First version: January 27 2015 This version: September 24, 2015

Submitted to Energy Journal April 21, 2015; Revised and resubmitted September 24, 2015; Accepted for publication November 17, 2015

IMPROVED REGULATORY APPROACHES FOR THE REMUNERATION OF ELECTRICITY DISTRIBUTION UTILITIES WITH HIGH PENETRATIONS OF DISTRIBUTED ENERGY RESOURCES

Jesse D. Jenkins [a], Ignacio J. Pérez-Arriaga [b]

Abstract

Under increasing penetration of distributed resources, regulators and electricity distribution utilities face greater uncertainty regarding the evolution of network uses and efficient system costs. This uncertainty can threaten revenue adequacy and challenges both cost of service/rate of return and incentive/performance-based approaches to the remuneration of distribution utilities. To address these challenges, this paper proposes a novel methodology to establish allowed utility revenues over a multi-year regulatory period. This method combines several "state of the art" regulatory tools designed to overcome information asymmetries, manage uncertainty, and align incentives for utilities to cost-effectively integrate distributed energy resources while taking advantage of opportunities to reduce system costs and improve performance. We use a reference network model to simulate a large-scale urban distribution network, demonstrate the practical application of this regulatory method, and illustrate its performance in the face of both benchmark and forecast errors.

Keywords: *Regulatory Economics; Network Regulation; Electricity Distribution; Distributed Energy Resources; Incentive Regulation; Managing Uncertainty.*

This is a pre-publication version of this paper, which will first appear in *The Energy Journal* in January 2017. Please cite as:

Jenkins, Jesse D. and Ignacio J. Pérez-Arriaga. (2017). "Improved regulatory approaches for the remuneration of electricity distribution utilities with high penetrations of distributed energy resources." *The Energy Journal* Vol. 38(1) (in press).

[a] Corresponding author. MIT Energy Initiative and Engineering Systems Division, Massachusetts Institute of Technology (MIT), 77 Massachusetts Ave., Cambridge, MA 02139, USA. Tel: +1 617 715 5367. Email: jessedj@mit.edu.

[b] Institute for Research in Technology (IIT), Comillas Pontifical University, Sta. Cruz de Marcenado 26, Madrid, Spain and Center for Energy & Environmental Policy Research, Massachusetts Institute of Technology (MIT), 77 Massachusetts Ave, Cambridge, MA, USA.

1 INTRODUCTION

Economies of scale and sub-additive firm costs make electricity distribution a natural monopoly activity, which necessitates economic regulation. In particular, regulators must establish the allowed revenues or remuneration of distribution utilities, which gives rise to several challenges.[1] First, regulators face incomplete and asymmetric information, as they cannot directly observe the utility's costs or service quality opportunities or the level of managerial effort expended (Joskow, 2014; Laffont & Tirole, 1993). This information asymmetry creates an opportunity for strategic behavior, as firms can increase profits if they convince regulators that they face higher costs than they really do, thus securing greater remuneration (Jamasb, Nillesen, & Pollitt, 2003, 2004; Cossent & Gómez, 2013). In addition, regulators must assess the prudence and efficiency of long-lived, capital-intensive utility investments, which forces regulators to manage uncertainty about future technological change and demand for network services (Cossent, 2013; Ofgem, 2013e). Finally, regulators must simultaneously balance inherent tradeoffs between incentivizing productive efficiency (or "X-efficiency") by rewarding utilities for pursuing cost savings on the one hand and maximizing allocative efficiency by minimizing rents collected from ratepayers on the other hand (Joskow, 2014), all while preserving incentives for adequate quality of service (Gómez, 2013; Cossent, 2013).

The proliferation of distributed energy resources

On top of these persistent challenges, the proliferation of distributed energy resources (DERs) is now actively transforming the delivery of electricity services and the use and management of distribution systems in many jurisdictions. Distributed generation and storage introduce bidirectional power flows and, at significant penetration levels, entail profound changes to the real-time operation of distribution systems (Cossent, Gómez & Frías, 2009; Cossent et al., 2011; Denholm, et al., 2013; Olmos, et al. 2013; Pudjianto, et al., 2014; Strbac, et al., 2012, Vergara et al., 2014). Widespread electric vehicle adoption could likewise necessitate new network investments and may enable new "vehicle to grid" services (Gómez, et al., 2011; Fernández, et al., 2011; Momber, Gómez & Söder, 2013). Advanced metering, time-varying rates, and energy management systems have the potential to make electricity loads more responsive to economic and operational signals than ever before (Conchado & Linares, 2012; Hurley,

[1] The authors note that establishing the allowed revenues of the utility, known variously as the ratemaking or remuneration process, is only one of the regulator's core responsibilities. A number of important regulatory challenges fall outside the scope of this paper, which focuses only on improving the core ratemaking or remuneration process. For example, regulators will likely need to establish a suite of performance incentives, in addition to the core incentives established by the process herein (see Cossent, 2013). In addition, after the total volume of allowed revenues is established, rates or tariffs for network users must be designed to ensure cost recovery, establish efficient signals for network use, and address other regulatory concerns, such as equity. For more on this topic, see (Pérez-Arriaga & Bharatkumar, 2014).

Peterson & Whited, 2013; Schisler, Sick & Brief, 2008). Efficient price signals, new control systems, and/or novel market actors are necessary to manage and coordinate each of these DERs and their associated services. These emerging technologies constitute a set of important new users of distribution systems, potential new competitors for the delivery of electricity services to end-users (Bronski, et al. 2014; Kind, 2013), and possible suppliers of services to distribution companies seeking to harness DER capabilities to avoid network investments or improve system performance (Bharatkumar et al., 2013; Poudineh & Jamasb, 2014; Trebolle, et al., 2010).

Distribution utilities may need to make substantial investments to accommodate increased penetration of DERs. In many jurisdictions, these new investments will coincide with significant expenditures necessary to install and manage advanced meters and modernize aging distribution systems to take advantage of new smart grid and active system management techniques (Cossent et al., 2011; Eurelectric, 2013). At the same time, the pace of change and impact of distributed energy resources on distribution systems is highly uncertain. For example, while solar photovoltaics generated less than 1 percent of Germany's electricity in 2009, solar constituted 6.3 percent of German electricity production and 21.5 percent of installed capacity in 2014 (Fraunhofer ISE, 2015; Wirth, 2014). While rapid solar adoption in Germany was principally driven by policy support, it is indicative of the rate at which DER penetration can increase, whether driven by policy, improved economics, or a combination thereof.

New challenges for distribution regulation

The rapid adoption or significant penetration of distributed energy resources exacerbates the fundamental regulatory challenges described above and strains both cost of service/rate of return and incentive/performance-based approaches to the remuneration of distribution utilities.

Cost of service regulation focuses centrally on the prudence of inputs, making it challenging for utilities to respond to rapidly evolving demands on distribution systems or focus on delivering improved performance. This approach also requires regulatory review of expenditures associated with thousands of individual distribution system assets, which has always posed a challenge for regulatory commissions with limited staff and resources (Gómez, 2013). The changing nature of cost drivers and emergence of novel cost-saving opportunities will further aggravate this challenge, making it difficult for regulators to identify and disallow cost recovery for all but the most obviously imprudent expenditures, weakening incentives for utilities to manage productive efficiency. As a result, utilities are often slow to adopt novel technologies and practices and may instead go through protracted cycles of internal testing and performance validation, regulatory approval for small-scale pilot projects, collection of data and assessment of pilots, presentation of results to regulators, and lastly, after many years, system-wide adoption of successful innovations (Malkin & Centollela, 2014). Finally, while the backwards-looking nature of cost of service regulation can manage heightened uncertainty through frequent *ex post* reviews or "rate cases," this comes at a significant cost: assured of cost recovery and with short periods between regulatory reviews during which utilities can profit from cost savings, utilities will be unlikely to pursue opportunities to efficiently integrate DERs, let alone take advantage of the capabilities these technologies may provide to reduce system costs or improve performance.

Incentive or performance-based regulation is also challenged by the evolving nature of the electricity marketplace. First, changing cost drivers and customer needs exacerbate uncertainty and make it increasingly difficult to establish *ex ante* revenue (or price) caps for a multi-year regulatory period. Regulators often employ statistical frontier benchmarking and yardstick approaches to assist them in establishing *ex ante* estimates of efficient network costs (Jamasb & Pollit, 2001). Yet as network uses and cost drivers evolve, benchmarking based on past utility performance will no longer provide an accurate estimate of the forward-looking efficient frontier. At the same time, the growth of DERs can introduce much more heterogeneity between distribution networks, further challenging statistical benchmarking and yardstick approaches (Cossent, 2013). Finally, regulators employing *ex ante* remuneration methods must grapple with two types of error: forecast error and benchmark error. As DER penetration might evolve quite rapidly, network costs may rise or fall due to unexpected changes in network uses, a case of forecast error. Alternatively, the regulator may fail to anticipate the emergence of new cost saving technologies or network management practices within the regulatory period that shift the efficient frontier, leading to a case of benchmark error. In either case, regulators risk establishing a multi-year *ex ante* revenue trajectory that is poorly aligned with realized costs, leading to either substantial rents (if revenues are too generous) or increased risk that firms will not be able to adequately finance necessary investments (if revenues are too low). Frequent *ex post* revisions or "re-openers" of the regulatory contract can address these errors, but at the expense of creating significant regulatory uncertainty that may raise the cost of capital for utilities and undermine incentives to manage productive efficiency (Ofgem, 2013e).

A novel regulatory approach

As such, regulators must be equipped with new, forward-looking tools to mitigate the effects of increased information asymmetries and identify the new efficient frontier for network investment, operation, and maintenance. In addition, regulators need remuneration mechanisms that align incentives for utilities to both efficiently accommodate DERs *and* take advantage of new capabilities to reduce network costs and improve service quality. This requires equalizing incentives for savings in both capital expenditures (CAPEX) and operational expenditures (OPEX) so that utilities will, for example, pursue cost-effective active system management or "non-wires" solutions to improve costs and performance. Finally, as uses of the distribution network evolve, regulators will need to manage greater uncertainty, including both benchmark and forecast errors.

This paper proposes a novel process for establishing the allowed revenues of an electricity distribution utility over a multi-year regulatory period (e.g. 5 years) and demonstrates its application as a practical solution to each of these imminent regulatory challenges. The proposed method is a novel combination of four "state of the art" regulatory tools: an engineering-based reference network model for forward-looking benchmarking of efficient network expenditures under increased DER penetration; an incentive compatible menu of contracts to elicit accurate forecasts from the utility, manage benchmark errors, and create incentives for cost saving efficiency efforts; a fixed share "fast money/slow money" approach to capitalizing expenditures and equalizing incentives for OPEX and CAPEX savings; and *ex post* automatic adjustment mechanisms, or "delta factors," to accommodate uncertainty in the evolution of network use and mitigate the impact of forecast errors.

To demonstrate the practical application of this method and prove its performance under uncertain conditions, we use a reference network model to simulate a realistic, large-scale urban distribution network under a variety of potential scenarios for load growth and DER penetration. Using this simulated network as a case study, we illustrate how to establish the *ex ante* revenue benchmark, set clear incentives for cost savings, calculate the allowed revenues for the regulatory period, and apply annual, *ex post* rules to true up final revenues to account for realized costs. We conclude by demonstrating this method's ability to substantially mitigate the impact of both benchmark and forecast errors and summarize the advantages of this regulatory approach under the increasing penetration of distributed energy resources.

2 THE *EX ANTE* REMUNERATION PROCESS

Figure 1 summarizes the full regulatory process for establishing the allowed revenues of electricity distribution utilities proposed by this paper. The remainder of this section demonstrates each of the major steps in this process.

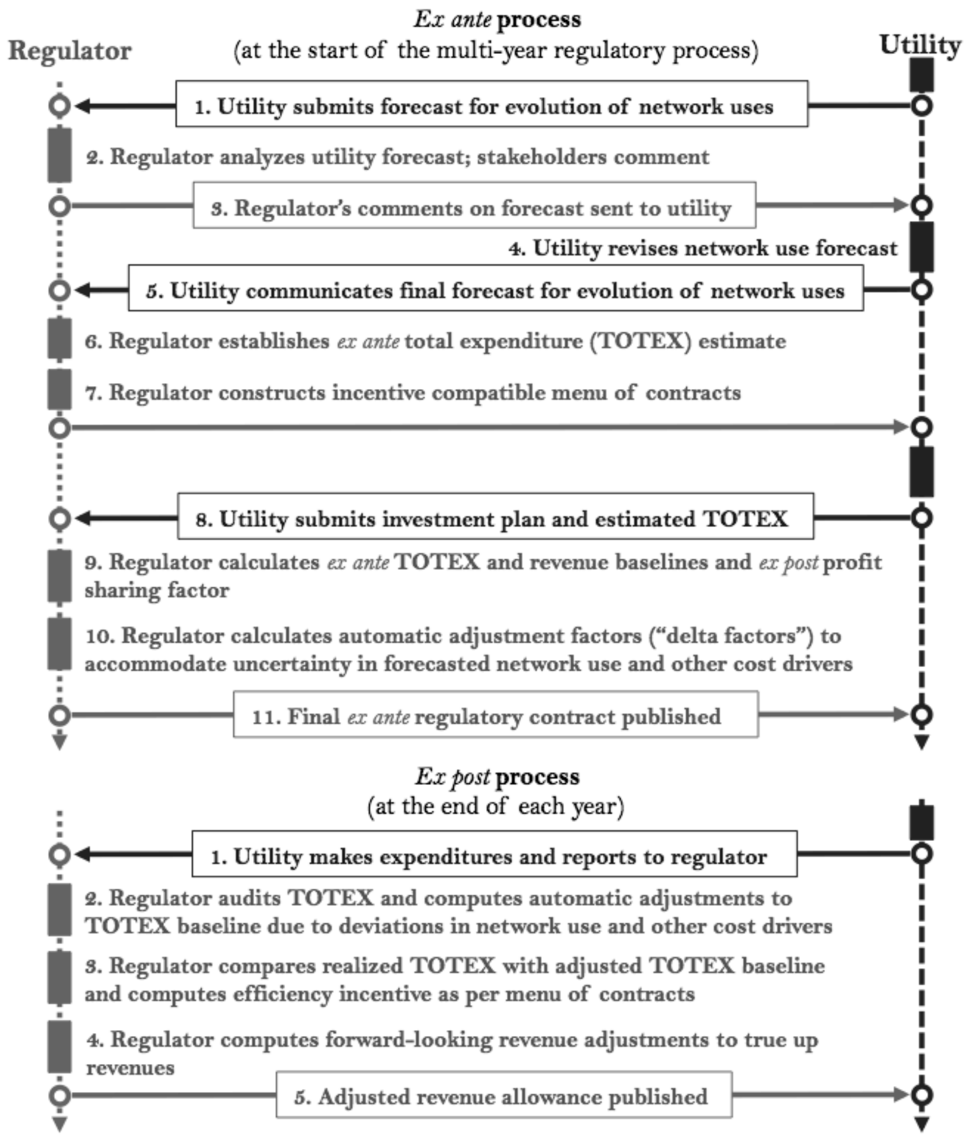

Figure 1. Proposed regulatory process for the remuneration of electricity distribution utilities

2.1 Forecasting the Evolution of Network Uses

The *ex ante* regulatory process begins when the utility submits a detailed forecast of the evolution of network uses over the upcoming multi-year regulatory period (e.g., a period of 3-8 years) (Step 1). This forecast should include a set of appropriately justified scenarios covering a range of the likely load and DER penetration levels, including discussion of the most likely geographic evolution of loads and DERs.

The utility may have an incentive to engage in strategic behavior during the construction of this forecast as the utility may believe that inflating estimates of load growth or DER penetration will lead to an increase in *ex ante* allowed revenues (Cossent & Gómez, 2013; Ofgem, 2010b). As such, the regulator must then critically review the preliminary forecast and allow a period of open comment by stakeholders (Step 2), providing an opportunity to illuminate any strategic inflation in expected cost drivers. At the same time, the use of automatic adjustment factors to account for any departures from the forecast over the regulatory period (see Section 2.6) minimizes the incentive to engage in strategic behavior at this stage. If forecasted load growth is inflated and realized load is much lower, for example, the *ex post* automatic adjustments will reduce the final allowed revenues accordingly.

After reviewing the forecast, the regulator will then submit clear comments to the utility on required changes or further analysis needed to construct a final forecast (Step 3). Upon receiving this feedback, the utility will then perform any required updates to their scenarios (Step 4) and re-submit a final forecast to the regulator for use throughout the remainder of the regulatory process (Step 5).

Importantly, in recognition of the inherent uncertainty in multi-year forecasts of network use, the regulatory process proposed herein does not depend on this "final" forecast proving precisely accurate. Instead, the forecast is used only to establish the initial *ex ante* estimate of total network expenditures, as described in Section 2.2. The estimated expenditures trajectory is then automatically adjusted *ex post* on an annual basis by applying the "delta factors" described in Section 2.6 to account for inevitable departures from this forecast. The ability to adjust automatically and accommodate for inevitable forecast errors is an important contribution of this proposed method, as demonstrated in Section 3.2.

2.2 Establishing the Regulator's *Ex Ante* Estimate of Efficient Expenditures

Next, the regulator must produce an *ex ante* estimate of efficient total network expenditures (TOTEX) necessary to meet the forecasted evolution of network use over a forward-looking regulatory period (e.g., a period of 3-8 years) (Step 6). To assist in this process, we propose the use of a reference network model (RNM), a distribution planning model which emulates the engineering design process of an efficient electric distribution company by specifying the placement and layout of all major distribution network components connecting one or more primary transmission interconnection substations with all power injection or consumption points (i.e., loads and DERs). Statistical benchmarking techniques commonly used to establish an *ex ante* estimate of efficient network expenditures are necessarily backwards looking. In the fast-evolving distribution utility environment, in which new cost drivers are emerging and new technologies and network management techniques are changing industry practice, benchmarking methods based on past utility performance will no longer provide an accurate estimate of the efficient frontier going forward. The use of an RNM can thus equip the regulator with a much-needed, forward-looking tool to benchmark efficient network expenditures and help the regulator overcome information asymmetries *vis-á-vis* regulated utilities.

An RNM typically takes as input the location and power injection/withdrawal profile of all network users as well as a catalog containing technical and cost information about available equipment, probability of component failure, and the cost and time burden of maintenance actions. Given these inputs, the RNM constructs a network to serve all network users while minimizing total network costs (including capital expenditures, operational expenditures, and a specified penalty for ohmic network losses) and meeting three specified quality of service constraints: (1) maximum system average interruption duration index (SAIDI); (2) maximum system average interruption frequency index (SAIFI); and (3) maximum acceptable voltage range at every node.

For regulatory benchmarking purposes, it is important to take into account the established layout of the utility's network and sunk investments in network components. The RNM should thus be run in a "brownfield" or network expansion mode taking as inputs the existing network layout and location of the utility's existing network users and specifying the layout of network reinforcements and extensions necessary to serve projected changes in network use over the regulatory period. The regulators would therefore require utilities to report information on their existing networks in a standard format including: the location, voltage level, contracted capacity, and injection/withdrawal profile of all existing network connections (loads and DERs); the layout, impedance, and capacity of the electrical lines and protection devices; and the capacity and location of transmission interconnection substations, high voltage/medium voltage substations, and transformers. This ability to explicitly take into account the heterogeneous nature of distribution networks is another key advantage of the RNM over statistical benchmarking techniques.

The regulator must also maintain the detailed library of standard network components used by the RNM, including cost and performance characteristics of cables, overhead lines, distribution transformers, substation components, and protection devices. This catalog should adequately characterize the real investment alternatives the utility may face. As such, this library should be updated regularly to reflect the current cost of standard components and expanded to include any new network components recently entering common use, such as new "smart grid" related components (i.e. ICT equipment, advanced power electronics, etc.). To avoid opportunities for strategic behavior via inflation of reported component costs, the regulator should develop costs for library components by benchmarking efficient unit costs across multiple utilities. For more on application of a RNM for regulatory benchmarking, see Cossent, 2013.

For use in regulatory proceedings, an RNM must be accurate enough to simulate established industry best practices. Over time, as novel, emerging techniques such as active system management, coordinated dispatch of distributed energy resources, or other measures become standard practice, the model must be updated to include these practices as well. However, it is appropriate for the RNM used in benchmarking to reflect current best practices at the *beginning* of the regulatory process. New methods adopted during the regulatory period that successfully reduce total system costs (or improve performance) will then be rewarded appropriately, and the model can be updated periodically to reflect any practices that have become widely adopted. In this manner, this proposed method works equally well despite the evolving nature of distribution network management, provided a suitable RNM is available which captures the best practices of an efficient network utility as of the beginning of the regulatory period.

In addition, while the information requirements necessary to employ an RNM can be significant, we note that similar requirements have been successfully implemented in Spain, Chile, and Sweden, each of which employs RNMs for benchmarking purposes in the remuneration process (see Cossent, 2013; Domingo et al., 2011; Jamasb & Pollitt, 2008). With the adoption of electronic equipment inventories and geographic information systems by electric utilities, the reporting requirements necessary for the regulator to employ an RNM are likely to become an increasingly negligible hurdle over time.

Lacking the real network data used in an actual regulatory proceeding, this paper instead simulates a realistic, large-scale urban distribution network in order to demonstrate the regulatory process proposed herein. Using the methods detailed in Vergara et al. (2014) and Jenkins (2014) and summarized in Appendix A, we simulate a synthetic network corresponding to a roughly 120 square mile portion of Denver, Colorado. This network has a peak demand of approximately 468 megawatts and includes more than 27,000 individual network connections, each corresponding to a unique metering point at one of three distribution voltage levels (240 volt, 12 kilovolt and 33 kilovolt).

Estimating the network asset replacement allowance

In addition to the new investments necessary to accommodate changes in network uses, some portion of existing network assets reach the end of their useful life and must also be replaced each year. To accommodate network replacement costs, regulators commonly allow the utility an investment allowance equal to the full replacement value of the retiring vintage of booked assets. However, this method is likely to over-compensate the utility. Replacing an existing network asset will almost certainly cost less than the original construction of that asset: trenches and rights of way for underground and overhead cabling have already been established, permits obtained, connections to other assets installed, etc. In addition, existing assets can often be repaired and repurposed, extending their useful life at lower cost than purchasing a new replacement asset. Therefore, regulators should hire an independent auditor to obtain the value of the retiring portion of the firm's booked assets and then assess the average replacement cost as a percentage of the original asset costs. This percentage can be considered the "extended lifetime factor" and should be applied to the full value of the retiring asset vintage to obtain an estimate of efficient replacement costs that will avoid over-compensating the utility.

For this demonstration, we use the estimated cost of the synthetic Denver network as the gross asset value of the existing network. We then assume an extended lifetime factor of 66.7% and make the simplifying assumption that assets are divided evenly into 40 annual vintages (assuming a 40 year average lifespan for network assets). Overnight replacement costs are then adjusted to current year costs by applying the PPI.

Using the reference network model to estimate network costs

To demonstrate the application of the RNM to estimate the new network reinforcements and upgrades and associated expenditures necessary to efficiently serve the forecasted evolution of network use, we use the synthetic Denver network in place of the real network data used in an actual regulatory proceeding and we use the load growth and PV penetration forecasts summarized in Table i. While we consider only solar PV growth in this demonstration, this method applies equally to any of the increasingly diverse range of distributed energy resources that may become active distribution network users, including energy storage devices, microturbines, combined heat and power and other distributed resources.

The RNM produces an estimate of new network investments necessary to accommodate forecasted changes in network use (i.e., load growth and DER penetration) and divides this estimate into two components: primary network investments and quality-related equipment (protection devices, voltage regulators, etc.) chosen by the model to optimize quality of service. This yields the total incremental network investment required over the regulatory period, expressed as overnight capital costs, summarized in Table ii.

The RNM also estimates annual operations and maintenance expenditures, which are divided into preventative maintenance and corrective maintenance costs (see Table ii). These values include maintenance of the existing network and new maintenance expenditures necessary to accommodate changes in network use over the regulatory period.

Table i. Forecasted evolution of network uses during the regulatory period

HORIZONTAL LOAD GROWTH (number of new load points)				
	Low Voltage	**Medium Voltage**	**High Voltage**	**Approx. total peak demand (kW)**
Avg. peak KW/point	6	100	1,000	
Base system	25,051	2,123	105	468,079
Forecast	25,551	2,163	108	496,710*
Incremental growth	500	40	3	28,631*
VERTICAL LOAD GROWTH (percent increase per load point)				
	Low Voltage	**Medium Voltage**	**High Voltage**	**Approx. total load (million kWh/year)**
Base system	-	-	-	2,100.7
Forecast	4.0	4.0	4.0	2,232.5*
* Note: includes combined impact of new load points and vertical load growth for each point				
SOLAR PV PENETRATION (number of new PV connections)				
	Low Voltage	**Medium Voltage**	**High Voltage**	**Approx. total peak generation (kW)**
Avg. peak KW/point	12	200	2,000	
Base system	0	0	0	0
Forecast	2,083	300	6	97,000

Table ii. Estimated efficient network expenditures to meet forecasted evolution of network uses

Network components	**New Network Investment**	**New Quality Equipment**	**Total New Network Investment**	**Preventive Maintenance**	**Corrective Maintenance**	**Total Maintenance**
	OVERNIGHT COSTS (US$)			ANNUAL COSTS (US$)		
LV feeders	$1,625,755	$0	**$1,625,755**	$814,148	$637,103	**$1,451,251**
LV/MV transformers	$2,293,146	$0	**$2,293,146**	$1,467,023	$66,973	**$1,533,996**
MV feeders	$1,178,007	$74,100	**$1,252,107**	$709,886	$623,117	**$1,333,003**
MV/HV substations	$0	$0	**$0**	$2,127,960	$589	**$2,128,549**
HV lines	$7,391,355	$0	**$7,391,355**	$237,752	$14,621	**$252,373**
Total	$12,488,262	$74,100	**$12,562,362**	$5,356,768	$1,342,403	**$6,699,171**

Next, the efficient investment and annual maintenance expenditures estimated in Table ii must be converted to the regulator's *ex ante* estimate of total network expenditures (TOTEX) for the regulatory period. Table iii depicts these calculations. First, the total overnight cost of incremental investments must be converted into an annual investment schedule. This schedule can allocate total expenditures evenly for each year, allocate expenditures proportionate to expected annual load or DER growth, or match the annual proportions in the utility's proposed investment plan. Here we simply divide total costs evenly for demonstration purposes. These overnight cost figures are then adjusted for inflation to current year dollars by applying an appropriate inflation index (here we use the U.S. producer price index or PPI).

Table iii. Regulator's ex ante estimate of efficient total network expenditures[2]

CAPEX (million $)	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total NPV**
Incremental investment							
Overnight cost (from RNM)		$2.51	$2.51	$2.51	$2.51	$2.51	
Inflation adjusted		$2.58	$2.64	$2.71	$2.77	$2.84	$11.22
Replacement investments							
Overnight cost		$6.97	$6.97	$6.97	$6.97	$6.97	
Inflation adjusted		$7.14	$7.32	$7.50	$7.69	$7.88	$31.10
Total investment (CAPEX)		$9.72	$9.96	$10.21	$10.46	$10.73	$42.32
OPEX (million $)							
Base estimate, no inflation	$6.48	$6.52	$6.57	$6.61	$6.66	$6.70	-
Inflation adjusted		$6.69	$6.85	$7.03	$7.20	$7.38	$29.13
TOTEX ESTIMATE (million $)							
Total network expenditures (TOTEX)		$16.40	$16.81	$17.24	$17.67	$18.11	$71.40
CAPEX share of TOTEX ("Slow Money")		59%	59%	59%	59%	59%	59%
OPEX share of TOTEX ("Fast Money")		41%	41%	41%	41%	41%	41%

Finally, the RNM estimates annual network maintenance costs in non-inflation-adjusted terms, which must be converted into an expenditure schedule. At the start of the period, we assume maintenance costs correspond to the cost of the base network, while costs in the final year of the regulatory period correspond to the expected total maintenance costs for the expanded network. We impute annual values for the interim years by assuming a compound annual growth in maintenance costs over the regulatory period. These values are then adjusted for inflation by applying the PPI. The regulator's *ex ante* estimate

[2] Table iii assumes a 5-year regulatory period and straight-line depreciation of regulated asset value over 40 year average asset life; initial gross asset value of $418.05 million evenly divided among 40 annual vintages for computation of average age of network assets; pre-tax return on equity is 10%; cost of debt is 5.5%; gearing ratio is 35% equity, 65% debt and WACC is 7.08%; inflation is 2.5%; discount rate is 6.5%; extended lifetime factor for replacement investments is 0.67.

of efficient TOTEX is thus the sum of inflation adjusted CAPEX (including incremental and replacement investments) and OPEX (network maintenance).[3]

2.3 Setting "Fast Money" and "Slow Money" Allocations to Equalize Incentives for CAPEX and OPEX Savings

The regulator can also use the expenditure estimates produced above to implement a TOTEX-based approach to capitalizing expenditures into the regulated asset value (RAV, also referred to as "regulated asset base" or "rate base"). If capitalized additions to the RAV are based on actual CAPEX, then a dollar in reduced CAPEX will also involve a reduction in the RAV and thus a reduction in the allowed return on equity and a corresponding decline in net profit for the utility's shareholders. This decline in net profit will offset some portion of any efficiency-related income awarded by the regulator, distorting tradeoffs between OPEX and CAPEX and potentially encouraging over-investment (Ofgem, 2009, 2013b).

Under a TOTEX-based approach, in contrast, both OPEX and CAPEX savings will face the same efficiency incentive, that is, a dollar of OPEX savings and a dollar in CAPEX savings will earn the utility the same efficiency-related income. Under this approach, introduced by Ofgem (2009), the regulator establishes a fixed portion of realized TOTEX, referred to as "slow money," which will be capitalized into the RAV (from which depreciation and cost of capital revenue allowances are calculated). The remainder of TOTEX is designated as "fast money," which is fully expensed annually. The regulator fixes these shares at the start of the regulatory period based on the *ex ante* estimates of CAPEX and OPEX in total expenditures. As such the share of CAPEX and OPEX in actual utility expenditures is free to depart from this expected share without impacting the utility's return on equity, allowing the utility to fully exploit cost-saving tradeoffs between both types of expenditure (see Ofgem, 2009, pp. 117-120, and Ofgem, 2013b, pp. 30-32 for more). In addition, using an RNM to estimate efficient investment and maintenance costs gives the regulator a new, objective tool to establish the fast money and slow money shares. Table iii includes the fast and slow money shares for the simulated network.

2.4 Constructing an Incentive-Compatible Menu of Contracts

The next step involves creating an incentive compatible menu of profit-sharing regulatory contracts for the utility (Step 7).[4] A menu of contracts specifies an *ex ante* regulatory allowance as well as clear rules

[3] Note that other business-related operational expenditures such as business support costs, pensions, etc. are not included in this simulation and are thus excluded from OPEX figures here. These expenditures would have to be accommodated in real revenue allowance determinations.

for *ex post* evaluation of actual expenditures and adjustments to final remuneration. The menu outlines a continuum of profit-sharing factors (sliding-scale efficiency incentives) wherein the strength of the profit-sharing factor depends on the ratio of the utility's estimate of network costs over the regulatory period to the regulator's estimate derived using the RNM in Step 6 (Section 2.2).

The use of profit sharing factors effectively spreads profits and rents as well as risks between the utility and ratepayers, incorporating qualities of both cost of service and incentive regulation. The regulator can tune the menu of contracts to appropriately balance incentives for productive efficiency and manage uncertainty while maintaining "incentive compatibility"—that is, a profit-maximizing firm will always earn the greatest profit and return on equity when actual expenditures match their *ex ante* estimate of necessary expenditures. Use of an incentive compatible menu of contracts is an important improvement over conventional approaches to profit or earnings sharing mechanisms, as the menu eliminates incentives for firms to artificially inflate their *ex ante* cost estimates while rewarding firms for revealing their true cost types to the regulator, helping minimize strategic behavior and overcome information asymmetries while creating incentives for the utility to improve productive efficiency.

Using the method introduced in Cossent & Gómez (2013), the regulator only needs to establish four discretionary regulatory parameters to create a continuous, incentive-compatible menu of contracts:

1. The weight placed on the regulator's estimate of efficient network expenditures relative to the utility's estimate, ω. This weight should depend on how reliable the regulator believes their estimate of future expenditures is likely to be relative to the accuracy of the firm's estimate. A higher value places more weight on the regulator's estimate, while a lower value places more weight on the firm's estimate.
2. The reference value for the profit-sharing factor (the portion of cost savings/increases to which the utility is exposed, also known as the efficiency incentive rate), SF_{ref}, which corresponds to the case where the utility's estimate of future expenditures aligns with the regulator's estimate ($\theta_{ex\ ante}$=1.0). A value of 1.0 corresponds to a pure revenue cap contract while a value of 0.0 corresponds to a cost of service contract. The regulator can thus tune the sharing factor to establish the strength of efficiency incentives faced by utilities in order to manage tradeoffs between incentives for efficiency and rent extraction. This parameter also plays an important role in managing the effects of benchmark errors

[4] Cossent and Gómez (2013) describe a practical method for creation of an incentive compatible menu of contracts, and this paper builds on that work herein. Additionally, Ofgem has successfully implemented this general approach since the fourth distribution price control review (DPCR4), enacted from 2005-2010 (Ofgem 2009, 2010a), and is now an integral part of Ofgem's RIIO framework (Ofgem, 2010c). The UK's approach, known as the Information Quality Incentive (IQI) is described in Crouch (2006) as well in Ofgem (2009, 2010b, 2013c) and Cossent and Gómez (2013). The theoretical framework for a menu of contracts is discussed in Laffont & Tirole (1993).

(see Section 3.2). Regulators should thus take into account the degree of uncertainty about future network costs when establishing this factor. In general, a higher profit-sharing factor (i.e., the firm is exposed to most of the risks and rewards of cost savings) performs better under lower levels of uncertainty, while a lower profit-sharing factor (which shares most risks and rewards with ratepayers) performs better under greater uncertainty (Schmalensee, 1989; see also Ofgem, 2010b at pp. 84-87 for further discussion of regulatory considerations in establishing the sharing factor or incentive rate).

3. The rate of change in the profit-sharing factor as the ratio between the utility's estimate and the regulator's estimate changes, SF_{roc}. This value can be set so as to control the spread in efficiency incentives faced by different utilities during the regulatory period. A larger value results in a wider range of profit-sharing factors offered, while a smaller factor results in a tighter range.

4. The reference value for the additional income payment, AI_{ref}, is used to ensure incentive compatibility of the menu of contracts. This reference value corresponds to the case where the utility's estimate of future costs aligns with the regulator's estimate ($\theta_{ex\ ante}$=1.0). The selected value can be used to tune expected profit margins for the utility.

Using these four parameters and the formulas in Appendix B, the regulator can then calculate the remaining initialization parameters necessary to construct a menu of contracts. Appendix B also describes the formulas to compute the appropriate *ex ante* regulatory contract and *ex post* efficiency incentive, the portion of realized over- or under-spending shared with the utility's shareholders.

An example menu of contracts is shown in Table iv below. The first row of Table iv describes the ratio between the regulator's estimate of efficient expenditures (as per Step 6, see Section 2.2) and the estimate submitted by the utility in their detailed business plan (Step 8). Given this ratio, the regulator sets the utility's allowed *ex ante* TOTEX baseline (row two) as well as the profit sharing factor (row three) and additional income (row four) awarded to ensure incentive compatibility. The first four rows of Table iv thus describe the full menu of contracts, while the remaining rows illustrate the efficiency incentive earnings (or penalty) associated with the level of actual network expenditures the utility manages to achieve *ex post*. Shaded cells in these rows correspond to cases in which the utility's *ex ante* expenditure forecast matches actual expenditures, demonstrating the incentive compatible nature of this matrix. For any realized value of network costs (i.e. horizontal row in the bottom half of Table iv), the utility will earn the greatest revenues in the case where realized costs match their *ex ante* forecast. Efficiency incentives are also preserved, as lowering realized costs below the utility's forecast (i.e. moving up in a vertical column) will increase the utility's final revenues (and *vice versa*). Note that while this table shows discrete values in each column, the formulas in Appendix B can also generate a continuous menu of contracts for any ratio between regulator and utility expenditure estimates.

Table iv. Example incentive compatible menu of profit-sharing contracts[5]

Ratio of firm's TOTEX estimate to regulator's TOTEX estimate [%]	$\theta_{ex\ ante}$	90	95	**100**	105	110	115	120
Ex ante TOTEX baseline [% of regulator's cost estimate]	$X_{ex\ ante}$	96.6	98.3	**100.0**	101.7	103.4	105.1	106.8
Sharing factor [%]	SF	80.0	75.0	**70.0**	65.0	60.0	55.0	50.0
Additional income [% of regulator's cost estimate]	AI	3.2	2.2	**1.0**	-0.2	-1.5	-2.9	-4.4
Ratio of realized *ex post* expenditures to regulator's TOTEX estimate [% of *ex ante* estimate]	$\theta_{ex\ post}$	Efficiency incentive [% of regulator's *ex ante* TOTEX estimate]						I
85		12.5	12.1	**11.5**	10.6	9.5	8.1	6.5
90		8.5	8.4	**8.0**	7.4	6.5	5.4	4.0
95		4.5	4.6	**4.5**	4.1	3.5	2.6	1.5
100		0.5	0.9	**1.0**	0.9	0.5	-0.1	-1.0
105		-3.5	-2.9	**-2.5**	-2.4	-2.5	-2.9	-3.5
110		-7.5	-6.6	**-6.0**	-5.6	-5.5	-5.6	-6.0
115		-11.5	-10.4	**-9.5**	-8.9	-8.5	-8.4	-8.5
120		-15.5	-14.1	**-13.0**	-12.1	-11.5	-11.1	-11.0
125		-19.5	-17.9	**-16.5**	-15.4	-14.5	-13.9	-13.5

2.5 Calculation of *Ex Ante* TOTEX and Revenue Baselines and Sharing Factor

With an estimate of efficient network expenditures and a menu of contracts in hand, the regulator can then assess the utility's estimate of network expenditures, which is submitted as part of their detailed business plan in Step 8. First, the regulator compares the utility's annual TOTEX estimate to the regulator's own estimate produced in Step 6 and establishes the *ex ante* TOTEX baseline for each year in the regulatory period as per equation (1):

$$X_{y,\, ex\ ante} = X_{y,\, reg.} \cdot \omega + X_{y,\, firm} \cdot (1\text{-}\omega) \qquad (1)$$

Where:

$X_{y,\, ex\ ante}$ *ex ante* annual TOTEX baseline in year y

$X_{y,\, reg.}$ regulator's *ex ante* estimate of efficient TOTEX in year y

[5] The menu of contracts in Table iv uses the following discretionary parameters: ω = 0.66; SF_{ref} = 0.7; SF_{roc} = -0.01; AI_{ref} = 1.0.

$X_{y,firm}$ firm's *ex ante* estimate of efficient TOTEX in year y

ω weight placed on the regulator's estimate

Next, using the menu of contracts produced in Step 7 and the ratio between the total net present value (NPV) of the utility's TOTEX estimate and the regulator's TOTEX estimate, the regulator determines the sharing factor and additional income allowances (see equations in Appendix B). Finally, the regulator calculates the *ex ante* allowed revenue baseline for the regulatory period as per Equations 2-8:

$$S_y = X_{y,\,ex\,ante} \cdot \sigma_y \tag{2}$$

$$F_y = X_{y,\,ex\,ante} - S_y \tag{3}$$

$$G_y = G_{y-1} - E_y + S_y \tag{4}$$

$$D_y = G_y \cdot Life^{-1} \tag{5}$$

$$RAV_y = \left(Life - Age_y\right) \cdot Life^{-1} \cdot G_y \tag{6}$$

$$C_y = RAV_{y-1} \cdot WACC \tag{7}$$

$$R_{y,\,ex\,ante} = F_y + D_y + C_y + AI \tag{8}$$

Where:

y index for years

S notional CAPEX allowance capitalized into RAV ("slow money")

σ regulator's expected share of CAPEX in TOTEX ("slow money share")

F notional OPEX allowance expensed annually ("fast money")

G total gross value of in-service assets

E gross value of assets reaching end of useful life

D annual capital depreciation allowance

$Life$ regulatory life of assets

RAV regulated asset value (gross value of assets less depreciation)

Age average age of assets

C annual allowance for repayment of debt and equity

$WACC$ weighted average cost of capital

AI additional income allowance from menu of contracts

$R_{ex\,ante}$ *ex ante* allowed revenues for each year of the regulatory period

Together, the *ex ante* TOTEX and revenue baselines and the *ex post* sharing factor define the contract between the regulator and the utility for the duration of the regulatory period. This regulatory contract provides the utility with a clear expectation of how their revenues will evolve over the regulatory period and provides explicit incentives for efficient management of network costs. Table v computes an example revenue allowance for a case in which the utility's estimate of TOTEX is higher than that of the regulator ($\theta_{\text{ex ante}} = 1.1$).

Table v. Example of TOTEX and revenue baseline calculations[6]

TOTEX ESTIMATES (M$)		Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	NPV
Regulator's estimate	X_{reg}		$16.40	$16.81	$17.24	$17.67	$18.11	$71.44
Utility's estimate	X_{firm}		$18.04	$18.50	$18.96	$19.43	$19.92	$78.59
TOTEX BASELINE (M$) AND MENU OF CONTRACTS PARAMETERS								
TOTEX baseline	$X_{ex\ ante}$		$16.96	$17.39	$17.82	$18.27	$18.72	$73.87
Ratio	$\theta_{ex\ ante}$	1.1	**Sharing Factor** *SF*		60%	**Additional income** *AI*		-$1.10
REVENUE BASELINE CALCULATIONS (M$)								
Capitalization								
Slow money	*S*		$10.05	$10.30	$10.56	$10.82	$11.09	
Gross asset value	*G*	$418.05	$417.65	$417.49	$417.60	$417.97	$418.61	
Avg. age of assets (yrs)	*Age*	19.50	19.52	19.53	19.52	19.50	19.47	
Regulated asset value	*RAV*	$214.25	$213.85	$213.70	$213.82	$214.20	$214.84	
Cost allowances								
Fast money	*F*		$6.91	$7.09	$7.27	$7.45	$7.63	$30.12
Depreciation	*S*		$10.45	$10.44	$10.44	$10.44	$10.45	$43.40
Cost of capital	*C*		$15.16	$15.13	$15.12	$15.13	$15.15	$62.91
Additional income	*AI*		-$0.25	-$0.26	-$0.27	-$0.27	-$0.28	-$1.10
Revenue baseline	$R_{ex\ ante}$		**$32.27**	**$32.40**	**$32.56**	**$32.74**	**$32.96**	**$135.33**

[6] Table viTable v uses the following parameters ω = 0.66; SF_{ref} = 0.7 SF_{roc} = -0.01; AI_{ref} = 1.0; σ = 59%; *WACC* = 7.09%; *Life* = 40 years; δ = 6.5%.

2.6 Calculating Automatic Adjustment Factors to Manage Uncertainty

While using an RNM and menu of contracts produces a clear revenue determination for the utility, the *ex ante* nature of this regime means there will always be uncertainty regarding the evolution of network uses, cost of capital, and network component costs over the regulatory period. This uncertainty can lead to two types of error: "forecast error," where costs rise or fall unexpectedly due to new network uses or other cost drivers (i.e., changes in cost of capital, etc.); and "benchmark error," where the regulator fails to anticipate the emergence of new cost saving technologies or practices within the regulatory period that shift the efficient frontier. In either case, the longer the regulatory period, the more substantial the effects of uncertainty can be on utility cost recovery and allocative efficiency (Ofgem, 2010b, 2013e). The regulator can mitigate benchmark error by tuning the sharing factor in the menu of contracts in Step 7. In particular, the impact of benchmark error on utility cost recovery declines as the sharing factor declines (and *vice versa*), as utilities and ratepayers share risks associated with divergences in realized costs from the *ex ante* benchmark (see Section 3.2).

Without additional measures, however, the impact of forecast errors can be substantial. We therefore propose a novel approach to calculate *ex ante* automatic adjustment factors, or "delta factors," simple formulas that will be applied *ex post* to correct the estimate of efficient network expenditures (the TOTEX baseline) to account for any deviations from the forecast for both load growth and DER adoption (Step 9). Using delta factors reduces the risk that the revenue determination will need to be re-opened during the regulatory period, increasing regulatory certainty. These delta factors also align incentives for the utility to connect and serve new DERs by ensuring cost recovery even if DER penetration grows more rapidly than expected.

To calculate the delta factors, the regulator employs the RNM to estimate network costs for a range of uncertainty scenarios designed to capture the likely range of potential evolution of load, DG penetration, or other important and uncertain cost drivers. To demonstrate this process, we construct nine uncertainty scenarios corresponding to all possible permutations combining three forecasts for load growth and three forecasts for DG penetration shown in Table vi.

Table vi. Uncertainty scenarios

LOAD GROWTH (number of new load points / percent vertical load growth)				
	Low Voltage	**Medium Voltage**	**High Voltage**	**Approx. total peak demand (kW)**
Low forecast	450 / 3.5	35 / 3.5	2 / 3.5	492,460*
Baseline forecast	500 / 4.0	40 / 4.0	3 / 4.0	496,710*
High forecast	550 / 4.5	45 / 4.0	4 / 4.5	500,980*

* Note: includes combined impact of new load points and vertical load growth for each point

SOLAR PV PENETRATION (number of new pv connections)				
	Low Voltage	**Medium Voltage**	**High Voltage**	**Approx. total peak generation (kW)**
Low forecast	1,875	270	5	86,500
Baseline forecast	2,083	300	6	97,000
High forecast	2,292	330	7	107,500

The regulator runs the RNM in brownfield mode to calculate the efficient network costs under each of these uncertainty scenarios. Table vii shows the results for our simulated network under the range of uncertainty scenarios in Table vi. Finally, the regulator determines the relationship between deviations in cost driver values and efficient network costs by performing a multivariate linear regression on the resulting estimated TOTEX for each scenario. In this demonstration, we calculate regression coefficients describing the change in TOTEX as a function of the divergence in load ($0.078 per kWh) and PV ($36.2 per kW) from the central forecast ($R^2 = 0.998$). These coefficients, which we call "delta factors," prescribe simple formulas to adjust the estimated TOTEX baseline *ex post* based on the realized evolution of network uses or other key cost drivers (see Section 3.1).

Table vii. Difference in estimated efficient network costs, load, and PV penetration across uncertainty scenarios

	Load (kWh)	**PV penetration** (kW)	**Total New Network Investment** (US$ Overnight Cost)	**Total Network Maintenance Costs** (US$ Annual Cost)	**Efficient TOTEX** (Million US$)
Uncertainty Scenario	**Difference from Baseline Case**				**NPV**
Low Load, Low PV	-19,821,979	-10,241	-$2,184,067	-$32,994	$69.47
Low Load, Central PV	-19,821,979	0	-$1,708,074	-$27,222	$69.90
Low Load, High PV	-19,821,979	10,963	-$1,339,456	-$21,491	$70.23
Baseline Load, Low PV	0	-10,241	-$520,576	-$6,670	$70.97
Baseline Load, Baseline PV	0	0	$0	$0	$71.44
Baseline Load, High PV	0	10,963	$327,716	$5,026	$71.74
High Load, Low PV	25,481,215	-10,241	$800,338	$13,583	$72.99
High Load, Baseline PV	25,481,215	0	$1,277,927	$19,926	$73.43
High Load, High PV	25,481,215	10,963	$1,661,622	$24,213	$73.78

Computing these delta factors concludes the *ex ante* regulatory process. At this point, the utility will have a clear TOTEX baseline for the regulatory period against which cost-saving efforts can be measured and rewarded, as well as a pre-defined set of rules for how *ex post* adjustments to revenues will be determined to account for deviations in both realized network costs (the sharing factor) and the actual evolution of network uses (the delta factors). This *ex ante* process thus provides strong regulatory certainty and clear incentives to optimize network costs during the regulatory period.

3 THE *EX POST* REGULATORY PROCESS

3.1 Applying Annual Adjustments to Allowed Revenues

At the conclusion of each year during the regulatory period, an *ex post* regulatory process commences to adjust the utility's allowed revenues in light of the realized evolution of system uses and utility expenditures.

First, the utility submits a detailed report on actual investment and operational expenditures (the utility's realized TOTEX) as well as details on the evolution of system uses (i.e., load growth and penetration of DER) (*ex post* Step 1). The regulator then audits these reports to ensure their accuracy and computes the automatic adjustments to the *ex ante* TOTEX baseline to account for any differences in actual network use as compared to the *ex ante* forecast (Step 2). For each year, the regulator calculates the annual adjustment to the TOTEX baseline in total NPV terms (Equations 9) for each of the key network uses or other cost drivers for which delta factors have been computed (i.e., in this demonstration, for both load growth and PV penetration). Since the utility would not be expected to make all of the expenditures to accommodate this deviation from the forecast in the immediate year, this total NPV adjustment is converted into a stream of inflation-adjusted annual expenditures spread across the remaining years in the regulatory period (Equation 10). The sum of all such annual adjustments to date is then added to each year of the *ex ante* TOTEX baseline to arrive at the adjusted *ex post* TOTEX baseline (Equation 11).

$$Z_{NPV} = \sum_d \Delta_d \cdot \left(\epsilon_{d,y} - \sum_{i=y_0}^{y-1} \epsilon_{d,i}\right) \tag{9}$$

$$Z_i = Z_{NPV} \cdot \tau^{-1} \cdot (1+\delta)^i \;\; \forall \; i \in [y, y+(\tau-1)] \tag{10}$$

$$X_{y,\,adjusted} = X_{y,\,ex\;ante} + \sum_{i=y_0}^{y} Z_i \tag{11}$$

Where:

y, i	indexes for years
Z_{NPV}	net present value adjustment to total TOTEX baseline
Δ_d	delta factor for cost driver d
ϵ_d	forecast error for cost driver d
Z	annual adjustment to allowed revenues
δ	regulatory discount rate
y_0	first year in the regulatory period
τ	number of years remaining in the regulatory period
$X_{adjusted}$	TOTEX baseline after adjustments for forecast errors

After calculating the adjusted TOTEX baseline, the regulator then compares the utility's realized TOTEX over the last year with the adjusted TOTEX baseline and calculates the efficiency incentive (Step 3) as per Equation 12. The efficiency incentive is the portion of the over/under-spend shared by the utility's shareholders, as specified by the sharing factor in the *ex ante* regulatory contract. Final allowed TOTEX is thus the utility's *ex post* realized TOTEX plus this efficiency incentive, as in Equation 13.

$$I_y = SF \cdot \left(X_{y,\,adjusted} - X_{y,\,ex\;post}\right) \tag{12}$$

$$X_{y,\,allowed} = X_{y,\,ex\;post} + I_y \tag{13}$$

Where:

I	efficiency incentive, or the portion of over/under-spend shared by utility shareholders
SF	the sharing factor specified in the *ex ante* regulatory contract

$X_{ex\ post}$ total network expenditures realized by the utility

$X_{allowed}$ total allowed network expenditures after adjustments for efficiency incentive

Next, the regulator calculates the *ex post* revenue allowance associated with the *ex post* allowed TOTEX, employing the same methods as in Equations 2-8. Note that regardless of the utility's actual CAPEX, the portion of allowed TOTEX capitalized into the RAV is determined by the slow money share set *ex ante*, maintaining balanced incentives for cost-saving efficiency efforts across both CAPEX and OPEX (see Section 2.3).

Finally, since revenues have already been collected over the course of the recently concluded year, the regulator must correct the utility's revenue allowance in future years to "true up" the collected revenues and the *ex post* revenue allowance (Step 4), as in Equation 14. This true up process ensures that the NPV of adjustments to future revenues corrects for the surplus or deficit in collected revenues over the recently concluded year. This true up is applied as a stream of annual adjustments over the next *N* years, where *N* is the length of the regulatory period, rather than a single lump sum correction, so as to smooth the impact on rates and avoid discontinuous rate increase/decreases. As allowed revenues are adjusted for the next *N* years, a portion of the true up corrections will be applied during the subsequent regulatory period. The regulator must therefore track these adjustments and add them to the revenue baseline calculated in the next regulatory period. This *N* year rolling window of true up corrections also ensures that the utility's incentives for cost savings are equalized across each year in the regulatory period, as no matter what year these savings are achieved, the utility will be entitled to collect the agreed share of those savings over the next *N* years.

$$R_{i,final} = R_{i,\ allowed} + (R_{y,\ allowed} - R_{y,\ collected}) \cdot N^{-1} \cdot (1+\delta)^{i-y}\ \forall\ i \in [y+1, y+N] \tag{14}$$

Where:

R_{final} final corrected revenue allowance after true up

$R_{allowed}$ revenue allowance after adjustment for efficiency incentive and forecast error

$R_{collected}$ actual revenues collected by the utility (*ex ante* revenue baseline plus prior adjustments)

δ regulatory discount rate

N the number of years in the regulatory period

y, i indexes for years

Tables viii and ix demonstrate the full application of the *ex post* annual adjustment process and formulas described above. In this hypothetical example, load ends up growing slower than forecasted, while PV penetration grows more rapidly (ϵ_{load} & ϵ_{PV}). As such, the delta factors are applied to adjust the *ex ante*

TOTEX baseline ($X_{ex\ ante}$) from an initial net present value of $73.9 million to the adjusted TOTEX baseline ($X_{adjusted}$) of $72.7 million to account for these deviations from the forecasted evolution of network uses. In this example, the utility ultimately expends just $64.3 million ($X_{ex\ post}$), achieving a 10 percent reduction in cost relative to the adjusted TOTEX baseline ($\theta_{\mathrm{ex\ post}} = 0.9$). Table viii thus illustrates the application of the sharing factor (here assumed to be 0.6) to calculate the efficiency incentive (I), which is then added to the adjusted TOTEX baseline to establish the final *ex post* allowed TOTEX ($X_{allowed}$). Table ix then illustrates how the annual revenues are trued up to account for the *ex post* allowed revenues associated with this final allowed TOTEX.

Table viii. Example of *ex post* annual corrections to allowed network expenditures (TOTEX)[7]

Year		**NPV**	**1**	**2**	**3**	**4**	**5**
DEVIATION IN NETWORK USE FROM FORECAST							
Load (M kWh)	(ϵ_{load})		-3.80	-7.67	-11.64	-15.69	-19.82
Solar PV (kW)	(ϵ_{PV})		+2,193	+4,385	+6,578	+8,770	+10,963
CUMULATIVE ADJUSTMENT TO TOTEX BASELINE (M$)							
***Ex ante* TOTEX baseline**	($X_{ex\ ante}$)	*$73.9*	$17.0	$17.4	$17.8	$18.3	$18.7
Cumulative adjustments: load		*-$1.5*	-$0.06	-$0.15	-$0.29	-$0.51	-$0.98
Cumulative adjustments: solar PV		*+$0.4*	$0.02	$0.04	$0.08	$0.13	$0.25
Adjusted TOTEX baseline ($X_{adjusted}$)		***$72.7***	**$16.9**	**$17.3**	**$17.6**	**$17.9**	**$18.0**
CALCULATION OF EFFICIENCY INCENTIVE AND EX POST ALLOWED TOTEX							
Realized TOTEX	($X_{ex\ post}$)	*$64.3*	$14.8	$15.1	$15.5	$15.9	$16.3
Difference	($X_{adjusted}$ - $X_{ex\ post}$)	*$8.4*	$2.2	$2.1	$2.1	$2.0	$1.7
Efficiency incentive	(I)	*$5.1*	$1.3	$1.3	$1.3	$1.2	$1.0
Final allowed TOTEX	($X_{allowed}$)	*$69.4*	$16.1	$16.4	$16.8	$17.1	$17.3

[7] Table viii uses the following parameters: $SF = 0.6$; $\Delta_{load} = \$0.078$/kWh; $\Delta_{PV} = \$36.2$/kW; $\delta = 6.5\%$.

Table ix. Example of *ex post* annual corrections to allowed revenues[8]

Year	*NPV*	1	2	3	4	5	6	7	8	9	10
Collected revenues ($R_{collected}$)	*\$134.7*	\$32.3	\$32.3	\$32.4	\$32.5	\$32.6					
***Ex post* allowed revenues** ($R_{allowed}$)	*\$133.1*	\$31.9	\$32.0	\$32.0	\$32.1	\$32.2					
Cumulative revenue correction	*-\$1.6*	\$0.00	-\$0.09	-\$0.18	-\$0.28	-\$0.39	-\$0.51	-\$0.43	-\$0.34	-\$0.24	-\$0.13
Final revenue allowance (R_{final})	*\$133.1*	\$32.27	\$32.24	\$32.23	\$32.24	\$32.26	-\$0.47	-\$0.39	-\$0.31	-\$0.22	-\$0.12

Table x shows the financial position of the utility under this example. As illustrated, because the utility was able to achieve significant cost savings, the utility's shareholders earn a final after tax return on equity of 7.3% for the regulatory period, above the target return on equity of 6.5%.

Table x. Final financial position of the utility[9]

Allowed revenues	\$133.1
Allowed costs	\$103.2
Fast money allowance	\$28.3
Depreciation allowance	\$43.3
Cost of debt	\$31.6
Revenues less costs	\$29.9
Efficiency incentive income	\$5.1
Earnings before interest & taxes	\$34.9
Taxes	\$12.2
Net profit	\$22.7
After-tax return on equity	7.3%

3.2 Performance Under Uncertainty: Mitigating Benchmark and Forecast Errors

The regulatory process described above includes multiple mechanisms to manage the effects of uncertainty. First, the use of delta factors effectively mitigates the impact of forecast errors by adjusting the allowed TOTEX baseline to account for deviations from the *ex ante* network use forecast. Figure illustrates the performance of these delta factors for the simulated Denver system across the range of

8

Table ix uses the following parameters: AI = \$1.1M; σ = 59%; $WACC$ = 7.09%; $Life$ = 40 years; δ = 6.5%.

9 Table x uses the following assumptions: Cost of debt = 5.5%; gearing ratio = 35% equity/65% debt; tax rate = 35%.

uncertainty scenarios described in Tables vi and vii. Despite deviations of plus or minus 1 percentage point per year in realized load growth and 11 percent in installed PV capacity, the delta factors correct the TOTEX baseline to within 1.2 percent of the efficient network expenditures necessary to accommodate the realized evolution of network and within 0.1 percent in the majority of scenarios. As Figure 2 illustrates, the errors appear to increase non-linearly. Further research should explore the performance of these delta factors across a wider range of variation in network use and explore alternative functional forms for the regression specifying the delta factors that may further improve performance. However, even the simple delta factors employed herein substantially reduce the impacts of forecast error, maintaining efficiency incentives and ensuring the firm can recover reasonably incurred expenditures throughout the regulatory period. The use of delta factors is thus a considerable advantage for an *ex ante* regulatory approach in the face of highly uncertain changes in network uses driven by the growing penetration of DERs.

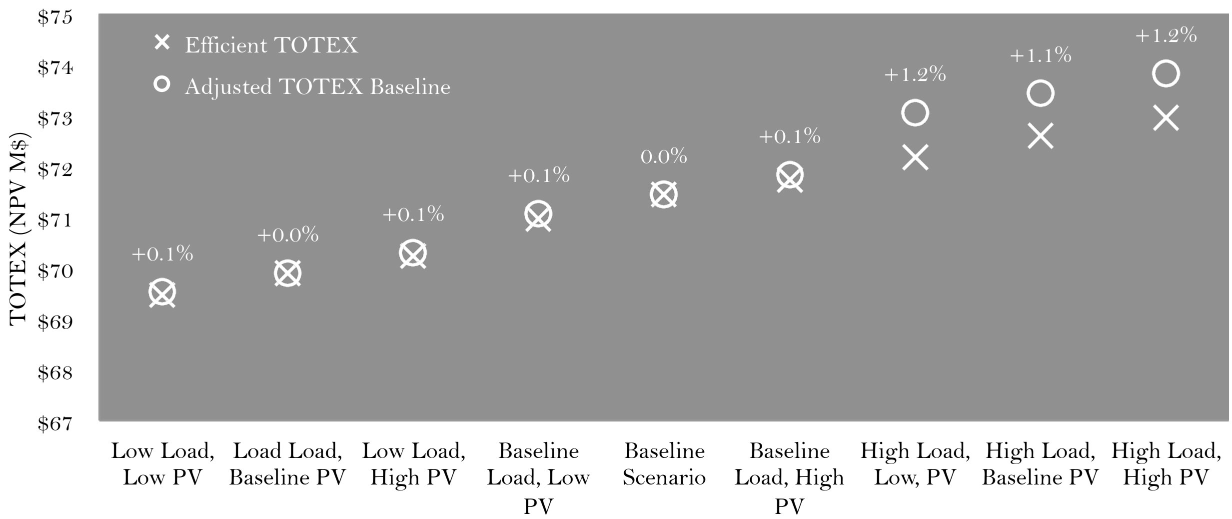

Figure 2. Performance of delta factors at mitigating forecast error: efficient TOTEX and adjusted TOTEX baseline across uncertainty scenarios[10]

While the delta factors successfully address forecast error, this regulatory process is still susceptible to benchmark error: that is, if the regulator errs in establishing their *ex ante* estimate of the efficient frontier for network costs due to a defect in the RNM or another error on the regulator's part, the TOTEX baseline may be set too high or too low, distorting efficiency incentives. Ideally, the regulator could minimize benchmark errors due to inaccuracies in the RNM by combining the regulator's benchmark with the firm's estimate of efficient TOTEX using the weighting factor, ω, used in the menu of contracts. The incentive compatibility of the menu of contracts will encourage the utility to submit

[10] Figure makes use of the following assumptions: Δ_{load} = \$0.078/kWh; Δ_{PV} = \$36.2/kW. See Tables vi & vii for load and solar PV penetration for each uncertainty scenario.

their most accurate TOTEX estimate, and if the utility's estimate proves more accurate, this would presumably mitigate benchmark errors. However, the additional income computed to ensure the incentive compatibility of the menu of contracts also depends on the weighting factor placed on the regulator's estimate (see Appendix B). This counteracts the ability of the firm's estimate to mitigate benchmark errors (see Figure). Counter-intuitively then, the weighting factor cannot help mitigate the impacts of benchmark error using this method. Fortunately, the regulator can still reduce the impacts of benchmark errors by carefully selecting the reference sharing factor parameter (SF_{ref}). As Figure illustrates, the error in allowed revenues due to benchmark error declines as the sharing factor declines (as anticipated by Schamelnsee, 1989). Regulators should thus carefully tune the sharing factor based on their confidence in the accuracy of their benchmarking techniques. Note that the remaining error in the case where the sharing factor is 0.0 is again due to the additional income parameter used to ensure the incentive compatibility of the menu of contracts. In both cases, then, the incentive compatibility of the menu of contracts is somewhat at odds with the desire to reduce sensitivity to benchmark errors. Future research should work to identify alternative methods for constructing an incentive compatible menu of contracts that does not share this feature and is less sensitive to benchmark errors.

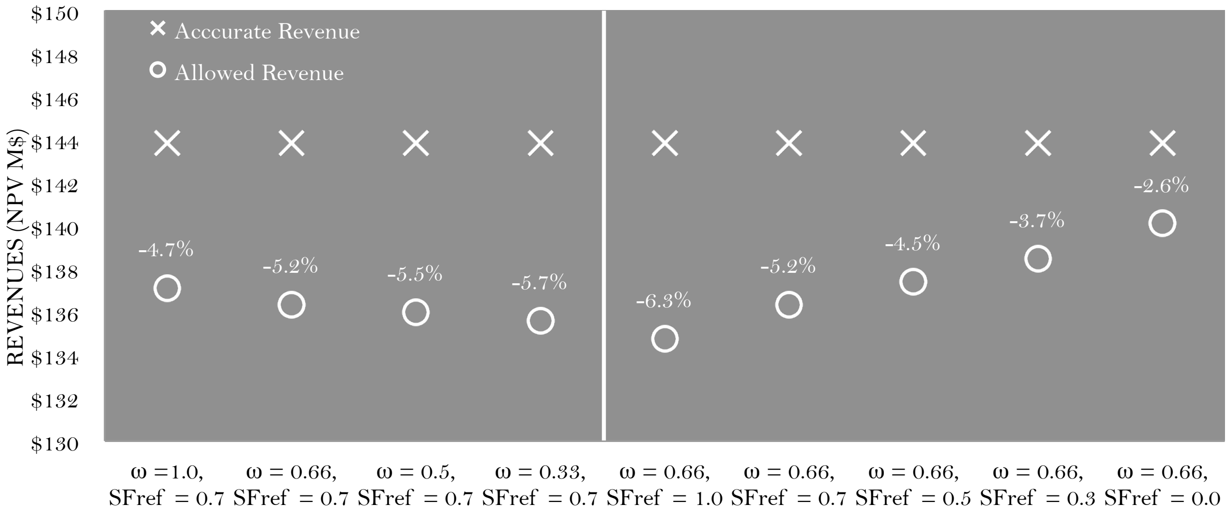

Figure 3. Impact of weighting factor and sharing factor parameters on benchmark error: effect on revenues under -10 percent error in regulator's TOTEX benchmark[11]

[11] Figure makes use of the following assumptions: SF_{roc} = -0.01; AI_{ref}= 1.0; σ = 59%; $WACC$ = 7.09%; $Life$ = 40 years; δ = 6.5%.

4 ADVANTAGES OF THE PROPOSED REGULATORY PROCESS

This paper proposes a novel regulatory process that offers several important advantages for the economic regulation of electricity distribution utilities, especially under increasing penetrations of distributed energy resources and smart grid technologies.

First, the regulatory regime proposed herein *helps overcome information asymmetry* by equipping the regulator with a reference network model (RNM). An RNM emulates the network planning practices of an efficient utility and equips the regulator with a forward-looking benchmark for efficient network expenditures that accommodates expected evolutions in network use, technology performance and costs, and network management practices. In effect, the RNM gives the regulator a tool with which to "peer into the future," a crucial ability in *ex ante* regulatory approaches. For example, RNMs have already been applied to assess the impact on distribution planning and costs due to large-scale deployment of DG and electric vehicles as well as the use of active network management (Cossent, et al., 2011; Fernández et al., 2011; Olmos et al., 2009; Vergara, et al., 2014). This forward-looking capability stands in contrast to statistical benchmarking techniques, which rely on backward-looking analysis of realized expenditures during prior regulatory periods and thus cannot capture the dynamic changes now unfolding in the electricity distribution sector. Additionally, as a reference network is constructed for each utility, using an RNM captures the heterogeneity of utility networks, a particularly important feature as DER penetration is likely to increase the heterogeneity between distribution networks. Combining the use of an RNM with an incentive compatible menu of contracts further reduces information asymmetry by incentivizing the utility to submit their most accurate estimate of future network expenditures. The incentive compatible property of the menu of contracts also *minimizes incentives for the utility to engage in strategic behavior* by inflating their estimate of necessary TOTEX, a significant advantage over other *ex ante* regulatory approaches that do not employ a menu of contracts.

Second, this regulatory process includes multiple features designed to *help regulators manage uncertainty.* The RNM can be used to explore a range of possible scenarios for the evolution of network uses (i.e., load growth and DER penetration). The results can then be used to compute delta factors, simple formulas to automatically adjust the efficient TOTEX baseline in light of the realized evolution of network use. These delta factors effectively *minimize the impacts of forecast errors*, a significant advantage given increased uncertainty about the likely evolution of network use over the coming years. Finally, by selecting the strength of the profit sharing factor, the regulator can also help *mitigate the impacts of benchmark error* (i.e., an error in the regulator's estimate of efficient TOTEX, irrespective of the evolution of network use). The lower the sharing factor, the closer the regulatory contract becomes to a cost-of-service contract, and thus the less sensitive the firm's profits are to differences in forecasted and realized costs, and *vice versa.* The regulator can thus select an appropriate sharing factor based on their confidence in the accuracy of their benchmark of efficient network expenditures.

Third, the profit sharing parameter established by the menu of contracts *creates clear incentives for the utility to seek cost-saving efficiency measures* throughout the regulatory period. This profit sharing incentive gives the utility's management and shareholders a direct stake in improving productive efficiency and thus *overcomes the moral hazard problem* that plagues cost-of-service regulation. The regulator can establish the strength of the efficiency incentives as desired through the design of the menu of contracts (i.e., setting the SF_{ref} and SF_{roc} discretionary parameters).

Fourth, the "fast money/slow money" TOTEX-based approach to capitalization of allowed *ex post* network expenditures also *equalizes incentives for the firm to optimize cost-saving tradeoffs* between network investments (CAPEX) and operational expenditures (OPEX). Without this approach, the utility may face distorted incentives that encourage over-spending on network assets *in lieu* of cost saving operational expenditures, including active system management or contracting with DER owners or aggregators to relieve system constraints. Removing this distortion and equalizing cost-saving incentives across both categories of network expenditures is thus an important step to encouraging innovative system management approaches, animating markets for distribution level system services, and incentivizing an evolution in the distribution utility business model.

Fifth, the regulator has significant flexibility and discretion to set the strength of the sharing factor parameters used to create the menu of contracts in order to *balance the fundamental regulatory tradeoffs* between allocative efficiency (extracting rents from the utility) and productive efficiency (providing incentives for cost savings). Furthermore, the incentive compatible nature of the menu of contracts will encourage firms with significant cost-saving opportunities to select a higher-powered incentive (thus improving productive efficiency) while firms closer to the efficient frontier will select a lower-powered incentive (improving allocative efficiency). Firms are thus incentivized to reveal their own cost type and actively participate in setting a regulatory contract that appropriately balances the moral hazard and adverse selection challenges.

Finally, it is important to note that this regulatory approach only considers the establishment of allowed TOTEX and the primary allowed revenues. These methods must be accompanied by appropriate incentives for the utility to maintain and improve quality of service, reduce losses, and meet other performance expectations (including customer service quality and environmental performance). See Cossent (2013), Malkin & Centolella (2013), and Ofgem (2010b, 2010c, 2013c, 2013d) for more on output or performance-based incentives for distribution utilities. Furthermore, while a well-designed menu of contracts provides strong incentives for efficiency and will encourage the utility to pursue novel and innovative approaches to network investment and management, additional, explicit incentives for long-term innovation may be necessary, including input-based incentives (such as an R&D cost passthrough), output-based incentives (financial incentives for adoption of novel technologies or practices), or competitive innovation funds (such as the UK's Low-carbon Innovation Fund). For discussion of network innovation incentives, see Bauknecht (2011), Lester & Hart (2012), Lo Schiavo et al. (2013), and Ofgem (2010c, 2013c, 2013d).

Acknowledgements

This research was supported by a National Science Foundation Graduate Research Fellowship and funding from the MIT Energy Initiative's Utility of the Future Study research consortium. See http://mitei.mit.edu/research/utility-future-study for a full list of consortium participants. Carlos Batlle and three anonymous reviewers provided valuable comments and feedback on earlier versions of this paper and Claudio Vergara provided assistance in developing the simulation methods used herein. The authors are solely responsible for the contents of this paper, including any errors.

REFERENCES

Averch, Harvey, and Leland L. Johnson. (1962). Behavior of the Firm Under Regulatory Constraint. American Economic Review, 52 (Dec.), 1052–1069.

Bauknecht, Dierk. (2011). Incentive Regulation and Network Innovations. EUI Working Papers (No. RSCAS 2011/02). Florence, Italy.

Bharatkumar, Ashwini, Scott Burger, Jesse D. Jenkins, Jorge Le Dantec, Ignacio J. Pérez-Arriaga, Richard D. Tabors, and Carlos Batlle. (2013). The MIT Utility of the Future Study: White Paper. Cambridge, MA: Massachusetts Institute of Technology. Available at https://mitei.mit.edu/system/files/UOF_WhitePaper_December2013.pdf

Conchado, Adela and Pedro Linares. (2012). The economic impact of demand-response programs on power systems. A survey of the state of the art. In A. Sorokin, et al. (Ed.), Handbook of networks in power systems. Berlin: Springer.

Cossent, Rafael. (2013). Economic regulation of distribution system operators and its adaptation to the penetration of distributed energy resources and smart grid technologies. Madrid, Spain: Universidad Pontificia Comillas.

Cossent, Rafael, and Tomas Gómez. (2013). Implementing incentive compatible menus of contracts to regulate electricity distribution investments. Utilities Policy, 27, 28–38.

Cossent, Rafael, Tomas Gómez, and Pablo Frías. (2009). Towards a future with large penetration of distributed generation: Is the current regulation of electricity distribution ready? Regulatory recommendations under a European perspective. Energy Policy, 37 (3), 1145–1155.

Cossent, Rafel, Luis Olmos, Tomas Gómez, Carlos Mateo, and Pablo Frias. (2011). Mitigating the Impact of Distributed Generation Advanced Response Options. International Transactions on Electrical Energy Systems, 21 (6), 1869–1888.

Crouch, Martin. (2006). Investment under RPI-X: Practical experience with an incentive compatible approach in the GB electricity distribution sector. Utilities Policy, 14 (4), 240–244

Denholm, Paul, Jennie Jorgenson, Thomas Jenkin, Marissa Hummon, David Palchak, Brendan Kirby, and Mark O'Malley. (2013). The Value of Energy Storage for Grid Applications The Value of Energy Storage for Grid Applications. NREL Technical Report (No. TP-6A20-58465).

Domingo, Carlos Mateo, Tomas Gómez, Alvaro Sánchez-Miralles, Jesús P. Peco, and Antonio C. Martínez. (2011). A Reference Network Model for Large-Scale Distribution Planning With Automatic Street Map Generation. IEEE Transactions on Power Systems, 26 (1), 190–197.

Eid, Cherrelle., Javier Reneses Guillén, Pablo Frías Marín, and Rudi Hakvoortis. (2014). The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives," Energy Policy, 75, 244-254.

Eurelectric. (2013). Active Distribution System Management: A key tool for the smooth integration of distributed generation. Brussels, Belgium.

Fernández, Luis P., Tomas Gómez, Rafael Cossent, Carlos Mateo Domingo, and Pablo Frías. (2011). Assessment of the Impact of Plug-in Electric Vehicles on Distribution Networks. IEEE Transactions on Power Systems, 26 (1), 206–213.

Fraunhofer ISE (2015). Energy Charts. Retrieved from https://www.energy-charts.de/index.htm

Gómez, Tomas. (2013). Electricity Distribution. In I. J. Pérez-Arriaga (Ed.), Regulation of the Power Sector. London: Springer-Verlag.

Gómez, Tomas, Ilan Momber, Michel River Abbad, and Alvaro Sánchez Miralles. (2011). Regulatory framework and business models for charging plug-in electric vehicles: Infrastructure, agents, and commercial relationships. Energy Policy, 39(10), 6360–6375.

Hurley, Doug, Paul Peterson, and Melissa Whited. (2013). Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States. Retrieved from http://www.synapse-energy.com/Downloads/SynapseReport.2013-03.RAP.US-Demand-Response.12-080.pdf

Jamasb, Tooraj, and Michael Pollitt. (2001). Benchmarking and regulation: international electricity experience. Utilities Policy, 9, 107–130.

Jamasb, Tooraj, and Michael Pollitt. (2008). Reference models and incentive regulation of electricity distribution networks: An evaluation of Sweden's Network Performance Assessment Model (NPAM). Energy Policy, 36 (5), 1788–1801.

Jamasb, Tooraj, Paul Nillesen, and Michael Pollitt. (2003). Gaming the Regulator: A Survey. The Electricity Journal, 16 (10), 68–80.

Jamasb, Tooraj, Paul Nillesen, and Michael Pollitt. (2004). Strategic behaviour under regulatory benchmarking. Energy Economics, 26 (5), 825–843.

Jenkins, Jesse. D. (2014). Economic regulation of electricity distribution utilities under high penetration of distributed energy resources: applying an incentive compatible menu of contracts, reference network model and uncertainty mechanisms. Cambridge, MA: Massachusetts Institute of Technology. Retrieved from http://dspace.mit.edu/handle/1721.1/90052

Joskow, Paul. L. (2005). Regulation of Natural Monopolies. MIT CEEPR Working Paper (No. 05-008). Cambridge, MA. Retrieved

Joskow, Paul. L. (2014). Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks. In N. L. Rose (Ed.), Economic Regulation and Its Reform: What Have We Learned. Chicago, IL: University of Chicago Press.

Kind, Peter. (2013). Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business. Washington, DC. Retrieved from http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf

Laffont, Jean-Jacques, and Jean Tirole. (1993). A Theory of Incentives in Procurement and Regulation. Cambridge, MA: MIT Press.

Lester, Richard. K., and David M. Hart. (2012). Unlocking energy innovation: how America can build a low-cost, low-carbon energy system. Cambridge, Mass.: MIT Press.

Lo Schiavo, Luca, Maurizio Delfanti, Elena Fumagalli, and Valeria Olivieri. (2013). Changing the regulation for regulating the change: Innovation-driven regulatory developments for smart grids, smart metering and e-mobility in Italy. Energy Policy, 57, 506–517.

Malkin, David, and Paul A. Centolella. (2013). Results-Based Regulation: A Modern Approach to Modernize the Grid. Atlanta, GA. Retrieved from http://www.gedigitalenergy.com/regulation/

Momber, Ilan, Tomas Gómez, and Lennart Söder. (2013). PEV Fleet Scheduling with Electricity Market and Grid Signals. In IEEE 10th International Conference on the European Energy Market (EEM), 1–8. Stockholm, Sweden.

National Renewable Energy Laboratory. (2013). Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States. Retrieved April 26, 2014 from http://en.openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states

National Renewable Energy Laboratory. (2014). PVWatts Calculator (March 2014 Beta Release). Retrieved from http://pvwatts.nrel.gov/

Ofgem. (2009). Electricity Distribution Price Control Review Methodology and Initial Results Paper. London. Retrieved from https://www.ofgem.gov.uk/publications-and-updates/electricity-distribution-price-control-review-methodology-and-initial-results-paper

Ofgem. (2010a). Electricity Distribution Price Control Review 5: Special conditions of the Electricity Distribution License. London.

Ofgem. (2010b). Handbook for implementing the RIIO model. London. Retrieved from https://www.ofgem.gov.uk/ofgem-publications/51871/riiohandbook.pdf

Ofgem. (2010c). RIIO: A new way to regulate energy networks. London. Retrieved from https://www.ofgem.gov.uk/ofgem-publications/51870/decision-doc.pdf

Ofgem. (2013b). Strategy decision for the RIIO-ED1 electricity distribution price control: Financial issues. London. Retrieved from https://www.ofgem.gov.uk/ofgem-publications/47071/riioed1decfinancialissues.pdf

Ofgem. (2013c). Strategy decision for the RIIO-ED1 electricity distribution price control: Outputs, incentives and innovation. London. Retrieved from https://www.ofgem.gov.uk/ofgem-publications/47068/riioed1decoutputsincentives.pdf

Ofgem. (2013d). Strategy decision for the RIIO-ED1 electricity distribution price control: Overview. London. Retrieved from https://www.ofgem.gov.uk/ofgem-publications/47067/riioed1decoverview.pdf

Ofgem. (2013e). Strategy decision for the RIIO-ED1 electricity distribution price control: Uncertainty mechanisms. London. Retrieved from https://www.ofgem.gov.uk/ofgem-publications/47070/riioed1decuncertaintymechanisms.pdf

Olmos, Luis, Rafael Cossent, Tomás Gómez, Carlos Mateo, Jeroen de Joode, Martin Scheepers, Frans Nieuwenhout, Jos Poot, Martijn Bongaerts, David Trebolle, Barbara Doersam, Stefan Bofinger, Umit Cali, and Norman Gerhardt. (2009). Case studies of system costs of distribution areas (No. WP 4, Deliverable 5). Petten, the Netherlands.

Pérez-Arriaga, Ignacio J., and Ashwini Bharatkumar. (2014). A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems. Center for Energy and Environmental Policy Research (CEEPR) Working Paper No. 2014-006. Massachusetts Institute of Technology, Cambridge, Massachusetts.

Pérez-Arriaga, Ignacio J., Sophia Ruester, Sebastian Schwenen, Carlos Batlle, and Jean-Michel Glachant. (2013). From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs. Florence, Italy. doi:10.2870/78510

Poudineh, Rahmatallah, and Tooraj Jamasb. (2014). Distributed generation, storage, demand response and energy efficiency as alternatives to grid capacity enhancement. Energy Policy, 67, 222–231.

Pudjianto, Danny, Marko Aunedi, Predrag Djapic, and Goran Strbac. (2014). Whole-Systems Assessment of the Value of Energy Storage in Low-Carbon Electricity Systems. IEEE Transactions on Smart Grid, 5 (2), 1098–1109.

Schisler, K., Sick, T., & Brief, K. (2008). The Role of Demand Response in Ancillary Service Markets. In IEEE Transmission and Distribution Conference and Exposition, 2008 (pp. 1–3). Chicago, IL: IEEE.

Schmalensee, Richard. (1989). Good Regulatory Regimes. The RAND Journal of Economics, 20 (3), 417–436.

Strbac, Goran, Marko Aunedi, Danny Pudjianto, Predrag Djapic, Fei Teng, Alexander Sturt, Dejvises Jackravut, Robert Sansom, Vladimir Yufit, and Nigel Brandon. (2012). Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future. Retrieved from https://www.carbontrust.com/media/129310/energy-storage-systems-role-value-strategic-assessment.pdf

Trebolle, David, Tomas Gómez, Rafael Cossent, and Pablo Frías. (2010). Distribution planning with reliability options for distributed generation. Electric Power Systems Research, 80 (2), 222–229.

Vergara, Claudio, Ignacio Perez-Arriaga, Carlos Mateo, and Pablo Frías. (2014). Estimating the Aggregate Impact of Distributed Photovoltaic Generation over Distribution Networks. IIT-Comillas Working Paper (No. IIT-14-034A). Madrid, Spain.

APPENDIX A. SIMULATING A REALISTIC URBAN ELECTRICITY DISTRIBUTION NETWORK USING A REFERENCE NETWORK MODEL

This appendix describes the process used to simulate a realistic, large-scale urban electricity distribution network for demonstrating the regulatory process proposed in this paper. In this case, the simulated network corresponds to a roughly 120 square kilometer section of Denver, Colorado. Employing the method developed in Vergara et al. (2014) and detailed in Jenkins (2014), we generate more than 27,000 individual network connection points with approximately 468 megawatts of total peak load. Network users are assigned to low, medium, or high voltage using random sampling from a trinomial distribution and then assigned a peak load (in kilowatts) and power factor by random sampling from a truncated normal distribution.[12] Each load point is then assigned to one of three customer types (residential, commercial, or industrial) by drawing from a trinomial distribution specified for each voltage level to match realistic shares of customer classes and then assigned with equal probability to one of ten distinct consumption profiles for each customer type. PV generators are likewise assigned one of six production profiles generated by the National Renewable Energy Laboratory (2014) solar PV production simulator. For each network user, profiles correspond to two non-consecutive days selected to match (1) the day of peak power withdrawal and (2) the day of peak power injection assuming penetration of photovoltaic (PV) generators in the network. These two days approximate the extremes in power flow to which the distribution network must be designed. Network users are then assigned to a specific geographic location using real street maps as a "scaffold" to constrain the location of network users and ensure a realistic network topology. The street map is first scanned and the layout of streets is recognized (Figure A.1). The layout of streets is then used as a proxy for the density of network connection points by using random sampling without replacement to assign each load point to a specific geographic coordinate along one of the recognized streets with equal probability per unit of street length (Figure A.2, left). Finally, we use the RNM discussed in Domingo et al. (2011) to construct a "greenfield" network from scratch using the location of network users as input and a standard catalog of network components (Figure A.2, right). See Jenkins (2014) for additional detail on simulation methods and parameters.

---

[12] A minimum peak power of 1 kilowatt is specified for each load point to prevent unrealistically small loads at the far "left tail" of the distribution.

Figure A.1. Street map of Denver, Colorado (at left) and resulting "scaffold" used to constrain the location of network users (at right)

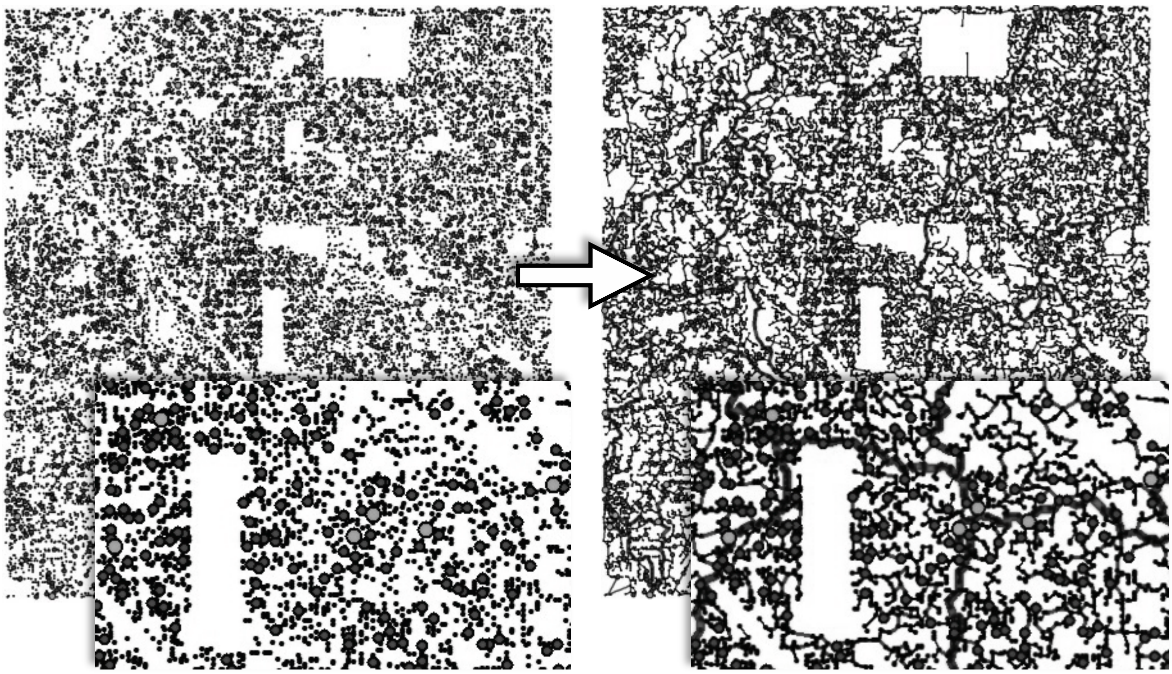

Figure A.2. Network users are assigned along the street map scaffold (at left) and the "greenfield" RNM constructs the simulated distribution network topology (at right)[13].

[13] **Error! Reference source not found.** depicts customers as dots: small for low voltage, medium for medium voltage, and large for high voltage. Distribution feeders shown as lines: thin for low and medium voltage and bold for high voltage.

APPENDIX B. FORMULAS FOR CONSTRUCTING AN INCENTIVE COMPATIBLE MENU OF CONTRACTS

Table B.i. Formulas for constructing an incentive compatible menu of contracts

(based on Cossent & Gomez, 2014)

Symbol	Description	Formula/constraint
DISCRETIONARY INITIALIZATION PARAMETERS		
$\boldsymbol{\omega}$	Weight on regulator's estimate [p.u.]	[0,1]
$\boldsymbol{SF_{ref}}$	Reference value for sharing factor [p.u. share of over/under-spend retained by firm]	[0,1]
$\boldsymbol{SF_{roc}}$	Rate of change of sharing factor with ratio	<0
$\boldsymbol{AI_{ref}}$	Reference value for additional income [% of regulator's estimate]	-
CALCULATED INITIALIZATION PARAMETERS		
$\boldsymbol{AI_{int}}$	Intercept of additional income	$AI_{ref} - 100 \cdot SF_{ref} \cdot (\omega - 0.5) = AI_{ref} - 100\alpha - 100^2 \cdot \beta$
$\boldsymbol{\alpha}$	1st order factor of additional income formula	$SF_{ref} \cdot (\omega - 1) + 100 \cdot SF_{roc} \cdot (1 - 2\omega)$
$\boldsymbol{\beta}$	2nd order factor of additional income formula	$SF_{roc} \cdot (\omega - 0.5)$
EX ANTE PARAMETERS		
$\boldsymbol{X_{firm}}$	Firm's *ex ante* TOTEX estimate [$]	Submitted by firm
$\boldsymbol{X_{reg.}}$	Regulator's *ex ante* TOTEX estimate [$]	Calculated by regulator using RNM
$\boldsymbol{\theta_{ex\ ante}}$	Ratio of firm's estimate to regulator's estimate [%]	$X_{firm} \,/\, X_{reg.}$
$\boldsymbol{X_{ex\ ante}}$	*Ex ante* allowed TOTEX baseline [% of regulator's estimate]	$100\omega + (1 - \omega) \cdot \theta_{ex\ ante}$
$\boldsymbol{SF}$	Sharing factor [p.u. share of over/under-spend retained by firm]	$SF_{ref} + (\theta_{ex\ ante} - 100) \cdot SF_{roc}$
$\boldsymbol{AI}$	Additional income [% of regulator's estimate]	$AI_{int} + \alpha \cdot \theta_{ex\ ante} - \beta \cdot \theta_{ex\ ante}^2$
EX POST PARAMETERS		
$\boldsymbol{X_{ex\ post}}$	Realized *ex post* TOTEX [$]	Submitted by firm and audited by regulator
$\boldsymbol{\theta_{ex\ post}}$	Ratio of realized *ex post* TOTEX to *ex ante* allowed TOTEX baseline [%]	$X_{ex\ post} \,/\, X_{reg.}$
$\boldsymbol{I}$	*Ex post* efficiency incentive [as % of regulator's estimate]	$(X_{baseline} - X_{ex\ ante}) \cdot SF \,/\, X_{reg}$