

The model was estimated by OLS using data on the eight GDNs for 2006-07. The benchmark was set at the upper quartile.

PB Power then used the regression results to forecast appropriate costs for the regulatory period, taking into account planned growth of the network and variations in repairs and PREs as well as standard assumptions regarding productivity, real price effects and regional factors and adjustments to pensions.

### Application to regulatory decision

The Ofgem adjusted PB Power's cost forecasts to take account of its own view on regional labour adjustments, gap closure, real price effects and ongoing efficiencies.<sup>173</sup>

### *Repair costs*<sup>174</sup>

PB Power's analysis of repair costs was based on regression analysis.

The dependent variable was repair costs.

The explanatory variable was a composite scale variable based on the proportion of costs attributable to four different work elements. These elements were: mains condition repairs, services condition repairs, mains interference repairs and service interference repairs.

The composite scale variable was represented by the function:

$$\text{CSV} = \sum U_n \cdot V_n / 1000$$

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<sup>172</sup> PB Power, *Gas Distribution Price Control Review Five Year Control (Opex), Report 5 East of England Network*, June 2007, pp. 34-46.

<sup>173</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 35.

<sup>174</sup> PB Power, *Gas Distribution Price Control Review Five Year Control (Opex), Report 5 East of England Network*, June 2007, pp. 49-61.

where  $U$  is the representational unit-costs for each repair type/pipe size and  $V$  is the corresponding actual volumes. The same representative unit-costs have been used for each network  $n$  and have been chosen by reference to contract rates for each of the four repair types.

The model was estimated using OLS with data on the eight GDNs in 2005-06.

PB Power set the benchmark at the upper quartile.

The regression analysis was supported by a bottom-up analysis based on PB Power's knowledge of the time taken to complete work of this nature, appropriate hourly rates and an allowance for materials and other costs.

PB Power then used the regression analysis to forecast appropriate costs for the regulatory period. The forecasts took into account planned growth of the network and variations in repairs and PREs as well as standard assumptions regarding productivity, real price effects, regional factors and adjustments to pensions.

#### Application to regulatory decision

The Ofgem adjusted PB Power's cost forecasts for its own view on regional labour cost adjustments, gap closure, real price effects and ongoing efficiencies.<sup>175</sup>

#### *Maintenance costs*<sup>176</sup>

PB Power initially benchmarked separate components of maintenance expenditure; however, this analysis was revised following industry consultation. PB Power's revised analysis<sup>177</sup> examined maintenance expenditure as a whole.

PB Power first identified routine maintenance costs that occur on an annual basis. PB Power then carried out an OLS regression to determine the efficient level of expenditure. Routine maintenance costs were the dependent variable and a composite scale variable was the explanatory variable.

PB Power then added additional non-routine costs based on a bottom-up assessment. Non-routine costs included local transmission system (LTS) on-line inspections, holder painting and governor overhauls.

#### Application to regulatory decision

The Ofgem simplified the composite scale variable so that it was based on numbers of pressure reduction stations, national transmission system (NTS) offtakes, governors and holders.

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<sup>175</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 36.

<sup>176</sup> Ofgem, *Gas Distribution Price Control Review, Updated Proposals*, September 2007, pp.10-12.

<sup>177</sup> PB Power's revised analysis is not directly available; therefore, information has been sourced from Ofgem documents where possible.

The Ofgem also reallocated some costs from routine to non-routine and included an additional cost associated with cathodic protection work which was a new requirement and therefore was not reflected in base year costs.<sup>178</sup>

The Ofgem set the benchmark at the upper quartile.

#### *Other direct costs*<sup>179</sup>

PB Power did not consider it appropriate to undertake bottom-up analysis of other direct costs given the diverse nature of activities involved.

PB Power benchmarked other direct costs using OLS regression analysis. The dependent variable was direct costs and the explanatory variable was network length. The data covered the eight GDNs for 2005-06.

PB Power considered that the regression was of sufficiently good fit that it was not necessary to undertake unit-cost analysis.

#### Application to regulatory decision

The Ofgem did not consider that the regression results were sufficiently robust, particularly when updating these for the 2006-07 data. The Ofgem therefore based its view of other indirect costs on the GDNs' own forecasts and then adjusted these forecasts for its own view of real price effects and ongoing efficiencies.<sup>180</sup>

#### 2.4.5 PB Power: Capex and repex benchmarking<sup>181</sup>

##### *Summary*

PB Power was commissioned by the Ofgem to undertake an assessment of the GDNs' forecast capex and repex.

PB Power's work broadly included:<sup>182</sup>

- a high-level assessment of policies, procedures and forecasting processes associated with capex and repex
- a review of GDNs' forecast costs to understand whether they were based on appropriate assumptions including the justification for their workload forecasts, assumptions for real price increases and productivity

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<sup>178</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p.37.

<sup>179</sup> PB Power, *Gas Distribution Price Control Review Five Year Control (Opex), Report 5 East of England Network*, June 2007, pp. 92-96.

<sup>180</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals, Supplementary Appendices* December 2007, p. 38.

<sup>181</sup> PB power prepared eight reports on capex and repex, one for each gas distribution business. Available at: <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=175&refer=Networks/GasDistr/GDPC R7-13> [accessed on 20 December 2011].

<sup>182</sup> Detailed methodology is available in chapter 2 of PB Power, *Capex and Repex Assessment, Reports*.

- an assessment of GDNs' efficiency for particular capex and repex categories by benchmarking costs across GDNs (this was done where cost drivers were sufficiently well-defined)
- bottom-up analysis to consider the appropriate costs for particular activities based on information submitted by the GDNs and PB Power's engineering experience.

### *Data*

The data were based on forecast costs submitted by the GDNs through the Ofgem's Business Plan Questionnaire. The forecasts were for the financial years from 2008-09 to 2012-13.

For most cost categories, actual cost data from 2005-06 were used to develop the benchmarks; data from 2006-07 were used for some categories due to variations in the 2005-06 data.<sup>183</sup>

### *Technique*

Benchmarking methods used included:

- regression analysis (where possible)
- unit-costs analysis
- bottom-up engineering-based analysis

### *Level of disaggregation*

PB Power analysed the following capex categories:

- LTS & Storage capex
- Connections capex
- Mains and Governors capex
- Other Operational capex
- Non-operational capex

PB Power analysed the following repex categories:

- Replacement Mains
- Replacement Services
- Replacement LTS pipelines

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<sup>183</sup> PB Power, *Capex and Repex Assessment, Report 5 East of England Network*, June 2007, p. 13.

### *Model specification*

Where regression analysis has been undertaken, the following functional form was employed:

$$\ln(\text{cost}) = \ln(K) + a \ln(w)$$

where  $w$  is the work load driver and  $K$  and  $a$  are constants.<sup>184</sup>

### LTS and storage capex

PB Power reviewed all major projects submitted by the GDNs to derive a set of benchmark unit-costs for LTS pipe-lines. The derived unit-costs were reviewed against PB Power's own unit-cost estimates.

PB Power reviewed both the need for an LTS project, based on available capacity and pressures from the NTS together with a review of the demand and growth assumptions used by the GDNs in their plans, and also the cost of alternative options for the GDN to meet its capacity requirements.

Where PB Power considered that capacity needs had been overstated they proposed a number of deferrals to projects, delaying construction for some projects within the price control period and deferring other projects to the next price control period.

The Ofgem's decision on LTS capex was based on PB Power's recommendations and consultation with GDNs. This led to some projects being allowed that PB Power originally recommended be delayed.<sup>185</sup>

### Connections capex

PB Power explored a number of regression models but concluded that the best model involved the log of normalised connection costs as the dependent variable and a composite variable, based on the weighted average of different pipe sizes (where the volume of each pipe size is multiplied by the unit-cost), as the explanatory variable. The model was estimated using OLS and data from 2006-07 for the eight GDNs. The benchmark was set at the upper quartile.<sup>186</sup>

The Ofgem adopted this model.<sup>187</sup>

### Mains and governors capex

PB Power explored a number of regression models. PB Power's preferred model included log normalised mains and governor costs as the dependent variable and a composite scale variable as the explanatory variable. The composite scale variable was based on the weighted average of different pipe sizes (where the volume of each pipe size is multiplied by the nominal unit-cost). The model was estimated using

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<sup>184</sup> Ibid, p. 13.

<sup>185</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals*, December 2007, pp. 29-30.

<sup>186</sup> PB Power, *Gas Distribution Price Control Review (Capex/Repex), Report 5 East of England Network*, pp. 33-48.

<sup>187</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals*, December 2007, p. 32.

OLS and data from 2005-06 for the eight GDNs. The benchmark was set at the upper quartile.<sup>188</sup>

The Ofgem adopted this model but included the data for both 2005-06 and 2006-07.<sup>189</sup>

#### Other operational capex and non-operational capex

For other operational capex and non-operational capex, PB Power reviewed these costs on a project basis, taking into account historical and forecast expenditure. The value of forecast costs over the five-year period for certain cost components were compared between GDNs for reasonableness. These cost components include: System operations capex, IS infrastructure capex, IS systems capex, Xoserve capex, Security capex, Tools/equipment capex, and other non-operational capex.

In response to submissions, the Ofgem undertook further analysis to consider the opex-capex trade-off. The Ofgem undertook a total expenditure (totex) regression which included opex plus governor, other operational and non-operational capex. The level of efficiency under the totex and direct opex regressions were compared and the direct opex forecasts for only one GDN were adjusted.<sup>190</sup>

#### Mains and services repex<sup>191</sup>

PB Power explored a number of regression models and concluded that the following log-linear model was most appropriate:

- normalised-log Mains and Services repex from 2005-06 as the dependent variable
- weighted average replacement cost as the explanatory variable.

where the weightings were based on the 2005-06 unit-costs for different diameters of mains which take into account the mains and services workload mix for each GDN (i.e., by multiplying the work volume by the nominal unit-costs of the activity). This approach was noted as not being sensitive to the actual level of the nominal costs but works on the relative costs between work types. The benchmark was set at the upper quartile.

The Ofgem applied this regression model but updated the analysis to include Mains and Services costs for 2006-07 and weightings based on 2008-09 unit-costs. The results were reported in 2005-06 prices.<sup>192</sup>

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<sup>188</sup> PB Power, *Gas Distribution Price Control Review (Capex/Repex), Report 5 East of England Network*, pp. 51-61.

<sup>189</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals*, December 2007, p. 34.

<sup>190</sup> Ibid, pp. 35-36.

<sup>191</sup> PB Power, *Gas Distribution Price Control Review (Capex/Repex), Report 5 East of England Network*, p. 90.

<sup>192</sup> Ofgem, *Gas Distribution Price Control Review, Final Proposals*, December 2007, p. 38.

### LTS repex

PB Power did not benchmark LTS repex as all major works were subject to competitive tender. Therefore, it considered that comparison of historical costs and other GDNs costs would be meaningless.<sup>193</sup>

#### *Analysis of model outputs (all cost categories):*

For each category of capex and repex, PB Power tracked forward the upper quartile benchmark from the base year to the end of the regulatory period 2012-13, taking account of the expected productivity improvements, real price effects and regional factors.

The Ofgem applied its own view of productivity improvements, real price effects and regional factors when applying the PB Power results.

### **2.5 The Ofgem's new regulatory approach**

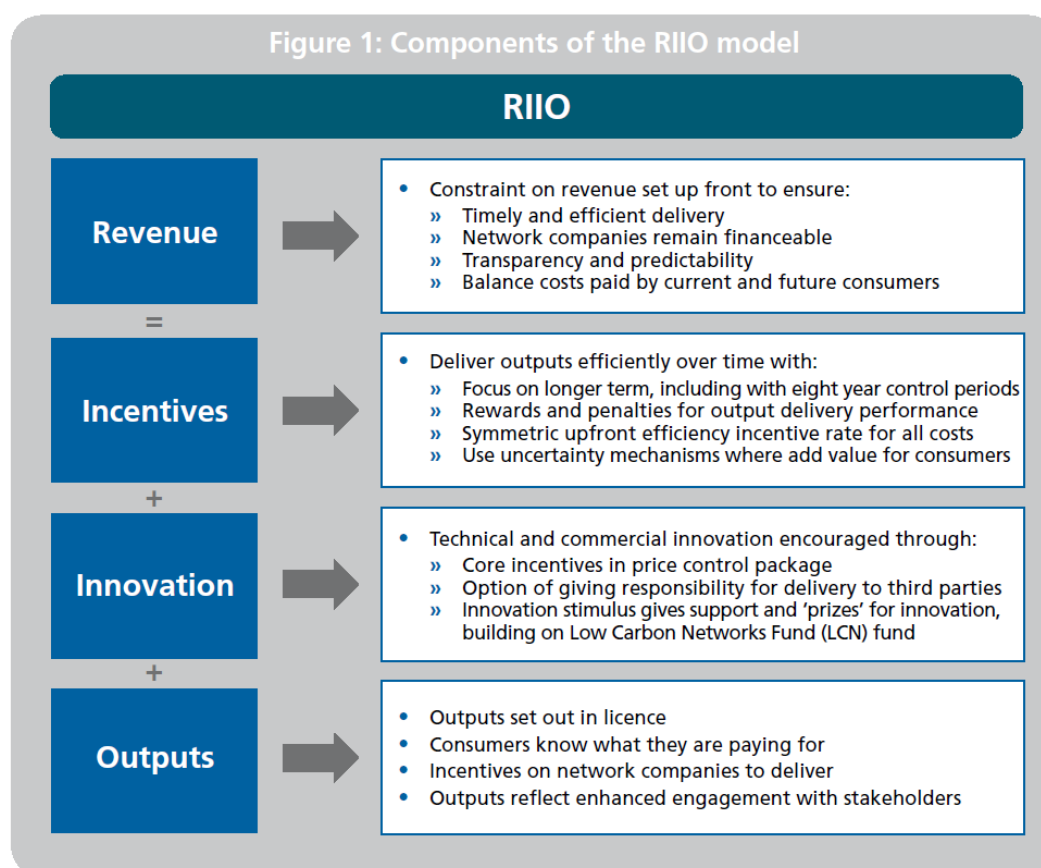
From 2013, the Ofgem will be introducing a new regulatory framework called Revenue, Incentives, Innovation and Outputs (RIIO). The new RIIO framework is described in the figure below and includes extending the length of the regulatory control period from five to eight years.<sup>194</sup>

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<sup>193</sup> PB Power, *Gas Distribution Price Control Review (Capex/Repex), Report 5 East of England Network*, p. 112.

<sup>194</sup> Ofgem, *RIIO, A New Way to Regulate Energy Networks, Final Decision*, October 2010.

## The Ofgem's new RIIO regulatory framework<sup>195</sup>



Under the RIIO framework the Ofgem expects that total cost benchmarking (that is opex plus capex) may be used as one piece of the evidence in revenue setting but will no longer form the logical basis to determine allowed revenue.<sup>196</sup>

In its report to the Ofgem, Frontier Economics recommended less focus on *ex post* benchmarking and more focus on future cost and total cost benchmarking. Frontier Economics recommended:

- For electricity and gas distribution - the continued use of COLS
- For electricity and gas transmission - a DEA method, using a model with one input and multiple outputs, and considering both constant and variable returns-to-scale assumptions.<sup>197</sup>

<sup>195</sup> Source: Ofgem, *RIIO, A new way to regulate energy networks, Final Decision*, October 2010, p. 3.

<sup>196</sup> Ofgem, *Handbook for Implementing the RIIO model*, October 2010, pp. 64-65.

<sup>197</sup> Frontier Economics, *RPI-X@20: The Future Role of Benchmarking in Regulatory Reviews, A Final Report prepared for Ofgem*, May 2010.

### 3 Ireland: Commission for Energy Regulation

#### 3.1 Overview of the Irish energy market

##### *Electricity*

The Electricity Supply Board (ESB), a government-owned statutory corporation, is the incumbent in the electricity market in Ireland. The ESB is vertically integrated; however, the generation, transmission, distribution and retail supply operations have been legally separated in accordance with European Union (EU) law.<sup>198</sup>

The ESB is licensed as the transmission system owner and is responsible for carrying out maintenance and construction of the system. EirGrid, created in 2006, is the independent state-owned body licensed as the transmission system operator and is responsible for the operation, development and maintenance of the transmission system.<sup>199</sup>

The ESB is licensed as the distribution system owner. The distribution system is operated by ESB Networks (ESBN). ESBN is a wholly-owned subsidiary of the ESB, created to undertake the functions of the distribution system operator such as operation, maintenance and development of the distribution system. ESBN is independent of the other activities of the ESB in terms of its legal form, organisation and decision making.<sup>200</sup>

The Single Electricity Market (SEM), established in 2007, is the wholesale market for electricity in both the Republic of Ireland and Northern Ireland. It is operated by the Single Electricity Market Operator (SEMO), a joint venture between EirGrid and SONI (the transmission system operator in Northern Ireland).<sup>201</sup>

Power generation in Ireland is currently carried out by ESB Power Generation (ESB PG) as well as a number of independent power stations. A generator wanting to connect to the electricity grid must hold a generation licence.<sup>202</sup> The generation market was fully liberalised from 2005 and ESB PG's revenue was regulated until the introduction of the SEM in 2007.<sup>203</sup>

In the retail market, ESB Customer Supply provides electricity for retail customers in its capacity as the Public Electricity Supplier. The electricity retail market was fully

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<sup>198</sup> Australian Competition and Consumer Commission, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research, Appendix to the Final Report to the Infrastructure Consultative Committee*, 5 June 2009, pp. 132 and 220.

<sup>199</sup> CER, *Electricity, Transmission Network, Transmission Licences*. Available at: <http://www.cer.ie/en/electricity-transmission-network-licences.aspx> [accessed on 5 March 2012].

<sup>200</sup> CER, *Electricity, Distribution Network, Licences*. Available at: <http://www.cer.ie/en/electricity-distribution-network-licences.aspx> [accessed on 5 March 2012].

<sup>201</sup> CER, *Electricity, Wholesale Market, Wholesale Trading Arrangements*. Available at: <http://www.cer.ie/en/electricity-wholesale-market-wholesale-trading-arrangements.aspx> [accessed on 5 March 2012].

<sup>202</sup> CER, *Electricity, Generation, Overview*. Available at <http://www.cer.ie/en/electricity-generation-overview.aspx> [accessed on 5 March 2012].

<sup>203</sup> CER, *Electricity, Generation, Regulated Generator Revenues*. Available at: <http://www.cer.ie/en/electricity-generation-regulated-generator-revenues.aspx> [accessed on 5 March 2012].

opened to competition in February 2005 and independent companies now supply almost half of the electricity consumed in Ireland. In April 2011, the tariffs of ESB Customer Supply ceased to be regulated.<sup>204</sup>

### *Gas*

Ireland has few natural gas resources and most of the gas consumed in Ireland is imported from the UK.<sup>205</sup>

The Bord Gáis Eireann, which is wholly owned by the government, owns both the gas transmission and distribution networks. Gaslink, an independent subsidiary, is the operator of both the gas transmission and distribution systems. The revenue and tariffs of Bord Gáis Eireann and Gaslink are subject to regulation.<sup>206</sup> While any party may seek a licence to own or operate a natural gas transmission or distribution network,<sup>207</sup> at present the incumbents Bord Gáis Eireann and Gaslink are the only participants in these markets.

The natural gas retail market has been open to competition since July 2007 and there are now eight retail suppliers.<sup>208</sup> Retail tariffs for the incumbent, Bord Gáis Energy, remain subject to regulation.<sup>209</sup>

### *Regulator*

The Commission for Energy Regulation (CER) is responsible for regulating the electricity and gas markets in Ireland. The powers of the CER to regulate electricity and gas are set out in the *Electricity Regulation Act 1999* and the *Gas (Interim) (Regulations) Act 2002* respectively. The CER is an independent body and is funded by a levy on regulated industries. The CER regulates annual revenues and tariffs of owners and operators of the transmission and distribution systems.<sup>210</sup>

The CER has been involved in the liberalisation of the electricity retail and generation markets in order to encourage competition and investment. The electricity generation market is open to competition, but any provider intending to construct infrastructure and generate electricity must obtain authorisation to do so from the CER.<sup>211</sup> The CER no longer regulate electricity retail tariffs but continues to regulate gas retail tariffs.

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<sup>204</sup> CER, *Electricity, Retail Market, Overview*. Available at: <http://www.cer.ie/en/electricity-retail-market-overview.aspx> [accessed on 5 March 2012].

<sup>205</sup> CER, *Gas, Overview*. Available at: <http://www.cer.ie/en/gas-overview.aspx> [accessed on 5 March 2012].

<sup>206</sup> Ibid.

<sup>207</sup> *Gas (Interim) (Regulation) Act 2002*, s. 16(1).

<sup>208</sup> CER, *Gas, Retail Market, Overview*. Available at: <http://www.cer.ie/en/gas-retail-market-overview.aspx> [accessed on 5 March 2012].

<sup>209</sup> CER, *Gas, Retail Market, Regulated Revenues and Tariffs*. Available at: <http://www.cer.ie/en/gas-retail-market-regulated-revenues-and-tariffs.aspx> [accessed on 5 March 2012].

<sup>210</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, p. 221.

<sup>211</sup> Ibid.

## *Appeals Process*

Under Part IV of the *Electricity Regulation Act*, parties have the right to appeal a decision made by the CER with regard to the modification of, refusal to modify, or refusal to grant a license or authorisation. However, parties are no longer able to appeal network access dispute decisions on substantive grounds. Judicial review is possible under section 32 of the *Electricity Regulation Act 1999* and is undertaken by the High Court. If the High Court finds substantial grounds for ruling in favour of the appellant, the original decision of the CER and/or the appeal panel will be declared invalid.<sup>212</sup>

### **3.2 Regulatory framework**

#### *Electricity*

Under section 35 of the *Electricity Regulation Act 1999*, the CER regulates tariffs for the use of, or connection to, the transmission and distribution systems. Tariffs must be based on the recovery of an appropriate proportion of costs incurred, and a reasonable rate of return.<sup>213</sup>

For transmission, the CER regulates the total allowed revenue that the transmission business can earn to cover the costs of both the transmission asset owner and operator. The allowed revenue for the following five years is determined during a five-yearly Price Review and then refined annually. The allowed revenue is then used to calculate tariffs that the transmission operator, EirGrid, may charge users of the transmission system (i.e., generators and demand customers). The CER approves the transmission tariffs annually.<sup>214</sup>

Every five years the CER sets the revenue that the distribution system operator, ESBN, may collect from electricity customers for the following five years. The allowed revenue is reviewed annually and is used to calculate the distribution tariffs, which are approved by the CER. The allowed revenue is collected from retailers via distribution use of system (DUoS) charges, which are based on a standing charge and the amount of energy used.<sup>215</sup>

#### *Gas*

The CER regulates revenues recovered and network tariffs charged by gas transmission and distribution businesses.

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<sup>212</sup> Ibid, p. 226.

<sup>213</sup> *Electricity Regulation Act 1999*, s 35(4).

<sup>214</sup> CER, *Electricity, Transmission Network, Regulated Revenues and Tariffs*. Available at: <http://www.cer.ie/en/electricity-transmission-network-regulated-revenues.aspx> [accessed on 5 March 2012].

<sup>215</sup> CER, *Electricity, Distribution Network, Regulated Revenues and Tariffs*. Available at: <http://www.cer.ie/en/electricity-distribution-network-regulated-revenues-and-tariffs.aspx> [accessed on 5 March 2012].

For gas transmission, the CER determines the revenue that the transmission business can earn to cover its efficient costs over the regulatory period.<sup>216</sup> The allowed revenue is revised annually and used to determine transmission tariffs. The same method is applied for gas distribution. A detailed price review is carried out every four or five years. Transmission and distribution price reviews have occurred on approximately the same timeline.<sup>217</sup>

### **3.3 Electricity distribution**

#### *Background*

The CER's most recent price review for the electricity distribution system operator, ESNB, was for the five year period 2011 to 2015. In its final decision, the CER stated that its objectives for setting the revenue were to ensure the following:<sup>218</sup>

- ESNB is able to maintain the distribution network to an adequate standard to meet customers' expectations
- The interests of final customers are protected, in the short and long term, by containing tariffs to the maximum extent possible while delivering efficient network investment
- ESNB is able to attract the necessary level of capital investment to support the approved level of renewal and extension of the network. In doing so, the CER wants to ensure that the items of work included in the investment plans of ESNB are necessary and provide value for money for customers in terms of the benefits they add
- Appropriate incentives are provided for ESNB to improve its efficiency where possible and that as much as possible of these savings are passed through to consumers. The CER has set incentives that are challenging but achievable
- The day-to-day intervention by the CER in the operation of ESNB is kept to a minimum.

The CER adopted an incentive-based model in the form of RPI-X regulation to determine the allowed revenue for ESNB.

ESNB's operating costs are fixed for a five-year regulatory period. If ESNB spends more than it is allowed, it bears the cost. If ESNB spends below what it is allowed, it can keep the surplus made in any year during the regulatory period for a period of five years. This is a means of incentivising efficiency. Customers benefit in the medium

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<sup>216</sup> CER, *Gas, Transmission Network, Regulated Revenues and Tariffs*. Available at: <http://www.cer.ie/en/gas-transmission-network-regulated-revenues-and-tariffs.aspx> [accessed on 5 March 2012].

<sup>217</sup> For gas transmission and distribution the first Price Review period was a four-year period from 2003 to 2007, the second a five-year period from 2007-08 to 2011-12, and the third is for a five-year period from 2012-13 to 2016-17.

<sup>218</sup> CER, *Decision on 2011 to 2015 Distribution Revenue for ESB Networks Ltd*, 19 November 2010, p. 22.

term by the progressive decrease in operating costs enforced at subsequent price reviews.<sup>219</sup>

For capital expenditure (capex), the CER sets an allowance based on investment plans submitted by ESNB. ESNB is required to manage its capex so it remains within the allowance, making adjustments to its plans in light of circumstances during the period. The CER monitors capex during the period, and carries out a review at the end of the period, to ensure that the capital projects undertaken were needed and the costs were efficiently incurred. Capex considered by the CER to be imprudent or inefficiently incurred is not allowed to be carried over to the next regulatory period as part of the regulated asset base (RAB). The review of both operating and capital expenditure takes into account windfall gains and losses.<sup>220</sup>

The CER also sets non-financial performance targets for ESNB. These targets are set for quality of supply, electrical losses and customer service. Financial incentives (rewards and penalties) are awarded based on these targets.<sup>221</sup>

### 3.3.1 Benchmarking opex

#### *Summary*

The CER engaged the services of engineering and technical consultant, Sinclair Knight Merz (SKM) to assist the CER in its assessment of ESNB's revenue proposal for the third price control period (PR3), 2011 to 2015. The CER adopted almost all of SKM's recommendations in regard to the relevant opex and capex proposed by ESNB.

SKM utilised the following benchmarking methods:<sup>222</sup>

- Top-down benchmarking using linear regression analysis. The independent variable applied was a Composite Scale Variable (CSV), being a weighted variable consisting of customer numbers, electricity units distributed and network length, and the dependent variable applied was opex plus non-network capex. ESNB was compared to electricity distribution networks (EDNs) in the United Kingdom (UK),<sup>223</sup> using information from the Ofgem's distribution price control review for the regulatory period 1999 to 2004 (DPCR3) and for the period 2005 to 2010 (DPCR4)
- Bottom-up benchmarking consisting of a direct analysis of costs and a comparison of ESNB with EDNs in the UK. The costs which were analysed were tree cutting costs, fault costs and IT/telecoms/system control costs
- For capex assessment, process analysis involving a review of ESNB's planning processes and an observation of plant sites and projects

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<sup>219</sup> Ibid, p. 4.

<sup>220</sup> Ibid.

<sup>221</sup> Ibid, p. 4.

<sup>222</sup> Sinclair Knight Merz, *CER Transmission and Distribution Price Review, Review of Distribution Operating Costs 2006 to 2015*, 23 June 2010a, pp. 67-69.

<sup>223</sup> That is, excluding Scotland EDNs, which are not responsible for 132kV assets.

- Trend analysis consisting of an analysis of 2006-2010 opex and capex on an ex post basis and a comparison with forecast opex and capex for the period 2011 to 2015.<sup>224</sup>

Further, SKM benchmarked ESBN's quality of service and non-financial performance. These measures refer to quality of service, electrical losses, and customer service. The approach which SKM adopted to benchmark quality of service involved a comparison of performance, as measured using a number of performance indicators, between ESBN and EDNs in the UK. The performance indicators considered by SKM included the following.<sup>225</sup>

- system average interruption frequency index (SAIFI)
- system average interruption duration index (SAIDI)
- system electrical losses
- customer charter and other customer service measures.

SKM cautioned that this analysis was not intended to be exhaustive but illustrative of the sensitivity of system performance to network topography, customer dispersion, fault rates, and the level of system automation.<sup>226</sup>

#### *Top-down benchmarking*

As ESBN is the only EDN in Ireland, SKM's opex benchmarking involved a comparison of ESBN distribution operation and 110kv transmission asset operation (110kv TAO) with 12 EDNs in the UK which are responsible for 132 kv assets. Scottish EDNs were excluded from SKM's analysis as they did not operate 132 kv assets.<sup>227</sup>

SKM noted that comparing ESBN with UK EDNs may not be appropriate on the basis that the ESBN network is four times greater in line length per customer base than EDNs in the UK. Further, SKM noted that some repair and maintenance costs in Ireland are inherently lower than in the UK. Nevertheless, this detailed knowledge of the differences between the Irish and UK networks means that comparing ESBN with EDNs in the UK is likely to be more meaningful than comparing ESBN with EDNs in other countries.<sup>228</sup>

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<sup>224</sup> CER, *Decision on 2011 to 2015 Distribution Revenue for ESB Networks Ltd*, 19 November 2010, pp. 4-9.

<sup>225</sup> SKM, *CER Transmission and Distribution Price Review, Review of Distribution Operating Costs 2006 to 2015*, 23 June 2010, p 51.

<sup>226</sup> Ibid, pp. 51-65, 78-79.

<sup>227</sup> Ibid, p. 84.

<sup>228</sup> Ibid, p. 29.

## *Data*<sup>229</sup>

For ESBN's distribution and 110kv TAO, SKM used opex and non-network capex data for the 2007 year.

SKM used comparable cost data for 12 EDNs in the UK for the 2007-08 year.

SKM also employed data on network characteristics for ESBN and the 12 EDNs in the UK.

SKM benchmarked costs for the 2007 year only. A longer time frame was not considered as exchange rates, inflation and Purchasing Power Parity indices fluctuated considerably in the period from 2008 to 2010, so a benchmark in 2007 was considered to be more reliable.<sup>230</sup>

The table below shows the comparison of available cost data for ESBN and the 12 EDNs in the UK.<sup>231</sup>

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<sup>229</sup> Ibid, p. 86.

<sup>230</sup> Ibid, p. 85.

<sup>231</sup> Source: SKM, *CER Transmission and Distribution Price Review, Review of Distribution Operating Costs 2006 to 2015*, 23 June 2010, pp. 96-97.

<b>SKM's comparison of comparable costs between ESBN and UK EDNs</b>	
<b>UK DNO Company Activity Costs</b>	<b>ESBN Distribution and 110kV Transmission Operating Costs</b>
<b>Direct Activities</b>	<b>Activity</b>
Load related new connections net	Non-repayable line diversions
Non load related non fault and replacement	System control ^
Non operational capex	Planned maintenance ^
Faults	Fault maintenance ^
Inspection & maintenance	Asset management ^
Tree cutting	
Network policy & R&D	<b>Metering</b>
	Meter reading
<b>Indirect Activities</b>	NQH data
Network design & engineering	Customer meter operation
Project management	Data aggregation
Engineering management & clerical support	
Control centre	Customer service subtotal
System mapping & cartography	Call centre charges
Customer call centre inc compensation claims	Area operations ^
Stores & procurement	Customer relations ^
Vehicles & transport	
IT & telecoms	<b>Provision of data</b>
Property management	DUOS and MRSO ^
HR & non operational training	Market systems support ^
Health & safety and operational training	Corporate charges ^
Finance & regulation	Safety ^
CEO Group, Legal secretary & community	Environment ^
	CER levy
<b>Total activity costs</b>	
	<b>Subtotal</b>
Atypical cash costs	
Pension deficit payments	<b>Commercial</b>
Metering (separate price control)	External repayable
Excluded services & de minimus activities	Supply repayable
Distributed generation less contributions	Other inter ESB
IFI (innovation incentives)	
Disallowed related party margins	Network rates
Statutory depreciation	Insurance
Network rates	Pension
Transmission exit charges	Other legal revenue miscellaneous
Pension deficit payments – related parties	
Non activity costs & reconciliation	<b>Subtotal</b>
<b>Total Annual Opex and Capex per Regulatory Accounts</b>	<b>Total excluding exceptionals</b>
	<b>Controllable costs</b>
	<b>Non controllable costs</b>
	^ESBN opex comparable with UK DNO
	+non network capex
	=comparable opex and non-network capex

### *Technique*

SKM applied linear regression analysis based on the same linear regression method applied by the Ofgem in the electricity distribution price control reviews DPCR3 and DPCR4.

Due to a lack of data, SKM was unable to replicate the regression method applied by the Ofgem in DPCR5 (refer to section 2.3) and therefore only compared ESNB's benchmarking results with the benchmarking results for the 12 EDNs' in the UK that were calculated during the Ofgem's distribution price control reviews, DPCR3 and DPCR4.<sup>232</sup>

### *Inputs*

SKM used 'opex plus non-network capex' as the dependent variable for ESNB and the 12 EDNs in the UK.

To limit the effects of year to year fluctuations in non-network capex, SKM used an average annual cost (non-network capex) for ESNB and compared this to the average non-network capex of the 12 EDNs in the UK.

While the Ofgem's analysis for EDNs' costs used opex as the dependent variable, SKM believed that 'opex plus non-network capex' was a more appropriate measure of recurrent, controllable operating costs. SKM argued it is reasonable to include non-network capex since these costs are business support costs, most of which are depreciated over short timeframes and that omitting these can distort comparisons. For example, while some businesses lease transport, which would constitute operating expenditure, others purchase transport, in which case financing costs would not appear as opex but would appear as depreciation incurred over the life of the asset. IT capex also contributes to improvements in efficiency and therefore should be included in benchmarking analysis.<sup>233</sup>

### *Outputs*

SKM developed two composite scale variables (CSV), which were weighted indices based on customer numbers (millions), units distributed (GWh) and length of network (000 km).

The first CSV, based on the Ofgem's method from DPCR3, was derived as follows:<sup>234</sup>

The CSV for company  $i$  =  $(1 + dUi/Ui + dLi/Li) Ci$  where:

- $dUi/Ui$  is the proportional deviation in units distributed from the overall average
- $dLi/Li$  is the proportional deviation in network length from the overall average

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<sup>232</sup> SKM, *CER Transmission and Distribution Price Review, Review of Distribution Operating Costs 2006 to 2015*, 23 June 2010, p. 95.

<sup>233</sup> Ibid, p. 84.

<sup>234</sup> Ibid.

- $C_i$  is customer numbers in millions.

The second CSV, based on the Ofgem's method for DPCR4, was similar to that applied in DPCR3 but greater weight was given to network length as follows:<sup>235</sup>

CSV =  $A^{0.5} \times B^{0.25} \times C^{0.25}$  where:

A = length of network (000 km)

B = customer numbers (million)

C = units distributed (GWh)

The CSV approach was preferred by SKM because a comparison of costs on a 'cost per customer' or 'cost per km' basis gave contradictory results. For example, ESNB's unit costs (opex plus non network capex) are €96 per customer and €1274 per kilometre, whereas the average EDN in UK has unit costs of €60 per customer and €2139 per km. A comparison on a per kilometre basis favours businesses with a higher network length. The 12 EDNs in the UK have an average of 26 metres of network per customer, whereas ESNB has an average of 75 metres of network per customer. This represents a network length which is three times greater relative to its customer base.<sup>236</sup>

SKM also noted the Ofgem's view that the principal drivers of network length, customer numbers and units distributed individually do not provide a suitable benchmark for operating costs. On this basis, the Ofgem used various weighted composite scale variables to benchmark costs.<sup>237</sup>

#### *Normalisation adjustments*<sup>238</sup>

SKM was of the view that the costs of the 12 EDNs in the UK and ESNB need to be normalised to ensure that only comparable activities and costs are benchmarked and to take account of differences in capitalisation policies.

EDNs in the UK report activity costs as direct costs only. Using the Ofgem's rules for cost reporting, SKM adjusted these costs to include appropriate indirect costs.

EDNs in the UK capitalise more costs than ESNB, particularly fault costs and a proportion of support activities. ESNB has retained a more traditional capitalisation policy and SKM confirmed these practices through a questionnaire.

ESNB reports operating costs on an activity basis, and these costs include indirect costs.

SKM then made adjustments to ensure the costs of the 12 EDNs in the UK were normalised with respect to ESNB's costs, taking account of the following:

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<sup>235</sup> Ibid, p. 95.

<sup>236</sup> Ibid, p. 84.

<sup>237</sup> Ibid, p. 95.

<sup>238</sup> Ibid, pp. 85-86.

- EDNs in the UK capitalised 23.5 per cent of operating costs. These costs were retained in operating costs for the regression analysis as they were not capitalised by ESBN
- EDNs in the UK capitalised part of System Control costs and Health and safety costs. These were included in operating costs for the regression analysis as they did not appear to be capitalised by ESBN
- ESBN operating costs excluded line diversions for the purpose of the regression analysis as these costs were capitalised by the EDNs in the UK
- Metering costs were excluded from the regression analysis. ESBN had full meter operator obligations, whereas the remaining meter operations were separately regulated for EDNs in the UK
- The call centres of the EDNs in the UK took mainly no-supply calls, whereas ESBN call centres handled meter reading calls and no-supply calls. Customer Call Centre costs were therefore excluded from the regression analysis. Other customer service costs were included for both ESBN and EDNs in the UK
- ESBN and EDNs in the UK both had responsibility for Distribution Use of System (DUoS) billing and meter point registration. Therefore, DUoS and Metering Registration System and Operations (MRSO) costs were included in the regression analysis
- Of ESBN's market systems IT costs, 25 per cent of total costs was included as opex in the regression analysis. This was an estimate of those IT costs supporting the MRSO meter registration activity, which is the proportion adopted by ESBN in its regression analysis
- Corporate costs, Safety, Environment, Insurance costs and Pension administration costs were included in the regression analysis
- ESI/licence fees, network rates and commercial excluded services costs were excluded from the regression analysis
- ESBN's 110 kV costs (transmission and distribution) are equivalent to the 132 kV costs of EDNs in the UK. The 110 kV fault and planned maintenance costs of the transmission system operator (TAO) EirGrid were included. EirGrid's other transmission operating costs relate to 400 kV, 220 kV and 110 kV costs and were included in proportion to EirGrid's 110 kV maintenance costs relating to ESBN. Equivalent TAO 110 kV costs are therefore included in the 2007 regression analysis
- EirGrid (the TAO) also has responsibility for some 110 kV activities carried out by EDNs in the UK, including network planning and system operation and control, due to the Single Electricity Market operations. These activities are integrated into 220 kV, 400 kV and generation planning and control activities. The 110 kV component of these costs is significant and includes operating costs of SCADA equipment in substations and associated telecommunications.

### *Model specification*

The table below shows the regression models estimated by SKM.

#### **Regression models estimated by SKM<sup>239</sup>**

<b>Model</b>	<b>Dependent variable</b>	<b>Independent variable</b>
Model 1	Opex + Non network capex	CSV1 (Ofgem, DPCR3)
Model 2	Opex + Non network capex	CSV2 (Ofgem, DPCR4)
Model 3	Opex	CSV1 (Ofgem, DPCR3)
Model 4	Opex	CSV2 (Ofgem, DPCR4)

SKM noted that ESBN is an outlier in terms of ‘cost per customer’ and ‘cost per km’ and it is not certain which of the Ofgem methodologies are most appropriate.<sup>240</sup>

### *Analysis of model outputs*

For each of the four models, SKM plotted the dependent variable (opex + non network capex) against the CSV based on the data for ESBN and the 12 EDNs in the UK. SKM derived the regression line and adjusted this line downwards to identify the efficiency frontier and the upper quartile frontier.<sup>241</sup>

SKM derived a regression line for ESBN using an SKM-estimated CSV. This regression line was then compared to the efficiency frontier and the upper quartile frontier for EDNs in the UK. The upper quartile frontier was considered to account for potential inaccuracies in the method that would result in outliers that would affect the upper frontier. SKM compared ESBN’s position with both the efficiency frontier and upper quartile frontier.

SKM found the following:<sup>242</sup>

- The R-squared correlation factor shows reasonable correlation for all studies
- The relative positions of the three most efficient EDNs are similar across all four models
- The efficiency gap for ESBN varies across the four models from €63m to €15m (for opex plus non-network capex models) and €40m to €5m for opex only models
- When only opex is considered, there is a smaller efficiency gap between ESBN and the 12 EDNs in the UK. However, SKM considered it necessary to include

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<sup>239</sup> Ibid, pp. 86-89.

<sup>240</sup> Ibid, p. 87.

<sup>241</sup> Ibid, pp. 88-89.

<sup>242</sup> Ibid, pp. 86-87.

all inputs, including non-network capex, and noted that in the recent DPCR5 price review, the Ofgem benchmarked EDNs opex plus non-network capex costs

- Model 2 was considered the most representative, which indicates that ESNB distribution and 110 kV opex plus non-network capex is around €33m from the efficiency frontier and €15m from the upper quartile frontier. This model suggests that ESNB costs are 7.5 per cent above the upper quartile of the costs for EDNs in the UK, and 16 per cent above the efficiency frontier.<sup>243</sup>

Based on Model 2, SKM recommended a reduction of 11 per cent in ESNB's controllable opex in 2015 compared to 2009. This is approximately the midway point between the efficiency frontier and the upper quartile frontier.<sup>244</sup>

### *Bottom-up benchmarking*

SKM noted that it is possible to benchmark certain costs directly, e.g., where costs are mainly fixed costs, or where a simple cost driver can be identified. This section considers the results of bottom-up benchmarking of certain maintenance activities, IT/Telecoms costs, and System Control Costs.

### Tree Cutting Costs<sup>245</sup>

Adopting the same costs used for top down benchmarking, SKM carried out benchmarking of tree cutting costs for 2007/08. Tree cutting costs are a significant part of planned maintenance costs, comprising 35 per cent for UK EDNs and 31 per cent for ESNB. SKM calculated UK tree cutting costs to be £63m (including overheads), giving a total cost with overheads of €196m for 780,482 km of overhead line, or an average of €251 per km of overhead line. In comparison, ESNB's typical tree cutting costs were calculated to be €17.5m per year for 163,203 km of line, or an average of €107 per km of overhead line.

SKM calculated tree coverage in Ireland to be 669,000 hectares or 4.7 hectares per km of line. Tree coverage in the UK was calculated to be 7,845,000 hectares or 10 hectares per km of line. Tree cutting costs may therefore be expected to be higher in UK than in Ireland. In addition, revised UK safety regulations place additional obligations on electricity networks to ensure that clearance between trees and lines is maintained to avoid contact and interruptions in supply. There is an amount of work required to achieve these safety standards in UK and this has led to an increase in tree cutting.

SKM noted that this demonstrates a significant limitation in benchmarking where local factors, sometimes of a temporary nature, can frustrate a like for like comparison. However, SKM accepted that ESNB's tree cutting activities appeared to be efficient.

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<sup>243</sup> Ibid, p. 87.

<sup>244</sup> Ibid, p. 69.

<sup>245</sup> Ibid, pp. 90.

### Fault Costs<sup>246</sup>

Using data sourced from the top-down benchmarking analysis, SKM calculated total fault costs in Ireland to be €329 per km and total fault costs in UK to be €492 per km.

However, the UK electricity network is 64 per cent underground cable and the network length is 27 metres per customer. In comparison, ESBN's network is only 13 per cent underground cable and has a network length of 75 metres per customer. Much of the medium-voltage and low-voltage overhead networks in Ireland are simple single-phase networks.

SKM noted that underground cable faults are more expensive to repair than overhead line faults. SKM concluded that UK fault costs per kilometre were inherently higher than in Ireland, and that ESBN was as efficient as the average UK EDN in respect of fault costs.

### IT/Telecoms costs and System Control support costs<sup>247</sup>

SKM compared IT/Telecoms costs and System Control support costs for ESBN and the 12 EDNs in the UK and found ESBN's cost to be relatively higher. This corresponded with the findings of one of ESBN's benchmarking studies, which indicated that some technical costs such as fault and maintenance (cost per km) were considered to be best in class, whereas support costs leave room for improvement. The study indicated that ESBN may have some unfavourable characteristics.<sup>248</sup>

SKM's view was that the ESB network is atypical and has characteristics which mean that costs per kilometre may be inherently lower than networks with a more typical mix of overhead line and underground cable.

### *Application to regulatory decision*

The CER considered that the benchmarking work completed by SKM provided a useful gauge to measure ESBN's performance against international best practice.

The CER noted SKM's advice that:

- its benchmarking results should be used with caution and there are difficulties associated with ensuring that similar costs are compared
- the benchmarking approach becomes more difficult as ESBN approaches UK EDN efficiency levels.

The CER noted that while these difficulties do arise, the benchmarking work still provides a useful tool to ensure that the recommendations put forward by SKM and the values approved by the CER within the final decision are sensible, consistent with

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<sup>246</sup> Ibid, p. 91.

<sup>247</sup> Ibid, p. 80.

<sup>248</sup> These reports of ESBN's consultants are not found on the CER's website or in ESBN's regulatory proposal.

international best practice, and will require ESBN to close the gap between it and international comparators.<sup>249</sup>

Based on its benchmarking analysis (top-down, bottom-up and trend)<sup>250</sup>, the CER concluded that ESBN's costs are 7.5 per cent above the upper quartile of the UK DNO costs and 16 per cent above the efficiency frontier. Consistent with SKM's recommendations for allowed costs, the CER ruled on a reduction of 11 per cent in controllable opex for the third price control period (PR3). The CER adopted almost all of SKM's recommendations for opex and capex allowances.<sup>251</sup>

In particular, the CER determined the following reductions in opex and capex.

CER reduced capex due to:<sup>252</sup>

- Payroll costs
- Productivity/efficiency improvements
- Deferral of certain capex
- Disallowed capex
- Related-party margins.<sup>253</sup>

The CER also discussed the allowances it approved for ESBN's operational costs for the PR3 regulatory period, based on SKM's recommendations:<sup>254</sup>

- Capital driven opex
- Operations and maintenance (system control, planned maintenance, fault maintenance)
- Asset maintenance (way leaves, forestry, mast interference payments)
- Metering (management of meters, collection of data, revenue protection services)
- Customer service (call centre, advertising and promotions)
- Information provision (meter registration system operator, DUoS billing)

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<sup>249</sup> CER, *Decision on 2011 to 2015 Distribution Revenue for ESB Networks Ltd*, 19 November 2010, pp. 59-60.

<sup>250</sup> SKM's trend analysis of ESBN has not been discussed further in this chapter as trend and ratio analysis are benchmarking methods already well-known to and used by the AER.

<sup>251</sup> CER, *Decision on 2011 to 2015 Distribution Revenue for ESB Networks Ltd*, 19 November 2010, p. 58.

<sup>252</sup> *Ibid.*, p. 8.

<sup>253</sup> Twenty-two per cent of ESBN's costs are provided by ESB Group units; e.g., call centre, corporate, IT services, telecoms services, international (asset management, design, project management, and other specialist services).

<sup>254</sup> CER, *Decision on 2011 to 2015 Distribution Revenue for ESB Networks Ltd*, 19 November 2010, pp. 60-63.

- Corporate overheads
- Research and development
- Non-controllable costs (regulatory levies, local authority rates).

### 3.3.2 Benchmarking capex

In assessing ESBN's proposed capital expenditure for the PR3 regulatory period, the CER reviewed:<sup>255</sup>

- the policies and standards adopted by ESBN that underpin the capex programme
- the procurement strategies used to procure plant and contractors' services
- the strategies adopted by ESBN to ensure that planning expenditure is needed, represents best value for the customer and is delivered in the timeframe
- the benefits that capex will bring to the system and whether these benefits are valued by the customer.

SKM reviewed ESBN's capex according to particular cost groups:

- new demand connections
- network reinforcement (including augmentation)
- non-load related capex (including replacement)
- non-network capex
- other capex.

SKM reviewed ESBN's 2006-10 capex on an *ex post* basis by visiting sites and substations and reviewing ESBN's design and planning standard and planning processes.<sup>256</sup> On the basis of this process approach, SKM assessed whether ESBN's actual capex was at an efficient and prudent level. This analysis formed the basis for recommending to the CER whether to approve the actual capex as efficient and to be included in the regulatory asset base for the next regulatory period.

SKM applied similar process analysis to 2011-15 forecast capex to form a view on whether the proposed capex was at an efficient level. SKM also identified potential efficiency savings and analysed<sup>257</sup>:

- ESBN's objective to maintain average DUoS

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<sup>255</sup> Ibid, pp. 77-78.

<sup>256</sup> SKM, *CER Transmission and Distribution Price Review, Review of Distribution Capital Expenditure 2006 to 2015*, 25 June 2010, pp. 71-72.

<sup>257</sup> Ibid, pp. 73-74.

- ESNB's payroll costs compared to other European countries
- ESNB's related-party margins in IT/telecom systems
- identification of improvements in productivity and efficiency
- ESNB's forecast growth rate of new connections.

Connections capex is driven by assumptions about national economic growth. This growth in turn drives the growth in electricity demand and new connections.<sup>258</sup>

Reinforcement capex is driven by new demand connections. The forecast capex is based on capacity margin, which is the excess of installed transformer capacity over demand.<sup>259</sup>

SKM reviewed ESNB's design and planning standards and planning processes and found them to be satisfactory. Although reinforcement planning is carried out as a separate exercise to non-load related expenditure planning, SKM recognised that projects are coordinated where appropriate. SKM preferred to see evidence of a systematic approach to overall capacity planning to ensure that there was a reconciliation of additional capacity with demand forecasts.<sup>260</sup>

Through process analysis, SKM viewed ESNB's network security standards as similar to international practice with n-1 security provided at primary transformer stations taking into account transfer capacity. SKM found that, overall there was little difference between security standards in UK and Ireland. However, the sparse network in parts of Ireland meant that for many rural substations there was limited post fault transfer capacity available to adjacent substations.<sup>261</sup>

The capacity margin of a substation is defined as the excess of capacity over demand taking the capacity of a substation to be 180 per cent of the installed name plate transformer rating. Capacity margin is a measure of the spare capacity that is available at individual substations and on the network overall.<sup>262</sup>

SKM found that significant capacity was added to ESNB's network during PR2.

The increase in overall capacity margin reflected the effect of transformer mix and the overall downturn in demand, whereas individual substations would have captured new demand due to new connections. There is expected to be a steep decrease in capacity margin when demand recovers as is expected in PR3.

Although capacity margin has increased, there remains a significant backlog in distribution network reinforcement, and SKM noted that in PR3 ESNB intends to

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<sup>258</sup> Ibid, pp. 7-8, 47-50.

<sup>259</sup> Ibid, pp. 8-10, 50-56.

<sup>260</sup> Ibid, p. 27.

<sup>261</sup> Ibid.

<sup>262</sup> Ibid.

catch up on the backlog of network reinforcement and makes no provision for any increase in peak demand.<sup>263</sup>

Based on this process analysis, SKM formed a view on ESBN's proposed reinforcement capex and made appropriate recommendations to the CER.

SKM also assessed ESBN's proposed non-load related capex. SKM believes that this capex is driven by the following factors:<sup>264</sup>

- output requirements for incentivised improvements in network performance
- to maintain network assets in acceptable condition
- to maintain satisfactory levels of system performance
- to maintain statutory obligations and safety and environmental standards

The particular network elements covered by this capex are:<sup>265</sup>

- overhead line refurbishment
- HV cables
- HV substations
- MV network renewal
- MV substation replacement
- LV urban and rural overhead line renewal
- LV cable replacement
- replacement of meters and time switches
- network control and associated telecoms

Accordingly, SKM assessed these cost groups using process analysis and engineering knowledge to form a view on the efficient cost levels for ESBN, and made recommendations to the CER.<sup>266</sup>

SKM also reviewed ESBN's proposed non-network capex. This capex refers to accommodation, transport and IT systems, and basic facilities required to support ESBN's management and operation of the network.<sup>267</sup>

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<sup>263</sup> Ibid, pp. 26-28.

<sup>264</sup> Ibid, p. 40.

<sup>265</sup> Ibid, pp. 10-13, 56-66.

<sup>266</sup> Ibid.

<sup>267</sup> Ibid, pp. 13-5, 66-70.

### 3.4 Gas distribution

The CER's most recent price control review for BGN's gas distribution operations was for the period 2007-08 to 2011-12. This was the second price control review (PR2). The first regulatory control period (PR1) was for 2003-04 to 2006-07.

For PR2, the CER<sup>268</sup>:

- Set a revenue cap for BGN
- Set an 80:20 capacity/ commodity split for tariffs
- Included a cost driver incentive associated with unanticipated growth in connections
- Allowed the pass-throughs for costs where BGN has little or no control over their level, e.g., the levy paid to fund CER
- Focused the correction factor on differences between actual and allowed revenue historically, and limited changes to prices in any one year from the correction factor at 5% (except in the case of pre-specified exceptional circumstances) with BGN recovering any revenue over this threshold in later years
- Used the Irish Harmonised Index of Consumer Prices (HICP) in the correction factors
- Incentivised BGN to reduce pass-through costs as much as possible by introducing a 50:50 sharing scheme for the majority of pass-through costs.

To conduct the price control review, the CER engaged Cambridge Economic Policy Associates, who led a consortium of consultants, to assist with all aspects of the review process. The group of consultants includes PKF, Indepen and AESL.<sup>269</sup>

The CER's determination of the allowed revenue included benchmarking BGN's opex using both bottom-up and top-down benchmarking methods. The top-down benchmarking of opex involved comparing BGN with GDNs in other countries and other network infrastructure businesses in other countries.<sup>270</sup> The CER's final decision on BGN's allowed opex for PR2 took account of both the top-down and bottom up analysis.<sup>271</sup> In assessing the reasonableness of BGN's proposed capex for the PR2 period, the CER undertook an engineering evaluation of the proposed capex.<sup>272</sup>

The CER clearly stated in its gas distribution determination of 2nd August 2007 for the period from 2007-08 to 2011-12 that it conducted top-down benchmarking of

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<sup>268</sup> CER, *Board Gáis Networks Revenue Review 2007/8 – 2011/12 – Distribution Decision Paper*, August 2007, pp. 5-6.

<sup>269</sup> Ibid, p. 14.

<sup>270</sup> Ibid, pp. 14-15.

<sup>271</sup> Ibid.

<sup>272</sup> Ibid, p. 6.

BGN's proposed opex.<sup>273</sup> However, a review of the publicly available information in the CER's website did not disclose any detailed reports of the benchmarking technique and method used by the CER. Similarly, a review of public information in the websites of the consultants engaged by the CER in the 2007 price control review did not result in any relevant information or reports on the benchmarking techniques used by these consultants.<sup>274</sup> Therefore a summary of the approach taken for opex and capex are described in sections 3.2.1 and 3.2.2 respectively.

### 3.4.1 Benchmarking opex

As part of its regulatory proposal for PR2, BGN provided the CER with a top-down benchmarking analysis of its distribution opex compared to distribution businesses in the UK and the USA. BGN's benchmarking analysis focused on a measure of efficiency that compared company's opex per km of network. BGN did not compare opex per customer or opex per unit of throughput as it considered that the Irish network characteristics, with relatively few connected customers and throughput given the length of the network, were not comparable with UK and US networks in that regard.<sup>275</sup>

The CER assessed BGN's analysis and carried out its own analysis. The CER's analysis involved:

- A form of trend analysis to understand how BGN's historical opex from 2003-04 to 2006-07 compared with BGN's forecast opex for 2007-08 to 2011-12<sup>276</sup>
- A bottom-up review of each category of BGN's proposed opex to assess whether the expenditure is required for the efficient operation of BGN's distribution business and the future development of the network. The CER also sought to verify its bottom up benchmarking analysis by comparing the specific activities and cost items proposed by BGN, with comparisons from other gas utilities<sup>277</sup>
- A top-down analysis of the efficiency of BGN's distribution business compared to gas distribution businesses in other countries and similar network infrastructure businesses in other countries. The top-down benchmarking informed the CER's view on the efficiency frontier for gas distribution and how BGN's performance compared with this frontier.

The CER compared BGN's opex with the set of comparator UK and US networks used in BGN's analysis as well as other US and Australian comparators.<sup>278</sup>

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<sup>273</sup> Ibid, p. 6.

<sup>274</sup> These consultants' websites can be accessed as follows: Cambridge Economic Policy Associates at [www.cepaa.co.uk](http://www.cepaa.co.uk), PKF at [www.pkf.com](http://www.pkf.com), Indepen at [www.indepen.co.uk](http://www.indepen.co.uk), and Advanced Engineering Solutions at [www.aesengs.co.uk](http://www.aesengs.co.uk).

<sup>275</sup> CER, *Board Gáis Networks Revenue Review 2007/8 – 2011/12 – Distribution Decision Paper*, August 2007, p. 44.

<sup>276</sup> Ibid, p. 43.

<sup>277</sup> Ibid, pp. 14-15.

<sup>278</sup> Ibid, p. 44.

The CER took into account all of the analysis in forming its view of efficient opex. The CER reduced BGN's total opex allowance by 0.5 per cent per annum, this was done by reducing or disallowing certain opex cost categories, including network maintenance, market development, support services, transportation costs, third party claims, shared services and rates.<sup>279</sup> The 0.5 per cent cost reduction was based on the top-down analysis which showed the BGN gas distribution network had scope to catch up with the efficiency frontier gas distribution businesses. This was equivalent to approximately a 28% and €94m reduction in opex.<sup>280</sup>

### 3.4.2 Benchmarking capex

In relation to capex, the CER undertook the following analysis:

- a form of trend analysis to understand how BGN's historical capex from 2003-04 to 2006-07 compared to forecast capex from 2007-08 to 2011-12 and how the historical trend of costs led to proposed capex for PR2<sup>281</sup>
- A bottom-up engineering-based assessment of BGN's proposed capital expenditure for PR2, based on three main categories:<sup>282</sup>
  - cost of replacing cast iron main pipes with polyethylene mains
  - new connections
  - reinforcement of the pipeline network.

Based on the above analysis, the CER reduced BGN's forecasts of various capex categories, leading to a total reduction in allowable capex by €46m for PR2.<sup>283</sup>

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<sup>279</sup> Ibid, p. 46.

<sup>280</sup> Ibid, p. 49.

<sup>281</sup> Ibid, p. 37.

<sup>282</sup> Ibid, p. 36.

<sup>283</sup> Ibid, p. 7.

## 4 New Zealand: Commerce Commission

### 4.1 Overview of the New Zealand energy market

#### *Electricity*<sup>284</sup>

Since 1987, the electricity market in New Zealand (NZ) has undergone a process of significant reform. The monopolistic segments of the electricity supply chain were separated from the contestable segments. Competition was introduced in the electricity generation and retailing sectors. The transmission and distribution of electricity businesses became regulated due to the natural monopolistic characteristics of these segments of the industry. The *Electricity Industry Reform Act 1998* provides that distribution and transmission businesses are prohibited from owning retail or generation businesses.

The wholesale market for electricity in NZ, established in 1996, is currently administered by M-co on behalf of the market regulator, the Electricity Authority (which replaced the Electricity Commission from 1 November 2010).

There are five main electricity generating businesses in NZ. They are also the dominant operators in the electricity retailing sector. Three of the five generating businesses are state-owned.

The electricity transmission grid is operated by Transpower. Transpower is a state-owned enterprise responsible for ensuring electricity supply security and quality.

Distribution of electricity from the grid is the responsibility of 29 distributors. The largest of these, Vector, supplies a third of the electricity distribution market as measured by number of connections. Ownership of distributors is through trust-owned businesses and public companies. Seventeen electricity distributors are subject to price-quality regulation. The remaining 12 electricity distributors are exempt<sup>285</sup> from price-quality regulation as they are consumer-owned.<sup>286</sup>

#### *Gas*<sup>287</sup>

The *Gas Act 1992* deregulated the gas sector and abolished:

- exclusive area retail franchises for gas utilities
- price controls on gas.

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<sup>284</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, p. 84.

<sup>285</sup> Under section 54G of the *Commerce Act 1986*. Available at: [http://www.legislation.govt.nz/act/public/1986/0005/latest/DLM87623.html?search=ts\\_act\\_Commerce+Act\\_resel&p=1](http://www.legislation.govt.nz/act/public/1986/0005/latest/DLM87623.html?search=ts_act_Commerce+Act_resel&p=1) [accessed on 1 December 2011].

<sup>286</sup> Commerce Commission, *Electricity Default Price Quality Path*, available at: <http://www.comcom.govt.nz/electricity-default-price-quality-path/> [accessed on 1 December 2011].

<sup>287</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, pp. 100-103.

The *Commerce Amendment Act 2008*, however, reintroduced price and quality regulation of gas pipeline businesses (distribution and transmission) which will take effect from 2012.

The two major suppliers of gas pipeline services are Powerco and Vector. Powerco is NZ's second-largest electricity and gas distribution company and operates gas and electricity networks throughout the North Island. Powerco also provides gas metering services. Vector's business activities include electricity distribution, natural gas distribution and transmission, and gas and electricity metering services. Other suppliers subject to regulatory arrangements are:

- Wanganui Gas, in relation to gas distribution
- Maui Development Limited, in relation to gas transmission.

### *Regulator*

The Commerce Commission (the NZCC) is NZ's competition enforcement and regulatory agency and was established under section 8 of the *Commerce Act 1986*. The NZCC is an independent Crown entity and is therefore not subject to direction from the government in relation to the carrying out of its enforcement and regulatory control activities.<sup>288</sup>

The NZCC sets price-quality paths for electricity and gas distribution and transmission businesses. It also assesses compliance with the path and administers information disclosure regimes in relation to electricity and gas services.<sup>289</sup>

The Electricity Authority is an independent Crown entity responsible for the efficient operation of the NZ electricity market. The Electricity Authority develops the structure for Transmission Agreements between transmission customers (i.e., generators and customers that connect directly to the grid) and Transpower. The Electricity Authority is also responsible for approving infrastructure investment plans.<sup>290</sup>

### *Appeal Process*

Determinations made by the NZCC can be appealed to the High Court. The appeals process is independent from the initial decision-making process. Prior to October 2008, the High Court's role was limited to reviewing the legality of decisions in relation to the electricity regime.<sup>291</sup>

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<sup>288</sup> The Commerce Commission, *About us*, available at: <http://www.comcom.govt.nz/about-us/> [accessed on 19 April 2012].

<sup>289</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, pp. 86 and 102.

<sup>290</sup> Electricity Authority, *About Us*, available at: <http://www.ea.govt.nz/about-us/> [accessed on 1 December 2011].

<sup>291</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, June 2009, p. 99.

From October 2008, the *Commerce Amendment Act 2008* allows the High Court to review the merits of determinations by the NZCC, including reviewing the NZCC's input methodology (IM) determinations.<sup>292</sup>

## **4.2 Regulatory framework**

Part 4 of the *Commerce Amendment Act 2008* requires the NZCC to set price-quality paths for regulated utilities. This involves setting:

- initial prices
- a price path based on CPI-X for the regulatory period
- quality standards.

The *Commerce Amendment Act 2008* also introduced provisions that prohibit the NZCC from using comparative efficiency benchmarking in order to set starting prices, rates of change or quality standards.<sup>293</sup>

The NZCC determines 'default' price-quality paths (DPP) for electricity distribution, gas distribution and gas transmission businesses. The default price-quality path applies to all service providers in the industry. However, once the default path is set, a regulated business may apply for a 'customised' price-quality path based on individual circumstances. The regulatory period is generally set at five-year intervals, but may be set for four years if determined appropriate by the NZCC.<sup>294</sup>

The purpose of default/customised price-quality regulation is:<sup>295</sup>

...to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances..

In relation to electricity transmission, the NZCC may set a price-quality path for Transpower (the sole provider) using a process it considers appropriate. The NZCC applied a 'building blocks' model to determine the maximum allowable revenue for Transpower for the period 1 April 2012 to 31 March 2015.<sup>296</sup>

## **4.3 Electricity distribution**

Consumer-owned electricity distribution businesses are exempt from price-quality regulation. 'Non-exempt' electricity distribution networks (EDNs) have been subject

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<sup>292</sup> *Commerce Act 1986*, s. 52Z.

<sup>293</sup> *Commerce Act 1986*, s. 53P (10).

<sup>294</sup> *Commerce Act 1986*, s. 53L and 53M.

<sup>295</sup> *Commerce Act 1986*, s. 53K.

<sup>296</sup> Commerce Commission, *Individual Price-Quality Path (Transpower): Reasons Paper*, December 2010, p. 3.

to default price-quality path regulation from 1 April 2009. The current regulatory control period applies from 1 April 2010 to 31 March 2015.<sup>297</sup>

The key components of the default price-quality path are:<sup>298</sup>

- maximum prices/revenues at the start of the regulatory period (i.e., starting prices)
- rates of change of prices (in the form of CPI-X)<sup>299</sup>
- minimum service-quality standards.

The NZCC made an initial decision on the price-quality path for EDNs on 30 November 2009, pending the development of input methodologies (IMs).<sup>300</sup> The IMs were determined in December 2010 for electricity distribution and transmission and gas pipelines. The Commission must review each input methodology no later than seven years after its date of publication and, after that, at intervals of no more than seven years.<sup>301</sup>

The determination for EDNs includes input methodologies that apply to default/customised price-quality regulation, and to information disclosure regulation. The determination includes input methodologies for asset valuation, cost allocation, regulatory tax treatment, the cost of capital, regulatory rules and processes, and matters relating to customised price-quality path proposals.<sup>302</sup>

The NZCC commenced a reset of the 2010-2015 default price-quality path to reflect the input methodologies ('mid-term decision'). This is further discussed in section 4.3.1 below. The following information is based on the NZCC documents in relation to the Initial Reset and the Draft Decision for the mid-term reset.

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<sup>297</sup> Commerce Commission, *2010-2015 Default Price-Quality Path*, Available at: <http://www.comcom.govt.nz/2010-2015-default-price-quality-path/> [accessed on 10 November 2011].

<sup>298</sup> Commerce Commission, *Consolidated Version of Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2010 (including all amendments as at 31 March 2011)*, 7 April 2011. Available at: <http://www.comcom.govt.nz/2010-2015-default-price-quality-path/> [accessed on 10 November 2011].

<sup>299</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, p. 36.

<sup>300</sup> 'Input methodology' has the meaning set out in section 52C of the *Commerce Act 1986*. The purpose of input methodologies is to promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation, or proposed regulation, of goods or services under Part 4 of the *Commerce Act 1986*. Once input methodologies are determined, they apply to both regulated parties and the Commerce Commission.

<sup>301</sup> Commerce Commission, *Input Methodologies*. Available at: <http://www.comcom.govt.nz/input-methodologies-2> [accessed on 4 April 2012].

<sup>302</sup> Commerce Commission, *Input Methodologies, Electricity Distribution*. Available at: <http://www.comcom.govt.nz/electricity-distribution/> [accessed on 4 April 2012].

#### 4.3.1 Overview of default price-quality path determination

##### *The price path (initial decision)*<sup>303</sup>

The initial price path developed by the NZCC provided a weighted average price cap based on notional revenue. The price cap limited aggregate price increases, but did not constrain prices for individual services, classes of services, or for different customer groups. The price path was indexed using a CPI-X mechanism. The CPI figure was derived annually based on observed historic values. The price path also identified those costs that may be passed through to consumers.

To derive notional revenue, the NZCC used a formula based on starting prices and quantities (see below). The quantities were from the pricing year ending two years prior (i.e., 2008-09) to the end of the relevant assessment period (i.e., 2010-11) ('t-2 approach').

##### **Formula for allowable notional revenue for the first assessment period**<sup>304</sup>

$R_{2011}$	is the allowable notional revenue for the First Assessment Period, being equal to: $\left( \sum_i P_{i,2010} Q_{i,2009} - K_{2010} \right) \times ((1 + \Delta CPI_{2011}) \times (1 - X))$
where	
$P_{i,2010}$	is the $i^{\text{th}}$ starting Price as specified in Schedule 1 of the Initial Reset Determination;
$Q_{i,2009}$	is the Quantity corresponding to the $i^{\text{th}}$ Price for the period 1 April 2008 to 31 March 2009;
$K_{2010}$	is the sum of all Pass-Through Costs, other than Commerce Act Levies, during the Pricing Period 1 April 2009 to 31 March 2010;
$X$	is the rate of change for the Non-exempt EDB (as specified in Schedule 2 of the Initial Reset Determination); and
$\Delta CPI_{2011}$	is the derived change in the CPI to be applied during the First Assessment Period, being equal to: $\frac{CPI_{Dec,2008} + CPI_{Mar,2009} + CPI_{Jun,2009} + CPI_{Sep,2009}}{CPI_{Dec,2007} + CPI_{Mar,2008} + CPI_{Jun,2008} + CPI_{Sep,2008}} - 1$

##### *Starting prices (initial reset)*<sup>305</sup>

The NZCC may set the starting prices, either:

- equal to the prices that applied at the end of the preceding regulatory period; or
- based on the current and projected profitability calculations for each supplier.<sup>306</sup>

<sup>303</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, p. iii and pp. 23-24.

<sup>304</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, Appendix B, p. 78.

<sup>305</sup> Ibid, pp. 34-35.

The NZCC set starting prices as those that applied at the end of the preceding regulatory period (that is, the prices as at 31 March 2010).

#### *Rate of change – X factor*

The NZCC may determine the rate of change (X factor) based on the long-run average productivity growth rate achieved by:

- electricity distribution networks in NZ; and/or
- businesses in comparable countries of relevant goods or services.

The NZCC may use any measure of productivity that it considers appropriate.<sup>307</sup>

The X factor is the same for all non-exempt EDNs; however, the NZCC may set an alternative X factor for individual EDNs if, in the NZCC's opinion this is necessary or desirable to either:

- minimise undue financial hardship to the EDNs
- minimise price shocks to consumers.<sup>308</sup>

The NZCC set the X factor at zero based on two Total Factor Productivity (TFP) analyses undertaken by Economic Insights (2009) and Pacific Economics Group (PEG) (2009).<sup>309</sup> These analyses are explained in detail in section 4.3.4.

#### *Quality standards*<sup>310</sup>

The default price-quality path provides the quality standards to be met by EDNs. Quality standards may be specified in a manner considered appropriate by the NZCC.<sup>311</sup>

For the period 2005 to 2009, quality standards were developed using averages of SAIDI and SAIFI reliability data and based on a 'no material deterioration' premise. That is, the quality standards were designed to ensure that no material deterioration in reliability occurred for the period. These quality standards also applied to the regulatory period commencing 1 April 2010.

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<sup>306</sup> *Commerce Act 2008*, s. 53P (3).

<sup>307</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, p. 37.

<sup>308</sup> *Commerce Act 1986*, s. 53P (8).

<sup>309</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, p. 45.

<sup>310</sup> *Ibid*, p. iii and Chapter 6.

<sup>311</sup> *Commerce Act 1986*, s. 53M (1) (b) and (3).

### *Mid-term reset*<sup>312</sup>

As discussed previously, the NZCC developed the input methodologies following the implementation of the initial DPP. The NZCC determined that the IMs would result in a materially different price path because, *inter alia*:

- the IMs excluded GST from the definition of CPI
- the existing price path allowed prices to move in line with a full GST-inclusive change in the CPI.

As a result, the NZCC undertook a ‘mid-term’ reset of the 2010-2015 DPP, with the new price levels taking effect from 1 April 2012.

The draft decision for the mid-term reset:

- changed the maximum allowable prices in 2012-13 so that each EDN is projected to earn a normal return between 2012-13 and 2014-15
- changed the maximum allowable rate of change in prices applying to all EDNs to reflect the new definition of the CPI specified under IMs
- changed the maximum allowable rate of change in prices applying to specific EDNs where this would minimise potential price shocks to consumers
- made other amendments to ensure the 2010-2015 DPP determination is consistent with the IMs.

The draft decision did not affect quality standards or the previously determined industry-wide X factor of zero per cent per annum.

### *CPI*<sup>313</sup>

The initial price path set by the NZCC in November 2009 allowed prices to move in line with the full CPI. That is, the price path included the impact of changes in the GST on the CPI.

The IMs that were subsequently developed excluded GST from the CPI. This was because EDNs can be reimbursed for direct GST costs. This change, combined with the 2010 increase in GST levels in NZ of 2.5 percentage points, resulted in a material change to the price path and the need for a mid-term reset of the price-path.

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<sup>312</sup> Commerce Commission, *2010-15 Default Price Quality Path for Electricity Distribution Draft Decisions Paper*, 19 July 2011, p. v.

<sup>313</sup> *Ibid*, pp. 4-8.

#### 4.3.2 Approach to projecting opex growth<sup>314</sup> (mid-term reset)

Opex growth is indexed throughout the regulatory period subject to changes in input prices, opex partial productivity growth, and output growth using the following formula:<sup>315</sup>

$$\Delta Opex = \Delta Opex Price - \Delta Opex PP + \Delta Output Quantity$$

where:

$\Delta Opex$  is the business-specific projected growth in nominal opex used in the starting-price modelling;

$\Delta Opex Price$  is the industry-wide projected growth in the opex input-price index, a weighted average of input-price indices for labour costs and non-labour costs;

$\Delta Opex PP$  is the industry-wide projected growth in opex partial productivity; and

$\Delta Output Quantity$  is the business-specific projected output-quantity growth.

##### *Change in opex price*

The opex price index is forecast using a weighted average of:

- an independent labour cost index (LCI) across all industries forecast
- an independent producer price index (PPI) forecast for all industries prepared by the NZ Institute of Economic Research (NZIER).

The weights used are 60 per cent for the LCI and 40 per cent for the PPI. The NZCC undertook sensitivity analysis on these weights.

##### *Change in opex partial productivity*

Opex partial productivity growth was set after consideration of:

- analysis, prepared by Economic Insights,<sup>316</sup> in relation to opex partial factor productivity growth rates of non-exempt NZ EDNs for the periods 1996 to 2008 and 2001 to 2008 respectively (the Economic Insights Report)
- a report, prepared by PEG for the Electricity Networks Association,<sup>317</sup> on opex partial factor productivity growth for all NZ EDNs for the periods 1999 to 2008 and 2001 to 2008 respectively (the PEG Report)

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<sup>314</sup> Ibid, pp. 32-36, 67-71.

<sup>315</sup> Ibid, pp. 67.

<sup>316</sup> Economic Insights, *Electricity Distribution Industry Productivity Analysis: 1996–2008*, September 2009.

- analysis of opex partial factor productivity growth rates of Victorian EDNs prepared for the Victorian Essential Services Commission.<sup>318</sup>

These studies provided mixed evidence in relation to opex partial productivity growth and the results varied depending on the time period chosen. In light of this mixed evidence, the NZCC set the annual opex partial productivity growth rate at zero per cent.<sup>319</sup> That is, the NZCC adopted a conservative approach and set no change in opex partial productivity growth.

#### *Output quantity growth*

Output quantity growth is calculated using real revenue projections for the period 2011 to 2015 for each EDN.

#### *Opex reasonableness check*

A ‘reasonableness check’ was employed in relation to projected opex allowances for 2012-13 to 2014-15. This ensured that no step change occurred.<sup>320</sup> It involved a comparison of:<sup>321</sup>

- average projected opex figures, deflated by the LCI and PPI for 2012-13 to 2014-15
- the average historical opex data for 2008 to 2010, in constant prices and scaled to reflect the IMs.

#### 4.3.3 Approach to projecting capex growth (mid-term reset)<sup>322</sup>

In projecting capex growth, the NZCC used the growth figures in forecast system capex from asset management plans (AMPs) submitted by the EDNs as a proxy.

Historical capex figures and forecasts from individual AMPs for the year of 2010 were used. Variances between 2010 and 2011 AMP capex forecasts and growth rates were tested and forecasts for growth rates were nominalised using the capital-goods price index (CGPI).

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<sup>317</sup> Pacific Economics Group, *Reset of Default Price Path for Electricity Distribution Businesses: Submission to the Commerce Commission, Report prepared for the Electricity Networks Association*, August 2009.

<sup>318</sup> Pacific Economics Group, *TFP Research for Victoria’s Power Distribution Industry: 2007 Update, Report prepared for Essential Services Commission*, 2008.

<sup>319</sup> Commerce Commission, *2010-15 Default Price Quality Path for Electricity Distribution Draft Decisions Paper*, 19 July 2011, p. 34.

<sup>320</sup> A step change is an incremental change in costs attributable to changes in the underlying cost drivers expected to occur after the base year, and hence not reflected in the recurrent expenditure (i.e. base opex). A step change generally reflects a cost associated with changes in regulatory obligations or a change in operating environment.

<sup>321</sup> Commerce Commission, *2010-15 Default Price Quality Path for Electricity Distribution, Draft Decision Paper*, 19 July 2011, p. 71.

<sup>322</sup> Ibid, pp. 36, 73.

The AMP forecasts were not independently verified. Further, historical capex disclosed under information disclosure can differ significantly from industry forecasts. However AMP data were used because of:

- limited impact of different capex growth assumptions on starting prices
- no explicit incentive to inflate forecasts when preparing the AMPs as the EDNs did not know at the time that the data would be used for setting starting prices.

Industry-average data were not used because of the wide variance in the capex needs of EDNs.

To allow for the non-linear shape of AMP capex projections, the starting-price modelling used individual growth projections for each EDN and for each year between 2011 and 2015. An average annual growth rate projection for each EDN was derived.

#### 4.3.4 Benchmarking to determine X factor

##### *Summary*

To determine the X factor, the NZCC relied on reports by Economic Insights and PEG.<sup>323</sup>

Both reports used TFP analysis to determine the X factor. The analysis incorporated:<sup>324</sup>

- the difference between the industry and economy-wide TFP growth rate
- the difference between the change in input prices for the industry and the economy.

The X factor is therefore calculated as:<sup>325</sup>

$$X \equiv \{\Delta TFP - \Delta TFP_E\} - \{(s_O \Delta w_O + s_K \Delta P_{KD}) - \Delta W_E\}$$

= TFP differential growth rate term – input price differential growth rate term.

where *TFP* is total factor productivity, *W* represents input prices, *S* is the input cost share, and *P<sub>KD</sub>* is the industry capital unit amortisation charge. Subscripts *O* and *K* represent operating costs and capital costs respectively. Subscript *E* refers to economy-wide variables.

The formula accounts for sunk costs and financial capital maintenance (FCM).<sup>326</sup>

<sup>323</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, p. 40.

<sup>324</sup> Ibid, p. 38.

<sup>325</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009, pp. ii, 7.

This method is equivalent to that used for determining the ‘B factor’ in the previous ‘thresholds’ regulatory regime (discussed in section 4.3.7).

#### *Application by the NZCC*

The NZCC relied on recommendations of the Economic Insights Report and the PEG Report in relation to its decisions for:

- the industry-economy TFP differential
- the industry-economy input-cost differential.

More weight was given to the results of Economic Insights Report because longer time periods were employed in that analysis and the NZCC considered that the longer time periods were more consistent with the objectives of the *Commerce Act 1986*.<sup>327</sup>

The NZCC may also use international productivity analysis when determining the X factor.<sup>328</sup> The Economic Insights Report included data on EDNs in Australia and investor-owned EDNs in the US. However, the NZCC did not directly incorporate this analysis in its determination of the X factor. The NZCC considered the NZ analysis sufficient to make a determination and that the international results were useful in order to provide a ‘sanity check’.<sup>329</sup>

#### 4.3.5 Economic Insights Report: Electricity distribution productivity analysis<sup>330</sup>

##### *Data used*

The Economic Insights Report primarily used data provided by EDNs under the *Electricity (Information Disclosure) Regulations*. The data included physical network factors, service quality and financial information for 13 years from 1996 to 2008,<sup>331</sup> covering:

- the 16 ‘non-exempt’ EDNs that are subject to the DPP
- the 12 EDNs that are consumer-owned and therefore exempt from the DPP.

Statistics New Zealand’s multi-factor productivity data series for the market (private/non-government) sector of the economy was compared with the results of the TFP analysis for the electricity distribution industry, for 1996 to 2008.<sup>332</sup>

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<sup>326</sup> The principle of FCM requires that an asset investor’s cost of investment will be recovered over the life of the asset, but the investor does not make any windfall gain or loss from the value of the initial investment.

<sup>327</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, p. 44.

<sup>328</sup> *Commerce Act 1986*, s. 53P(6).

<sup>329</sup> Commerce Commission, *Initial Reset of Default Price-Quality Paths for Electricity Distribution Businesses*, 30 November 2009, pp. 46-47.

<sup>330</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009.

<sup>331</sup> *Ibid*, p. 10.

<sup>332</sup> *Ibid*, pp. 38-39.

International data provided by the Essential Services Commission for Victoria and for investor-owned US electricity distribution businesses were also used.<sup>333</sup> Finally, confidential information collected by Economic Insights for earlier benchmarking studies in relation to Victorian EDNs was used.<sup>334</sup>

### *Benchmarking technique*

The data were used to calculate trend rates of productivity growth for the NZ electricity distribution industry as a whole, as well as for the group of ‘non-exempt’ EDNs.<sup>335</sup> Fisher TFP index-number method was used to measure productivity change (i.e., a weighted average of changes in output quantities divided by a weighted average of changes in input quantities).<sup>336</sup> This approach was adopted because of its relative simplicity and because the approach is considered to be consistent with the purposes of the legislation.<sup>337</sup>

### *Input quantities*<sup>338</sup>

#### Operating expenditure

The quantity of operating and maintenance expenses was derived by deflating the sum of the grossed-up values of direct costs per kilometre and indirect costs per customer by the index of labour costs for the electricity, gas and water sector. The grossed-up values of direct costs per kilometre and indirect costs per customer were used as the value of operating costs because these measures reflected the purchases of actual labour, materials and services used in operating the electricity distribution system and because they excluded rebates.<sup>339</sup> The index of labour costs for the electricity, gas and water sector was used as the price of operating expenditure as it directly measures the price of a major component of operating expenditure.

#### Overhead network

The electricity distribution overhead network, measured in MVA kilometres,<sup>340</sup> was used as a proxy for the quantity of poles and wires that form the overhead network.

Conversion of the different kilovolt lines to MVA kilometres was calculated as follows:<sup>341</sup>

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<sup>333</sup> This set of data was also used in the PEG Report: Pacific Economics Group (PEG) (2008), *TFP Research for Victoria’s Gas Distribution Industry: 2007 Update, Report prepared for the Essential Services Commission*, December 2008.

<sup>334</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009, p. 32.

<sup>335</sup> Ibid, p. 16.

<sup>336</sup> A mathematical representation of the Fisher TFP index is available at: Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009, pp. 22-23.

<sup>337</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009, p. 3.

<sup>338</sup> Ibid, p. 15.

<sup>339</sup> AC loss rental rebates.

<sup>340</sup> MVA denotes ‘Mega volt amperes’.

<sup>341</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009, p. 14.

- Low-voltage distribution lines were converted using a factor of 0.4
- High-voltage distribution lines were converted using factors of 2.4 for 6.6kV lines, 4 for 11kV lines, 8 for 22kV lines, 15 for 33kV lines, 35 for 66 kV lines, and 80 for 110 kV lines.

These factors were based on analysis undertaken by Parsons Brinckerhoff Associates (2003) and were considered to reflect NZ operating conditions.

### Underground network

The electricity distribution underground network (in MVA kilometres) was used as a proxy for the quantity of underground cables that form the underground network). The calculation of total underground MVA kilometres was based on the same factors as listed above for total overhead MVA kilometres.

### Transformers and other assets

The electricity distribution transformers installed (in KVA<sup>342</sup>) was used as a proxy for the quantity of transformers and other assets.

### *Input weights<sup>343</sup>*

The value of total costs was formed by summing the estimated value of operating expenditure and 12.5 per cent of total (estimated) Indexed Historic Cost (IHC). The latter was based on the assumption of a common depreciation rate of 4.5 per cent and an opportunity cost rate of eight per cent for capital assets.<sup>344</sup> When calculating sunk costs and FCM, total costs were derived by summing operating expenditure and amortisation charges.

Opex was weighted according to its share in total cost. The residual weight was allocated to capital inputs. The three capital input components are weighted according to their shares in 2004 optimised deprival value (ODV) multiplied by the overall capital share in total cost.

### *Output quantities<sup>345</sup>*

### Throughput

The number of kilowatt-hours of electricity supplied by distributors was used as a measure of the quantity of electricity distribution throughput.

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<sup>342</sup> KVA denotes 'Kilo volt amperes'.

<sup>343</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, 1 September 2009, p. 15.

<sup>344</sup> NZ Institute of Economic Research (NZIER), *Analysis of Lines Business Costs*, Report prepared for Ministry of Economic Development, Wellington, 2001.

<sup>345</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, September 2009, pp. 14-15.

### System line capacity

The quantity of electricity distribution system line capacity was measured by total MVA kilometres. This provided a more representative measure of system line capacity compared to either line length alone or by simply summing the product of line kilovolt rating by corresponding line kilometres. Total MVA kilometres were calculated using the same factors as listed above for total overhead MVA kilometres.

An alternative capacity measure, which reflects the ability to meet capacity demands, is the overall system capacity. It was measured by multiplying:

- the electricity distribution industry's installed distribution transformer kVA capacity of the last level of transformation to the utilisation voltage; and
- the total kilometres of mains length, including voltages but excluding street-lighting and communications lengths.

The report considered that distribution transformer capacity had grown rapidly over the last several years and failure to recognise the important contribution of increased distribution transformer capacity would lead to downward biased estimate for the system capacity.<sup>346</sup>

### Connections

The number of connections was used as a proxy for connection-dependent and customer service activities.

### Omission of a reliability measure

The Economic Insights report identified limitations associated with the analysis, such as omitting a measure of 'reliability' as an additional output variable. However, the report concluded:<sup>347</sup>

all common reliability measures involve improvements being decreases in the variable rather than increases as in the productivity framework. Previous attempts to convert reliability measures into a format consistent with the productivity framework have proven unsuccessful.

### Output weights<sup>348</sup>

Output cost shares were derived using a Leontief cost function.<sup>349</sup> A weighted average of the output cost shares was formed using the share of each observation's estimated costs in the total estimated costs for all EDNs for the period 1996 to 2002. This produced the output weights:

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<sup>346</sup> Ibid, p. iii.

<sup>347</sup> Ibid, p. 20.

<sup>348</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, September 2009, pp. 14-15.

<sup>349</sup> See, for example, Lawrence D, *Regulation of Electricity Lines Businesses, Analysis of Lines Business Performance – 1996–2003*, Meyrick and Associates Report prepared Commerce Commission, Canberra, 19 December 2003, pp. 14-15.

- for throughput of 22 per cent
- for system capacity of 32 per cent
- for connections of 46 per cent.

#### *Regression model to estimate TFP growth trend*

Trend TFP growth rates were estimated using a regression-based trend analysis method used in the Lawrence study (2003).<sup>350</sup> Growth rates were determined by a regression of the logarithm of the TFP index (calculated for each EDN at each point in time) against a constant and a linear time trend. The estimated coefficient with the time trend variable is the growth rate. This technique was used to reduce the extent that endpoint outliers distorted the estimated growth rate and thus to provide a better representation of the underlying trend growth over the whole period.<sup>351</sup>

#### *Analysis of model outputs*

The TFP results were incorporated with the input-price growth differential (i.e., the difference in input price growth between the industry and the economy). The input-price growth differential was calculated by considering a unit change in amortisation charges. The amortisation charges were calculated on the basis of *ex ante* financial capital maintenance. The calculation used the full 13-year period (1996 to 2008).

The capital-goods price index was not used because of the quality of available data, namely, the erratic movements in the price index suggest the data were unreliable.

#### *Statistical testing of model*

Four partial productivity indices were derived and analysed to support the total productivity results. These partial measures were: opex, overhead lines, underground cables and transformers.<sup>352</sup>

For sensitivity analysis, the regression model was re-estimated by:<sup>353</sup>

- replacing the 12.5 per cent ODV user cost proxy with consistent amortisation charges both pre- and post-tax
- replacing lines system capacity with overall system capacity output measure.

The analysis was repeated with only non-exempt EDNs, which accounted for approximately 80 per cent of the industry throughput.

The results of the TFP analysis were compared with the results of TFP analysis in relation to Victorian and US investor-owned businesses.<sup>354</sup>

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<sup>350</sup> Ibid.

<sup>351</sup> Economic Insights, *Electricity Distribution Productivity Analysis: 1996-2008*, September 2009, p. 21.

<sup>352</sup> Ibid, pp. 24-26.

<sup>353</sup> Ibid, pp. 27-28.

The Economic Insights analysis for Victoria EDNs used a specification similar to that used in the study of NZ EDNs. The analysis was extended to include a series that used the overall system capacity output specification. Growth rates were also reported using the regression-based trend analysis method.

#### 4.3.6 PEG: Productivity study for the Electricity Networks Association<sup>355</sup>

##### *Data*<sup>356</sup>

The data were provided by the EDNs under the *Electricity (Information Disclosure) Regulations*. This set of data was supplemented with data extracted from threshold compliance statements. These compliance statements were published by EDNs to demonstrate compliance with regulatory price and quality thresholds that applied under the previous regulatory regime (refer to section 4.3.7).

The raw data were compiled by Pricewaterhouse Coopers (PwC) and used to calculate the TFP estimates.

PEG also used data on Multi-factor Productivity, CPI and the capital goods price index compiled by Statistics New Zealand. These data were used to develop the economy-wide components of both the TFP differential and input price differential. PEG also used the CPI and capital goods price index in the computation of the industry input price index.

PEG considered two possible time periods, 1999 to 2008 and 2001 to 2008, respectively.

##### *Benchmarking technique*<sup>357</sup>

PEG used the Törnqvist index to calculate the TFP annual average growth rate.

The formulas used by PEG are as follows:<sup>358</sup>

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<sup>354</sup> There are two relevant studies of Victorian EDNs. These are: Economic Insights, *Energy Network Total Factor Productivity Sensitivity Analysis*, Report by Denis Lawrence to the Australian Energy Market Commission, Canberra, 9 June 2009; and Pacific Economics Group, *TFP Research for Victoria's Gas Distribution Industry: 2007 Update*, Report prepared for the Essential Services Commission, Madison, December 2008. The US study is Pacific Economics Group, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Presentation to IRM3 Stakeholders, Toronto, 25 March 2008.

<sup>355</sup> Pacific Economics Group, *X Factor Recommendations for New Zealand Electricity Distribution Price Controls*, July 2009.

<sup>356</sup> Ibid, p. 11.

<sup>357</sup> Ibid, pp. 12-14.

<sup>358</sup> Pacific Economics Group, *X Factor Recommendations for New Zealand Electricity Distribution Price Controls*, July 2009, pp. 12-14.

Input quantity index:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (S_{j,t} + S_{j,t-1}) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right). \quad [1]$$

Here in each year  $t$ ,

$Input\ Quantities_t$  = Input quantity index

$X_{j,t}$  = Input quantity subindex for input category  $j$

$S_{j,t}$  = Share of input category  $j$  in applicable total cost.

Output quantity index:

$$\ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) = \sum_k \frac{1}{2} \cdot (S_{k,t} + S_{k,t-1}) \cdot \ln\left(\frac{Y_{k,t}}{Y_{k,t-1}}\right). \quad [2]$$

Here in each year  $t$ ,

$Output\ Quantities_t$  = Output quantity index

$Y_{k,t}$  = Output quantity subindex for output category  $k$

$S_{k,t}$  = Share of input category  $k$  in applicable total revenue.

Annual growth rate:

$$\ln\left(\frac{TFP_t}{TFP_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \quad [3]$$

TFP trend:

$$\begin{aligned} trend\ TFP_t &= \frac{\sum_{t=1999}^{2008} \ln\left(\frac{TFP_t}{TFP_{t-1}}\right)}{9} \\ &= \frac{\ln\left(\frac{TFP_{2008}}{TFP_{1999}}\right)}{9} \end{aligned} \quad [4]$$

Inputs<sup>359</sup>

Inputs were divided into two categories:

- operation and maintenance (O&M) expenses
- capital inputs.

<sup>359</sup> Ibid, pp. 14-16.

Lack of available data prevented the disaggregation of O&M expenses into labour and non-labour inputs.

The total cost of electricity distribution was calculated as power distribution O&M expenses plus the cost of plant ownership. O&M cost figures were obtained from Information Disclosure Statements. Capital cost was calculated using a capital service price method. That is, the cost of capital was equal to the capital quantity index multiplied by the price of capital services.

The input quantity index was constructed as a weighted average of input quantity indices for capital and O&M inputs. Growth in each input quantity index was calculated in inflation-adjusted terms. Each input quantity subindex was ‘deflated’ using an input price subindex.

The approach to quantity trend measurement assumed that the growth rate in the cost of any class of input  $j$  is the sum of the growth rates in the input price and the quantity indices for that input class.

The quantity subindex for O&M was the ratio of the aggregate O&M expenses to the CPI. The CPI was chosen as the opex price subindex because PEG did not have detailed data in relation to the composition of the EDNs’ O&M costs.

A simplified service price approach was chosen to measure capital cost. The cost of a given class of utility plant  $j$  in a given year  $t$  ( $CK_{j,t}$ ) is the product of a capital service price index ( $WKS_{j,t}$ ) and an index of the capital quantity at the end of the prior year ( $XK_{j,t-1}$ ).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}$$

The capital quantity index is constructed using inflation-adjusted data in relation to the value of the utility plant.

In constructing indices, the value of each EDN’s Regulatory Asset Base (RAB) in 2004 was adopted as the benchmark or starting year. This is the year of the most recent revaluation of the EDNs’ capital stock. The following formula was used to calculate the capital quantity index:

$$XK_{j,t} = (1 - d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}$$

where  $d$  is the depreciation rate and  $VI_{j,t}$  is the value of gross additions to the utility plant.

The asset-price index ( $WKA_t$ ) is equal to the capital goods price index for electricity distribution and control apparatus. The depreciation rate for each company was measured as the regulatory value of its depreciation expenditures divided by the RAB of the previous year. An average regulatory depreciation rate is calculated for each company for 1999 to 2004 and for 2005 to 2008.

This regulatory depreciation rate was used to measure capital costs using an *ex post* approach. This approach examined the actual gross returns to capital at the end of each period. For each year, this was measured as an EDN's regulated revenue minus O&M and regulatory depreciation expenses, divided by the value of the RAB at the end of the preceding year.

The formula for the capital service price index is:

$$WKS_t = r_t \cdot WKA_{j,t-1} + d \cdot WKA_{j,t}$$

where  $r_t$  is the ex post return on capital.

#### Input growth rates<sup>360</sup>

The growth rate in each input quantity index was a weighted average of the growth rates in quantity indices for capital and O&M inputs. The weights were based on the shares of these inputs in total electricity distribution cost.

#### *Outputs*<sup>361</sup>

The growth in the output quantity index was a weighted average of growth in three output quantity indices: the number of customers, total delivery volumes (GWh) and non-coincident demands (GW). These output choices corresponded to the billing determinants for the EDNs, or the services which generated the EDNs' revenues.

PEG used the associated revenues (e.g., fixed customer charges for number of customers) to weight the aggregated output index. The revenue shares were updated annually for each EDN, which led to a 'chain weighted' output quantity index.

#### *TFP index estimation*<sup>362</sup>

The growth rate in each EDN's TFP index was the difference between the growth rates in the industry's output and input quantity indices.

#### *Input Price Indexes*<sup>363</sup>

PEG also developed input price indexes for the electricity distribution industry. This was a cost-share weighted average of the growth in input price indices of capital and O&M inputs. Total 'cost' was constrained to equal total revenue, so that the long-run trend in industry revenues was equal to the trend in industry costs.

#### *Analysis of model outputs*

PEG calculated the X factor as follows:<sup>364</sup>

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<sup>360</sup> Ibid, p. 16.

<sup>361</sup> Ibid, pp. 11-12.

<sup>362</sup> Ibid, p. 16.

<sup>363</sup> Ibid, p. 16.

<sup>364</sup> Ibid, p. 30.

X = Industry TFP trend - NZ MFP trend

+ NZ input price trend - Industry input price trend

The table below shows the eight different models estimated by PEG to determine the X factor. The models are based on different combinations of time periods for the four components of the X factor. For four of the models, PEG assumed an input price differential of zero (represented by 'na' in the table below). That is, the industry input price trend is equivalent to the NZ economy-wide input price trend.<sup>365</sup>

PEG recommended to the NZCC an X factor of between 0.66 per cent (model six) and -1.17 per cent (model seven).<sup>366</sup>

#### X factor models estimated by PEG<sup>367</sup>

Model	Time period – <i>Industry TFP</i>	Time period – <i>NZ MFP</i>	Time period – <i>NZ input price</i>	Time period – <i>Industry input price</i>
1	1999-2008	1999-2008	1999-2008	1999-2008
2	1999-2008	2000-2008	2000-2008	1999-2008
3	2001-2008	1999-2008	1999-2008	2001-2008
4	2001-2008	2000-2008	2000-2008	2001-2008
5	1999-2008	1999-2008	na	na
6	1999-2008	2000-2008	na	na
7	2001-2008	1999-2008	na	na
8	2001-2008	2000-2008	na	na

#### 4.3.7 Thresholds regime for electricity distribution 2001 to 2009

##### *Previous regulatory framework*<sup>368</sup>

Before the *Commerce Amendment Act 2008*, the NZCC established price and quality thresholds to assess the performance of electricity distribution and electricity transmission businesses. The thresholds were used to identify businesses whose performance required further examination. Where one or more thresholds were

<sup>365</sup> Ibid, pp. 31-34.

<sup>366</sup> Ibid, p. 35.

<sup>367</sup> Derived from information in Pacific Economics Group, *X Factor Recommendations for New Zealand Electricity Distribution Price Controls*, July 2009, pp. 32-34.

<sup>368</sup> Commerce Commission, *Regulation of Electricity Lines Businesses Targeted Control Regime Threshold Decisions (Regulatory Period Beginning 2004)*, 2004, pp. 1-3.

breached, the NZCC could establish a post-breach inquiry and could set the business's prices, revenue or quality.

There were two relevant thresholds:

- a quality threshold
- a price path threshold, of the form  $CPI-X$ .

The quality threshold was based on average historic performance and was designed to ensure that there was no material deterioration in reliability.

The price path threshold included a business-specific X factor, comprised of:

- a 'B factor', that measured industry-wide improvements in productivity, determined through total factor productivity (TFP) analysis. This analysis was conducted using a similar method to the Economic Insights Report as discussed in section 4.3.5 above
- a 'C factor', that measured the relative performance of groups of EDNs, comprised of:
  - a 'C1 factor' which was a comparative/relative productivity component determined through multilateral total factor productivity (MTFP) analysis
  - a 'C2 factor' which was a comparative/relative profitability component, determined by comparing 'residual' rates of return.

#### *Summary of method for determining the C factors<sup>369</sup>*

##### Deriving the C1 factors: MTFP analysis

MTFP analysis was undertaken by Lawrence (2003).<sup>370</sup> Distribution businesses were ranked on the basis of an MTFP index value averaged over the past five years. Businesses were categorised as above-average performers, average performers or below-average performers. This took into account any clear 'step points' occurring in the rankings to mitigate any issue of EDNs being on the boundary.

Distribution businesses performing close to the industry average were assigned a C1 factor of zero. Below-average performers were assigned a positive C1 factor. Above-average performers were assigned a negative C1 factor. The C1 factor was valued at 1, 0 and -1 for below-average, average and above-average performers, respectively.

The magnitude of the C1 factor was determined by the annual rate of productivity change required for EDNs in the group to achieve the average productivity of the sector within two regulatory periods (i.e., ten years). That is, the C1 factor was the

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<sup>369</sup> Ibid, pp. 55-57.

<sup>370</sup> Lawrence D, *Regulation of Electricity Line Businesses, Analysis of Lines Business Performance – 1996-2003*, Meyrick and Associates Report Prepared for the Commerce Commission, 19 December 2003.

productivity change required for the lower group to reach the same productivity levels as the middle group. The negative value for the higher productivity group meant that EDNs in that group were allowed to retain relatively more of the efficiency gains that they made over the regulatory period.

#### Deriving the C2 factors: Residual rate of return analysis

Profitability was calculated using post-tax and pre-rebate (or pre-discount) 'residual' rates of return (ROR). Residual RORs were calculated by deducting operating expenditure, normalised depreciation and tax adjustments from distribution business deemed revenue, and dividing by Optimised Deprival Value (ODV). Residual RORs were averaged over the period 2000 to 2002.

EDNs were ranked according to their average residual ROR and identified as average, above average or below average relative to the industry. Clear 'step points' occurring in the rankings were considered to mitigate possible boundary issues.

EDNs with below-average residual ROR's were assigned a negative C2 factor. EDNs with above-average residual ROR's were assigned a positive C2 factor. The remaining (average) EDNs received a C2 factor of zero.

The magnitude of the C2 factors were selected to bring profits more into line over the next five years. The value of the C2 factors were 1, 0, and -1 for EDNs with above-average, average and below-average residual RORs respectively.

#### Deriving the X factor

The productivity and profitability components (i.e., the C1 and C2 factors) for each distribution business were summed together. The business-specific C factor was added to the industry-wide B factor to determine the X factor that applied to each EDN for the five-year regulatory period.

#### *Reason for removing thresholds regime and comparative benchmarking*

The New Zealand Ministry of Economic Development described the intention of the thresholds as:

a diagnostic tool to identify *prima facie* evidence of any firm abusing its market power by earning excessive profits, or of any firm operating in a highly inefficient manner. But thresholds, which are backed by the threat of further scrutiny and potentially regulatory control, inevitably create strong incentives for the firms they apply to.... To date thresholds have been based on generally backward-looking information and do not take into account the forward-looking circumstances of individual firms (such as the need for major new investments). As a result, some firms may avoid making expenditures that would be efficient, in order to avoid breaches of their threshold. This is because it may be invidious to breach, i.e. the public and media may see a breach as evidence of overcharging even if the breach was justified in order to make a necessary investment. Furthermore, firms may avoid breaching because the consequences of a breach are unknown at the time of the breach (the Commission may decide to take no action, require the firm to come back into compliance with the thresholds, or may declare control).

Thus, the regime appears to promote adversarial processes, which may impact negatively on business confidence and certainty for investors.<sup>371</sup>

The *Commerce Amendment Act 2008* replaced the thresholds regime with the current default price-quality path regulation. As discussed above, the default price-quality path applied to all non-exempt EDNs from 1 April 2009.<sup>372</sup> The business-specific C factor component of the X factor no longer applied as under the default price-quality path all EDNs have the same X factor. This reduced the costs associated with the regulatory decision-making process.

#### 4.3.8 The Lawrence study: Relative productivity and profitability performance<sup>373</sup>

##### *Data*<sup>374</sup>

In estimating the C factors under the previous thresholds regime,<sup>375</sup> the Lawrence study (2003) used Disclosure Data provided by the EDNs under the *Electricity (Information Disclosure) Regulations 1999*. The data included information on physical network characteristics, service quality and financial information. Five years of data from 1999 to 2003 were used to derive the C factor groupings.

##### *Method for determining C1 productivity factor*

##### Technique<sup>376</sup>

The relative productivity performance of the 28 EDNs was examined using an extension of the TFP index concept called Multilateral TFP (MTFP). The multilateral translog index developed by Caves, Christensen and Diewert (1982) (the CCD index) allowed comparison of the absolute levels and growth rates of productivity with panel data.

The CCD index identifies the proportional change in MTFP between two adjacent observations. An index is created by setting an observation (usually the first in the database) equal to one and then multiplying all subsequent observations by the relative change. The index for any other observation then gives the productivity level relative to the observation set equal to one. The resulting comparison between any two observations (between two EDNs or two periods in time) will be independent of

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<sup>371</sup> Ministry of Economic Development, *Review of Regulatory Control Provisions Under the Commerce Act 1986: Discussion Document*, April 2007, p. 59. Available at: <http://www.med.govt.nz/business/competition-policy/review-of-regulatory-control-provisions-of-the-commerce-act/review-of-regulatory-control-provisions-under-the-commerce-act-1986-discussion-document-published-4-april-2007> [accessed on 1 December 2011].

<sup>372</sup> As noted above, EDNs may still apply to the NZCC for a customised price-quality path to accommodate specific individual circumstances.

<sup>373</sup> Lawrence D, *Regulation of Electricity Line Businesses, Analysis of Lines Business Performance – 1996-2003*, Meyrick and Associates Report Prepared for Commerce Commission, 19 December 2003.

<sup>374</sup> *Ibid*, p. 25.

<sup>375</sup> Lawrence (2003) also developed a B factor using the TFP method. As the TFP method is similar to the Economic Insights Report (2009) (refer section 4.3.5), a description of the 2003 analysis is not included here.

<sup>376</sup> Lawrence D, *Regulation of Electricity Line Businesses, Analysis of Lines Business Performance – 1996-2003*, Meyrick and Associates Report Prepared for Commerce Commission, 19 December 2003, pp. 54-55.

which observation in the database was set equal to one. Another way of explaining this is that the index compares each observation to a hypothetical EDN with the industry average (i.e., over all utilities and time periods) output, input, revenue shares and cost shares.

The CCD index is given by:<sup>377</sup>

$$\begin{aligned} \log(TFP_m/TFP_n) &= \sum_i (R_{im} + R_i^*)(\log Y_{im} - \log Y_i^*)/2 - \sum_i (R_{in} + R_i^*)(\log Y_{in} \\ &\quad - \log Y_i^*)/2 - \sum_j (S_{jm} + S_j^*)(\log X_{jm} - \log X_j^*)/2 \\ &\quad + \sum_j (S_{jn} + S_j^*)(\log X_{jn} - \log X_j^*)/2 \end{aligned}$$

where:

$R_i^*$  is the revenue share of output  $i$  averaged over all utilities and time periods,

$S_j^*$  is the cost share of input  $j$  averaged over all utilities and time periods

$\log Y_i^*$  is the average of the log of output  $i$

$\log X_j^*$  is the average of the log of input output  $j$

#### Input quantities<sup>378</sup>

Five inputs are used: operating expenditure, overhead line capacity, underground line capacity, transformer capacity and other capital (therefore  $j$  in the above formula runs from 1 to 5).

#### Operating expenditure

The quantity of each EDN's operating expenses was calculated by:

- summing the grossed-up values of direct costs per network kilometre and indirect costs per customer
- deflating this value by the index of labour costs for the electricity, gas and water sectors.

The grossed-up values of direct costs per kilometre and indirect costs per customer were used as the value of operating costs because these measures best reflected the actual purchases of labour, materials and services used in operating the lines business, excluding rebates. The index of labour costs for the electricity, gas and water sector was used as the price of operating expenditure as it directly measures the price of a major component of operating expenditure.

<sup>377</sup> Ibid, p. 54.

<sup>378</sup> Ibid, pp. 31-32.

### Overhead line capacity

Overhead MVA kilometres was used as a proxy for the quantity of poles and wires input in the overhead network. A constant-price ODV was used for poles and wires. The following conversion rates were applied:

- Low-voltage distribution lines were converted to MVA kilometres using a factor of 0.4
- 6.6kV high-voltage distribution lines using a factor of 2.4
- 11kV high-voltage distribution lines using a factor of four
- 22kV high-voltage distribution lines using a factor of eight
- 33kV high-voltage distribution lines using a factor of 15
- 66 kV lines using a factor of 35
- 110 kV lines using a factor of 80.

These factors were based on a review of the factors used by Parsons Brinckerhoff Associates (2003) and were considered to reflect NZ operating conditions. For example, the effective capacity of an individual line depended not only on the voltage of the line but also on a range of other factors, including the number, material and size of conductors used, the allowable temperature rise, and the limits through stability or voltage drop.

### Underground line capacity

Underground MVA kilometres was used as a proxy for the quantity of underground cables input (calculated in the same way as for overhead line capacity). A constant-price ODV was used for underground cables.

### Transformer capacity

The KVA of the distributor's installed transformers is used as a proxy for the quantity of transformer inputs.

### Other capital

The ODV was used as a proxy for the quantity of other capital inputs, such as computers and control systems. The share of total ODV attributable to these assets was estimated for the average of distributors having disaggregated ODV information in each of four groups (rural high density, rural low density, urban high density and urban low density). The shares of other assets in total ODV range from two to four per cent. The price of other assets was assumed to remain unchanged over the period.

### Input weights<sup>379</sup>

The value of total costs was calculated by summing the estimated value of operating expenditure and 12.5 per cent of total ODV. In accordance with NZIER (2001), a common depreciation rate of 4.5 per cent and an opportunity cost rate of eight per cent for capital assets were assumed.

To allocate ODV to the four asset classes, a weighted average is taken for shares for the EDNs that have this data in each of four groups (rural high density, rural low density, urban high density and urban low density) and apply these shares to all EDNs in the respective group.

Input weights are calculated based on the share of the cost of each of the five inputs in total cost.

### Output quantities<sup>380</sup>

There are three outputs used: throughput of electricity supplied, system line capacity and number of connections (therefore  $i$  in the above formula runs from 1 to 3).

#### Throughput

The quantity of throughput was measured by the number of kilowatt-hours of electricity supplied.

#### System line capacity

The quantity of the system capacity was measured by its total MVA kilometres (calculated in the same way as for overhead line capacity). This was considered to provide a more representative measure of system capacity than either line length or a measure involving kilovolt kilometres.

#### Connections

The number of connections was used as a proxy for the number of connection dependent and customer service activities.

#### Measure of service quality excluded

Service quality was not included as an explicit output because of difficulties associated with model estimation.

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<sup>379</sup> Ibid, pp. 31-32.

<sup>380</sup> Ibid, pp. 30-31.

### Output weights<sup>381</sup>

NZ-based empirical evidence was relied on where possible. The output cost shares were derived from a Leontief cost function using revised data for 1996–2002. A weighted average of the output cost shares was formed using the share of each observation's estimated costs in the total estimated costs for all distributors and all time periods. This produced an output cost share for throughput of 22 per cent, for system line capacity of 32 per cent and for connections of 46 per cent.

### *Method to derive the C2 factor*<sup>382</sup>

### Background<sup>383</sup>

It was noted in the report that the range of ownership structures made the task of assessing the relative profitability of NZ EDNs difficult.

The EDNs were broadly divided into three groups:

- commercial businesses that issue dividends to shareholders
- trusts which offer 'dividends' to consumers/owners in the form of explicit rebates which may take the form of line-charge holidays
- trusts which provide a 'return' to their consumers/owners implicitly in the form of lower prices.

This increased the difficulty of assessing profitability against normal commercial criteria, such as the rate of return. Additional information was required to attempt to adjust for ownership influences. Instead the EDNs were assessed on the basis of pre-rebate prices. This was equivalent to treating the explicit trust rebates as a form of dividend to 'shareholders'.

### Method<sup>384</sup>

EDN profitability was calculated based on a residual rate-of-return measure.

The residual rate-of-return was derived by:

- Total revenue (made up of 'deemed' revenue plus revenue from 'other' business plus AC loss rental rebates less payment for transmission charges less avoided transmission charges less AC loss rental expense paid to customers)
- less: tax equivalent payments plus operating expenditure (derived by grossing up direct line costs per kilometre and indirect costs per customer) plus estimated depreciation (calculated as 4.5 per cent of ODV)

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<sup>381</sup> Ibid, pp. 30-31.

<sup>382</sup> Ibid, pp. 59-62.

<sup>383</sup> Ibid, pp. 59-60.

<sup>384</sup> Ibid, p. 61.

- and dividing the result by the ODV.

EDNs were then identified as those with high, medium or low rates of return. EDNs with low rates of return were those with a tax-adjusted residual rate of return of less than six per cent and those with high rates having tax-adjusted residual rates of return in excess of 8.1 per cent. Approximately one-third of the EDNs fell into each group.

*Analysis of model results (C1 and C2 factors)*<sup>385</sup>

The C1 (relative productivity) factors were:

- –1 per cent for above average EDNs
- zero per cent for average EDNs
- one per cent for below average EDNs.

The C2 (relative profitability) factors were:

- -1 per cent for EDNs with relative low profitability
- zero per cent for EDNs with average profitability
- one per cent for EDNs with relatively high profitability.

The total C factor (C1 plus C2) therefore ranged between two (corresponding to EDNs with low productivity and high profitability) and negative two (corresponding to EDNs with high productivity and low profitability). However, no EDN received a total C factor score of two per cent and therefore the C factors ranged from 1 to -2 per cent.

*Application to regulatory decision*<sup>386</sup>

In the final decision for the regulatory period between 2004 and 2008, the NZCC's approach to setting the C factors was based on the results of the relative performance analysis undertaken by the Lawrence study (2003).<sup>387</sup>

As the B factor for all EDNs was set at one, the final X factors (B plus C1 plus C2) ranged between two per cent and –1 per cent.

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<sup>385</sup> Ibid, p. 63.

<sup>386</sup> Commerce Commission, *Regulation of Electricity Lines Businesses Targeted Control Regime Threshold Decisions (Regulatory Period Beginning 2004)*, 1 April 2004, pp. 55-63.

<sup>387</sup> Ibid, p. 3.

### *Alternative models considered*

#### Quality benchmarking<sup>388</sup>

The NZCC did not include quality benchmarking in the determination of the X factor. This was because the price-quality regressions were sensitive to the model specification used and were unable to separately identify the contribution of service quality to price. Further, the explanatory power of the models was poor when total cost was included in the analysis.

#### Frontier-based analysis<sup>389</sup>

The NZCC also considered whether a frontier-based comparative analysis was more appropriate than an average-based approach.

The Lawrence study (2003) suggested that frontier approaches were sensitive to data errors and can lead to unachievable X factor targets being set. Given the quality of the relevant data for NZ EDNs, the study argued that an average estimation approach would minimise the impact of data errors and omissions.

Given the sensitivity of a frontier-based approach to outliers, the NZCC reset the price path threshold for the regulatory period beginning in 2004 on the basis of average rather than frontier performance.

## **4.4 Gas distribution**

### *Background*<sup>390</sup>

Prior to 1992, the NZCC set price controls for the gas supply industry. As a result of the passage of the *Gas Act 1992*, the industry was deregulated and in April 1993, a 'light-handed' regulatory regime was introduced. Information disclosure obligations were introduced in 1997.

In 2003, the Minister of Energy announced an inquiry into whether introducing regulatory control for gas transmission and/or distribution businesses was necessary. In 2004, the NZCC recommended that only the two largest gas distribution businesses, Powerco and Vector, be subject to regulatory control. Other businesses were exempt from regulatory control.

The Control Order came into effect in 2005 and provisional authorisations were granted until 2008 when the NZCC released its final decision on the authorisations that applied to Powerco and Vector. The Authorisations expire on 1 April 2012. The default price-quality paths introduced by the *Commerce Amendment Act 2008* will then apply.

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<sup>388</sup> Ibid, pp. 37-40.

<sup>389</sup> Ibid, p. 40.

<sup>390</sup> Commerce Commission, *Final Decision on Control Authorisations for Powerco and Vector*, October 2008, pp. 7-13.

#### 4.4.1 Draft decision for default price-quality path

##### *Summary*

The default price-quality paths for gas distribution businesses (GDNs) and gas transmission businesses (GTNs) are determined simultaneously.<sup>391</sup> The NZCC's draft decision was released in November 2011. The default price-quality path will apply from July 2012 until September 2016.<sup>392</sup>

The default price-quality path requires the determination of the following key components:

##### *The form of control*<sup>393</sup>

A weighted average price cap for GDNs is used. This involves deriving notional revenue based on starting prices and quantities that are lagged by two periods. Pass-through costs are then added.<sup>394</sup>

##### *Starting prices for the price path*<sup>395</sup>

The *Commerce Amendment Act 2008* requires that starting prices are either:

- those that applied at the end of the preceding regulatory period; or
- prices based on the current and projected profitability of each supplier.<sup>396</sup>

With the exceptions of Powerco and Vector, the NZCC set the starting prices for GDNs as those prices that were at 30 June 2010. Clawback will be applied if this results in under-recovery. Powerco and Vector's starting prices are the prices at the expiry of the current Authorisations (discussed in section 4.4.3).

##### *Rates of change for the price path*<sup>397</sup>

The *Commerce Amendment Act 2008* requires the rate of change to be based on the rate of improvements in long-run average productivity achieved by:

- suppliers of the services in NZ; and/or
- suppliers in other comparable countries;

using a measure of productivity considered appropriate by the NZCC.<sup>398</sup>

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<sup>391</sup> The NZCC refers to GDNs and GTNs collectively as gas pipeline businesses (GPBs).

<sup>392</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, p. 33.

<sup>393</sup> Ibid, pp. 22-23.

<sup>394</sup> Ibid, pp. 36-38.

<sup>395</sup> Ibid, pp. 29-30.

<sup>396</sup> *Commerce Amendment Act 2008*, s 53P(3).

<sup>397</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, pp. 24-25.

<sup>398</sup> *Commerce Amendment Act 2008*, s. 53P(6).

Economic Insights was commissioned to:<sup>399</sup>

- assess whether the long-run productivity growth rate of NZ GDNs and GTNs is significantly different from that of the NZ economy as a whole
- assess whether input price growth for NZ GDNs and GTNs is significantly different from that for the NZ economy as a whole
- review international rates of TFP.

The Economic Insights study is described in more detail in sections 4.4.2 and 4.6.2 for GDNs and GTNs respectively.

Based on the Economic Insights analysis, the NZCC set the X factor at zero for both GTNs and GDNs.<sup>400</sup>

#### *Quality standards*<sup>401</sup>

The *Commerce Amendment Act 2008* allowed for the integration of the price and quality paths through price incentives to meet quality standards. However the NZCC draft decision found that the lack of robust historical information across the gas sector prevented the development of integrated price-quality paths, at this stage.

The NZCC determined that one quality standard will apply to GDNs, namely, response times to emergencies (RTEs). All GDNs must comply with the quality standard for each year of the regulatory period. The quality standard for GDNs requires 80 per cent of all emergencies to be attended within 60 minutes and 100 per cent of all emergencies must be attended within three hours.

#### 4.4.2 Economic Insights: Total factor productivity analysis

##### *Summary*<sup>402</sup>

Economic Insights assessed the long-run productivity growth rate of NZ GDNs and GTNs in order to determine whether they were significantly different from that of the NZ economy as a whole. Economic Insights also examined whether input price growth for NZ GDNs and GTNs is significantly different to that for the NZ economy as a whole. The analysis for GDNs is described in this section. The corresponding analysis applied to GTNs is reviewed in section 4.6.2.

Economic Insights employed three approaches:<sup>403</sup>

- a direct approach using information currently available for NZ GDNs

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<sup>399</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, Initial Report Prepared for Commerce Commission, 10 February 2011.

<sup>400</sup> Ibid, p. 5.

<sup>401</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, pp. 15-21.

<sup>402</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, Initial Report Prepared for Commerce Commission, 10 February 2011, p. 1.

<sup>403</sup> Ibid, pp. 2-5.

- an indirect approach using information available on overseas GDNs performance
- an indirect approach using information from other industries.

#### *Direct approach – exploratory Total Factor Productivity (TFP)*

##### Data<sup>404</sup>

Economic Insights reviewed Information Disclosure Data supplied by GDNs under the *Gas (Information Disclosure) Regulations 1997* and other available data to assess whether the data would support the direct approach. This involved examining:

- coverage
- the extent to which definitions of the series are clearly specified
- consistency over time and between businesses
- the extent to which the data are publicly accessible
- the degree of stakeholder ownership.

Economic Insights found that the data did not have the sufficient completeness, consistency or accuracy in order to support a robust TFP analysis of the long-run average productivity improvement rate achieved.

Data were available for:<sup>405</sup>

- Vector Distribution for the period 2006 to 2010
- Powerco for the period 2004 to 2010
- GasNet for the period 1999 to 2010.

##### Technique

Economic Insights undertook preliminary analysis based on a TFP specification of two inputs and two outputs.<sup>406</sup>

Economic Insights noted that the method is exploratory and illustrative of potential TFP results. Further, Economic Insights stated that additional data are required before a robust TFP analysis could be undertaken and before a long-run average productivity improvement rate could be estimated.<sup>407</sup>

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<sup>404</sup> Ibid, pp. 11-16.

<sup>405</sup> GasNet is a company owned by Wanganui Gas which owns and operates gas distribution networks in New Zealand's Central North Island.

<sup>406</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, Initial Report Prepared for Commerce Commission, 10 February 2011, p. 15.

<sup>407</sup> Ibid, p. 17.

### Inputs<sup>408</sup>

Economic Insights employed two inputs: opex and pipeline length.

Opex was a scaled up value of direct costs per kilometre and indirect costs per customer. The electricity, gas and water (EGW) sector labour cost index for salary and ordinary time wage rates was used as a proxy for the price of opex inputs.

Pipeline length was used as a proxy for the annual quantity of capital inputs. Average pipeline length was used assuming constant composition of pipeline across the industry.

Two input weightings were considered. The first was used as a proxy for exogenous annual capital costs by taking 12.5 per cent of the reported asset value. The second was to use an endogenous annual cost of capital calculated as the difference between reported revenue and the calculated value of opex. It was found that the two approaches provided similar results. As a result, the findings from the first (exogenous cost) approach were employed.

### Outputs<sup>409</sup>

Economic Insights employed two outputs: energy throughput (kilojoules) and customer numbers.

Economic Insights considered two output weightings:

- In relation to cost-based output, weights of 25 per cent for throughput and 75 per cent for customer numbers were applied. This was consistent with PEG (2007).<sup>410</sup>
- in relation to revenue-based output, weights of 75 per cent for throughput (reflecting variable charges) and 25 per cent for customer numbers (reflecting fixed charges) were applied. These weights were based on Vector's distribution pricing schedules and average consumption patterns. Further, the proportions were similar to revenue shares reported by PEG (2007) for Ontario GDNs.

### Analysis of model results<sup>411</sup>

Difficulties arose in relation to deriving a single gas distribution industry TFP growth rate. First, this was because of the varying time periods for which data were available and second, a difficulty arose with the assumption of a constant composition of pipelines across the industry as a whole.

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<sup>408</sup> Ibid, p. 16.

<sup>409</sup> Ibid, p. 16.

<sup>410</sup> Pacific Economics Group, *Rate Adjustment Indexes for Ontario's Natural Gas Utilities*, Report Prepared for the Ontario Energy Board, Madison, 2007.

<sup>411</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, Initial Report Prepared for Commerce Commission, 10 February 2011, p. 20.

However, by using the relatively short period from 2006 to 2010 (the only period for which data were available for all three GDNs) and weighting TFP growth for this period by:

- shares in industry throughput for 2010, a weighted-average annual TFP growth rate of –0.8 per cent was derived.
- shares of customer numbers, a weighted-average annual TFP growth rate of 1.2 per cent was derived.

Economic Insights estimated economy-wide productivity growth levels based on the multi-factor productivity data from Statistics NZ from 1997 to 2009.<sup>412</sup> For consistency with the period of data available on GDNs, the economy-wide TFP growth rate was estimated for the 2006-2009 period.

The results suggested:

- no significant difference in TFP growth rates between the gas distribution industry and the economy<sup>413</sup>
- no input price difference between the gas distribution industry and the economy as a whole.

Based on this analysis, an X factor of zero was recommended.<sup>414</sup>

#### *Indirect approach – Overseas GDNs<sup>415</sup>*

Economic Insights compared TFP trends and key characteristics of the NZ gas distribution industry with overseas gas industries, including in Australia, North America and the UK. A wide range of TFP growth rates was identified throughout the world. Because of environmental and other differences, Economic Insights concluded that direct international comparisons were not appropriate.

The method applied in the studies conducted by Economic Insights for the Australian GDNs is summarised below.

Economic Insights have conducted three TFP studies for Australian GDNs:

- Lawrence (2007a) initially constructed a TFP model for three Victorian GDNs (Envestra Victoria, Multinet and SP AusNet) from 1998 to 2006<sup>416</sup>
- Economic Insights extended the study to include Jemena Gas Networks' (JGN's) New South Wales (NSW) distribution network from 1999 to 2009<sup>417</sup>

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<sup>412</sup> Ibid, p. 22.

<sup>413</sup> Ibid, p. 24.

<sup>414</sup> Ibid, p. 25.

<sup>415</sup> Ibid, pp. 26-32.

<sup>416</sup> Lawrence, D, *The Total Factor Productivity Performance of Victoria's Gas distribution Industry*, Meyrick and Associates Report to Envestra, Multinet and SP AusNet, Canberra, 23 March 2007.

- The above study was further extended to include Envestra Ltd's South Australian and Queensland networks from 1999 to 2010.<sup>418</sup>

### Data

The data used in these studies were supplied by Envestra, JGN and the three Victorian GDNs and collected in response to common detailed data surveys. The surveys covered key output and input value, price and quantity information.

### Technique

These studies undertook a TFP index-number-based approach.

### Inputs

Eight inputs were used: opex; lengths of transmission pipelines; high pressure pipelines; medium pressure pipelines; low pressure pipelines and services; meters; and other capital. Further, the physical quantities of the principal assets were used as a proxy for the quantity of capital input. This was to ensure that the results were not affected by the different depreciation profiles used by the businesses.

### Outputs

Three outputs were used: throughput, customer numbers and system capacity.

The system capacity was equal to the volume of gas held within a gas network. This was converted to standard cubic meters using a pressure correction factor based on the average operating pressure.

The volume of the distribution network was calculated using:

- pipeline length data for high, medium and low distribution pipelines
- estimates of the average diameter of each of these pipeline types.

The quantity of gas contained in the system was a function of the networks' operating pressure.

Cost-based output shares were derived using an econometric cost function as in Lawrence (2007a). Data for the three Victorian GDNs from 1998 to 2006 were employed. A weighted average was calculated using the share of each observation's estimated costs in the total estimated costs for all GDNs and all time periods.

The following cost-based output shares were calculated:

- throughput of 13 per cent

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<sup>417</sup> Economic Insights, *The Productivity Performance of Jemena Gas Networks' NSW Gas Distribution System*, Report by Denis Lawrence to Jemena Gas Networks (NSW) Ltd, Canberra, 18 August 2009.

<sup>418</sup> Economic Insights, *The Productivity Performance of Envestra's South Australian and Queensland Gas Distribution Systems*, Report by Denis Lawrence to Envestra Ltd, Canberra, 30 September 2010.

- customers of 49 per cent
- system capacity of 38 per cent.

#### *Indirect approach – Other industries<sup>419</sup>*

Economic Insights investigated whether X factor decisions may be informed by the TFP performance of related industries. Economic Insights reviewed TFP growth rate information for:

- NZ EDNs<sup>420</sup>
- Overseas electricity networks, including Australia
- The broader electricity, gas and water (EGW) sector
- The ‘virtual TFP’ approach used by some European regulators. The virtual comparator approach sets an industry’s productivity growth as a weighted average of productivity growth rates for other sectors of the economy that perform similar functions.

Economic Insights found that this indirect approach analysis supported the conclusions of the direct analysis. In summary, this analysis supported a value of zero for the X factor for NZ GDNs.<sup>421</sup>

#### *Application to regulatory decision*

The NZCC, in its draft determination, set the X factor at zero for GDNs.<sup>422</sup>

#### 4.4.3 Powerco and Vector authorisations: 2008 to 2012

The 2008-2012 Authorisations were determined by the NZCC in three stages.<sup>423</sup> The NZCC:

- determined the allowable level of revenue for the regulatory period using the building blocks model and an implied level of service quality and future demand. Consultants Parsons Brinckerhoff Associates (PBA) and Meyrick and Associates undertook an *ex ante* review of forecast operational and capital expenditures and

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<sup>419</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, 2011, pp. 33-40.

<sup>420</sup> Studies conducted by Economic Insights (2009) and PEG (2009) (refer to sections 4.3.5 and 4.3.6 respectively).

<sup>421</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, 10 February 2011, p. 40.

<sup>422</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, pp. 24-25.

<sup>423</sup> NZ Commerce Commission, *Final Decision on Control Authorisations for Powerco and Vector*, 30 October 2008, p. 72.

indirect opex. PBA examined capex and direct opex. Details on these studies are provided below

- set the initial period prices (Po) and the subsequent rate of change (X factor) to ensure that revenue path was 'smooth'. The NZCC set a revenue path that compensated customers for 50 per cent of costs incurred since the control order was introduced
- set the terms of authorisation using a CPI-X price path combined with provisions designed to protect service quality.

#### 4.4.4 Parsons Brinckerhoff Associates: Review of opex and capex

##### *Summary*

In carrying out its expenditure review of opex and capex for Vector and Powerco, PBA.<sup>424</sup>

- examined the configuration of the gas distribution networks and the businesses asset management practices
- undertook a 'bottom-up' approach that examined components of the capital and opex expenditure proposals each year of the control period. These were assessed for efficiency and to ensure that they were 'reasonably incurred' in light of the key drivers and reasons provided by the businesses. Historical and forecast costs were also compared. However, this approach was not used in relation to Powerco because Powerco's forecast capex information was considered to be of poor quality. Historical cost information was the primary approach used for Powerco capex assessment
- undertook a 'top-down' approach, where Powerco's and Vector's capex and opex were compared with seven gas distribution businesses in Australia.

##### *Data*

In March 2006, Powerco and Vector provided:<sup>425</sup>

- a capital expenditure forecast, categorised into different expenditure categories;
- details of historic capital expenditure, categorised into the same expenditure categories as used for forecasting
- details of historic and forecast gas sales, categorised by customer segment

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<sup>424</sup> PBA, *Gas Control: Powerco Limited Review of Capital and Operating Expenditures, Final Recommendations*, September 2008, p. 3 and PBA, *Gas Control: Vector Review of Capital and Operating Expenditures, Final Recommendations*, September 2008, p. 11.

<sup>425</sup> PBA, *Gas Control: Powerco Limited Review of Capital and Operating Expenditures*, August 2007, pp. 34-35 and PBA, *Gas Control: Vector Review of Capital and Operating Expenditures*, August 2007, pp. 28-29.

- details of historic and forecast connection numbers, categorised by customer segment
- asset age profiles
- an assessment of asset condition
- a description of major capital works projects programmed over the forecast period with a description, rationale and budget for each project
- historic and forecast operational cost data categorised into different expenditure categories.

Standardised cost categories for capex and opex data had not been developed. The result was that Vector and Powerco provided the data using different categories.

PBA's analysis was updated as more data became available following the draft decision.

Data on seven Australian gas distribution businesses were made available as a result of Access Arrangement Determinations. The data included information on operating environments, such as volume distributed, customers, network length and regulatory period and capital and operating expenditure.<sup>426</sup>

The data for Powerco, Vector and the Australian GDNs were averaged across the regulatory period and converted to 2006 NZ dollars.

#### *Assessment of Opex – Top down approach<sup>427</sup>*

##### Technique

The top down approach undertaken by PBA was based on ratio and trend analysis.

##### Inputs

The input used in the analysis was total operating costs aggregated across the regulatory period and normalised to NZ\$ 2006.

##### Outputs

The outputs used in the analysis were: number of customers, volumes distributed (terrajoules) and network length (km).

##### Model specification

PBA plotted total opex against the following variables:

- number of customers

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<sup>426</sup> Ibid, p. 69 (Powerco) and p. 34 (Vector).

<sup>427</sup> Ibid, pp. 68-70 (Powerco) and pp. 89-92 (Vector).

- volumes distributed
- network length.

PBA identified a trend line through the data points and assessed where Powerco and Vector were located relative to the trend line. The method used to identify the trend line was not specified.

PBA compared the GDNs' annual percentage change in operating expenditure across each year of the regulatory period.

### Analysis of results

PBA used the results from the top-down analysis to inform the bottom-up analysis.

### *Assessment of Opex – Bottom-up approach*

#### Powerco

PBA assessed Powerco's opex.<sup>428</sup>

- by reviewing Powerco's historical and proposed direct operating expenditure levels to assess trends, and by setting the forecast expenditure levels. PBA also reviewed the results from the earlier benchmarking exercise carried out on Powerco's operating expenditure levels
- in relation to each expenditure category, PBA:
  - reviewed the 2007 operating expenditure to ensure that each expense was reasonably incurred
  - derived a future baseline operating expenditure level per main expense category using the historical expenditure trends and the 2007 expenditure levels
  - reviewed the 2008 budgeted operating expenditure to ensure that each item was reasonably incurred. The full-year expenditure level was estimated
  - calculated the final recommended operating expenditure level for the remainder of the Initial Control Period.

Direct operating expenditure was disaggregated into:

- maintenance, including
  - scheduled maintenance
  - reactive maintenance

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<sup>428</sup> PBA, *Gas Control: Powerco Limited Review of Capital and Operating Expenditures, Final Recommendations*, September 2008, p. 66.

- customer-driven maintenance
- engineering support
- rates.

### Vector

PBA reviewed Vector's forecast direct operating expenditure.<sup>429</sup> That is, PBA:

- analysed expenditure material provided by Vector in response to requests for information, with a particular focus on the details provided for cost categories and the justification provided for these expenditures. This included analysis of actual, forecast and budgeted material
- reviewed Vector's historical operating expenditure patterns in relation to forecast expenditure levels. This involved detailed analysis of the efficiency of 2006 expenditure levels, so that 2006 could be used as a base year for establishing future trends
- based its recommendations of direct operating expenditure included in the PBA Initial Review Report on the bottom-up approach described above
- carried out high-level benchmarking of Vector's costs against those of similar GDNs in Australia. This top-down approach provided a cross-check on the reasonableness of Vector's operating expenditure forecasts and of PBA's recommendations
- relied on publicly available data to support recommendations. Where these data were not available, PBA used its judgement and industry experience to inform its recommendations.

### Application to regulatory decision

The NZCC adopted the recommendations of PBA's bottom-up opex benchmarking analysis.

### *Assessment of Capex – Top-down approach*<sup>430</sup>

#### Technique

PBA used ratio analysis in relation to the top-down approach. PBA compared three input-to-output ratios for Powerco, Vector, and the Australian GDNs.

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<sup>429</sup> PBA, *Gas Control: Vector, Review of Capital and Operating Expenditures, Final Recommendations*, September 2008, p. 12.

<sup>430</sup> PBA, *Gas Control: Powerco Limited Review of Capital and Operating Expenditures*, August 2007, pp. 39-42 and PBA, *Gas Control: Vector Review of Capital and Operating Expenditures*, August 2007, pp 33-36.

### Inputs

The input used was total capex forecast, averaged across the regulatory period and converted to 2006 NZ dollars.

### Outputs

The outputs used in the analysis were: number of customers, volumes distributed (TJ) and network length (km).

### Model specification

PBA compared the following:

- capex per customer;
- capex per volume distributed; and
- capex per network length;
- compound annual growth rate of number of customer connections.

### Analysis of results

PBA used results from this high-level benchmarking to cross-check the reasonableness of Vector's and Powerco's forecast capital costs and to inform the bottom-up benchmarking.

### *Assessment of Capex – Bottom-up approach*

#### Powerco

In order to assess Powerco's forecast capex, PBA<sup>431</sup>:

- reviewed Powerco's historical and proposed capital expenditure levels to assess trends, and to set the forecast expenditure levels;
- considered results from an earlier benchmarking exercise carried out on Powerco's capital expenditure levels;
- reviewed the 2007 capital expenditure to ensure that each expense was reasonably incurred;
- reviewed the 2008 budgeted capital expenditure to ensure that each expense was reasonably incurred and to estimate the anticipated full-year expenditure level;

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<sup>431</sup> PBA, *Gas Control: Powerco Limited, Review of Capital and Operating Expenditures, Final Recommendations*, September 2008, p. 33.

- derived a future baseline capital expenditure level from the historical expenditure trends, the expected demand and consumption growth on the network, and the reasonable 2007 and 2008 expenditure levels;
- identified and reviewed additional major projects or programs identified by Powerco that should be included over and above the baseline expenditure; and
- determined the final recommended capital expenditure level for the remainder of the Initial Control Period.

### Vector

The PBA undertook a high-level benchmarking exercise that compared Vector's costs against those of similar GDNs in Australia.

In relation to Vector's forecast capital expenditure levels, PBA reviewed<sup>432</sup>:

- the configuration of Vector's gas distribution network and its asset management practices, including the use of field services contracts;
- Vector's forecasts in relation to demand and customer numbers;
- Vector's response to the NZCC's requests for expenditure information, with a focus on the details provided for various cost categories and the justification provided for that expenditure;
- Vector's past expenditure forecast and the actual expenditure; and
- publicly available data.

### Application to regulatory decision

The NZCC adopted the PBA's recommendations that were based on the 'bottom-up' capex benchmarking.

#### 4.4.5 The Lawrence (2007) study: Indirect opex assessment<sup>433</sup>

### *Summary*

In reviewing Powerco and Vector's proposed indirect operating costs, the Lawrence (2007) study examined:

- past levels of Powerco and Vector's direct and indirect costs;
- costs of 28 EDNs in NZ; and

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<sup>432</sup> PBA, *Gas Control: Vector, Review of Capital and Operating Expenditures, Final Recommendations*, September 2008, p. 11.

<sup>433</sup> Lawrence D, *Powerco and Vector Indirect Cost Review*, Meyrick and Associates Report Prepared for Commerce Commission, 5 September 2007.

- costs of 12 EDNs in Australia.

### *Data*

The NZCC used accounting and statistical indirect opex data provided by Powerco and Vector under the gas disclosure regime. This included:

- direct costs per kilometre and indirect costs per customer for 2002 to 2006; and
- systems statistics on kilometres of line and number of customers for each distributor.

Indirect expenditure is:

‘...all expenditure that is not directly related to managing the system of that pipeline owner; but does not include-

- (a) Capital expenditure, depreciation, interest, and tax
- (b) Any expenditure related to operating or maintaining that system.’<sup>434</sup>

However, the regulations do not:

- prescribe an approach to cost allocation;
- require that businesses disclose details of how costs were allocated; nor
- require a company to maintain a consistent methodology between years.

Indeed, the Lawrence (2007) study noted that the analysis was limited by such problems associated with the data. For example, Vector applied inconsistent approaches to the categorisation of the 2005 and 2006 data. In contrast, Powerco aggregated data so that cost categories contained a wide range of cost items relating to different cost drivers.<sup>435</sup>

Data on EDNs in NZ was sourced from the Information Disclosure data provided by the EDNs to the NZCC.

Indirect costs data on Australian EDNs was obtained from Australian state-based regulators’ reports. This included data in relation to:<sup>436</sup>

- customer service;
- advertising and marketing; and
- other operating costs (which included regulatory, billing and revenue collection).

### *Technique*

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<sup>434</sup> Ibid, p. 18.

<sup>435</sup> Ibid, p. iii.

<sup>436</sup> Ibid, p. 31.

The analysis compared:

- total indirect operating expenses as a proportion of total operating revenues for NZ EDNs; and
- total indirect operating expenses as a proportion of total network revenue for Australian EDNs.

### *Analysis of outputs*

The Lawrence (2007) study concluded that there was no evidence to suggest that the overall level of indirect costs reported by Powerco and Vector were excessive.

The assessment of the appropriate indirect costs was therefore based on the analysis of Powerco's and Vector's historical and forecast indirect costs.

## **4.5 Gas transmission**

### *Background*

Gas transmission networks (GTNs) in NZ were not subject to price control between 1992 and 2011. The *Commerce Amendment Act 2008* reintroduced price controls for gas transmission and distribution businesses from 2012.<sup>437</sup>

#### 4.5.1 Draft decision for default price-quality path

### *Summary*

The default price-quality paths for gas distribution businesses (GDNs) and gas transmission businesses (GTNs) are determined simultaneously. The NZCC's draft decision was released in November 2011. The default price-quality path will apply from July 2012 until September 2016.<sup>438</sup>

The default price-quality path requires the determination of the following key components:

### *Form of control*<sup>439</sup>

The NZCC used a total revenue cap for GTNs because it provided greater incentives for innovation and investment, compared to a weighted average price cap.<sup>440</sup>

### *Starting prices for the price path*<sup>441</sup>

The *Commerce Amendment Act 2008* requires that starting prices must be either:

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<sup>437</sup> For more information refer to section 4.4.

<sup>438</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, p. 33.

<sup>439</sup> Ibid, pp. 22-23.

<sup>440</sup> Ibid, pp. 39-41.

<sup>441</sup> Ibid, pp. 28-30.

- those that applied at the end of the preceding regulatory period; or
- prices based on the current and projected profitability of each supplier.<sup>442</sup>

Starting prices for GTNs were set as the prices that prevailed at 30 June 2010. Clawback will be applied if this price regime results in under-recovery by the GTNs.

#### *Rates of change for the price path*<sup>443</sup>

The rate of change is determined by improvements in long-run average productivity rates achieved by:

- NZ suppliers; and/or
- suppliers in other comparable countries,

using a measure of productivity considered appropriate by the NZCC.<sup>444</sup>

Economic Insights was commissioned to:

- assess whether the long-run productivity growth rates of NZ GDNs and GTNs were significantly different from that of the NZ economy as a whole;
- assess whether input price growth for NZ GDNs and GTNs was significantly different to that for the NZ economy as a whole; and
- review international rates of TFP.

In response to the Economic Insights report, the NZCC issued a draft decision that set the X factor at zero for both GTNs and GDNs.

#### *Quality standards*<sup>445</sup>

The *Commerce Amendment Act 2008* allowed for the integration of the price and quality paths through price incentives to meet quality standards. However the NZCC draft decision found that the lack of robust historical information across the gas sector prevented the development of integrated price-quality paths, at that stage.

The NZCC determined that one quality standard will apply to both GDNs and GTNs, namely, response times to emergencies (RTEs). All GDNs and GTNs must comply with the quality standard for each year of the regulatory period. For GTNs, the quality standard requires that 100 per cent of all emergencies must be attended within three hours.

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<sup>442</sup> *Commerce Amendment Act 2008*, s 53P(3).

<sup>443</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, pp. 24-25.

<sup>444</sup> *Commerce Amendment Act 2008*, s 53P(6).

<sup>445</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, p. 15.

#### 4.5.2 Economic Insights: Total factor productivity analysis

##### *Summary*<sup>446</sup>

Economic Insights assessed the long-run productivity growth rate of NZ GTNs and GDNs in order to determine whether they were significantly different from that of the NZ economy as a whole. Economic Insights also examined whether input price growth for NZ GTNs and GDNs is significantly different to that for the NZ economy as a whole. The analysis for GTNs is described in this section. The analysis applied to GDNs is reviewed in section 4.4.2.

Economic Insights employed two main approaches:

- a direct approach using information currently available on NZ GTNs;
- an indirect approach using information on GTNs from other countries.

##### *Direct approach – exploratory TFP*

##### Data<sup>447</sup>

Data are available for Vector Transmission from 1997 to 2010. There was not sufficient data on Maui Development Ltd for it to be included.<sup>448</sup>

##### Technique

A TFP specification was used that incorporated two inputs and two outputs.<sup>449</sup>

##### Inputs

The two inputs used were: opex and pipeline length.

Opex was derived by scaling up values of direct costs per kilometre and indirect costs per customer. Electricity, gas and water (EGW) sector labour cost index for salary and ordinary time wage rates are used as a proxy for the price of opex inputs.

Pipeline length was used as a proxy for the annual quantity of capital input.

The inputs were weighted by taking 12.5 per cent of the reported asset value (a proxy for an exogenous annual capital cost).<sup>450</sup>

##### Outputs

Energy throughput (gigajoules) and asset value was used as a proxy for system capacity. Cost-based output weights of 25 per cent for throughput and 75 per cent for customer numbers were applied.

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<sup>446</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity, Initial Report for Commerce Commission*, 10 February 2011.

<sup>447</sup> Ibid, p. 16.

<sup>448</sup> Ibid, p. 22.

<sup>449</sup> Ibid, p. 15.

<sup>450</sup> The inputs and weightings are the same as the model for GDNs.

### Analysis of model outputs

Vector's exploratory TFP growth rate was assumed to represent the TFP growth rate for the gas transmission industry.

Economic Insights estimated economy-wide productivity growth levels based on the multi-factor productivity data from Statistics NZ from 1997 to 2009.<sup>451</sup>

Results suggested:

- Vector's growth rate was 0.5 per cent between 1997 and 2010. This is consistent with the estimated economy-wide MFTP for 1997 to 2009;<sup>452</sup> and
- no identifiable input price difference existed between the NZ gas transmission industry and the economy as a whole.

Based on this analysis, Economic Insights recommended a productivity differential of zero and an X factor of zero.<sup>453</sup>

### *Indirect approach*

An international comparison of the TFP performance of GTNs was not undertaken because of the lack of available international data.<sup>454</sup> There were also limited international studies of TFP growth for GTNs.

### *Application to regulatory decision*

As a result of the direct and indirect analysis, the NZCC issued a draft determination that set the X factor at zero for GTNs.<sup>455</sup>

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<sup>451</sup> Economic Insights, *Regulation of Suppliers of Gas Pipeline Services – Gas Sector Productivity*, 2011, p. 22.

<sup>452</sup> Ibid, p. 24.

<sup>453</sup> Ibid, p. 25.

<sup>454</sup> Ibid, p. 31.

<sup>455</sup> Commerce Commission, *Initial Default Price-Quality Paths for Gas Pipeline Businesses*, Draft Reasons Paper, 21 November 2011, pp. 24-25.

## 5 Netherlands: Office of the Energy Regulator

### 5.1 Overview of the Dutch energy market<sup>456</sup>

#### *Electricity*

Prior to the liberalisation of the Dutch electricity market in 1998, the market was dominated by four power generators which formed the so-called ‘centralised’ market. The four generators, namely EPON, EZH, EPZ and UNA, co-operated through an organisation called SEP (a joint stock company owned by its members). SEP owned and operated the high-voltage transmission grid and had a statutory monopoly on imports until 1998. SEP stopped coordinating the centralised market after the establishment of the Transmission System Operator, TenneT, in October 1998. However, SEP maintained ownership of TenneT and its transmission assets until November 2001, when TenneT was purchased by the State and SEP was dissolved. Consequently, the electricity transmission system is now totally separated and owned by the national government.<sup>457</sup>

Despite market reform, a few generators continue to dominate the Dutch electricity market. Four large electricity businesses, Electrabel, E.ON Benelux, Essent and Nuon, are active in both generation and retail and control around 65 per cent of the generation market and 80 per cent of the retail market. The remainder of the generation and retail markets is made up of a number of smaller businesses.<sup>458</sup> There are 63 distribution networks, which are owned by eight different electricity distribution businesses. Each of these businesses also operates gas distribution networks.<sup>459</sup>

#### *Gas*

The gas transmission network in the Netherlands is operated by Gas Transport Services B.V (GTS). While GTS is a subsidiary of state-owned Gasunie, the dominant gas infrastructure provider in the Netherlands, it is required to operate independently of Gasunie in accordance the *Dutch Gas Act 2000*. This is to ensure that the transport and trade of gas are kept separate. Gas Terra, an international gas trading company, controls 80 per cent of the Dutch gas wholesale market. The gas retail market is comprised of three major suppliers controlling around 79 per cent of the market.<sup>460</sup>

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<sup>456</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, pp. 251-256.

<sup>457</sup> Ibid, pp. 251-252.

<sup>458</sup> Ibid, p. 252.

<sup>459</sup> Netherlands Competition Authority (NMa), *Overview system operators*. English translation available at: [http://www.microsofttranslator.com/bv.aspx?from=&to=en&a=http%3A%2F%2Fwww.nma.nl%2Fregulering%2Fenergie%2Felektriciteit%2Fregulering\\_regionale\\_netbeheerders%2Foverzicht\\_netbeheerders\\_en\\_ontheffingen%2Fdefault.aspx](http://www.microsofttranslator.com/bv.aspx?from=&to=en&a=http%3A%2F%2Fwww.nma.nl%2Fregulering%2Fenergie%2Felektriciteit%2Fregulering_regionale_netbeheerders%2Foverzicht_netbeheerders_en_ontheffingen%2Fdefault.aspx) [accessed on 1 December 2011].

<sup>460</sup> European Regulators Group for Electricity and Gas, *2011 National Report of Energiekamer to the European Commission*, 2011, p. 31. Available at: [http://www.energy-regulators.eu/portal/page/portal/EER\\_HOME/EER\\_PUBLICATIONS/NATIONAL\\_REPORTS/National%20Reporting%202011/NR\\_En/C11\\_NR\\_Netherlands-EN.pdf](http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202011/NR_En/C11_NR_Netherlands-EN.pdf) [accessed on 1 December 2011].

There are also 16 small independent suppliers.<sup>461</sup> There are presently nine gas distribution businesses, eight of which also operate electricity distribution networks.<sup>462</sup>

### *Regulator*

The energy sector is subject to specific energy laws, including the *Electricity Act 1998*, the *Gas Act 2000*, the *Independent Grid Administration Act* and the relevant EU Directives and Regulations. The *Independent Grid Administration Act 1998* provides for the separation of network operation from energy generation and retailing.<sup>463</sup>

The Office of Energy Regulation (DTe),<sup>464</sup> which is a department of the Netherlands Competition Authority (NMa), is responsible for the regulation of gas and electricity markets in the Netherlands. Under the *Electricity Act 1998* and the *Gas Act 2000*, the DTe is responsible for determining tariffs for the use of energy transmission and distribution networks. The tariff should be set at a level that is possible for the network operators to earn a reasonable return while encouraging efficient operation and sufficient investment in network quality. Network operators are required to submit 'quality and capacity documents' (QCDs) once every two years to report on, among other things, their performance regarding the quality and capacity of their networks.<sup>465</sup>

### *Appeal Process*

All decisions of the NMa may be appealed. A party to a decision who is not satisfied with the NMa's finding has up to six weeks from the date that the decision is released to request an 'Objections Procedure'. This involves a substantive review of the NMa's decision by a separate team within the NMa, and is overseen by the NMa's Legal Department. Should the Objections Procedure not resolve a dispute, parties may apply for judicial review of the NMa's decision. The court at first instance considers both the merits and legality of the regulatory decision.<sup>466</sup>

In energy, most of the decisions have proceeded to the Objections Procedure phase, and around 75 per cent of decisions have been appealed. In terms of tariff methodology decisions, almost 100 per cent of those decisions have been appealed.<sup>467</sup>

## **5.2 Regulatory framework**

The DTe is responsible for the economic regulation of transmission and distribution network operators in the electricity and gas sub-sectors.

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<sup>461</sup> Ibid.

<sup>462</sup> NMa, *Overview system operators*.

<sup>463</sup> NMa, *Energy Legislation*, Available at: [http://www.nma.nl/en/legal\\_powers/energy\\_legislation/default.aspx](http://www.nma.nl/en/legal_powers/energy_legislation/default.aspx) [accessed on 18 April 2012].

<sup>464</sup> Also known as 'Energiekamer'.

<sup>465</sup> NMa, *Energy Regulation*, Available at: [http://www.nma.nl/en/our\\_work/energy\\_regulation/default.aspx](http://www.nma.nl/en/our_work/energy_regulation/default.aspx) [accessed on 18 April 2012].

<sup>466</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, p. 255.

<sup>467</sup> Ibid, p. 256.

### 5.2.1 Electricity and gas distribution<sup>468</sup>

The DTe regulates eight distribution businesses that supply both electricity and gas, and one distribution business that supplies gas only. All distribution businesses are wholly owned by Dutch municipalities and provinces. Electricity and gas distribution businesses are subject to price-cap regulation with a system of national yardstick competition. Allowed revenue is adjusted annually by the formula  $(I + CPI - X + q)$ . The productivity yardstick ( $X$ ) is currently equal for all businesses (except for some regional difference allowances) and is based on sector-average cost per unit of output, including an estimate of the productivity growth for the sector during the regulatory period. The quality yardstick ( $q$ ) is measured based on the system average interruption duration index (SAIDI). The system of yardstick competition is used to provide incentives for network businesses to increase productivity and improve quality as higher profits can be earned when a business achieves higher productivity or quality than the sector-average performance. The regulatory period is for three years, the most recent being between 2011 and 2013 inclusive. The DTe refers to distribution businesses as regional grid managers. For consistency with other chapters, in this document electricity grid managers are referred to as electricity distribution network operators (EDNs).

### 5.2.2 Electricity transmission<sup>469</sup>

There is only one Dutch electricity transmission business, TenneT, which is wholly state-owned. It is regulated via revenue-cap regulation with a yardstick that is based on an international benchmark, combined with a frontier shift component based on productivity growth of transmission businesses in other countries. The regulatory period is set for three to five years, with the most recent being between 2011 and 2013 inclusive. The allowed revenue is adjusted annually by the formula  $(I + CPI - X)$ , where  $X$  is the efficiency-incentive component. Quality is regulated through setting out standards rather than providing financial incentives. The system of yardstick competition provides incentives to improve cost efficiency as higher profits can be achieved if the business achieves higher cost savings than expected.

Costs are determined according to a standardised method. The DTe collects annually information on actual operating expenses (opex), investments, depreciation (based on regulatory accounting rules) and energy volumes supplied to customers. To guarantee security of supply in the Netherlands, a separate system is used for assessing expansion investments. The DTe assesses capital investments to determine whether these have been incurred efficiently and adjusts the revenue cap and tariffs, but only for the amount of the investment which it determines to be efficient. Based on the revenue cap, TenneT will draft annually a tariff proposal for all tariff components, given expected energy volumes. This proposal is assessed and approved by the DTe.

### 5.2.3 Gas transmission<sup>470</sup>

In 2008, the NMa established methods of regulation for the period 2009 to 2012 in order to calculate the efficiency factors for the legal tasks that are assigned to the

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<sup>468</sup> NMa, *2011 National Report of Energiekamer to the European Commission*, 2011, pp. 11-13.

<sup>469</sup> Ibid.

<sup>470</sup> Ibid, p. 25.

transmission network operator, including transport and related services, balancing services and quality conversion services. The sole gas transmission network operator, GTS, is also legally required to submit a tariff proposal for all tariff components. The tariffs are set for each entry and exit point on the basis of cost reflection.

In determining the efficiency factor, costs are estimated for operational costs (including labour and energy costs) and capital costs (concerning regulated asset base (RAB), weighted average cost of capital (WACC), and depreciation). When setting individual tariffs, assumptions are made concerning volume. It is the transmission network operator that carries the burden of the so-called 'volume risk'.<sup>471</sup>

In June 2010, the Trade and Industry Appeals Tribunal annulled the methods of regulation for the period 2009 to 2012 on the basis that the Minister of Economic Affairs was not the competent authority to issue a policy ruling on which the DTe's methods of regulation were based. The policy ruling set the capital costs by prescribing the RAB, WACC and depreciation periods. The Tribunal decided, however, that the NMa should still determine methods of regulation for the period 2006 to 2008.

In order to give clarity to the past, present and future tariff levels as soon as possible, the NMa Board determined the methods of regulation for GTS from 2006 onwards. These methods of regulation were published in 2011. This enabled the establishment of tariffs based on these new methods of regulation from 2012 onwards. In 2011, the same tariffs as set for 2010 were used.

### **5.3 Electricity distribution**

#### **5.3.1 Regulatory framework**

There have been five regulatory determinations since the price-cap system was introduced in 2000 for electricity distribution businesses. These correspond to the following periods, 2001 to 2003, 2004 to 2006, 2007 to 2009, 2008 to 2010,<sup>472</sup> and the current period 2011 to 2013. The regulatory period is usually set for three years.

The regulatory framework involves:

- first, determining the total allowable revenues, where the starting point is that each electricity distribution network (EDN) ought to be able to realise the same revenues per unit of output
- adding the price component (in the form of CPI-X)
- adding the quality component (the *q* factor).

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<sup>471</sup> Volume risk refers to a situation whereby energy market participants face uncertainty about future volumes of consumption or production, leading to the potential for over or under estimation of costs and a risk that the allowed revenues or prices set by the regulator is less than sufficient to cover actual costs given actual volumes.

<sup>472</sup> It is unclear why there is an overlap between the regulatory periods 2007 to 2009 and 2008 to 2010. There appears to have been a change to the regulatory framework.

Both the X factor and the q factor are determined separately at the beginning of every regulatory period.<sup>473</sup>

These three core components of the regulatory framework are explained in more detail below. The information relates to the first three regulatory periods and has primarily been sourced from non-certified English translations of the DTe's regulatory documents in relation to the second and third regulatory periods, and from secondary sources, as referenced.

#### *Allowable revenue determination*

The DTe determined the total allowable revenue for the first year of the regulatory period as the sum of the tariffs and cost drivers applying to the various tasks of the EDNs as per the tariff structure in section 36 of the *Electricity Act*. The allowable revenue determined the maximum that an EDN may charge on the basis of set standard volumes of the cost drivers. The allowable revenue was adjusted annually in line with the change in the CPI and other components of the price-cap formula.<sup>474</sup>

From the third regulatory period, the DTe began to take into account 'objectifiable regional differences' to recognise that some exogenous environmental factors, specifically the number of water crossings, resulted in higher costs for some EDNs. Therefore, an extra allowance was applied to the standardised costs (defined below) and included in the allowable revenue before annual adjustments.<sup>475</sup>

Up until the third regulatory period, the DTe recalculated total allowed revenues of EDNs on the basis of the difference between estimated and realised change in productivity. This retrospective settlement was abolished from the third regulatory period (2007 to 2009) onwards so that the EDNs would have a greater incentive to operate more efficiently.<sup>476</sup>

#### *Price component (X factor)*

In the first regulatory period (2001 to 2003), the DTe determined that the X factor for the first two regulatory periods would be based on two components:<sup>477</sup>

- general efficiency component – for the purpose of ensuring that the general (average) change in the productivity of the sector is passed on to customers, and to create incentives for EDNs to compete to be more efficient than the industry average, thereby potentially receiving greater revenue
- individual efficiency component – for the purpose of ensuring that all EDNs reach the same efficient-cost level at the end of the second regulatory period.

The intention behind the individual efficiency component was to allow relatively inefficient businesses to bring their tariffs down to an efficient level during the first

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<sup>473</sup> NMa, *Method Decision*, Non-certified English translation, June 2006, pp. 3-5.

<sup>474</sup> NMa, *Addendum B BIJ to the Method Decision*, June 2006, p. 2.

<sup>475</sup> NMa, *Addendum A to the Method Decision*, June 2006, p. 11.

<sup>476</sup> *Ibid*, p. 3.

<sup>477</sup> NMa, *Addendum B to the Method Decision*, 11 September 2003, pp. 3-4.

two regulatory periods. Then, once the initial efficiency differences had been removed, tariffs would then change in line with the general efficiency component only.<sup>478</sup> However, the new regulatory framework was implemented within a relatively short time period,<sup>479</sup> and the decisions made for the first regulatory period, in particular the determination of the individual efficiency component of the X factor, were subject to significant legal dispute. As a result of legal disputes, the DTe amended the X factor four times during the three years of the first regulatory period.<sup>480</sup>

The disputes related to:<sup>481</sup>

- the use of a single benchmarking model and method without checking for consistency across different methods and models
- the mechanistic application of the benchmarking results in contrast to intentions indicated during consultation
- the legality of including different values of the X factor for different businesses
- the quality of the data used for the benchmarking analysis.

Following a period of negotiation between the DTe and the EDNs it was agreed that:<sup>482</sup>

- the X factor would be the same for all EDNs for the first regulatory period
- for second regulatory period, individual X factors would be included, such that all the EDNs would converge to the same level of efficiency by the end of the period.

An amendment to the *Electricity Act 1998* in 2003 was also undertaken to enable the DTe to include the individual efficiency component to the X factor for the second regulatory period. It was not intended that the individual efficiency component would be included in the third and subsequent regulatory periods as inefficient EDNs were expected to have ‘caught up’ with efficient EDNs by the end of the second regulatory period.<sup>483</sup>

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<sup>478</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice, prepared for the AEMC*, 2008, p. 34.

<sup>479</sup> Legislative amendment occurred in July 1998. This was followed by the release of the DTe’s first consultation document in July 1999, and the publications of model development and guidelines during 2000. The new framework took effect from January 2001.

<sup>480</sup> Nillesen and Pollitt, *The 2001-3 Electricity Distribution Price Control Review in the Netherlands: Regulatory Process and Consumer Welfare*, *Journal of Regulatory Economics*, 31, February 2007, p. 262.

<sup>481</sup> Ibid, pp. 269-275.

<sup>482</sup> Ibid, pp. 276-277.

<sup>483</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice, prepared for the AEMC*, 2008, pp. 34-36.

In the third regulatory period, however, the X factor was not the same for all EDNs because a business-specific equalisation factor was included. This equalisation factor was effectively an *ex post* adjustment to tariffs to take into account actually realised efficiency changes, rather than forecast changes from the second regulatory period.<sup>484</sup>

### *Quality component*<sup>485</sup>

The DTe's regulation of quality, through the quality term (the q factor), is intended to incentivise EDNs to maintain an adequate level of service quality. This form of regulation was introduced by the DTe in the second regulatory period to ensure that the EDNs did not overemphasise cost efficiency at the expense of quality of services. The 'experience' of consumers in relation to the reliability of the grid of the respective EDN (translated into the number of minutes of supply interruption) is central to the quality component. Under the DTe's regulatory determination, a q factor was determined for each EDN. If an EDN invested more in quality of service, this would reduce the number of interruption minutes. If an EDN that provided higher quality than the average EDN, then it could charge higher tariffs.

### 5.3.2 X factor determination: General change in productivity

The following information is sourced from non-certified English translations of the DTe's method decision annex relating to the second regulatory period and a summary of the method prepared by the Brattle Group in 2008 for the Australian Energy Market Commission (AEMC), as referenced.

The general change in productivity component of the X factor was determined using a simple unit-cost index calculation. The rate of productivity growth across the whole electricity distribution sector was measured. All of the electricity distribution businesses in the Netherlands that are subject to regulation were included in the estimation.<sup>486</sup>

### *Data*

The data were taken from regulatory accounts. The general efficiency component for every regulatory period subsequent to the second regulatory period was based on the measured change in productivity of the preceding period excluding the final year and including the final year of the period preceding this.<sup>487</sup>

### *Technique*<sup>488</sup>

The DTe used a unit-cost approach.<sup>489</sup> The unit-cost index is constructed as the ratio of standardised costs to composite output. The growth rate is then calculated as the annual percentage change in the unit-cost index.

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<sup>484</sup> Ibid, p. 34.

<sup>485</sup> NMa, *Method Decision*, Non-certified English translation, June 2006, p. 4.

<sup>486</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice, prepared for the AEMC*, 2008, pp. 34-35.

<sup>487</sup> NMa, *Annex B to Method Decision*, September 2003, p. 10.

<sup>488</sup> Ibid, pp. 6-8.

### *Inputs*<sup>490</sup>

The inputs are the ‘standardised economic costs’, which includes operating and capital costs.

Operating costs are measured in accordance with the regulatory accounting rules. The DTe considered all costs to be controllable, unless they satisfy the conditions applicable to investments. Non-controllable costs may be passed directly onto customers.

Capital costs are the sum of depreciation and a cost-of-capital allowance.

### *Outputs*<sup>491</sup>

A ‘composite output’ was constructed in the following way. For each EDN, the composite output is the revenue it charges each customer group associated with each tariff element, weighted by the proportion of its total revenue associated with that customer group and tariff element. This excludes initial and on-going connection charges.

Initial connection charges were excluded completely because the volume of new connections changes unpredictably from year to year.

Standing (ongoing) connection service charges were initially excluded as the definitions used differed across EDNs. An estimate of the standing connection service charges for each EDN was calculated based on each EDN’s market share in 2000.<sup>492</sup> These estimates were then added to the composite output developed above.

### *Method*<sup>493</sup>

The general change in productivity of the sector is equal to the weighted average of the change in productivity of all ‘efficient’ EDNs during the measurement period. Productivity in this regard is expressed as the cost per composite output.

The general change in productivity in the sector must meet the condition that the allowable revenue of the sector at the end of the regulatory period is cost efficient (assuming the existence of efficient EDNs). This means that the allowable revenue of the sector at the end of the regulatory period must be equal to the total costs incurred by the sector in that year. The DTe determined that, for the second regulatory period (2004 to 2006), allowable revenue would be described in terms of prices in 2002 and volumes in 2005.<sup>494</sup>

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<sup>489</sup> The NMa (Ibid, p. 7) and Brattle Group (2008) refer to the method as a TFP index-number approach.

<sup>490</sup> NMa, *Annex B to Method Decision*, September 2003, pp. 4-6.

<sup>491</sup> Ibid, p. 7.

<sup>492</sup> Refer to Ibid, p. 7 for more detail.

<sup>493</sup> Ibid, pp. 7-9.

<sup>494</sup> Ibid, p. 8.

The measurement of the general change in productivity only applies to those EDNs who were already cost efficient at the beginning of the year in which the first measurement took place; i.e., in 2000. The DTe noted that if inefficient businesses were to be included in the measurement, this would give rise to a distorted picture of the general change in productivity.<sup>495</sup> This is because a relatively inefficient business can realise greater productivity improvements than a business operating on the industry frontier.

The efficient cost level is actualised annually by adjusting this level using the general efficiency component of the X factor and is expressed per unit of composite output.

A sufficiently representative cross-section of the electricity distribution sector must belong to the group of efficient businesses. An efficient EDN would continue to participate in future determination of the general change in productivity. For example, an EDN is deemed to be efficient if in 2002 its cost per composite output was less than, or equal to, the actualised efficient-cost level. The actualisation is necessary because a general change in productivity had occurred since the determination of the efficient level on the basis of data from 2000, which also applied to efficient EDNs. An EDN who had a DEA score of one in 2000 also belonged to this group, in accordance with the X factor decision for the first regulatory period.

#### *Application to regulatory decision*

The DTe did not deduct an input price differential from the estimated general efficiency growth rate. This implicitly assumed that the electricity distribution costs can be expected to rise at the rate of CPI inflation generally in the Dutch economy.<sup>496</sup>

In the second regulatory period, the DTe made some adjustments to allow some time for EDNs to become accustomed to the 'yardstick competition' form of regulation. This included reducing the X factor by 0.5 percentage points to correct for estimation error.<sup>497</sup>

#### 5.3.3 X factor determination: Individual efficiency component

The analysis for the individual efficiency component of the X factor was undertaken by Frontier Economics in 2000.<sup>498</sup> The details of this study are described below. The information was sourced from a Frontier Economics report to the DTe in 2000 and secondary material, as referenced.

#### *Data used*<sup>499</sup>

Due to data limitations, Frontier Economics chose to benchmark distribution and supply (retail) businesses together. The cost data were collected by the DTe from the

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<sup>495</sup> Ibid.

<sup>496</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice*, prepared for the AEMC, 2008, p. 35.

<sup>497</sup> Ibid, p. 9.

<sup>498</sup> Frontier Economics, *Choice of Model and Availability of Data for the Efficiency Analysis of Dutch Network and Supply Businesses in the Electricity Sector*, February 2000.

<sup>499</sup> Ibid, pp. 6, 12-13.

regulated businesses for the purpose of informing the setting of the  $P_0$  values for 2000.

Data were available only for 1996. Data for 1999 and estimates for 2000 were expected to be available on the same basis over the next few months following Frontier Economics' study.

The comparator group for the EDNs was identified as 20 Dutch network businesses, although Frontier Economics noted that data from other countries were likely to be used at the next stage as further comparators for certain networks with unusual characteristics.<sup>500</sup>

### *Benchmarking technique<sup>501</sup>*

The limited number of data observations led to the decision to adopt a Data Envelopment Analysis (DEA) approach, using Malmquist Total Factor Productivity Index, as the principal method to estimate efficiency.

### *Inputs<sup>502</sup>*

Frontier Economics derived the following estimates of total distribution and supply costs as input measures:

- operating expenditure
- operating expenditure plus tangible depreciation

where operating expenditure includes the following cost items: materials, services, wage costs and other costs.

Most of the uncontrollable cost items (e.g., charges to other network operators, or purchases of energy) were eliminated from the cost base and the level of remaining uncontrollable costs was minimal. The costs associated with the performance of transmission activities were removed from the analysis.

### *Outputs<sup>503</sup>*

Since model selection could not be based upon econometric tests, Frontier Economics employed combinations of the following output variables:

- electricity distributed (kWh)
- number of consumers (total, small and large)
- network length

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<sup>500</sup> No further information on the use of international data is available.

<sup>501</sup> Ibid, p. 6 and Annex 4, pp. 44-45.

<sup>502</sup> Ibid, pp. 11-12.

<sup>503</sup> Ibid, pp. 11-12.

- transformer numbers
- network density.

Frontier Economics requested input from the businesses to identify environmental factors that may affect the efficiency scores and to provide relevant data on these so that the impact of environmental factors on the efficiency scores could be tested.<sup>504</sup>

Frontier Economics noted that insufficient data were available to incorporate variables such as peak demand and service quality.<sup>505</sup>

#### *Model specification*<sup>506</sup>

This section describes the various DEA models estimated by Frontier Economics. All the models were estimated under both Constant Returns-to-Scales (CRS) and Variable Returns-to-Scale (VRS) specifications.

Model 1 is a simple model with only two potential cost drivers (units distributed and customer numbers). It was noted that these are key outputs for any distribution and supply business.

Model 2 is similar to Model 1, but attempts to capture differences in the composition of customer base by splitting the number of consumers into two groups, namely large and small customers.

Model 3 builds upon Model 2 by further including variables that represent complexity of the network; i.e., network length and number of transformers. It was noted that increases in either of these variables normally result from higher operating expenditure.

Model 4 incorporates another variable for network dispersion – network density, defined as network length per customer.

Model 5 is analogous to Model 1 but uses operating expenditure plus tangible depreciation as the input, rather than operating expenditure only. This last model moved towards a total-cost benchmark by including a measure of capital consumption. Since the measure used by Frontier Economics was the depreciation charge reported by individual businesses, the measured efficiency scores reflected differences in accounting policy. In its next stage of the analysis, Frontier Economics intended to standardise the depreciation charge and to include a cost of capital to derive a total cost figure on a consistent basis.<sup>507</sup>

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<sup>504</sup> The final model includes number of transformers and network route length as explanatory variables.

<sup>505</sup> Frontier Economics, *Choice of Model and Availability of Data for the Efficiency Analysis of Dutch Network and Supply Businesses in the Electricity Sector*, February 2000, p. 11.

<sup>506</sup> Ibid, pp. 11-12.

<sup>507</sup> The final model adopted by the DTe includes standardised capital costs as part of the measure of total costs as the input variable.

### DEA models estimated by Frontier Economics<sup>508</sup>

	Inputs	Outputs
Model 1	Opex	Units distributed Customer numbers
Model 2	Opex	Units distributed Small customer numbers Large customer numbers
Model 3	Opex	Units distributed Small customer numbers Large customer numbers Network length Transformer numbers
Model 4	Opex	Units distributed Small customer numbers Large customer numbers Network length Transformer numbers Network density
Model 5	Opex plus tangible depreciation	Units distributed Customer numbers

### *Alternative techniques considered<sup>509</sup>*

Only a single year of information was made available to Frontier Economics, which ruled out total factor productivity analysis over time.

There were only about 20 Dutch network businesses that could be included, which limited the usefulness of regression-based analysis.

Frontier Economics also considered that Stochastic Frontier Analysis was vulnerable to the effect of small sample sizes, since the decomposition of variation into random and efficiency-related components requires a large number of data points to be statistically significant.

Frontier Economics considered that, while all methods are less effective with smaller sample sizes, DEA techniques are less data-intensive than econometric methods. Therefore, Frontier Economics concluded that the DEA method was the most appropriate approach, given the data limitations.

### *Analysis of model outputs<sup>510</sup>*

For each of the five models, and under both CRS and VRS specifications:

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<sup>508</sup> Frontier Economics, *Choice of Model and Availability of Data for the Efficiency Analysis of Dutch Network and Supply Businesses in the Electricity Sector*, February 2000, p. 11.

<sup>509</sup> Ibid, pp. 5-6.

<sup>510</sup> Ibid, pp. 13-17.

- businesses that were identified as being on the frontier were assigned an efficiency score equal to one, and businesses that were not on the frontier were assigned an efficiency score of less than one based on their relative distance from the frontier.
- businesses were then ranked based on the efficiency score, from highest to lowest. If a number of businesses defined the frontier then the super-efficiency-score procedure, developed by Andersen and Petersen (1993),<sup>511</sup> was used to evaluate the extent to which inputs could be increased whilst still keeping the company on the frontier. This procedure was used to rank the businesses with an efficiency score of one.
- For each business, average score for the five model specification was computed.

#### *Application to regulatory decision*<sup>512</sup>

The DTe chose to apply a DEA model based on total controllable costs to prevent perverse incentives to inefficiently shift costs from opex to capex. The DTe also selected the most complex model specification.<sup>513</sup> The DEA model employed measured input as total costs, calculated by the sum of opex, depreciation and standardised capital costs. The outputs were energy delivered, number of large customers, number of small customers, peak demand at distribution level, peak demand at transmission level, and environmental variables including the number of transformers and network route length.<sup>514</sup> The DTe employed the constant returns-to-scale assumption as it considered that the businesses could merge or demerge to optimise scale.<sup>515</sup>

Based on the chosen model, efficient EDNs were assigned an efficiency score equal to one, and inefficient EDNs were assigned an efficiency score of less than one.

The DEA scores were multiplied by the costs of the EDNs to establish the ‘efficient costs’ for 2000. In the second regulatory period, the present value of the efficient costs from 2000 was obtained by applying the general change in productivity between 2000 and 2003.<sup>516</sup>

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<sup>511</sup> Andersen P and N Petersen, *A Procedure for Ranking Efficient Units in Data Envelopment Analysis*, Management Science, 39, October 1993, pp. 1261-1264.

<sup>512</sup> The Frontier Economic report summarised here is the preliminary report as both the final report and the DTe’s decision paper for the first regulatory period are unavailable. Therefore relevant information from the literature has been used to identify the final model applied by the DTe.

<sup>513</sup> Frontier Economics, *Competing Monopolists a New Era*, Frontier Bulletin, November 2000, p. 3.

<sup>514</sup> Ajodhia V, K Petrov and G Scarsi, *Benchmarking and its Applications*, Zeitschrift für Energiewirtschaft, 27 (4), 2003, pp. 269-270.

<sup>515</sup> Nillesen and Pollitt, *The 2001-3 Electricity Distribution Price Control Review in the Netherlands: Regulatory Process and Consumer Welfare*, Journal of Regulatory Economics, 31, February 2007, p. 264.

<sup>516</sup> NMa, *Annex B to Method Decision*, 2003, p. 4.

## 6 Canada

### 6.1 Overview of Canadian energy sector

In Canada, the federal government is responsible for the regulation of international and inter-provincial trade and commerce.

The National Energy Board (NEB) is an independent federal agency responsible for:

- regulating the construction and operation of interprovincial and international oil and gas pipelines as well as international and designated interprovincial power lines
- regulating pipeline tolls and tariffs for pipelines under its jurisdiction
- regulating exports and imports of natural gas as well as exports of oil, natural gas liquids and electricity
- regulating oil and gas exploration, development and production in frontier lands and offshore areas not covered by provincial or federal management agreements.<sup>517</sup>

Intra-state electricity industries are governed by provincial governments. There are significant differences between the electricity industries and regulatory frameworks for each of the ten provinces.

Only Alberta and Ontario have competitive wholesale electricity markets and have introduced some amount of retail competition. The transmission system in Alberta is operated by an independent system operator. Québec, Manitoba and British Columbia have also introduced wholesale competition. Other provinces and territories continue to be supplied by one utility. Often, government-owned utilities also own and operate the transmission system.<sup>518</sup>

#### *Benchmarking in Canada*

CAMPUT is a self-funded, non-profit organisation whose membership is made up of federal and provincial regulators for electricity, gas and water utilities.<sup>519</sup> In 2010, CAMPUT commissioned First Quartile Consulting (1QC) and Elenchus Research Associates (ERA) to investigate whether benchmarking may be used as a regulatory and reporting tool for Canadian electricity utilities (the CAMPUT Report).

The CAMPUT Report noted that formal benchmarking was already undertaken in a number of Canadian jurisdictions and in some cases, regulated businesses provided

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<sup>517</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, p. 355.

<sup>518</sup> Ibid, p. 354.

<sup>519</sup> CAMPUT: *Canada's Energy and Utility Regulators*. Available at: [http://www.camput.org/public\\_index.html](http://www.camput.org/public_index.html) [accessed on 1 December 2011].

benchmarking studies as an input into price/revenue reviews.<sup>520</sup> For example, the Ontario Energy Board (OEB) undertook a benchmarking exercise in relation to its electricity distribution networks (EDNs) and gas distribution networks (GDNs) and Hydro-one, Ontario's major electricity transmission network (ETN) operator, has provided its own benchmarking studies to the OEB to inform rate reviews.<sup>521</sup> Benchmarking undertaken by the OEB is discussed in the following section 6.2.

The CAMPUT Report also identified a number of network characteristics and operational environments in Canada that make it more difficult to undertake benchmarking analysis across energy utilities. This was found to be in contrast with countries such as the UK where there are a limited number of very large utilities that:

- have the same system design standards
- are subject to the same weather patterns
- have similar customer density
- are subject to the same regulatory regime.<sup>522</sup>

## **6.2 Overview of Ontario energy sector**

### *Electricity*

Until 1998, the electricity sector in Ontario was dominated by the state-owned Ontario Hydro, which was responsible for generating electricity, undertaking transmission system planning, providing rural and remote distribution services.

Ontario Hydro produced over 90 per cent of the province's electricity and controlled the balance of supply through non-utility generation contracts. Local businesses distributed electricity from Ontario Hydro to consumers, and Ontario Hydro sold electricity directly to Ontario's large industrial customers and to rural and remote retail customers.<sup>523</sup>

In 1999, Ontario Hydro was separated into five separate businesses:<sup>524</sup>

- Ontario Power Generation Inc (OPG). OPG assumed Ontario Hydro's generation assets and the direct customer, retail and wholesale operations. OPG's shares are held by the Province of Ontario.
- Hydro One Inc (Hydro One). Hydro One assumed the transmission and rural distribution business, as well as the obligation to serve remote communities. It is

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<sup>520</sup> First Quartile Consulting LLC and Elenchus Research Associates, *CAMPUT Benchmarking for Regulatory Purposes*, April 2010, p. 38.

<sup>521</sup> A 'rate review' is essentially a price determination and is the term commonly used by North American regulators.

<sup>522</sup> First Quartile Consulting LLC and Elenchus Research Associates, *CAMPUT Benchmarking for Regulatory Purposes*, April 2010, p. 28.

<sup>523</sup> Blake, Cassels and Graydon LLP, *Overview of Electricity Regulation in Canada*, March 2008, PtIV(A)(1).

<sup>524</sup> Ibid.

the largest local distribution company (LDC) in Ontario, with the remaining LDCs generally owned by municipalities.

- Independent Electricity System Operator (IESO). The IESO administers electricity markets in Ontario and directs the operation of Ontario's transmission grid.
- Ontario Electricity Financial Corporation (OEFC). The OEFC assumed all other assets and liabilities of Ontario Hydro and is responsible for non-utility generation contracts.
- Electrical Safety Authority (ESA). The ESA is responsible for regulating safety matters associated with the generation, transmission, distribution, retail or use of electricity in Ontario.

Competition was introduced into the electricity wholesale and retail market on 1 May 2002. The government continued to set electricity prices for low-volume consumers and other designated consumers until 2004. From 2004, an electricity price plan (called a Regulated Price Plan or RPP) was developed by the OEB.<sup>525</sup> The RPP is offered to residential and low-volume electricity consumers. The RPP is designed to ensure that the price paid by consumers reflected the price paid to electricity generators. Alternatively, these consumers can enter into a contract with an electricity retailer. The RPP is reviewed every six months.<sup>526</sup>

Presently, Hydro One is a Crown corporation wholly owned by the Province. Hydro One Networks Inc is the owner and operator of 97 per cent of Ontario's transmission assets and is a wholly owned subsidiary of Hydro One. Hydro One also operates the largest EDN in Ontario and primarily serves rural areas.<sup>527</sup>

There are 86 other EDNs in Ontario mainly owned by municipalities. The six largest (other than Hydro One) provide electricity to 40 per cent of all customers in Ontario. These are: Enersource Hydro Mississauga, Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc, Toronto Hydro Electric Systems Limited and Veridian Connections.

*Gas*<sup>528</sup>

Two major gas utilities operate in Ontario:

- Enbridge Gas Distribution Inc (Enbridge)
- Union Gas Limited (Union).

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<sup>525</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, p. 354.

<sup>526</sup> OEB, *Regulated Price Plan*, Available at: <http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Regulated+Price+Plan> [accessed on 17 January 2012].

<sup>527</sup> Blake, Cassels & Graydon LLP, March 2008, Pt IV(A)(4).

<sup>528</sup> Brattle Group, *Use of Total Factor Productivity Analyses in Network Regulation: Case Studies of Regulatory Practice*, report to the AEMC, October 2008, pp. 37-42.

Enbridge is the largest natural gas distribution utility in Canada. It provides gas to about 1.9 million residential, commercial, and industrial customers. More than half of these customers buy gas directly from Enbridge. The remaining customers buy gas from a marketer. Enbridge also has financial interests in the US portion of the Alliance Pipeline, the Vector Pipeline, and the Enbridge Offshore Pipelines.

Union delivers natural gas and related services to approximately 1.3 million residential, commercial and industrial customers in northern, south-western and eastern Ontario. Union also provides natural gas transportation and storage services for utilities in Ontario, Quebec, and the US.

Union and Enbridge differ in that:

- Enbridge serves the Toronto metropolitan area where customer density is significantly higher than the service territory of Union
- Union is involved in major gas storage and transmission business.

*Regulator*<sup>529</sup>

The Ontario Energy Board (the OEB) regulates Ontario's electricity and natural gas industries under the *Ontario Energy Board Act 1998*.

The OEB sets electricity transmission and distribution rates, and approves budgets and fees for the Independent Electricity System Operator (IESO). The OEB also sets the rate for the Standard Supply Service and those distribution utilities that supply electricity directly to consumers.

Electricity generators, transmitters, distributors, wholesalers and retailers, and the IESO, must obtain an operating licence from the OEB. OEB approval is required for the construction of electricity transmission lines longer than two kilometres and specific business arrangements involving the regulated parts of Ontario's electricity industry. The OEB may review IESO market rules and hear appeals arising from IESO orders.

The OEB regulates Ontario's natural gas utilities by:

- issuing licenses to marketers who sell natural gas to residential or small commercial consumers
- reviewing proposed changes to gas prices
- determining whether the construction of gas pipelines are in the public interest, having regard to: an assessment of the safety of the proposed pipeline, the economic feasibility of the proposed pipeline, community benefits, security of supply and environmental impacts

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<sup>529</sup> Ontario Energy Board, *What We Do*. Available at: <http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/What+We+Do> [accessed on 17 January 2012].

- approving geological formations for storage of natural gas
- reviewing proposed sales of gas distribution systems or proposed mergers between gas utilities
- determining compensation payable to landowners when storage pools are situated on their property and where an agreement with the landowner cannot be reached
- reviewing agreements between municipalities and gas utilities in relation to the right to deliver gas service and use road allowances or utility easements.

### *Appeal Process*

Decisions made by the OEB and the NEB may be appealed on questions of jurisdiction or law. OEB decisions may be appealed to the Ontario Divisional Court. NEB decisions may be appealed to the Federal Court of Appeal.

## **6.3 Electricity distribution**

### 6.3.1 Regulatory framework<sup>530</sup>

In 2000, the OEB replaced a ‘cost of service’ regulation model with an ‘incentive regulation framework’ (IR framework) for EDNs. The form of the IR framework is reviewed in each regulatory period. Since 2000, however, the IR framework has been based on a price cap:  $PCI = P - X \pm Z$ .

That is, the price cap index (*PCI*) is determined by the inflation rate (*P*), a productivity-offsetting factor (*X*) and unforeseen events (*Z*). These factors are explained in more detail below.

### 6.3.2 3<sup>rd</sup> Generation incentive regulation

The OEB determined that the 3<sup>rd</sup> Generation Incentive Regulation Plan (3<sup>rd</sup> IR Plan) would apply for three years plus a re-basing year. An EDN commences the 3<sup>rd</sup> IR plan following its rebasing review.<sup>531</sup> The OEB has staggered the rebasing reviews for EDNs between 2008 and 2011. A rebasing review involves a full cost-of-service analysis.<sup>532</sup>

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<sup>530</sup> OEB, *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario’s Electricity Distributors*, July 2008, ch. 2, pp. 5-43.

<sup>531</sup> Ibid, p. 7.

<sup>532</sup> OEB, *Multi-year Electricity Distribution Rate Setting Plan Selection of Electricity LDCs for Rebasing* (EB-2009-0028 and EB-2006-0330). Available at: <http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Multi-year+Electricity+Distribution+Rate+Setting> [accessed on 16 January 2012].

The OEB may initiate a review of the 3<sup>rd</sup> IR Plan before the end of the three-year regulatory period if an EDN's rate of return either exceeds or falls short of the allowed return by 300 basis points (known as an 'off-ramp').<sup>533</sup>

The OEB decided to use the Gross Domestic Product Implicit Price Index (GDP-IPI) for Canada as the measure of inflation (*P*). The economy-wide measure was considered to be easier to implement compared to an industry-specific inflation rate.<sup>534</sup>

The *X* factor is the sum of:<sup>535</sup>

- an inflation differential
- an industry-productivity factor
- a 'stretch factor'.

The inflation differential is the difference between economy-wide output price changes compared to changes in input prices for the electricity distribution industry. The OEB set this inflation differential in the 3<sup>rd</sup> IR Plan at zero.<sup>536</sup>

The productivity factor is the rate of change in productivity of the electricity distribution industry. It was derived from estimates of the long-run trend in TFP growth using US data (refer to section 6.3.3).

The 'stretch factor' is an EDN's individual productivity target. The stretch factor was determined by grouping EDNs into three groups using two methods: a unit-cost analysis and an econometric method for estimating cost function. Each group was assigned a stretch factor value, where the value was higher for EDNs assigned to the least efficient group. The stretch factor groupings are recalculated each year as new data become available (refer to section 6.3.4).

The OEB commissioned Pacific Economic Group (PEG) to advise on the setting of the *X* factor for the 3<sup>rd</sup> IR plan.

The *Z* factor accounts for unforeseen events that impact on costs where the events are beyond management control. This includes events such as natural disasters or changes to the tax regime. In order for a *Z* factor to be included, the event must meet requirements of causation, materiality and prudence.

In addition, the OEB can provide intra-term approval for pass-through of additional unplanned capital expenditure to customers. EDNs who receive this approval and rate relief must provide annual reports to the OEB on capital expenditure and are subject to a prudence review at the time of rebasing.<sup>537</sup>

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<sup>533</sup> OEB, *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, July 2008, p. 38.

<sup>534</sup> Ibid, p. 10.

<sup>535</sup> Ibid, pp. 11-20.

<sup>536</sup> Ibid, p. 11.

<sup>537</sup> OEB, *Supplemental Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, September 2008, p. 33.

### 6.3.3 PEG: Analysis to determine the industry productivity factor<sup>538</sup>

#### *Background*

The 3<sup>rd</sup> IR Plan provides that all EDNs are subject to the same industry- productivity factor that is set at the start of 3rd IR plan. This industry productivity factor remains fixed throughout the term of the plan. This is irrespective of when an EDN commences the plan.<sup>539</sup>

#### *Data*

Three sets of input and output data were considered by PEG for the industry productivity analysis, these included:

- 69 US EDNs from 1988 to 2006
- Ontario EDNs from 1988 to 1997
- Ontario EDNs between 2002 and 2006.

This included previously calculated TFP indices.

The US EDN data were obtained from the Federal Energy Regulatory Commission (FERC). This dataset had been provided by major US investor-owned EDNs.<sup>540</sup>

The Ontario data were provided by Ontario EDNs to the OEB pursuant to the Reporting and Record Keeping Requirements (RRR) established by the OEB. The OEB uses this dataset to assess future opex and capex and reliability performance proposals made by EDNs. Data for Ontario EDNs were not available between 1998 and 2001.

PEG concluded:

- there were insufficient data on Ontario EDNs to estimate the long-run TFP growth rates directly
- TFP growth rates of US distributors may be used as a proxy to for productivity trends in Ontario.

The OEB agreed with this conclusion. However the OEB expects to have collected sufficient data from Ontario EDNs by 2012 to estimate long-run TFP growth rates using Ontario data.<sup>541</sup>

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<sup>538</sup> PEG, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report to the Ontario Energy Board, February 2008.

<sup>539</sup> OEB, *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, July 2008, pp. 19-20.

<sup>540</sup> PEG, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report to the Ontario Energy Board, February 2008, p. 46.

<sup>541</sup> OEB, *Supplemental Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, September 2008, p. 12.

PEG also proposed that the timeframe for TFP analysis be limited to between 1995 and 2006 as transitory conditions, such as abnormal economic or weather conditions would distort TFP estimates.<sup>542</sup> This was rejected by the OEB and the full set of data on US EDNs from 1988 to 2006 was employed in the final analysis to determine the productivity factor.<sup>543</sup>

### *Benchmarking Technique*

The industry-productivity factor was determined using a TFP index-number-based technique. The TFP growth rates were derived using a Tornqvist Index. The TFP trend is then the simple average of annual TFP growth rates.<sup>544</sup>

The OEB considered that this technique:

- was simpler compared to alternative ‘econometric’ techniques
- was better understood by stakeholders
- was widely used in other jurisdictions.

In addition, the consultants for the EDNs agreed that the index-based approach is appropriate.<sup>545</sup>

### *Inputs*<sup>546</sup>

PEG developed input price sub-indices and input quantity sub-indices for each of three inputs, namely capital, labour, and materials and other services.

A cost-of-service approach was used to calculate capital costs and capital quantities. The cost of a given class of utility plant in a given year is the product of a capital service price index and an index of the capital quantity at the end of the prior year. The capital service price index is a function of the cost of construction assets. The capital quantity index is derived from inflation-adjusted estimates of the value of each utility plant, commencing in 1964.

The labour price variable was constructed from data from the US Bureau of Labor Statistics (BLS). National Compensation Survey (‘NCS’) data for 2004 were used to construct average wage rates. The wage levels were a weighted average of the NCS pay level for each job category using weights that correspond to the electric, gas, and sanitary (EGS) sectors in the US. Values for other years were calculated by adjusting the 2004 level for changes in the employment cost index by region, from 1988 to 2006.

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<sup>542</sup> PEG Feb 2008, pp. 61-63.

<sup>543</sup> OEB, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors*, September 2008, p. 12.

<sup>544</sup> PEG, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report to the Ontario Energy Board, February 2008, p. 34.

<sup>545</sup> OEB, *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario’s Electricity Distributors*, July 2008, p. 19.

<sup>546</sup> PEG, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report to the Ontario Energy Board, February 2008, p. 47.

Prices for other operating and maintenance (O&M) inputs were assumed to be constant in a given year across all the sampled businesses. The prices are adjusted in line with the US GDP-IPI.

#### *Outputs*<sup>547</sup>

The output quantity variables are:

- the number of retail customers
- total electricity delivered (kWh).

A sub-index for each quantity variable was created and each sub-index is weighted by its cost elasticity share: 0.63 for customer numbers and 0.37 for electricity deliveries.

The cost elasticity shares were estimated by solving a system of equations using Zellner's seemingly unrelated regression estimation technique (SURE).<sup>548</sup> The set of equations included a trans-log cost function and three restrictions to ensure homogeneity in input prices, as shown below.<sup>549</sup>

Cost function:

$$\begin{aligned} \ln C = & \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\ & + \frac{1}{2} \left[ \sum_h \sum_k \gamma_{hk} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n \right] \\ & + \sum_h \sum_j \gamma_{hj} \ln Y_h \ln W_j + \sum_h \alpha_h \ln Z_h + \alpha_t T + \varepsilon \end{aligned} \quad [\text{A4.2}]$$

Where:  $C$  denotes cost,  $Y$  denotes output variables,  $W$  denotes input variables,  $Z$  denotes environmental variables,  $T$  is a time trend and  $\varepsilon$  is the error term.

Restrictions:

$$\sum_{h=1}^N \frac{\partial \ln C}{\partial \ln W_h} = 1 \quad [\text{A4.3}]$$

$$\sum_{h=1}^N \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \quad \forall j = 1, \dots, N \quad [\text{A4.4}]$$

$$\sum_h \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \quad \forall j = 1, \dots, K \quad [\text{A4.5}]$$

<sup>547</sup> Ibid, p. 47.

<sup>548</sup> Zellner, A, *An Efficient Method of Estimating Seemingly Unrelated Regression Equations and Tests for Aggregation Bias*, Journal of the American Statistical Association, 1962, pp. 348-368.

<sup>549</sup> PEG, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, Report to the Ontario Energy Board, February 2008, pp. 128-132.

The cost function (for estimating the cost elasticity shares) included the following output quantity and input price variables:<sup>550</sup>

- customer numbers
- electricity deliveries
- input prices for capital and labour inputs
- the percentage of the total value of distribution plant that is not under ground
- the number of gas distribution customers of the utility, which identifies the extent to which the utility has diversified its activities into gas distribution
- the percentage of deliveries to residential and commercial customers
- a measure of service territory forestation
- the total miles of distribution line
- a trend variable that identifies the magnitude of costs that shift over time for reasons other than changes in the specified business conditions.

The dataset used to estimate the cost elasticity shares was consistent with that used to estimate TFP trends for US EDNs. However, it also contained data from additional US EDNs.

#### *Model specification*

The Tornqvist index was derived as follows:<sup>551</sup>

Growth in the input quantity index:

$$\ln\left(\frac{\text{Input Quantities}_t}{\text{Input Quantities}_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (S_{j,t} + S_{j,t-1}) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}}\right). \quad [12]$$

Here in each year  $t$ ,

$\text{Input Quantities}_t$  = Input quantity index

$X_{j,t}$  = Input quantity subindex for input category  $j$

$S_{j,t}$  = Share of input category  $j$  in applicable total cost.

Growth in the output quantity index:

<sup>550</sup> Ibid, pp. 130-132.

<sup>551</sup> Ibid, pp. 34-36.

$$\ln\left(\frac{\text{Output Quantities}_t}{\text{Output Quantities}_{t-1}}\right) = \sum_j \frac{1}{2} \cdot (S_{k,t} + S_{k,t-1}) \cdot \ln\left(\frac{Y_{k,t}}{Y_{k,t-1}}\right). \quad [13]$$

Here in each year  $t$ ,

$\text{Output Quantities}_t$  = Output quantity index

$Y_{k,t}$  = Output quantity subindex for output category  $k$

$S_{k,t}$  = Cost elasticity share for output category  $k$ .

The annual growth rate in the TFP index is then calculated as the growth rate in the output quantity index less the growth rate in the input quantity index.

The TFP trend is then calculated as the simple average of annual TFP growth rates.

#### *Statistical testing of model*

PEG examined whether estimates of TFP for US electricity distributors could be used as a proxy for TFP for electricity distributors in Ontario.<sup>552</sup> PEG:

- undertook TFP analysis for US and Ontario businesses for 1988 to 1993, 1993 to 1997, and 2002 to 2006
- estimated TFP data for Ontario distributors for 1997 to 2002 and thereby reconstructed the Ontario data set for the entire period, 1988 to 2006
- identified a strong correlation between TFP growth estimates for US and Ontario electricity distributors
- concluded that the US TFP analysis provided a useful proxy for TFP trend for Ontario distributors.

#### *Application to regulatory decision*

The average annual TFP growth rate for US EDNs was estimated at 0.72 per cent between 1988 and 2006. This figure was used as the productivity factor component of the X factor determination by the OEB for all Ontario EDNs for the term of the 3<sup>rd</sup> IR Plan.

#### 6.3.4 PEG: Analysis to determine the stretch factors

##### *Summary*

PEG used comparative benchmarking to determine the stretch factor component of the X factor. EDNs were placed into three groups based on the results of two different benchmarking methods, an econometric method and a unit-cost method. Each of the three groups was assigned a value for the stretch factor such that the more efficient groups of EDNs were allocated lower stretch factors relative to the less

<sup>552</sup> Ibid, p. 54.

efficient groups. The allocation of EDNs to the three groups was revised annually based on the newly available data. This process rewarded distributors who obtain intra-term efficiency improvements.<sup>553</sup>

#### *Data*<sup>554</sup>

Itemised cost data are sourced from OEB's Trial Balance reports. The Trial Balance reports are provided annually under the OEB's RRRs. These financial records comply with Ontario's Uniform System of Accounts (USoA) and are supported by audited financial statements. The Trial Balance reports also provide itemised data on gross plant value. This included accumulated 'amortisation' (depreciation) on electric utility property, plant and equipment, and accumulated amortization of intangible plant. Capital spending data were also provided by audited financial statements.

Data on outputs, revenue and utility characteristics were sourced from Performance Based Regulation reports that are submitted annually by EDNs to OEB.

Additional data was obtained from Statistics Canada, and from geographical surveys.

#### *Benchmarking technique*

Two benchmarking methods were used to group the EDNs:

- an econometric method described in section 6.3.5
- a unit-cost method described in section 6.3.6.

#### 6.3.5 Econometric method

##### *Data*

The econometric model used data available from 2002 to 2006 for 86 EDNs in Ontario. EDNs were excluded from the study in cases where at least two years of data were not available.<sup>555</sup> The model was updated to include 2007 data when it became available.<sup>556</sup>

##### *Inputs*<sup>557</sup>

Total operating (OM&A) cost was the dependent variable in the econometric model.

##### *Input prices*<sup>558</sup>

An input price index developed by PEG was included as an explanatory variable in the econometric model and found to be statistically significant. The input price index

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<sup>553</sup> OEB, *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, July 2008, pp. 20-23.

<sup>554</sup> PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, pp. 36-38.

<sup>555</sup> Ibid, p. 43.

<sup>556</sup> PEG, *Efficiency Ranking and Cohorts for the 2009 Rate Year*, July 2008, p. 1.

<sup>557</sup> PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, p. 45.

<sup>558</sup> Ibid, pp. 46-47.

reflected changes in OM&A input prices over time and between businesses. The index was a weighted average of the price of labour and the price of miscellaneous inputs such as materials and services.

The price of labour was constructed using 2001 census data. Average income was disaggregated by educational levels and by Ontario's cities. Changes in the labour price were calculated using an index of labour cost trends in Ontario.

The price index for miscellaneous materials and services was derived from the Ontario Gross Domestic Product Implicit Price Index for Final Domestic Demand ('GDP-IPI-FDD').

The cost share variables, labour and miscellaneous, were weighted 50/50. These weights were adjusted formulaically so that the labour cost share was higher (lower) in Ontario's cities where wage rates are expected to be high (low).

### *Output Quantities*

PEG considered three output variables in the econometric research, these were statistically significant:<sup>559</sup>

- the number of retail customers
- the total retail delivery volume
- the total circuit km of distribution line as a proxy for the distances over which power is carried.

PEG also identified three environment (business condition) variables that were statistically significant cost drivers:<sup>560</sup>

- the percentage of circuit kilometres of lines that are underground. Underground lines typically involve higher capital costs and lower OM&A expenses. The extent of underground lines varies greatly across Ontario's distribution systems
- a binary variable that indicates the extent that the company's service territory is located on the Canadian Shield. Rural areas of the Canadian Shield are generally forested. OM&A expenses are expected to be higher on the Canadian Shield
- a measure of system age:  $N_t - N_{10} / YNDX$  where,  $N_t$  is the number of customers served in each year  $t$  and  $YNDX$  is a weighted index of the three output quantities.

A rural forestation variable was not statistically significant.

The model also includes a time trend variable.

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<sup>559</sup> Ibid, p. 46.

<sup>560</sup> Ibid, pp. 47-51.

*Model specification:*<sup>561</sup>

A double-log model was employed and included a full set of quadratic input price and output terms:<sup>562</sup>

$$\begin{aligned} \ln C = & \alpha_o + \sum_i \alpha_i \ln Y_i + \sum_j \alpha_j \ln W_j + \sum_\ell \alpha_\ell \ln Z_\ell + \alpha_t T \\ & + \frac{1}{2} \left[ \sum_i \gamma_i \ln Y_i \ln Y_i + \sum_j \gamma_j \ln W_j \ln W_j \right] \\ & + \varepsilon. \end{aligned} \quad [A4]$$

Where  $C$  denotes total operating costs,  $Y$  denotes output quantities,  $W$  denotes input prices,  $Z$  denotes environmental variables,  $T$  is a time trend and  $\varepsilon$  is the error term

The double-log model with quadratic terms was used because it could accommodate both unusually large and small business operating scales. Three of the four parameter estimates for the quadratic terms were statistically significant.

*Model specification testing*

PEG considered the translog functional form. However the data did not support the full translog model and negative output elasticities were being produced.<sup>563</sup>

For the chosen double log model with quadratics, the business condition variables were included in the final version of the model if their elasticity estimates were plausible (e.g., sensibly signed) and significantly different from zero (90 per cent confidence).<sup>564</sup>

Groupwise heteroskedasticity was present and corrected using an ‘in house’ Gauss estimation procedure.<sup>565</sup>

The model was re-estimated using a sub-set of the data between 2003 and 2006. The results were compared with the results from the full set of data (2002 to 2007).<sup>566</sup>

PEG also considered the following explanatory variables:

- a capital quantity index.<sup>567</sup> However, in preliminary estimations, the variable lacked statistical significance. The index may be used in future versions of the model when additional data are obtained
- a reliability index.<sup>568</sup> However, PEG considered that an increase in the quantity and quality of the data that measures reliability is required before this variable can be included in the model.

<sup>561</sup> PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, p. 51.

<sup>562</sup> Source: PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, p.76.

<sup>563</sup> Ibid, p. 51.

<sup>564</sup> Ibid, p. 52.

<sup>565</sup> Ibid, p. 51.

<sup>566</sup> Ibid, p. 55.

<sup>567</sup> Ibid, pp. 62-65.

<sup>568</sup> Ibid, pp. 65-67.

### *Analysis of model results*<sup>569</sup>

Estimates from the econometric cost model were used to predict OM&A costs for each EDN in each time period.

The three most recent years of each EDN's OM&A costs<sup>570</sup> (2005-2007) were averaged and compared with the average of the predicted costs from the model for the same timeframe. Statistical analysis was then used to determine whether an EDN's costs were significantly greater or less than the models predicted costs (at the 90 per cent confidence level). Accordingly EDNs were classified as:

- Significantly superior performers (if average costs were significantly lower than predicted)
- Significantly inferior performers (if average costs were significantly higher than predicted)
- Average cost performers (otherwise)

EDNs were also ranked based on the difference between actual and predicted costs for the most recent three year period.

#### 6.3.6 Unit-cost method

##### *Data*

The unit-cost method used the same cost data as the econometric method. That is, data available from 2002 to 2006 for 86 EDNs in Ontario.<sup>571</sup> The model was updated to include 2007 data when it became available.<sup>572</sup>

##### *Inputs*

The input variable was the logged OM&A costs for each EDN for each time period less the sample average value for all EDNs in that time period.<sup>573</sup>

##### *Outputs*

PEG constructed an output quantity index by weighting three output variables, circuit kms, retail deliveries and number of customers served. The weights were based on econometric estimates of cost elasticities, estimated under sample mean conditions. The resulting weights were:

- circuit kms - 9.9 per cent
- retail deliveries - 38.5 per cent

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<sup>569</sup> Ibid, pp. 55-56.

<sup>570</sup> The initial analysis in PEG (March 2008) used the years 2004 to 2006, the updated analysis PEG (July 2008) used 2005 to 2007.

<sup>571</sup> PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, p. 58.

<sup>572</sup> PEG, *Efficiency Ranking and Cohorts for the 2009 Rate Year*, July 2008, p. 1.

<sup>573</sup> PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, p. 77.

- number of customers served - 51.6 per cent.<sup>574</sup>

First the log of each output variable for each EDN in each time period less the sample average value in each time period is calculated. Then the weights are applied to form the output quantity index.<sup>575</sup>

#### *Model specification*

The unit-cost index was obtained by dividing the input variable by the output quantity index.

#### *Peer groups*

PEG then developed 12 peer groups:<sup>576</sup>

- First, EDNs were grouped by region so that EDNs within each group would more likely face similar input price and forestation challenges
- Second, within each region, EDNs were grouped by size to reflect the potential for scale economies
- Third, EDNs were sorted to reflect different degrees of undergrounding, rates of population growth, and system age.

Hydro-one had no comparable peer group.

#### *Analysis of model results*<sup>577</sup>

An annual unit-cost index for each EDN was reported (note these annual values are relative to the sample mean – refer to input and output calculation).

A three-year average unit-cost index was then calculated for each EDN using the most recent three years.

For each peer group, the average, across the peer group, of the three-year average unit-cost indices was calculated. This value was set as the peer group's 'benchmark'.

Each EDN in the full sample was then ranked according to the difference between its three-year average unit-cost index and its peer group average.

These 'unit-cost' rankings were compared with the 'econometric' rankings. The Spearman rank correlation co-efficient was used to compare the two results. A Spearman rank correlation coefficient provides the direction and extent of the relationship between the rankings of the set of businesses. The result supports the notion that the two sets of rankings are similar.<sup>578</sup>

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<sup>574</sup> PEG, *Benchmarking the Costs of Ontario Power Distributors*, March 2008, p. 57.

<sup>575</sup> Ibid, pp. 76-77.

<sup>576</sup> Ibid, pp. 57-58.

<sup>577</sup> Ibid, p. 58.

<sup>578</sup> Ibid, p. 62.

### *Sensitivity testing of benchmarking results*<sup>579</sup>

PEG undertook a sensitivity analysis of the July 2008 results to investigate two potential issues:<sup>580</sup>

- the sensitivity of benchmarking results where a firm may be incorrectly identified as being on the Canadian Shield
- the treatment of charges billed by Hydro One to distributors ‘embedded’ within its network for the use of LV facilities.

The results suggested that these issues did not significantly impact on the reported outcomes.

In the first test, PEG investigated the sensitivity of its benchmarking results by re-calculating the results of the econometric model with one EDN, Renfrew Hydro, classified as ‘off’, rather than ‘on’ the Canadian Shield. Renfrew Hydro was used because it may have been misclassified as serving territory on the Canadian Shield. Three of the 83 distributors changed stretch factor groups in this test. Renfrew Hydro itself was not impacted.<sup>581</sup>

The second set of sensitivity tests concerned Hydro One’s charges to distributors embedded within its service territory for the use of LV facilities. PEG tested two proxies for LV charges. Out of the 83 distributors, four distributors changed stretch factor groups using the first LV proxy and two distributors changed stretch factor groups based on the second LV proxy.<sup>582</sup>

### *Application of model results to regulatory decision*

OEB’s final decision was based on both the econometric and unit-costs analysis developed by PEG.

From the econometric model results (described above), distributors were classified as:

- ‘statistically superior’ if their actual OM&A costs were lower than the costs predicted by the econometric model and the difference is statistically significant
- ‘statistically inferior’ if their actual OM&A costs were higher than the costs predicted by the econometric model and the difference is statistically significant
- an ‘average cost performer’.<sup>583</sup>

From the unit-cost model rankings (based on the percentage difference between the three-year average unit costs and the peer group benchmark) EDNs were classified as

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<sup>579</sup> PEG, *Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate Year: Update*, December 2008.

<sup>580</sup> Ibid, p. 1.

<sup>581</sup> Ibid, p. 2.

<sup>582</sup> Ibid, pp. 3-5.

<sup>583</sup> OEB, *Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario’s Electricity Distributors*, July 2008, pp. 21-23

in the top quartile, middle two quartiles or bottom quartile on the unit-cost comparison.

The classifications from the econometric and unit-cost models were combined to place EDNs in stretch factor groups, as per the table below:<sup>584</sup>

Group	Benchmarking Evaluations	Stretch Factor Value
I	Statistically superior and in top quartile on OM&A unit-cost comparison	0.2%
II	In middle two quartiles on OM&A unit-cost comparison	0.4%
III	Statistically inferior and in bottom quartile on OM&A unit-cost comparison	0.6%

The OEB employed the stretch factor groups as recommended by PEG.<sup>585</sup>

The OEB determined the values for each stretch factor group (as reported in the table above), after reviewing the advice of PEG and after considering the views of stakeholders. Lower stretch factors were assigned to the more efficient distributors because there was less scope for productivity improvements compared with the less efficient businesses. The OEB:<sup>586</sup>

- recognised that stretch factors were an important tool that was needed to influence and motivate distributor behaviour
- regarded incremental productivity gains above the expected industry trend achievable and that the gains should be shared with ratepayers. As a result, all stretch factors are greater than zero
- recognised the possibility of misclassification of distributors but did not consider this a reason to reduce the stretch factors so that they are of little or no materiality
- believed that the stretch factor must provide incentives for incremental productivity improvement for the least efficient distributors and not act as a punitive measure.

The stretch factor values for each group, as reported in the table above, remain in effect for the term of the 3rd IR Plan.

The classifications of each EDN are re-evaluated annually and an EDN may be reassigned to a different stretch factor group during the term of the IR plan. This approach rewards distributors for efficiency improvements during the term of the IR plan. The OEB annually publishes the revised stretch factor groups in August.

<sup>584</sup> Source: OEB, *Supplemental Report of the Board on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity Distributors*, September 2008, p. 22.

<sup>585</sup> PEG, *Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate Year: Update*, December 2008, Tables 3, 4 and 5.

<sup>586</sup> OEB, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 2008, pp. 20-21.

## *Benchmarking by Hydro One*

Given its size, Hydro One's cost structures and productivity levels cannot easily be compared to other transmission and distribution businesses in Ontario. As a result, Hydro One has commissioned its own benchmarking studies in support of its transmission and distribution reviews. Please refer to the following benchmarking studies for more information:

- PA Consulting Group (2007), *Hydro One Distribution Benchmarking Study: Using Information from 2004-2006*, October
- First Quartile Consulting (2008), *Hydro One Update of Transmission Benchmarking Study: Using Information from 2004-2006*, September
- Mercer (2008), *Compensation Cost Benchmarking Study: Hydro One Networks Inc.*, September
- CN Utility Consulting (2009), *Vegetation Management Benchmarking Study*, September.

## **6.4 Gas distribution**

### 6.4.1 Background

The two major GDNs in Ontario, namely Enbridge and Union Gas, are subject to regulation by the OEB. Each regulatory period is for five years. The most recent regulatory period is from 2008 to 2012.

For the latest regulatory period the OEB considered the use of productivity measures for inclusion in an incentive regulation (IR) plan of the form:  $P = P_o + RPI - X$ , where  $X$  is the rate of expected productivity of the gas industry over the regulatory period, RPI is retail price index (inflation index) and  $P_o$  is the starting price or revenue.<sup>587</sup>

The OEB engaged Pacific Economics Group (PEG) to undertake input price and productivity analysis to develop an  $X$  factor, and to recommend the design of the rate and revenue cap for Enbridge Gas and Union Gas. This initial study was released on 30 March 2007. After considering responses to the initial study, PEG issued a final report on 20 November 2007 ('PEG Study').<sup>588</sup>

Enbridge engaged the Brattle Group and Professor Bernstein of the Florida International University (the Brattle Group Study) to also undertake a productivity assessment.<sup>589</sup>

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<sup>587</sup> Lowry M and L Getachew, *Price Control Regulation in North America: Role of Indexing and Benchmarking*, The Electricity Journal, 2009, pp. 63-76.

<sup>588</sup> Lowry M and Getachew L, *Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry*, Review of Network Economics, Vol. 8, Issue 4, December 2009 ('PEG Study').

<sup>589</sup> Brown T and Moselle B, The Brattle Group, *Use of Total Factor Productivity Analyses in Network Regulation: Case Studies of Regulatory Practice*, October 2008 ('Brattle Group Study'). Enbridge

A number of difficulties arose in the process of setting the IR plan. First, only two GDNs exist in the sector. This was not considered to be sufficient to develop productivity targets.<sup>590</sup> Second, there was no readily available Canadian gas industry data to calculate industry TFP. Third, the operating conditions of the Ontario GDNs are substantially different from neighbouring US gas distributors and this prevented the use of US data to estimate an approximate TFP for Ontario GDNs.<sup>591</sup>

In forming its final decision on Enbridge's and Union's rates, the OEB considered the consultants and the arguments of the parties to the proceeding, including Enbridge and Union, and consumer and large-user groups. As a result, no single analysis can be identified as the method employed by the OEB.

#### 6.4.2 PEG and Brattle Group productivity studies

##### *Data used*

Both the PEG Study and Brattle Group Study estimated future TFP growth for the Ontario gas distribution sector by analysing productivity changes among 36 US gas distributors. US data were used as there was insufficient data available in relation to the Ontario gas distribution sector.<sup>592</sup>

The Brattle Group Study estimated TFP growth across all 36 US businesses. The PEG Gas Study estimated TFP growth based on a subset of those 36 US businesses that were comparable to the Ontario gas distributors in terms of scale.

The data on input prices, productivity, and usage trends of Enbridge and Union from 2000 to 2005 was sourced from the OEB.

The data on US gas distribution utilities from 1994 to 2004 was obtained from Uniform Statistical Reports (USRs) filed with the American Gas Association. Operating data were also obtained from reports to state regulators and, in the case of the 2004 operating data, Platts GasDat package data were used. Data on the delivery volumes and customers served by US gas utilities were obtained from Energy Information Administration's (EIA) Form EIA-176.<sup>593</sup>

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were advised by Dr Paul Carpenter of the Brattle Group and Professor Jeffrey Bernstein of the Florida International University.

<sup>590</sup> Lowry and Getachew analysed the case of two gas distributors in a country where one faces slow customer growth and the other faces rapid customer growth. The results suggest that the distributors' TFP growth will vary. See Lowry M and Getachew L, PEG Study, December 2009, pp. 325-345.

<sup>591</sup> Lowry M and Getachew L, PEG Study, December 2009, p. 326.

<sup>592</sup> Brown T and Moselle B, Brattle Group Study, October 2008, p. 40.

<sup>593</sup> Whitman, Requardt & Associates prepare Handy Whitman Indexes of trends in the construction costs of US gas and electric utilities. Other sources of input price data are: R.S. Means and Associates, the Bureau of Labor Statistics of the US Department of Labor, and the EIA. See Brown, T and Moselle B, Brattle Group Study, October 2008, p. 46.

### *Technique*

Both the PEG and Brattle Group studies used a TFP method and both recommended that the X factor should be derived from the sum of the:<sup>594</sup>

- Productivity Differential (the difference between the productivity trends of the Ontario gas utility industry and the economy)
- Input Price Differential (the difference between the input price trends of the economy and the gas utility industry).

The most significant difference between the two studies was that the PEG Study used an econometric approach to estimate TFP. The Brattle Group study used an index number approach to estimate TFP.<sup>595</sup>

### *Inputs and weighting*

The PEG and Brattle Group studies both used the same inputs and weights.

The trends in input quantity indices were cost-share weighted averages of quantity indices for labour, material and supply (M&S), capital, and gas use.

Quantity indices for labour, M&S and gas use were calculated as total expenses in constant dollars.

Alternative measures of capital were considered, with different depreciation and valuation assumptions.<sup>596</sup> The book value of plant and straight line depreciation were recommended by PEG.

### *Outputs and weighting*

Two outputs were used in the PEG study: customer numbers and volume of gas disaggregated by customer groups. An elasticity-weighted output index was derived using all 36 US businesses in the dataset.<sup>597</sup>

The Brattle Group study employed an output index that was based on volumes of gas distributed to customers. Customers were disaggregated into three groups, weighted by the share in total distribution revenues. The revenue-share weight took into account number of customers and volume of gas. This was because customers are

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<sup>594</sup> The PEG study also included an 'Average Use per Customer' term, not required under the Brattle Group study. See Brown, T and Moselle B, Brattle Group Study, October 2008, p. 39.

<sup>595</sup> Brattle Group, *Use of Total Factor Productivity Analyses in Network Regulation: Case Studies of Regulatory Practice*, report to AEMC, October 2008.

<sup>596</sup> Two methods of calculating the capital index were used: 1) geometric decay – 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; and 2) cost-of-service – book (historic dollar) valuation of plant and straight line depreciation.

<sup>597</sup> See Lowry M and Getachew L, PEG Study, December 2009, pp. 329-30.

charged both per unit of gas delivered and a fixed charge for their connection to the network.<sup>598</sup>

### *Analysis of model outputs*

Both studies:<sup>599</sup>

- calculated the productivity differential by estimating the difference between the economy-wide productivity growth in Canada and the estimated TFP trend for the US gas sector
- used private business sector data on the Canadian economy from 1992 to 2003 as published by Statistics Canada in order to estimate economy-wide productivity
- estimated the economy-wide input price inflation using data on the Canadian Gross Domestic Product Implicit Price Indices (GDP-IPI).

In order to calculate input price inflation for the gas sector:

- The PEG study used Canadian data from Enbridge and Union from 2000-2006 and from Stats Canada
- the Brattle Group study used US data for 1994 to 2004 from Uniform Statistical Reports.<sup>600</sup>

### *Application to regulatory decision*

Based on the above analysis the PEG and Brattle Group studies recommended an X factor of 2.04 per cent and -0.14 per cent respectively.<sup>601</sup>

In relation to Enbridge, the OEB employed a revenue cap and revenue adjustment formula where the Distributor Revenue Requirement in each period ( $DRR_t$ ) is a function of:<sup>602</sup>

- the average revenue per customer in the previous period
- the average number of customers in the current period ( $C_t$ )
- the inflation co-efficient (P) (which replaced the X factor)
- the inflation rate (INF) (based on the Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand

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<sup>598</sup> Brown, T and Moselle B, Brattle Group Study, October 2008, p. 41.

<sup>599</sup> Brattle Group, *Use of Total Factor Productivity Analyses in Network Regulation: Case Studies of Regulatory Practice*, report to AEMC, October 2008, p. 42.

<sup>600</sup> Ibid, p. 41.

<sup>601</sup> Ibid, p. 39.

<sup>602</sup> Ontario Energy Board, *Decision: In the Matter of an Application by Enbridge Gas Distribution Inc. for an Order or Orders Approving or Fixing Rates for the Distribution, Transmission and Storage of Natural Gas, effective January 1, 2008*, p. 8.

- plus pass through costs (Y) and exogenous factors (Z), such as regulatory or tax requirements.

Adjustment Formula	$DRR_t = \left( \frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}} \right) * (1 + P * INF) * C_t + Y_t + Z_t$
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The X factor was replaced with the inflation co-efficient that varies over the term of the IR Plan as follows:

Year	Inflation Coefficient (“P”)
2008	0.60
2009	0.55
2010	0.55
2011	0.50
2012	0.45

Based on the assumed inflation rate of 2.04, this implies an X factor of 0.816 per cent in 2008, 0.918 per cent in 2009 and 2010, 1.02 per cent in 2011 and 1.12 per cent in 2012. The X factor would therefore average 0.96 per cent over the five years of the regulatory period. This figure is about half way between the X factors in the PEG and Brattle Group studies.<sup>603</sup>

For Union, the OEB fixed the X factor in the price cap index at 1.82 per cent for the regulatory period. This value was within the range of X factor values proposed by PEG and Brattle group studies. All other aspects of the Enbridge decision were applied to Union.<sup>604</sup>

<sup>603</sup> Ibid., p. 12.

<sup>604</sup> Ibid.

## 7 United States

### 7.1 Overview of the United States energy sector

#### *Electricity*<sup>605</sup>

Electricity utilities in the United States (US) are investor-owned, publicly owned, or co-operatively owned.

Most investor-owned utilities (IOUs) are vertically integrated, operating in generation, transmission and distribution, although many procure electricity from wholesale markets rather than owning generation assets. IOUs range in size and may be regulated at the national (interstate operations) and/or state level (intra-state operations).

Publicly owned utilities are utilities owned by governments at the local, municipal, state, regional or federal level. The regulatory regime that applies to publicly owned utilities varies between states. In most states, public utilities are regulated by local governments or are self-regulated. The Public Utility Commission exercises jurisdiction over some of public utilities' operations and rates.

Electricity cooperatives operate non-profit electric systems that are privately owned and controlled by the members they serve. Some states exercise authority over rates and operations of electricity cooperatives. Other states exempt cooperatives from regulation.

Federally-owned or chartered utilities market wholesale electricity to the four federal power marketing agencies (PMAs). The PMAs own and control transmission assets to deliver power to wholesale and direct-service customers. PMAs buy and sell power in the wholesale market to match supply and demand.

'Non-utilities' generate, transmit, or sell electricity but do not operate regulated retail distribution franchises. These include wholesale non-utility affiliates of regulated utilities, merchant generators, PMAs, independent transmission businesses that own and operate transmission facilities but do not own generation or retail distribution facilities or sell electricity to retail customers and other qualifying facilities.

#### *Gas*<sup>606</sup>

The natural gas market in the US is integrated with the gas markets of Canada and Mexico. Both the spot and futures markets for natural gas are very active, having been deregulated for several decades.

The US natural gas industry is largely privately owned with little vertical integration. The only public ownership in the industry is found in gas distribution with publicly-owned gas distributors accounting for about seven per cent of all domestic gas sales.

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<sup>605</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, pp. 400-402.

<sup>606</sup> Ibid, p. 404.

Businesses that operate interstate gas pipelines and local gas distribution networks are subject to regulation of rates and/or services. Gas producers and marketers are not subject to economic regulation.

## **7.2 Federal regulatory framework**

In the US, electricity and gas utilities operating interstate are regulated by the Federal Energy Regulatory Commission (FERC) while utilities operating intra-state are regulated by the relevant state-based public utilities commission.<sup>607</sup> Some state public utilities commissions' may regulate retail prices where competitive retail markets have not yet been introduced.

In US jurisdictions, regulated energy utilities are generally required to submit a 'rate case' to the regulator. Rate cases are assessed separately for individual utilities. Most rate cases result in prices being reset with reference to costs in a single 'test year'. The test year is usually the most recent year for which actual data are available. However, prices may be reset on the basis of forecasted costs for the year. Once prices are reset, they generally do not change until the company or customer representatives request a new rate case.<sup>608</sup> Rate cases generally occur every three to four years.<sup>609</sup>

Performance-based regulation has replaced cost-of-service regulation in some states. In some cases, TFP studies are used as an input to setting the X factor based on data provided by distribution businesses to the FERC. The Lawrence (2003) study noted that while the accuracy of the data at a firm level was generally accepted, significant debate existed in relation to the use of a nation-wide sample to calculate TFP given the variance in company structures and operating conditions.<sup>610</sup>

Statistical benchmarking studies are rarely commissioned by regulators in North America. They are occasionally filed by utilities in support of rate applications. The studies mostly use US data and employ econometric and indexing methods.<sup>611</sup>

The private sector benchmarking studies range in size and scope and a utility's participation is voluntary.<sup>612</sup>

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<sup>607</sup> Ibid, pp. 401-404.

<sup>608</sup> The negotiation process may lead to a set of prices for a certain number of years or a rate of change for prices, etc.

<sup>609</sup> Brattle Group, *Use of TFP Analyses in Network Regulation, Case Study of Regulatory Practice*, report prepared for the AEMC, October 2008, p. 46.

<sup>610</sup> Lawrence D, *Regulation of Electricity Line Businesses, Analysis of Lines Business Performance – 1996 -2003*, Meyrick and Associates Report Prepared for Commerce Commission, December 2003, p. 13.

<sup>611</sup> Lowry and Getachew, *Statistical Benchmarking in Utility Regulation*, Energy Policy, 2009, p. 1324.

<sup>612</sup> First Quartile Consulting LLC and Elenchus Research Associates Inc, *CAMPUT Benchmarking for Regulatory Purposes*, April 2010, p. 24.

### *US data*<sup>613</sup>

In the US, IOUs must provide disaggregated financial and accounting data to the FERC on a quarterly and annual basis. The data must comply with the 'uniform system of accounts' (USofA) developed by the FERC. Electric utilities must also provide information on operational statistics on the electric system, such as line length, voltages and numbers of customers by various types.

Municipal and cooperative utilities have also been required to provide USofA data to the FERC. This requirement has recently been relaxed, but many municipal and cooperative utilities still track costs according to the USofA.

Many utilities use USofA data to:

- assess their own performance relative to others in the industry
- set improvement targets
- find peer businesses to contact for discussions regarding operational practices.

Transmission network operators are required to report reliability data to the North American Electric Reliability Corporation (NERC).

## **7.3 Overview of the California energy market**

### *Electricity*<sup>614</sup>

The Independent System Operator manages most of California's electricity transmission system. The Independent System Operator is overseen by the FERC.

The California Public Utilities Commission (CPUC) regulates seven investor-owned electricity utilities. These include three major utilities: Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company (SDG&E). Smaller utilities are also included: Sierra Pacific Power Company, Pacific Power & Light and Bear Valley Electric Services.

### *Gas*

Most of the natural gas used in California is supplied from out-of-state natural gas productions basins. It is delivered into California through an interstate natural gas pipeline system that is regulated by the FERC.<sup>615</sup>

Four investor-owned natural gas utilities are regulated by the CPUC. Pacific Gas & Electric and SDG&E are combined electric and natural gas utilities. Southern California Gas Company is a stand-alone natural gas utility whose parent company

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<sup>613</sup> First Quartile Consulting LLC and Elenchus Research Associates Inc, *CAMPUT Benchmarking for Regulatory Purposes*, April 2010, pp. 29-31.

<sup>614</sup> CPUC, *Regulatory Responsibilities of the California Public Utilities Commission*, April 2011.

<sup>615</sup> CPUC, *Natural Gas and California*, Available at: <http://www.cpuc.ca.gov/PUC/energy/Gas/natgasandCA.htm> [accessed on 19 November 2011].

owns the electricity utility operator, SDG&E. Southwest Gas is a smaller gas utility that provides gas to the Lake Tahoe Basin and to parts of Southern California.

#### **7.4 Regulatory framework**

The CPUC regulates investor-owned electric and natural gas utilities operating in California. It derives its powers from the California state constitution. The CPUC has plenary authority over the operations of the electric and gas utilities. It sets retail rates through traditional General Rate Cases (GRCs) as well as by allocating costs among utility customers in other types of proceedings.<sup>616</sup>

The CPUC is also responsible for monitoring and enforcing safety standards in the industry. It undertakes environmental assessments of proposed transmission lines, power plants or other major facilities.<sup>617</sup>

##### *General rate case*

A GRC generally occurs every three years for both gas and electricity utilities. As part of the GRC, the CPUC may review a utility's operations and costs, including conducting a detailed review of a utility's revenues, expenses, and fixed-asset investments to establish an approved revenue requirement.<sup>618</sup>

Approximately 45 per cent of the revenue requirements are set in GRCs by the CPUC and the FERC. The remaining 55 per cent consist of pass-through costs determined to be reasonable by the CPUC.<sup>619</sup>

In the GRC proceedings the CPUC determines three key components: the base-year revenue requirement, an annual adjustment rate for post-test-year period (commonly called attrition years), and incentive payments. These are determined by considering 'just and reasonable revenue requirements' while ensuring that the utility offers safe and reliable services. The CPUC determines:<sup>620</sup>

- the just and reasonable test-year revenue requirements that include all operating expenses and capital costs such as the costs of all operating or customer-related programs necessary to provide safe and reliable utility service in the test year
- a just and reasonable post-test-year ratemaking mechanism to adjust annual revenue requirements in subsequent years until the next resetting
- incentive mechanisms for the safe and reliable operation of the utility's services and energy efficiency programmes.

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<sup>616</sup> CPUC, *Regulatory Responsibilities of the California Public Utilities Commission*, April 2011, p. 1.

<sup>617</sup> Ibid.

<sup>618</sup> CPUC, *General Rate Case (GRC)*. Available at: <http://www.cpuc.ca.gov/cfaqs/generalratecasegrc.htm> [accessed on 18 November 2011].

<sup>619</sup> CPUC, *Electricity and Gas Utility Cost Report: Public Utilities Code Section 747 Report to the Governor and Legislature*, April 2011, p. 7.

<sup>620</sup> CPUC, *Decision on Test Year 2008 General Rate Cases for San Diego Gas and Electric Company and Southern California Gas Company*, July 2008, pp. 5-6.

The utility must demonstrate that the rates they request are just and reasonable and that the ratemaking mechanisms are fair.

The GRC process is as follows:

- A utility applies for a rate increase and provides supporting financial information that justifies the proposed cost increases
- The utility notifies interested parties and its customers of the proposed changes within specified timeframes<sup>621</sup>
- A public hearing is held. A key stakeholder in this process is the Division of Ratepayer Advocates (DRA). The DRA is an independent division of the CPUC. Its role is to advocate on behalf of the customers of regulated public utilities. It represents consumers in the CPUC proceedings, including rate settings, investigations, and rule makings. The DRA also participates in CPUC-sponsored working groups, advisory boards, workshops, and other forums. The DRA also evaluates utility proposals, investigates issues, presents findings and formal testimony, litigates complaints, and makes recommendations to the CPUC and to other forums.<sup>622</sup> The DRA must 'represent and advocate on behalf of the interests of public utility customers and subscribers...to obtain the lowest possible rate for service consistent with reliable and safe service levels'.<sup>623</sup> The DRA also has statutory rights to obtain information from utilities through discovery and other means. The CPUC is required to provide sufficient legal support for the DRA, and provide the DRA with its own lead counsel<sup>624</sup>
- After considering the evidence, the CPUC makes recommendations, findings, and conclusions
- The CPUC may instigate a review of the decision and interested parties may request a review or appeal the decision
- Re-hearings may occur or parties may propose a settlement on certain aspects of the decision<sup>625</sup>
- The CPUC will only consider a proposed settlement if it is in the public interest. The CPUC must be convinced that the parties had a sound and thorough understanding of the application and of the underlying assumptions and data that are on the record.<sup>626</sup>

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<sup>621</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, p. 465.

<sup>622</sup> Ibid, p. 476.

<sup>623</sup> *California Public Utilities Code*, s. 309.5.

<sup>624</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, p. 476.

<sup>625</sup> Ibid, pp. 470-472.

<sup>626</sup> CPUC, *Decision on Test Year 2008 General Rate Cases for San Diego Gas and Electric Company and Southern California Gas Company*, July 2008, p. 6.

### 7.5 Example of San Diego Gas and Electric Company

Price caps in the form of an industry-specific inflation index and productivity index differential (including a stretch factor), were approved for the gas and electric distribution services of San Diego Gas and Electric Company (SDG&E) in 1999 for the years 1999 to 2002. They were subsequently extended to 2003.<sup>627</sup> The company commissioned total factor productivity (TFP) studies for both electricity distribution and gas distribution.<sup>628</sup>

The next GRC was approved for four years from 2004 to 2007.<sup>629</sup> SDG&E had argued that given previous years' efforts to improve efficiency, the stretch factor should be set to zero. However, the CPUC ordered SDG&E to resubmit their proposal to include either:

- an X factor adjusted to reflect good to excellent performance in the industry and exclude poor performance; or
- a stretch factor that offsets mediocre performance.<sup>630</sup>

In the resulting settlement, the productivity factor and stretch factor were replaced with a minimum floor and maximum ceiling on the allowed annual adjustment (escalation factor).<sup>631</sup>

For the GRC applying from 2008 to 2011, SDG&E submitted a TFP/benchmarking study prepared by PEG (PEG 2006 study) in its application, filed in December 2006.<sup>632</sup> The PEG 2006 study employed two methods to assess the productivity and efficiency performance of SDG&E's gas distribution services: an index-number-based TFP analysis and an econometric cost function analysis. These are discussed in section 7.6.1 below.

In December 2010, SDG&E filed its test year 2011 GRC application. This is being reviewed by the CPUC.<sup>633</sup> The PEG 2010 study in support of PRC 2013 is an

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<sup>627</sup> Lowry and Getachew, *Price Control Regulation in North America: Role of Indexing and Benchmarking*, The Electricity Journal, 2009, p. 67.

<sup>628</sup> PEG, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario: Report to the Ontario Energy Board*, February, 2008, p. 97.

<sup>629</sup> SDG&E, *Prepared Direct Testimony of Herbert S. Emmrich on behalf of San Diego Gas & Electric Company before the Public Utilities Commission of the State of California*, Exhibit no. SDG&E-46, December, 2010, p. 3.

<sup>630</sup> CPUC, *Decision on Southern California Gas Company and San Diego Gas & Electric Company's Phase 2 Post-test Year 2004 Ratemaking, Earnings Sharing, Incentive Proposals and 2004 Incentive Proposals*, March 2005, p. 78. Available at: [http://docs.cpuc.ca.gov/PUBLISHED/FINAL\\_DECISION/44820.htm](http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm) [accessed on 19 December 2011].

<sup>631</sup> Ibid, p. 64.

<sup>632</sup> SDG&E, *Application of San Diego Gas & Electric Company for Authority to Update Its Gas and Electric Revenue Requirement and Base Rates Effective on Jan. 1, 2008*, (U 902-M), A06-12-009, Exhibit SDGE-33, prepared by Pacific Economics Group.

<sup>633</sup> SDG&E, *SDG&E 2012 GRC Filing*, Available at: <http://sdge.com/node/989> [accessed on 25 November 2011].

index-number-based TFP study.<sup>634</sup> In summary, the study used data spanning ten years from 1999 to 2008. Productivity trends for gas distribution and electricity distribution are disaggregated into aggregate levels of productivity for: the utilities as a group; large California distributors as a group; and SDG&E itself.

#### 7.5.1 PEG 2006 study for San Diego Gas and Electric Company<sup>635</sup>

This PEG study was submitted with SDG&E's 2006 rate-change application. It is part of the expert testimony in the hearing and settlement process for this GRC. The study of electricity and gas distribution covers two parts. The first examining industry and company-specific total factor productivity (TFP) performance using the index-number approach. The second, developing econometric cost functions for a sample of gas and electric utilities to assess SDG&E's relative efficiency in providing gas and electric distribution services.<sup>636</sup>

##### *Index-number-based approach*<sup>637</sup>

A Tornqvist index was used to construct TFP growth. That is, a weighted output growth was used, using weights from the econometric cost function approach relative to cost-weighted input growth.

In relation to electricity distribution, the PEG 2006 study involved:

- Sample: 77 major investor-owned electricity distributors in the US from 1994 to 2004
- Services covered: Electricity distributor services covering distribution, customer accounts, sales and general administration
- Outputs: revenue weighted electricity sales (in kilowatt hours; 50 per cent) and customers (50 per cent)
- Inputs: cost weighted sum of labour, capital, fuel and non-labour O&M inputs
- Findings:

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<sup>634</sup> Lowry M and D Hovde, *Productivity Research for San Diego Gas and Electric, prepared direct testimony of Mark Newton Lowry before the Public Utilities Commission of the State of California*, Exhibit No. SDG&E-44, Application 10-12-2010, August 6, 2010.

<sup>635</sup> The description is not based on the original PEG study, primarily drafted by Mark Lowry, due to no access to the report. Instead, the summary is based on two papers: Lowry and Getachew, *Price Control Regulation in North America: Role of Indexing and Benchmarking*, The Electricity Journal, 2009 that summarises the PEG benchmarking work and Division of Ratepayer Advocates, *Report on Total Factor Productivity for San Diego Gas & Electricity Company, Southern California Gas Company General Rate Case: Test Year 2008*, 6 July, 2007 that replicates and critiques the PEG study (refer to footnote 443).

<sup>636</sup> Division of Ratepayer Advocates (DRA), *Report on Total Factor Productivity for San Diego Gas & Electricity Company, Southern California Gas Company General Rate Case: Test Year 2008*, 6 July, 2007, p.1.

<sup>637</sup> DRA, *Report on Total Factor Productivity for San Diego Gas & Electricity Company, Southern California Gas Company General Rate Case: Test Year 2008*, 6 July, 2007.

- the electricity distribution industry experienced TFP growth at an annual rate of 1.08 per cent
- SDG&E electricity distribution experienced TFP growth at an annual rate of -0.66 per cent. This was the lowest among the three sampled California utilities.

In relation to gas distribution, the PEG (2006) study involved:

- Sample: 34 large gas distributors, from 1994 to 2004. Some gas distributors also provided gas transmission and/or storage services
- Services covered: Gas distributor services covering gas transmission, storage, customer accounts, sales and general administration; costs comprising operation and maintenance expenses and costs of plant ownership; expenses for customer service and information and uncollectible bills are excluded because those expenses rose sharply over the sample period due to circumstances beyond management control
- Outputs: revenue weighted throughput (27 per cent) and customers (73 per cent)
- Inputs: cost weighted sum of labour, capital, fuel and non-labour O&M inputs
- Findings:
  - Over the sample period, the gas distribution industry experienced the TFP growth at an annual rate of 0.63 per cent
  - SDG&E gas distribution TFP growth was an annual rate of -0.66 per cent. This was found to be lowest among the three sampled California utilities
  - the average TFP growth of good to excellent performers (i.e., top 50 per cent<sup>638</sup>) was 0.76 per cent per year.

DRA concluded that PEG's findings for both electric and gas distribution were reasonable.

#### *Econometric cost function approach<sup>639</sup>*

The PEG (2006) developed an econometric cost model to examine the costs efficiency of the gas distribution services provided by SDG&E relative to a sample of GDNs. This model is discussed in detail below. A similar model was also employed for electricity distribution services and is only briefly reviewed.

#### *Data<sup>640</sup>*

The data used in the PEG 2006 study included 41 gas distributors for the years 1994 to 2004.

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<sup>638</sup> That is the top 50 per cent based on the rankings from the econometric cost model approach described below.

<sup>639</sup> DRA, *Report on Total Factor Productivity for San Diego Gas & Electricity Company, Southern California Gas Company General Rate Case: Test Year 2008*, 6 July, 2007.

<sup>640</sup> Lowry and Getachew, *Price Control Regulation in North America: Role of Indexing and Benchmarking*, The Electricity Journal, 2009, p. 68.

Early data were from the Uniform Statistical Reports filed annually by gas utilities with the American Gas Association. Basic cost and quantity information for interstate gas pipelines was obtained from reports to state regulators that were based on FERC Form 2 reports. Gas distribution operating cost data were from the Platts *GasDat* package and compiled by commercial vendors.

Input price data were sourced from Whitman, Requardt & Associates; R.S. Means and Associates; Global Insight; the Bureau of Economic Analysis (BEA) of the US Department of Commerce; the Bureau of Labor Statistics (BLS) of the US, Department of Labor, and the Energy Information Administration (EIA) of the US Department of Energy.

#### *Dependent variable*<sup>641</sup>

The dependent variable in this model is the total cost of gas distribution. The total cost of gas distribution is operation and maintenance (O&M) expenses, and the cost of gas plant ownership.

O&M expenses are the total gas O&M expenses of the utility less expenses for natural gas production and procurement, transmission services by others, and franchise fees. In other words, it is the gas delivery cost covering costs incurred by local distribution companies (LDCs) in gas transmission, storage, local delivery, account information, and other customer services, and administrative and general services.

A capital-service price approach is used to measure the cost of capital that is based on the economic value of utility plant. This method controls for differences between utilities in relation to the age of their plants. The cost of capital is the product of a capital quantity index and the price of capital services.

#### *Independent variables*<sup>642</sup>

Three input price variables are measured in the model:<sup>643</sup>

- labour price index measured using employment survey data
- non-labour O&M input price index using relevant Global Insight indexes
- a capital service price index capturing both the cost of depreciation and the real rate of return.

The two output quantity variables in the model are: number of retail customers and volume of retail deliveries.

Three additional business condition variables are included in the cost model:<sup>644</sup>

- the percentage of distribution main not made of cast iron. Greater use of cast iron, as was common in the early days of the industry, involves higher maintenance and/or higher capital replacement costs

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<sup>641</sup> Ibid.

<sup>642</sup> Ibid, p. 69.

<sup>643</sup> Ibid, p. 17 for more information.

<sup>644</sup> Ibid, p. 72.

- the number of power (electricity) distribution customers served by the utility. This captures the extent to which the company has diversified into power (electricity) distribution
- a binary variable that equals one if a company serves a densely settled urban core.

A trend variable is included to capture a change in costs for reasons not explicitly captured in the model, for example, the impact of technological change.

#### *Model specification*<sup>645</sup>

The actual total cost ( $C_i$ ) incurred by business,  $i$ , in service provision is the product of minimum achievable cost ( $C_i^*$ ) and an efficiency factor ( $Eff_i$ ). That is:

$$\ln C_i = \ln C_i^* + \ln Eff_i$$

where, the minimum achievable cost is a function of cost drivers that include output quantities, input prices and relevant business condition variables.

The flexible Translog functional form was employed because it allows the elasticity of cost with respect to an output to vary with the value of another output. Other types of functional forms are more limited in that they do not allow this to occur.

#### *Analysis of results*<sup>646</sup>

The total cost function is estimated using a feasible generalised least squares (FGLS) procedure to identify inefficiency. For each company under consideration, the percentage difference between the actual cost and the predicted cost is the percentage difference between the efficiency of the firm and the (predicted) efficiency of a sample mean firm. For SDG&E, this is:

$$\ln \left( \frac{C_{SDG\&E,t}}{\hat{C}_{SDG\&E,t}} \right) = \ln \left( \frac{Eff_{SDG\&E,t}}{Eff_{AVE}} \right)$$

That is, the percentage difference between SDG&E's actual cost relative to the 'efficient' cost predicted by the model, given the business conditions, is a measure of its cost efficiency performance.

The mean efficiency score of each firm is the average percentage difference between actual and predicted costs over the most recent three-year period. The businesses are ranked according to this efficiency score. It was found that SDG&E's costs were 25 per cent below the predicted costs for the three-year period between 2002 and 2004 and that SDG&E costs were statistically significantly different from the average efficiency level, at the 95 per cent confidence level. That is, the results suggest that SDG&E was relatively efficient given its operating environment.

<sup>645</sup> Ibid, p. 69.

<sup>646</sup> Ibid, p. 69.

### *Modelling electricity distribution*<sup>647</sup>

The econometric cost model for the electricity distribution industry was similar to that used for the gas distribution industry. For example, total costs of electricity distribution services was a function of: input prices for labour, capital and non-labour O&M, output quantities measured as the number of customers and throughput of the industry, exogenous business condition variables and a time trend. Ten exogenous business condition variables are included, including distribution line length, percentage of plan overhead, customer growth, and percentage of residential and commercial customers.

#### 7.5.2 Application to regulatory decision

The PEG (2006) study was submitted as part of SDG&E's application for a rate increase. It formed part of SDG&E's evidence in the GRC public hearing and settlement processes. Based on the index number-based TFP analysis for both gas and electricity, SDG&E sought a progressive productivity factor that would apply to the whole business and would increase from 1.1 per cent per annum by 0.1 per cent per annum over the six-year GRC period. Based on the econometric relative cost analysis, SDG&E sought a stretch factor of zero (to apply to the business as a whole).<sup>648</sup>

The DRA argued that the progressive productivity factor should start from 1.3 per cent per annum with a stretch factor of 0.2 per cent per annum for subsequent years.<sup>649</sup>

The CPUC final decision was based on a settlement between the company and the interveners. The result was fixing the utilities future annual revenue rather than determining the individual components of the annual adjustment rate from the base year revenue, such as the productivity offsetting factor or the stretch factor.<sup>650</sup>

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<sup>647</sup> DRA, *Report on Total Factor Productivity for San Diego Gas & Electricity Company*, Southern California Gas Company General Rate Case: Test Year 2008, 6 July, 2007, Exhibit 40, pp. 33-41.

<sup>648</sup> CPUC, *Settlement Agreement Regarding San Diego Gas and Electric Company Post-test Year Ratemaking*, 18 January, 2008, Appendix 3 to Decision, Chapter 3G-7: San Diego Gas & Electric Company 2008 Test Year GRC A.06-12-009 DRA Differences to SDG&E Requests Other Issues.

<sup>649</sup> Ibid.

<sup>650</sup> CPUC, *Decision on Southern California Gas Company and San Diego Gas & Electric Company's Phase 2 Post-test Year 2004 Ratemaking, Earnings Sharing, Incentive Proposals and 2004 Incentive Proposals*, March 2005, s 7.

## 8 Japan: Agency for Natural Resources and Energy

### 8.1 Overview of Japanese energy market

#### *Electricity market*

Traditionally the Japanese electricity sector was made up of ten<sup>651</sup> privately owned vertically integrated utilities covering each of the ten administrative regions of Japan and another publically owned wholesale electricity supplier active nationally. However due to reforms aimed at liberalising the market which began in 1995 there are now 22 power producers and suppliers in the competitive segment of the market and the nationally owned J-Power was privatised in 2004. The six largest generators, TEPCO, KEPCO, Chuden, Kyuden, Tohokuden, and J-Power, account for a total of 65 per cent of Japanese electricity generation.<sup>652</sup>

#### *Gas market*

The Japanese gas industry is made up of many regional vertically integrated suppliers. In 2007 there were 213 general gas utilities operating in Japan, 33 of which were publicly owned. The four major providers, Tokyo Gas, Osaka Gas, Toho Gas, and Saibu Gas, had a combined market share of 76.4 per cent. In addition to these 213 gas utilities there were also 1600 small community gas distributors.<sup>653</sup> Most of Japan's natural gas is imported for power generation. In 2008 there were 27 natural gas terminals, and, subject to safety requirements, there are no business restrictions on the development of new terminals.<sup>654</sup>

#### *Regulator*

The key regulation affecting electricity is the *Electricity Utilities Industry Law* which is administered by the Ministry of Economy, Trade and Industry (METI), specifically by the Agency for Natural Resources and Energy (ANRE). The Japan Free Trade Commission also takes some regulatory responsibility and oversees the emerging competition in wholesale and retail markets.<sup>655</sup>

While prior to reforms the market was dominated by privately owned regulated monopolies, competition has slowly been introduced into contestable parts of the market. In 1995 a wholesale market was established, entry was allowed to businesses supplying retail sales of electricity to very large-volume users, and the yardstick competition method of price regulation was introduced.<sup>656</sup> In 2000 legislation was amended to allow regulated third party access to existing infrastructure. In 2003 the legislation was further amended and functional separation was imposed on the 10

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<sup>651</sup> Before Okinawa was returned to the Japanese by the Americans in 1972, there were only nine businesses as there were only nine regions.

<sup>652</sup> International Energy Agency (IEA), *Energy Policies of IEA Countries – Japan 2008 Review*, OECD/IEA, Paris, 2008, p. 131.

<sup>653</sup> Ibid, p. 109.

<sup>654</sup> Ibid, pp. 112-115.

<sup>655</sup> Ibid, p. 126.

<sup>656</sup> ACCC, *Project on Benchmarking International Regulatory Processes and Practice: Country-based Research*, Appendix to the Final Report to the Infrastructure Consultative Committee, 5 June 2009, p. 12.

incumbent vertically integrated businesses. This included prohibitions on discriminatory access and cross-subsidisation. In 2003, the Electric Power System Council of Japan was established as an independent, private, non-profit organisation, to oversee third party access to the transmission grid. In 2004 the threshold energy consumption required for an end user to be eligible to choose their supplier was reduced from two megawatts to 500 kilowatts. This threshold was further reduced in 2005 to 50 kilowatts such that customers that made up 63 per cent of electricity consumption were eligible to choose their electricity provider.<sup>657</sup>

Gas production and distribution are regulated under the *Gas Business Act*, with use of LNG in other Industries being regulated under the Electricity Utilities Industry Law and the High-Pressure Gas Safety Law. These regulations are the responsibility of the ANRE. A process of liberalisation commenced in the gas industry from 1995. This began with large-scale consumers of gas being able to choose their supplier and over time progressively smaller businesses have become able to choose. In 2008, the liberalised share of the gas market accounted for 60 per cent of gas consumption in Japan. In 1995, the METI also began the implementation of price-cap regulation with yardstick competition. From 2004, the METI amended the *Gas Business Act* forcing existing businesses to allow access to their infrastructure by third parties.<sup>658</sup>

## **8.2 Regulatory framework – Gas distribution**

### **8.2.1 Yardstick benchmarking**

The way in which prices are regulated in the Japanese gas industry is through the utilisation of price-cap regulation with yardstick competition.<sup>659</sup> The basic premise of yardstick regulation, as introduced by Shleifer, is to introduce virtual competition between businesses operating in different markets.<sup>660</sup> In the context of the Japanese gas industry, yardstick benchmarking is used to alter the costs included in the calculation of the regulated price to encourage streamlining of costs for relatively inefficient businesses.<sup>661</sup> This introduces indirect competition by comparing the costs of like businesses to determine an approximation of the efficient level of costs for that particular group of businesses. Businesses which report higher costs relative to other businesses in their group are penalised. The penalty takes the form of a reduction of the value of costs allowed in the determination of the business' regulated price. This acts to reduce the incentive for business to report higher costs for the determination of their regulated price. The reason for this is that if a business reports higher cost they will be subject to penalties that will lower the price they may charge, and therefore their profits.<sup>662</sup>

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<sup>657</sup> International Energy Agency (IEA), *Energy Policies of IEA Countries – Japan 2008 Review*, OECD/IEA, Paris, 2008, pp. 125-126.

<sup>658</sup> Ibid, p. 112.

<sup>659</sup> Suzuki, A., *Yardstick Competition to Elicit Private Information: An Empirical Analysis of the Japanese Gas Distribution Industry*, Social Science Research Network, 2008, pp. 3-8.

<sup>660</sup> Shleifer, A., *A Theory of Yardstick Competition*, R.A.N.D. Journal of Economics, 16(3), 1985.

<sup>661</sup> Op. Cit., p. 3.

<sup>662</sup> Ibid. p. 10.

The yardstick method of regulation was introduced in 1995. There is no fixed review period and review only takes place when a regulated business petitions for a price revision. Since 1995 there have been 14 applications for price revisions in five different years.<sup>663</sup>

### 8.2.2 Benchmarking approach to determine X factor

#### *Data used*

Cost data were collected from all gas businesses during the first assessment in 1995. From that point onwards only businesses petitioning for a cost revision have provided new data. For businesses that do not provide data, the most recent data submitted are used for analysis.<sup>664</sup>

#### *Grouping method*

Businesses are assigned to relative assessment groups on the basis of: whether they are publically or privately owned, geographical location, raw materials used, and method of production.<sup>665</sup> There are also further adjustments such that there are no groups that are too large or too small to enable further analysis.<sup>666</sup> For example if the number of businesses in a geographical region is too small those businesses may be merged into a larger neighbouring region's group.

#### *Technique*

Regression analysis is conducted for each relative assessment group.<sup>667</sup> No further information on the regression analysis is available.

#### *Inputs*

It is unknown exactly which costs or cost categories are used as the dependent variables in the regression analysis, however roughly speaking, the cost categories are split into two types: costs related to equipment investment, and those related to general overhead costs.<sup>668</sup>

In order to ensure that like costs are compared to like costs, adjustments are allowed for exceptional costs. These exceptions include: large investments, installation of smart meters, and costs relating to gas reformation.<sup>669</sup>

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<sup>663</sup> Ibid, p. 11.

<sup>664</sup> Ibid, p. 11.

<sup>665</sup> Ibid, p. 9.

<sup>666</sup> Unofficial English translation of: Agency for Natural Resources and Energy, METI, *General Energy Inquiry Conference City Energy Sectional Meeting*, 11<sup>th</sup> City Gas Enterprise Tariff System Branch meeting handout, 18 October 1995, pp. 113-114.

<sup>667</sup> Ibid, pp. 121-122.

<sup>668</sup> Ibid, p. 123.

<sup>669</sup> Ibid, pp. 119-120.

### *Outputs*

No information available on the explanatory variables used in the regression.

### *Model*

No information available on the specification of the cost model.

### *Analysis of model results*

After cost driver regression analysis, the results of the regressions are used to make adjustments to the business' actual costs. These adjusted costs are then used for relative assessment of businesses in the same group and to assign scores for each business for each cost category.<sup>670</sup> Comparisons are made on the basis of the level of costs and the rate of change of costs for each business, as follows.<sup>671</sup>

#### Comparison of the levels of costs

After regression analysis, for each cost category, the ratio of the estimated value for each firm and the average value for all businesses in the same relative assessment group are calculated. This ratio is called the common adjustment coefficient. To find the value for the costs used in relative assessment, the common adjustment ratio is multiplied by each firm's actual costs. However, as regression analysis may lead to some divergence in business' costs, which are not due to differences in effort toward improving efficiency on the part of the businesses, these costs are further modified before being compared. Rather than simply using the common adjustment coefficient, the coefficient is summed with one, and then divided by two.<sup>672</sup> This figure is called the practical common adjustment coefficient. By adding one and dividing by two, the gap between business' costs in the relative assessment is moderated as each firm's practical common adjustment coefficient will become closer in value.

After costs have been adjusted in this manner, each firm is assigned a score in each cost category. The firm with the lowest cost is given 100 points and the firm with the highest cost is given zero points. The rest of the businesses are then assigned scores between zero and 100, relative to how their costs compare to these two businesses.

#### Comparison of the rate of change of costs

The rates of change of business' adjusted costs are compared in a similar manner to the level of adjusted costs. The rates of change for businesses within a relative assessment group are compared and the firm with the greatest cost reduction will receive 100 points and the firm with the lowest cost reduction will receive zero points. Again the remaining businesses receive between 100 and zero points depending on where their rates of change fall with comparison to the two businesses at the extremes.

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<sup>670</sup> Ibid, pp. 121-122.

<sup>671</sup> Ibid, pp. 124-125.

<sup>672</sup> Ibid, pp. 121-122.

### Assignment of efficiency groups

After scores have been assigned for the level and rate of change for each cost category, the sum of these two scores is used to create an overall score for each firm. These overall scores are used to place each firm into one of three efficiency groups. Businesses with overall scores in the top third are placed into efficiency group I, businesses with scores in the middle third are placed into efficiency group II, and businesses with scores in the lowest third are placed into efficiency group III.

### *Application to regulatory decision*

After each firm's cost categories have been allocated to their respective efficiency groups, for the purpose of price determination, these cost categories are adjusted according to this allocation. Group I receives no adjustment, group II receives a decrease of 0.5 per cent, group III receives a decrease of one per cent.<sup>673</sup> That is to say, for example, that if a firm's labour costs were in group II, for the purpose of price determination, its labour costs would be reduced by 0.5 per cent leading to a lower regulated price.

### **8.3 Regulatory framework - Electricity distribution**

Based on the information provided by the METI<sup>674</sup>, and documents from the OECD,<sup>675</sup> the regulatory framework and the benchmarking method applied to the assessment of electricity distribution businesses is relatively similar to the method applied to gas distribution businesses, as described above. One salient difference between the two regulatory regimes is that the yardstick assessment rates for businesses in the electricity sector are: zero per cent for businesses in efficiency group I, one per cent for businesses in efficiency group II, and two per cent for businesses in efficiency group III.<sup>676</sup>

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<sup>673</sup> Suzuki, A, Op. Cit., 2008, p. 9.

<sup>674</sup> A PowerPoint Presentation document was provided by the METI regarding price regulation in the electricity sector to explain regulation in the gas industry.

<sup>675</sup> OECD, *Regulatory Reform in Japan: Regulatory Reform in the Electricity Industry*, 1999, pp. 18-19. Available at: <http://www.oecd.org/dataoecd/45/7/2506728.pdf> [accessed on 25 January 2012].

<sup>676</sup> Loc. Cit.