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Abstract

Ongoing changes in the delivery of electricity services and the use and management of electricity distribution systems – including the proliferation of distributed energy resources, smart grid technologies (i.e., advanced power electronics and information and communication technologies) and active system management techniques – present new challenges for the economic regulation of electricity distribution utilities. In particular, regulators are likely to face increased uncertainty regarding the evolution of network uses and the efficient cost of network investments and maintenance, as well as an increased informational disadvantage *vis-à-vis* the regulated utility. These challenges are important for both cost of service (or rate of return) regulation and incentive regulation approaches (also known as revenue or price cap regulation, RPI-X, performance-based regulation, or output-based regulation). This paper proposes a novel process for establishing the allowed revenues of an electricity distribution utility and demonstrates its application as a practical solution to the imminent regulatory challenges discussed above. The proposed method is a new combination of three established regulatory tools: an engineering-based reference network model (RNM) for forward-looking benchmarking of efficient network expenditures; an incentive compatible menu of contracts to elicit accurate forecasts from the utility and establish profit-sharing incentives for cost saving efficiency efforts; and *ex post* automatic adjustment mechanisms, or "delta factors," to accommodate uncertainty in the evolution of network use and minimize forecast error. Simulation of a realistic, large-scale urban distribution network is used to demonstrate, step-by-step, the practical implementation of this novel regulatory process and illustrate the advantages for the economic regulation of electricity distribution utilities under increasing penetration of distributed energy resources and smart grid technologies.

Keywords: Economic Regulation, Electricity Distribution, Network Utilities, Monopoly Regulation, Remuneration, Menu of Contracts, Reference Network Model

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Introduction

Ongoing changes in the delivery of electricity services and the use and management of electricity distribution systems – including the proliferation of distributed energy resources, smart grid technologies (i.e., advanced power electronics and information and communication technologies) and active system management techniques – present new challenges for the economic regulation of electricity distribution utilities. In particular, regulators are likely to face a range of new cost drivers and new uses of the system, increased uncertainty regarding the evolution of network uses and the efficient cost of network investments and maintenance, as well as an increased informational disadvantage *vis-à-vis* the regulated utility. These challenges are important for both cost of service (or rate of return) regulation and incentive regulation approaches (also known as revenue or price cap regulation, RPI-X, performance-based regulation, or output-based regulation). This paper proposes a novel process for establishing the allowed revenues of an electricity distribution utility and demonstrates its application as a practical solution to the imminent regulatory challenges discussed above.[1]

Section 1 introduces the key challenges in the economic regulation of electricity distribution utilities, including incomplete and imperfect information, uncertainty, opportunities for strategic behavior on the part of the regulated utility, and inherent tradeoffs between maximizing X-efficiency and allocative efficiency. The section then describes how these challenges will be exacerbated by the ongoing evolution of the delivery of electricity services and increasing penetration of distributed energy resources and smart grid technologies.

Section 2 introduces an improved regulatory process for establishing allowed revenues for distribution utilities. The proposed method is a new combination of three established regulatory tools: an engineering-based reference network model (RNM) for forward-looking benchmarking of efficient network expenditures; an incentive compatible menu of contracts to elicit accurate forecasts from the utility and establish profit-sharing incentives for cost saving efficiency efforts; and *ex post* automatic adjustment mechanisms, or “delta factors,” to accommodate uncertainty in the evolution of network use and minimize forecast error. Next, simulation of a realistic, large-scale urban distribution network is used to demonstrate the practical implementation of this novel regulatory process and illustrate the advantages for the economic regulation of electricity distribution utilities under increasing penetration of distributed energy resources.

1 This paper is adapted from Jenkins, J.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.” (Masters Thesis). Massachusetts Institute of Technology. Available at: http://bit.ly/JDJenkinsThesis

1. Regulatory Challenges Under High Penetrations of Distributed Energy Resources and Smart Grid Technologies

1.1. Introduction to the Economic Regulation of Electricity Distribution Utilities

Electricity distribution is a natural monopoly activity. The combination of economies of scale, subadditive firm costs, and significant barriers to entry make electric distribution activities a poor candidate for market competition, thus requiring regulatory intervention to prevent monopoly abuse of market power (Cossent, 2013; Gómez, 2013a, 2013b; Joskow, 2005).

As such, distribution utilities have historically been subject to various forms of economic regulation and, along with transmission network activities, remain a regulated sector even in electricity markets that have undergone privatization and/or deregulation of generation or retail activities. Indeed, effective regulation of electricity network utilities is a critical cornerstone of any well-functioning, competitive market segments and has important welfare consequences for electricity consumers and society regardless of market structure (Joskow, 2013).

The economic regulation of electricity distribution utilities involves two key tasks: first, the regulator must determine the sum of revenues the regulated utility is allowed to collect to fairly remunerate their operating and investment costs (the cost recovery or remuneration challenge); and second, the regulator must determine how the utility should collect these revenues from their network users (the cost allocation or tariff design challenge). While both are key regulatory activities, this paper focuses exclusively on the first of these tasks, which entails establishing the principal financial incentives for the regulated firm.[2]

Determining the allowed revenues or remuneration of distribution utilities must confront several regulatory challenges. First, the regulator does not know the utility's cost or service quality opportunities *ex ante*, nor can the regulator directly observe the utility's managerial effort to capture efficiency opportunities (Joskow, 2013; Laffont & Tirole, 1993). As a result of this *incomplete information*, the utility knows much more about their cost opportunities than the regulator, introducing considerable *information asymmetries*. In addition, the regulator must assess the prudence and efficiency of capital-intensive utility investments with relatively long asset lives (often measured in decades). This introduces additional challenges associated with *uncertainty* about future technological change and demand for network services. Together, these challenges create a significant opportunity for *strategic behavior* on the part of the regulated utility, wherein the firm uses its information advantage in the regulatory process to increase its allowed revenues and profits or achieve other managerial objectives (Averch & Johnson, 1962; Jamasb, Nillesen, & Pollitt, 2003, 2004; Joskow, 2013; Laffont & Tirole, 1993). In particular, the firm would like to convince the regulator that it is a higher cost firm than it really is, taking advantage of the regulator's need to comply with the *firm participation constraint* (e.g., ensure the financial viability of the regulated firm).

2 For discussion and proposed solutions for the cost allocation or tariff design challenge, see Pérez-Arriaga, I. & Bharatkumar A. (2014).

Regulators have adopted a variety of approaches to confront these challenges and balance tradeoffs between incentivizing managerial effort by creating financial incentives for the firm to pursue cost savings on the one hand and minimizing economic rents collected by the utility from ratepayers on the other hand (Cossent, 2013; Joskow, 2013). In economic terms, this is a tradeoff between productive efficiency or "X-efficiency"—that is, ensuring firms are optimizing their production functions to minimizing the inputs used to produce a given level of output—and allocative efficiency—that is, ensuring prices reflect costs and social welfare is maximized by eliminating deadweight losses due to monopoly abuse of market power.

Two general approaches to the regulation of network utilities have emerged, which, in their "pure" form, reflect alternative approaches to this tradeoff between X-efficiency and allocative efficiency.

Cost of service regulation (or rate-of-return regulation) is essentially a "cost-plus" contract negotiated between the regulator (on behalf of ratepayers and society) and the utility (Gómez, 2013b), wherein the regulator sets allowed revenues to equal realized costs plus a regulated rate of return. Since revenues are aligned with realized costs through frequent *ex post* reviews and adjustments and returns are limited, cost of service regulation mitigates the impact of uncertainty. In addition, cost of service can readily ensure firms remain financeable (i.e., meet the firm participation constraint). Finally, if the rate of return is set efficiently (i.e., high enough to attract sufficient investment into the sector and not too high so as to charge ratepayers more than necessary), this regulatory approach also maximizes allocative efficiency. The tradeoff inherent to a pure cost of service approach is that regulated firms have little-to-no incentive to pursue cost saving efficiency efforts, leading to an unmitigated moral hazard and significant X-inefficiency.

Incentive regulation (also known as price cap, revenue cap, or performance regulation) takes the opposite approach. The regulator caps allowed revenues or prices *ex ante* for a set period (e.g., 3-8 years). Firm profitability and returns on investment thus depend on the utility "beating the cap"—that is, reducing realized costs below the price or revenue cap. This approach eliminates the moral hazard problem and creates a high-powered incentive for the exertion of managerial effort to optimize X-efficiencies (Beesley & Littlechild, 1989; Laffont & Tirole, 1993). The tradeoff is significant exposure to uncertainty and the potential for substantial rents to be left to the utility, reducing allocative efficiency.

While the "pure" forms of cost of service and incentive regulation appear to occupy opposite approaches to the fundamental tradeoffs facing the regulator, in practice, the actual implementation of either approach tends to be less diametrically opposed. Both the potential to disallow recovery of imprudently incurred costs and lags between rate cases introduce some incentives to improve X-efficiency into cost of service regulation. A the same time, incentive regulation involves periodic "ratchets" of the revenue or price cap, which after a fixed period of time, realign revenues with the utility's actual costs, thus effectively transferring the economic savings due to exertion of managerial effort from the firm back to ratepayers and improving allocative efficiency.

Indeed, theoretical developments indicate that the preferable regulatory mechanism is a balance between a pure cost of service approach and a pure revenue cap incentive approach. This approach takes the form of a *sliding scale* regulatory mechanism in which allowed revenues are partially fixed *ex ante* so as to create incentives for cost reduction and improved X-efficiency and partially responsive *ex post* to changes in realized costs to improve rent extraction and allocative efficiency and mitigate uncertainty (Gómez, 2013b; Joskow, 2013; Schmalensee, 1989). This regulatory regime effectively shares profits and rents as well as risks between the utility and ratepayers based on a profit-sharing factor (or efficiency incentive rate) between 1.0 (corresponding to a pure price/revenue-cap incentive regulation) and 0.0 (corresponding to a pure cost of service approach). The regulator can choose the precise sharing factor to manage tradeoffs between incentives for efficiency and rent extraction and manage uncertainty about future costs and demand. In particular, under lower levels of uncertainty, a higher profit-sharing factor (i.e., the firm is exposed to most of the risks and rewards of cost savings) performs better, while a lower profit-sharing factor (which shares most risks and rewards with ratepayers) performs better under higher levels of uncertainty (Schmalensee, 1989).

Furthermore, the regulator can improve on a single profit-sharing factor by offering a regulated utility *a menu of regulatory contracts* with a continuum of different sharing factors (Cossent & Gómez, 2013; Laffont & Tirole, 1993). This menu of contracts allows the firm to play a role in selecting the strength of the incentives for cost saving. If constructed correctly, this menu will establish "incentive compatibility"—that is, the design of the menu ensures that a profit-maximizing firm will always be better off (i.e., earn the greatest profit and return on equity) when actual expenditures match the firm's *ex ante* estimate of necessary expenditures. Incentive compatibility thus eliminates incentives for firms to artificially inflate their cost estimates while rewarding firms for revealing their true cost types to the regulator, helping minimize strategic behavior and overcome information asymmetries. Furthermore, a profit-motivated firm with less opportunity to reduce costs will choose a low-powered incentive, while a firm with large efficiency opportunities will choose a high-powered incentive, helping manage the tradeoffs between X-efficiency and allocative efficiency. Despite strong theoretical advantages, the use of a menu of regulatory contracts in the regulation of electricity distribution utilities has been very limited in practice (see Cossent & Gómez, 2013; Cossent, 2013; Crouch, 2006; Joskow, 2013; Ofgem, 2009, 2010b, 2013c).

Regulators can further reduce information asymmetries and improve regulatory outcomes by adopting both *regulatory accounting system*s, which systematically collecting data from regulated firms regarding their costs, assets, performance indicators, and other information needed in the regulatory process (Cossent, 2013), and *benchmarking techniques*, which compare the utility's actual costs and performance to a reference or benchmark of efficient performance (Cossent, 2013; Gómez, 2013b; Jamasb & Pollitt, 2001, 2003).[3] For example, regulators can employ *engineering reference or norm models* to construct an ideal or efficient representative

3 Other approaches to benchmarking include comparing a firm's performance to the actual performance of one or more similar firms (known as "yardstick competition") or to an estimate of efficient performance derived through statistical analysis of the measured performance of a large number of similar firms ("frontier benchmarking"). See Cossent (2013) and Jamasb & Pollitt (2001, 2003) for reviews.

firm, which can be compared to the performance of the actual regulated firm (Cossent, 2013; Domingo, et al., 2011; Jamasb & Pollitt, 2008).[4]

1.2. Regulatory Challenges in an Evolving Electricity Distribution Sector

Regardless of which regulatory approach is implemented, the increasing penetration of distributed energy resources (including distributed generation and storage, demand response, and electric vehicles), "smart grid" technologies (i.e., advanced power electronics and information and communication technologies), and active distribution system management techniques raises new challenges for the regulation of electricity distribution utilities.

These new regulatory challenges stem primarily from the impacts of distributed energy resources (DER) on power system operations and electricity market structure, as well as new capabilities for distribution system management enabled by smart grid technologies.

Distributed generation (DG), for example, increases competition for centralized generation sources and can upend the traditional top-down, unidirectional flow of power in transmission and distribution systems. Multi-directional power flows across distribution networks may soon be the norm in many jurisdictions,[5] and new opportunities are emerging for the decentralized provision and trade of electricity services.

Distributed storage (DS) could entail profound changes to the real-time operation of electric power systems. Cost-effective and scalable electrical or thermal storage technologies would offer a buffer between system supply and demand, new ways to provide ancillary services to network operators, and opportunities to temporally shift energy supply to maximize the value of energy production and meet peak demands (Denholm, et al., 2013; Pudjianto, et al., 2014; Strbac, et al., 2012).

Demand response (DR), time-varying rates, and advanced metering infrastructure are making electricity loads more responsive to economic and operational signals than ever before (Hurley, Peterson & Whited, 2013). DR has also become an important resource in markets for energy, capacity, and ancillary services (Schisler, Sick & Brief, 2008). Conversely, the proliferation of customer-owned DG, particularly variable distributed solar and wind technologies, may make generation less controllable and predictable, making enhanced visibility and monitoring of DG,

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4 Using a combination of engineering models and optimization methods, these methods can construct a realistic, efficient reference network, including estimated investment and maintenance costs as well as energy losses and quality of service levels, taking into account the particularities of the real regulated firm's service territory (i.e., the location and profiles of network users, cost and performance of available technology components, and geographic constraints on network layout). The key parameters of this reference network can then be employed as indicators of efficient performance for the real, regulated firm.

5 For example, as of September 2014, more than one-third of residential feeders in Hawaiian Electric Company's service territory have installed peak DG capacity (mostly solar PV) equal to or greater than the minimum daytime load on those circuits, indicating frequent potential for reverse power flows across LV/MV substations (HECO, 2014; Yost, 2014). Similarly, as of April 2013, 29 percent of MV/HV substations in Enel's Italian service territory experience reverse power flows at least 1 percent of the year while 21 percent of substations experience reverse flows 5 percent of the year or more (Lama, 2013). Bidirectional power flows are increasingly common in other jurisdictions as well, including California, Germany, Spain, and elsewhere.

loads, and network components and active management of distribution systems increasingly important (Cossent, et al., 2011; Eurelectric, 2013).

Widespread adoption of electric vehicles (EVs) would constitute an important new class of electricity system users and loads. Efficient price signals and/or new control systems will be essential to manage and coordinate EV charging and potential “vehicle-to-grid” services (Momber, Gómez & Söder, 2013). The need to coordinate EV charging schedules may give rise to new business models and market actors (Gómez, et al., 2011), while new network investments must accommodate and enable EV users (Fernández, et al., 2011).

Last, but perhaps most significantly, a cost-effective combination of DG, DS, DR and EVs—whether in the format of an autonomous or semi-autonomous physical microgrid or as a virtual decentralized aggregation of each of these components—may challenge the current centralized paradigm of the electric utility, initiating a transition towards a more decentralized structure and organization of the power sector (Kind, 2013; Newcomb, Lacy & Hansen, 2013; Bronski, et al., 2014).

Together, these new technologies and capabilities are leading to the emergence of innovative business models utilizing distributed energy systems, or DESs—systems combining one or more DERs with ICT capabilities to deliver value to electricity end-users, market actors, and/or system operators (Bharatkumar et al., 2014)—which may further transform the landscape of electricity markets.

In combination, these changes to system operation and market structure may be at least as profound as the wave of industry restructuring, liberalization, and regulatory reform that spread across numerous jurisdictions during the 1980s and 1990s[6] (Bushnell & Borenstein, 2000; Pérez-Arriaga, 2013). The ongoing evolution of the delivery of electricity services will entail new customer demands and uses for the distribution system, new DER and smart grid-related cost drivers for the utility, and new opportunities to harness emerging technologies and services to reduce distribution system costs and improve quality of service. These changes will exacerbate several of the fundamental regulatory challenges described in Section 1.1 and will confront regulators employing both cost of service and incentive approaches to the economic regulation of distribution regulation.

1.2.1. New cost drivers, uses of system, and opportunities to reduce costs and improve performance

Firstly, the evolution of the delivery of electricity services described above will entail several new cost drivers for electricity distribution utilities, as well as new demands and changing uses of the distribution system. Utilities will need to make substantial investments to accommodate new classes of users, such as DG and EVs. Large-scale penetration of DERs within distribution utilities networks will likely increase the total costs of business-as-usual management of the distribution system (that is, a continued “fit-and-forget” grid management strategy) (Cossent, Gómez, &

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6 Earlier reforms include the restructuring of the Chilean electricity market in 1981, introduction of independent power producers in the United States via the Public Utilities Regulatory Policy Act (PURPA) of 1978.

Frías, 2009; Cossent et al., 2011). Substantial future investments will be required to fulfill the distribution utility's open access requirements and connect new DER system users as well as to enable the system to deal with bidirectional power flows, potentially increased volatility in peak demand, and new DG-related system peaks at various voltage levels. In many jurisdictions, these new investment needs will coincide with substantial expenditures necessary to modernize aging distribution systems,[7] install advanced metering infrastructure, and take advantage of the capabilities provided by new smart grid technologies. The growth of DERs will also place new demands on utilities, creating new customer classes with different needs while changing use of system patterns. At the same time, DERs can heighten competition for distribution utilities (Bharatkumar, et al., 2014), offering new ways to deliver electricity services to end-users that reduce their dependence on the grid or even bypass it entirely (Bronski, et al. 2014). Both new demands and increased competition will therefore require distribution utilities to focus on delivering improved outputs at a competitive cost.

Under cost of service regulation, it will likely be difficult for utilities to respond to new demands while taking full advantage of the capabilities provided by DER and smart grid technologies. Cost of service regulation's focus on the prudence of *inputs* makes it challenging for utilities to respond to evolving demands for *outcomes* or focus on delivering improved *performance,* such as enhanced resiliency or access for distributed resources to sell services to system operators or wholesale markets (Malkin & Centolella, 2013). Traditional cost of service regulation generally requires utilities meet minimum performance levels, but provides little incentive or reward for utilities that deliver a higher quality of service or new outcomes and services.

At the same time, cost of service regulation provides weak incentives for utilities to take full advantage of cost-saving opportunities made available by DER and smart grid technologies and active system management techniques. Utilities only profit from any realized savings until the next rate-case, when regulators will reset rates to align with the cost of providing service. Utilities are thus encouraged to focus primarily on short-term cost savings, sacrificing the opportunities that could be unlocked if utilities were incentivized to invest with a longer-term view. In addition, this approach requires regulatory review of expenditures associated with thousands of individual distribution system assets,[8] which has always posed an expensive challenge for regulatory commissions with limited staff and resources (Gomez, 2013a). 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 all but the most obviously imprudent or wasteful investments, further weakening incentives for firms to manage X-efficiency. While cost of service can ensure adequate cost recovery for utilities, the moral hazard problem will thus be compounded.

Finally, the backwards-looking nature of cost of service regulation introduces substantial regulatory risk for utilities in an actively evolving marketplace that can impede utility efforts to innovate and take advantage of new technologies and capabilities. In reviewing the prudence of

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7 The American Society of Civil Engineers estimates that simply maintaining the existing infrastructure of U.S. electricity utilities will require $673 billion in new investment by 2020 (American Society of Civil Engineers, 2011).

8 The large number and variety of distribution system assets is in contrast to the relatively large and discrete investments made by transmission network companies or generation companies prior to restructuring.

utility investments, regulators typically rely on the incremental development of established best practices with the implicit assumption that the past is an appropriate guide for the future. As such, traditional regulation frequently requires utilities to justify novel investments and departures from established practices by proving that such changes will result in a net reduction in utility costs (Malkin & Centolella, 2013). If a utility adopts a novel technology that fails to perform as expected, regulators may disallow cost recovery. As a result, utilities are often slow to adopt innovative technologies and practices and may instead go through a protracted cycle of internal testing and performance validation, regulatory approval for small-scale pilot projects, collection of data and assessment of pilot results, presentation of results to regulators, and finally, after many years, system-wide adoption of improved technologies or practices. Cost of service regulation can thus present a major barrier to the evolution of distribution utilities in light of both changing customer needs and new DER and smart grid technology capabilities.

Incentive regulation is also challenged by the evolving nature of the electricity marketplace. The emergence of new cost drivers and changing customer needs make it increasingly difficult to establish an effective *ex ante* revenue (or price) cap. Regulators often employ statistical frontier benchmarking and yardstick approaches to assist them in establishing *ex ante* estimates of efficient network costs. Yet as network uses and drivers of cost rapidly evolve, benchmarking based on past utility performance or cost will no longer provide an accurate estimate of the forward-looking efficient frontier. At the same time, the growth of DG can introduce much more heterogeneity between distribution network costs, further challenging statistical benchmarking approaches (Cossent, 2013). For example, the availability of solar, wind, biomass/biogas, and combined heat and power resources differs substantially from location to location and is likely to lead to divergent evolution of distribution networks in different regions. Without improved, forward-looking tools to assist in accurately estimating efficient network costs, regulators may set *ex ante* revenues that are poorly aligned with realized costs, leading to either substantial rents and reduced allocative efficiency (if revenues are too generous) or increased risk that firms will not be able to adequately finance necessary investments (if revenues are too low).

In addition, as the sector evolves, distribution utilities are likely to develop more intimate and immediate knowledge about new cost drivers and opportunities than the regulator, heightening information asymmetries and creating new opportunities for strategic behavior. Tools to overcome the regulator's information disadvantages will thus become even more critical for effective incentive regulation.

In summary, regulators must be equipped with forward-looking tools to identify the impacts of new DER-related network uses on distribution costs and overcome information asymmetries. in addition, regulators need remuneration mechanisms that both incentivize utilities to accommodate DERs *and* take advantage of new DER or smart grid opportunities to improve cost and performance outputs. As always, regulators must also ensure firms can raise necessary debt and equity to finance needed investments (i.e. meet firm participation constraint).

1.2.2. Increased uncertainty about the evolution of network needs, cost drivers, and opportunities

Changes in the delivery of electricity services and growth of DER will also increase uncertainty about the evolution of distribution cost drivers and network uses. For example, while solar photovoltaics (PV) generated less than 1 percent of Germany's electricity needs in 2008, PV met nearly 6 percent of German demand in 2013, just five years later (Wirth, 2014). While this rapid growth was driven in large part by generous policy support, it is indicative of the rate at which DER penetration can increase, whether driven by policy, improved economics, or a combination thereof.

Cost of service approaches can address this heightened uncertainty through more frequent *ex post* reviews or "rate cases" as cost drivers and network uses evolve. However, managing uncertainty in this manner comes at a cost: an even greater reduction in incentives for cost savings. Assured of cost recovery in this manner, utilities will be unlikely to pursue the cost saving opportunities presented by new DER and smart grid capabilities. In sum, traditional cost of service regulation can manage uncertainty and ensure adequate cost recovery for the utility but at the expense of substantial declines in X-efficiency and higher costs for network users in the long-term.

Heightened uncertainty presents a more fundamental challenge to incentive regulation. As uses of the network and the new technologies available to utilities may evolve quite rapidly, network costs may deviate substantially from *ex ante* regulatory estimates, leading to two types of error: forecast error and benchmark error. Costs may rise or fall unexpectedly due to new network uses (e.g., the rapid penetration of newly subsidized or newly cost competitive DG), an example of forecast error. Alternatively, the regulator may fail to anticipate the emergence of new cost saving technologies or practices within the regulatory period that shift the efficient frontier, leading to benchmark error. In either case, regulators employing *ex ante* remuneration methods may be at greater risk of either violating the firm participation constraint if cost recovery is too low or leaving significant economic rents to the utility by being too generous in setting the *ex ante* revenue cap. More frequent *ex post* reviews and adjustments to remuneration levels can address these challenges, but again, at a cost. Frequent *ex post* revisions of remuneration levels and "re-openers" of the regulatory contract can create significant regulatory uncertainty and thus may raise the cost of capital for distribution utilities as well as potentially undermining efficiency incentives.

Regulators therefore need new tools to manage uncertainty and ensure adequate cost recovery and firm participation while preserving regulatory certainty and incentives for cost reduction and X-efficiency.

1.2.3. Heightened trade-offs between CAPEX and OPEX

Finally, the emergence of DER and smart grid capabilities will heighten tradeoffs between capital expenditures (CAPEX) and operational expenditures (OPEX) in distribution utility operations. For example, distribution utilities can achieve important cost savings by adopting an active system management approach, especially as DG shares increase (Cossent et al., 2009, 2011; Eurelectric, 2013; Olmos et al., 2009; Poudineh & Jamasb, 2014; Trebolle, et al., 2010). Setting up ICT and advanced grid management infrastructure that allows distribution utilities to more actively manage distribution network configuration and make use of DESs for their daily grid operations will entail substantial upfront CAPEX. However, such investments will in turn enable distribution utilities to increasingly contract with or procure system operation services from DER owners or aggregators, including CAPEX deferral, volt-var support, loss reduction, congestion management, or reliability improvement (Poudineh & Jamasb, 2014; Trebolle et al., 2010). These contractual arrangements or new markets for system services can increase utility OPEX while reducing CAPEX. Alternatively, CAPEX related to new smart grid capabilities can enable improved workforce and reduce truck rolls, leading to OPEX savings. In short, the most efficient tradeoff between CAPEX and OPEX is likely to change significantly and evolve over time. Both traditional cost of service and incentive approaches to regulation will need to be updated to fully exploit new opportunities to effectively balance increasingly important tradeoffs between these two expenditure categories.

Under cost of service regulation, utilities traditionally only earn a regulated return on capital investments.[9] Allowed returns are calculated based on the utilities "rate base" or regulated asset value (RAV) which includes the cumulative, non-depreciated share of capitalized expenditures. Under cost of service regulation, utilities can thus be discouraged from reducing CAPEX, as this may impact their rate base and allowed returns. At the same time, the intrinsically poor incentives for cost saving under cost of service approaches make it unlikely that firms will fully exploit the most efficient tradeoffs between capital and operational expenditures.

While incentive regulation will reward firms for efficiently reducing total costs, traditional incentive regulation can also distort incentives between savings achieved via reductions in CAPEX versus OPEX. While incentive regulation will reward the utility equally for saving a dollar of CAPEX or a dollar of OPEX, if only CAPEX is capitalized into the utility's revenue base, then that 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 shareholders. This decline in net profit will offset some portion of the efficiency-related income, distorting tradeoffs between OPEX and CAPEX and potentially encouraging over-investment (Ofgem, 2009, 2013b).

Regardless of which regulatory approach is used, regulators therefore need mechanisms to equalize incentives for CAPEX and OPEX savings and ensure utilities fully exploit these opportunities.

9 In part to address the issues discussed in this section, some regulators employing cost of service approaches allow utilities to capitalize a portion of their operational expenditures. This practice is the exception not the rule however.

2. New Solutions for the Regulation of Electricity Distribution Utilities

To address the combination of challenges described in Section 1, regulators can employ a novel combination of three established best practices or “state of the art” regulatory tools: an engineering-based reference network model (RNM) for forward-looking benchmarking of efficient network expenditures (Cossent, 2013; Domingo et al., 2011); an incentive compatible menu of contracts to elicit accurate forecasts from the utility and create incentives for cost saving efficiency efforts (Cossent & Gómez, 2013; Cossent, 2013; Crouch, 2006); and *ex post* automatic adjustment mechanisms, or “delta factors,” to accommodate uncertainty in the evolution of network use and minimize forecast error.[10]

The proposed regulatory process involves *ex ante* calculation of allowed revenues and establishment of clear rules for annual *ex post* evaluations of actual expenditures and adjustments to final allowed revenues, incorporating qualities of both cost of service and incentive regulation. Allowed revenues are partially fixed *ex ante* so as to provide strong incentives for the regulated utility to implement cost saving measures and improve X-efficiency. At the same time, final allowed revenues are partially responsive *ex post* to changes in realized costs to improve rent extraction and allocative efficiency and to mitigate uncertainty. This regulatory process also equalizes efficiency incentives across operational and capital expenditures (OPEX and CAPEX), and mitigates the impacts of uncertainty on both ratepayers and the regulated firm. In addition, the proposed methods equip the regulator with powerful tools to overcome their informational disadvantages *vis-à-vis* the regulated firm and minimizes incentives for the firm to engage in strategic behavior during the regulatory process.

Using a simulated large-scale urban distribution network (described in Section 2.1), this section introduces and provides a step-by-step demonstration of this novel regulatory process (Section 2.2).

2.1. Simulating a Large-scale Urban Distribution Network for Demonstration of the Regulatory Process

To demonstrate the regulatory process proposed herein, this paper simulates a realistic, large-scale urban distribution network. The methodology employed for this simulation was originally developed in Vergara, et al., (2014) and employs the reference network model (RNM) described in Domingo et al., (2011). This paper modifies and extends these methods to create a realistic simulated network for a roughly 120 square kilometer (km-sq) section of Denver, Colorado, encompassing more than 27,000 individual load points and approximately 468,000 kilowatts (kW) of peak load (see Table 1). Several scenarios for the growth of this network are also simulated, capturing the network expansion, reinforcements, and maintenance costs necessary

10 This general method is first proposed in Cossent (2013a) Chapter 5 and Cossent and Gómez (2013) and is developed further herein, including demonstration of implementation of the proposed method. The methods herein, particularly the menu of contracts approach, also draw on the practical experience of the UK Office of Gas and Electricity Markets (Ofgem), as published in Ofgem (2009, 2010b, 2013a, 2013b, 2013c) and related methods. The use of annual automatic adjustment factors to account for deviations from forecasted load growth and other network uses is also demonstrated.

to accommodate a range of possible increases in loads and the penetration of distributed solar photovoltaic (PV) generators.

TABLE 1: CHARACTERISTICS OF SIMULATED NETWORK

Location				**Denver, Colorado**	
Simulation area				120.3	km-sq
Population density				1,580.5	persons/km-sq
Estimated population				190,187	Persons
Estimated load power density – Base network				3,890	kW/km-sq
Estimated peak power demand – Base network				468,079	kW
Load Points – Base Network					
	LV	**MV**	**HV**	**Total**	
Industrial	0	212	42	254	
Commercial	6,263	1,274	63	7,600	
Residential	18,788	637	0	19,425	
Total	25,051	2,123	105	27,279	

2.1.1. Defining network user profiles and assigning geographic locations

The creation of the simulated distribution system begins with the specification of key simulation parameters describing the composition and characteristics of network users (loads and DG) and other characteristics of the network, summarized in Table 2. The load power density parameters are based on the population density of the simulation location,[11] while the total load density is then allocated across voltage levels as follows: 32 percent low-voltage (LV), 45 percent medium-voltage (MV), and 22 percent high-voltage (HV).[12] LV customers are connected at 240 volts (V), MV customers are 12 kV, and HV customers are connected at 33 kV.

11 The population density of Denver is 1,580.5 persons per km-sq (U.S. Census Bureau, 2011) and there are 2.3 persons per habitation in the city (U.S. Census Bureau, 2014). At an average peak demand of 1.84 kilowatts (kW) per habitation, consistent with the typical residential customer served by Xcel Energy, the distribution utility serving Denver, this yields a residential demand density of 1,249 kW per km-sq. Residential customers make up 32 percent of Xcel Energy's Colorado retail electricity sales (U.S. Energy Information Administration, 2012), so the residential demand density is scaled up to account for non-residential loads, leading to a total load power density of 3,890 kW per km-sq.

12 Data was unavailable on the actual allocation of power density at each voltage level for Xcel Energy's service territory. These values were selected to match the share of residential, commercial, and industrial loads in Xcel's Colorado territory (U.S. Energy Information Administration, 2012), using residential loads as a proxy for LV customers, commercial loads as a proxy for MV customers, and industrial loads as a proxy for HV customers. Note that an estimated 7 percent of Xcel Energy's Colorado customers reside in the 120 km-sq region of Denver encompassed by this simulated network (data derived from Navigant Consulting, 2010). The estimated power density derived above yields a total peak power demand of 468,079 kW in the simulated network, which is also 7 percent of Xcel's actual total summer peak demand (ibid.), verifying that this method yields a realistic power demand density.

TABLE 2: NETWORK USER PARAMETERS FOR SIMULATED NETWORK

Parameter	Unit	LV	MV	HV
Load power density	kW/km-sq	1,249	1,765	876
Load point average power	kW	6	100	1,000
Load average power factor	p.u.	1	1	1
Load StDev power	p.u.	0.28	0.2	0.2
Load StDev energy	p.u.	0.28	0.2	0.2
Load StDev PF	p.u.	0.1	0.125	0.2
PV average power	kW	12	200	2,000
PV average capacity factor	p.u.	0.19	0.20	0.21
PV average PF	p.u.	1	1	1
PV StDev power	p.u.	0.2	0.2	0.2
PV StDev capacity factor	p.u.	0.1	0.1	0.1
PV StDev PF	p.u.	0	0	0

The average peak power and power factor for each individual load or DG in the simulation is determined by random sampling from a truncated normal distribution[13] with mean and standard deviation specified for each voltage level as in Table 2. The average power for each load point are set to be representative of typical LV, MV, and HV customers in Denver.[14] The average power factor for each load point is set to 1.0. Peak power is assumed to vary more significantly for lower voltages, while power factor varies more significantly at higher voltages.

Three types of loads are considered by this simulation: residential, commercial, and industrial loads. Load points are divided among these customer types based on the shares specified for each voltage level in Table 3, and each load point is assigned one of ten different 48-hour load profiles for each customer type (Figures 1-3). The shares of loads by customer type were selected to ensure that the share of total annual electricity consumption for industrial, commercial, and residential consumers in the simulated network closely matches the real distribution of retail electricity sales in Colorado.[15] Load profiles for residential and commercial customers are derived from simulated hour-by-hour annual load profile data from Department of Energy (DOE) reference building models and correspond to TMY3 meteorological database

13 A minimum peak power of 1 kW is specified for each load point to prevent unrealistically small loads at the far “left tail” of the distribution.

14 Xcel segments commercial and industrial customers into three classes based on peak contracted demand: less than 25 kW; 25-200 kW; and greater than 200 kW. This paper assumes these values correspond to LV, MV, and HV connections.

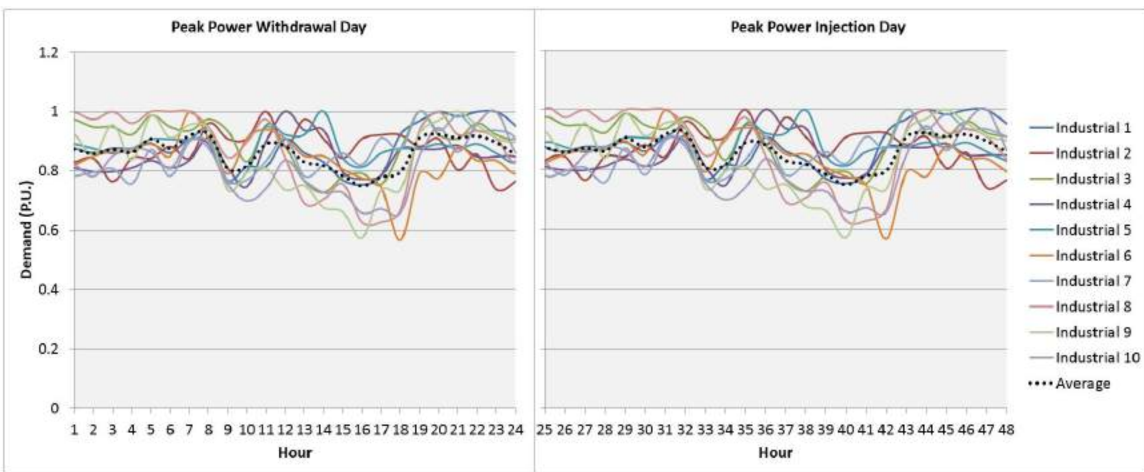
15 The share of total electricity sales by customer class for Xcel’s Colorado territory is as follows: 32 percent residential; 45 percent commercial; 22 percent industrial (U.S. Energy Information Administration, 2012).

characteristics for Denver (National Renewable Energy Laboratory, 2013), yielding realistic load profiles specific to the simulation area.[16] As the DOE dataset does not include industrial load profiles, ten different load profiles are created to approximate industrial loads.[17] The 48 hour profiles selected for the simulation correspond to two non-consecutive days in the annual DOE dataset selected to match (1) the day of peak net power withdrawal and (2) the day of peak power injection assuming penetration of photovoltaic (PV) generators in the network.[18] These two days approximate the extremes in power flow to which the distribution network must be designed.

TABLE 3: DISTRIBUTION OF LOAD PROFILES IN SIMULATED NETWORK BY LOAD TYPE

Parameter	Unit	LV	MV	HV
Industrial profile share	p.u.	0	0.1	0.4
Commercial profile share	p.u.	0.25	0.6	0.6
Residential profile share	p.u.	0.75	0.3	0

FIGURE 1: INDUSTRIAL LOAD PROFILES



16 The DOE reference building load profile database contains four residential building load profiles. Six additional residential load profiles are created by altering these base load profiles to yield a total of ten different residential profiles. Ten commercial load profiles are selected from the 16 available commercial profiles in the DOE dataset.

17 Since industrial load profiles are very dependent of the particular process they supply, a nearly-constant consumption with some hourly variability can be assumed. Industrial profiles are therefore constructed as a random walk around a base demand level.

18 Given the DOE reference building loads and annual PV production data Denver, peak net power demand occurs at 18:00 hours on July 26th and peak reverse power flow occurs at 13:00 hours on March 11th.

FIGURE 2: COMMERCIAL LOAD PROFILES

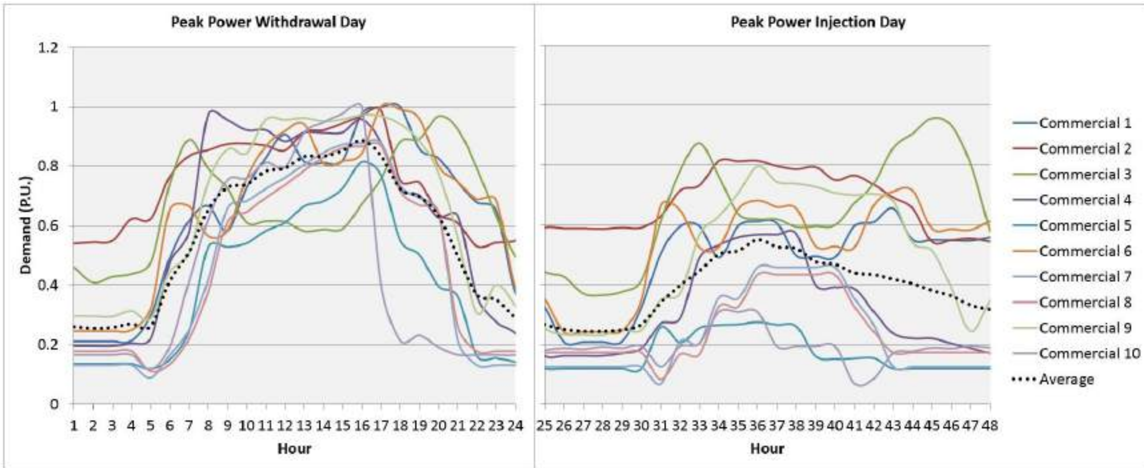
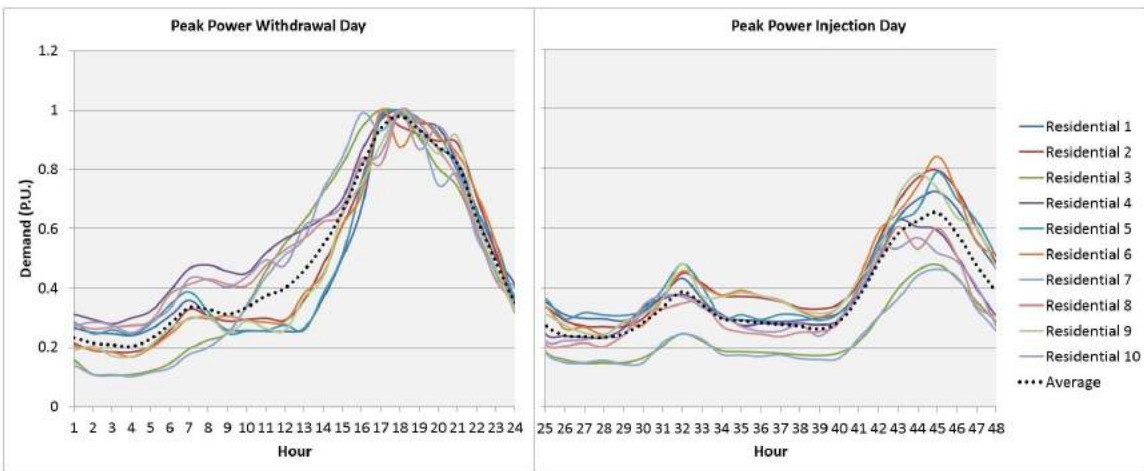


FIGURE 3: RESIDENTIAL LOAD PROFILES



PV generators are assigned one of six PV production profiles generated by the DOE's PVWatts solar PV production simulator (National Renewable Energy Laboratory, 2014) and correspond to TMY3 meteorological database characteristics for Denver, yielding realistic production profiles (Figure 4). From the annual hourly production data produced by PVWatts, two non-consecutive 24-hour periods are again selected to match (1) the day of peak net power withdrawal (load minus PV production) and (2) the day of maximum net power injection given the penetration of PV generators in the network.[19] Six profiles are produced from the PVWatts calculator corresponding to five possible fixed alignments of rooftop-mounted panels as well as one single-axis tracking system. Individual generators are randomly assigned a profile with a probability of 0.5 for a south-facing roof-mounted system and 0.1 for each of the other five profiles.

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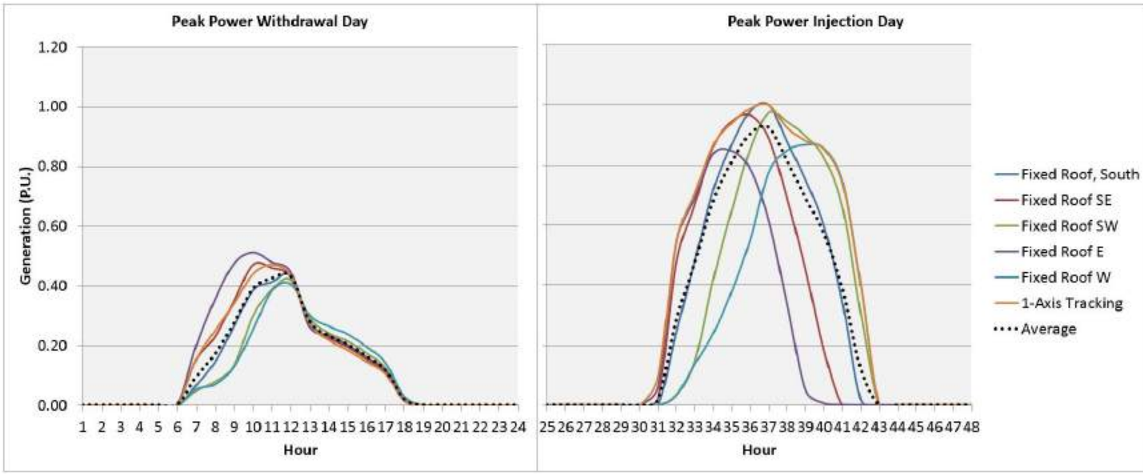
19 Given the DOE reference building loads and annual PV production data Denver, peak net power demand occurs at 18:00 hours on July 26th and peak reverse power flow occurs at 13:00 hours on March 11th.

FIGURE 4: SOLAR PV PRODUCTION PROFILES



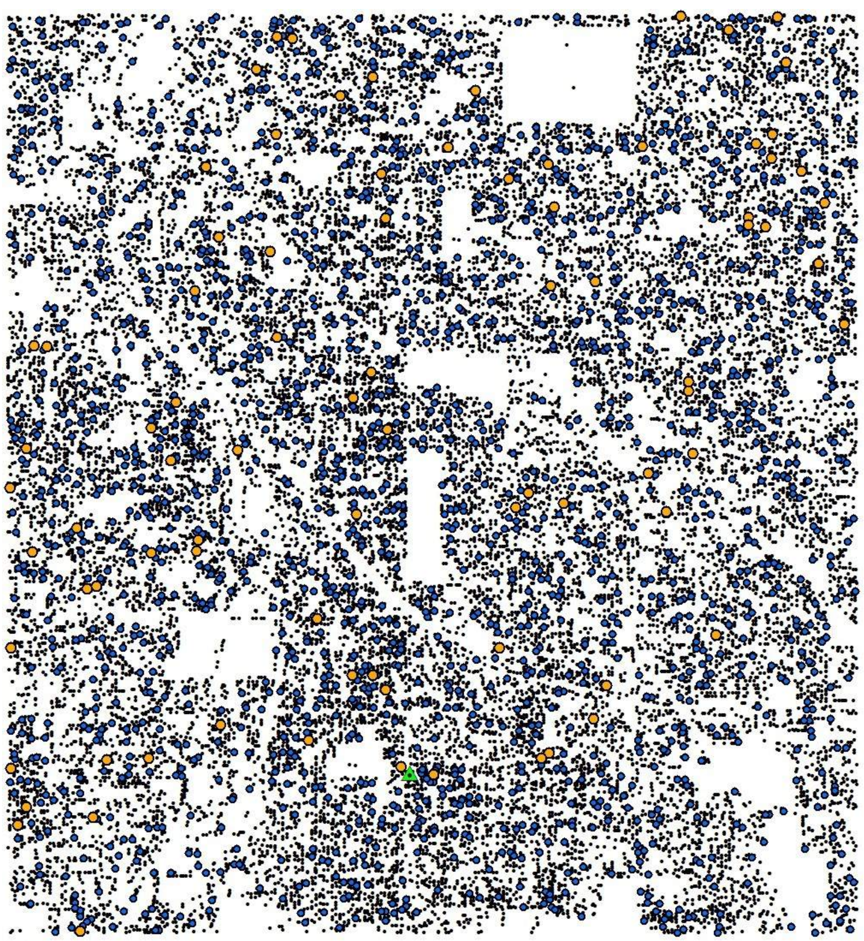
Next, the simulation method ensures a realistic network topography by using real street maps for a 120 square kilometer portion of Denver as a "scaffold" to constrain the location of network users (Figure 5). The street map is first scanned and the layout of streets is recognized. The layout of streets 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 an equal probability per unit of street length (Figure 6). The location of the primary transmission interconnection substation is assigned as per specification in the configuration files. Only load points are included in the base network. For network expansion scenarios including DG penetration, the location of PV generators connected to LV and MV feeders is determined by matching the generators with an existing load point using a placement algorithm which attempts to minimize the difference between the annual electricity generation of the PV system and the annual electricity consumption of the load point (both measured in kWh/year).[20] Large PV systems connected to the HV sub-transmission network are randomly placed at one of several pre-defined locations meant to designate likely connection points for such large systems.

20 This placement algorithm is meant to mimic customer placement decisions under the practice of "net metering," wherein PV owners receive a credit on their electricity bill for each kWh of electricity generated by their PV system, generally with a limit set such that the total credits cannot exceed the customer's total electricity consumption.

FIGURE 5: STREET MAP OF SIMULATED DISTRIBUTION NETWORK AREA (DENVER, COLORADO) AND RESULTING "SCAFFOLD" FOR NETWORK TOPOLOGY (AT RIGHT)

FIGURE 6: NETWORK USERS ARE ASSIGNED ALONG STREET MAP SCAFFOLD

LV customers shown as small black dots; MV customers medium-sized blue dots; HV customers larger orange dots; primary transmission substation shown as green triangle.



2.1.2 - Constructing the network with the reference network model

After the location and profiles of network users are determined, an RNM is used to construct the simulated distribution network. A description of the model can be found in Domingo et al. (2011). This model was developed by Comillas University in collaboration with the Spanish national regulator to calculate allowed remuneration of electricity distribution companies, and it has been applied to research the impact on distribution networks of large-scale deployment of DG, active network management, and electric vehicle penetration (Cossent et al., 2011; Fernández et al., 2011; Olmos et al., 2009).

The RNM emulates the engineering design process of an 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 DG). The network is constructed to minimize total network costs (including capital expenditures, operational expenditures, and ohmic network losses) while 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.

The RNM is able to run in two modes: a "greenfield" mode and a "brownfield" or expansion-planning mode. The greenfield mode builds an efficient network from scratch using the location , voltage, and maximum contracted power flow of each network user and each transmission substation in conjunction with simultaneity factors to size network components. The simultaneity factors for each network component specify what portion of total power flow downstream of the component contributes to peak power flow for that component and capture the heterogeneity of network users (i.e., not all load points peak at the same hour). See Domingo et al. (2011) for more on these factors. The brownfield mode takes an established network layout as an input and determines additional network components and reinforcements necessary to accommodate changes in network uses. The brownfield mode also takes into account 48-hour power consumption and injection profiles for each network user (load or DG).[21]

In both modes, the RNM builds out a network with four voltage levels in a balanced three-phase configuration (LV at 240 V, MV at 12 kV, and HV-1 and HV-2 at 33 and 66 kV). Network components are selected from a standard catalog file which contains technical and cost information about available equipment and the cost and time burden of maintenance and power restoration actions. The RNM also employs an algorithm that constrains the layout of network components to align with the corresponding street map for the area (see Domingo et al., 2011). This algorithm ensures a realistic layout of the network by avoiding placing overhead or underground distribution lines through the middle of city blocks and minimizing the number of crossings of major avenues. Finally, the model takes into account the cost of capital, lifetime of assets, discount rate, and the cost of losses.

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21 To account for the diversity embedded in the thirty load profiles used in the simulation, the simultaneity factors used in the brownfield model runs are calculated by adjusting the factors used in the greenfield runs upwards to ensure consistency between the two modes. For example, a simultaneity factor of 0.92 is already embedded in the mix of LV load profiles used in the Denver simulation. Thus, the LV customer simultaneity factor of 0.3 used in the Greenfield run is adjusted upwards by dividing by 0.92 to arrive at the simultaneity factor used for LV customers in the brownfield runs: 0.3 / 0.92 = 0.33.

To construct the simulated distribution network for Denver, this paper first employs the RNM in greenfield mode to build the base network layout. Next, the layout generated by the greenfield run is used as the input for a brownfield run of the RNM which recalculates the optimal network design taking into account the 48-hour power profiles of network users.

The resulting base network is depicted in Figure 7. The total network investment cost estimated by the RNM is $418.05 million (in overnight costs) as shown in Table 4. This is the estimated replacement value of the network and is used to calculate the RAV of the utility at the outset of the regulatory period.

TABLE 4: ESTIMATED EFFICIENT NETWORK COSTS FOR THE SIMULATED BASE NETWORK

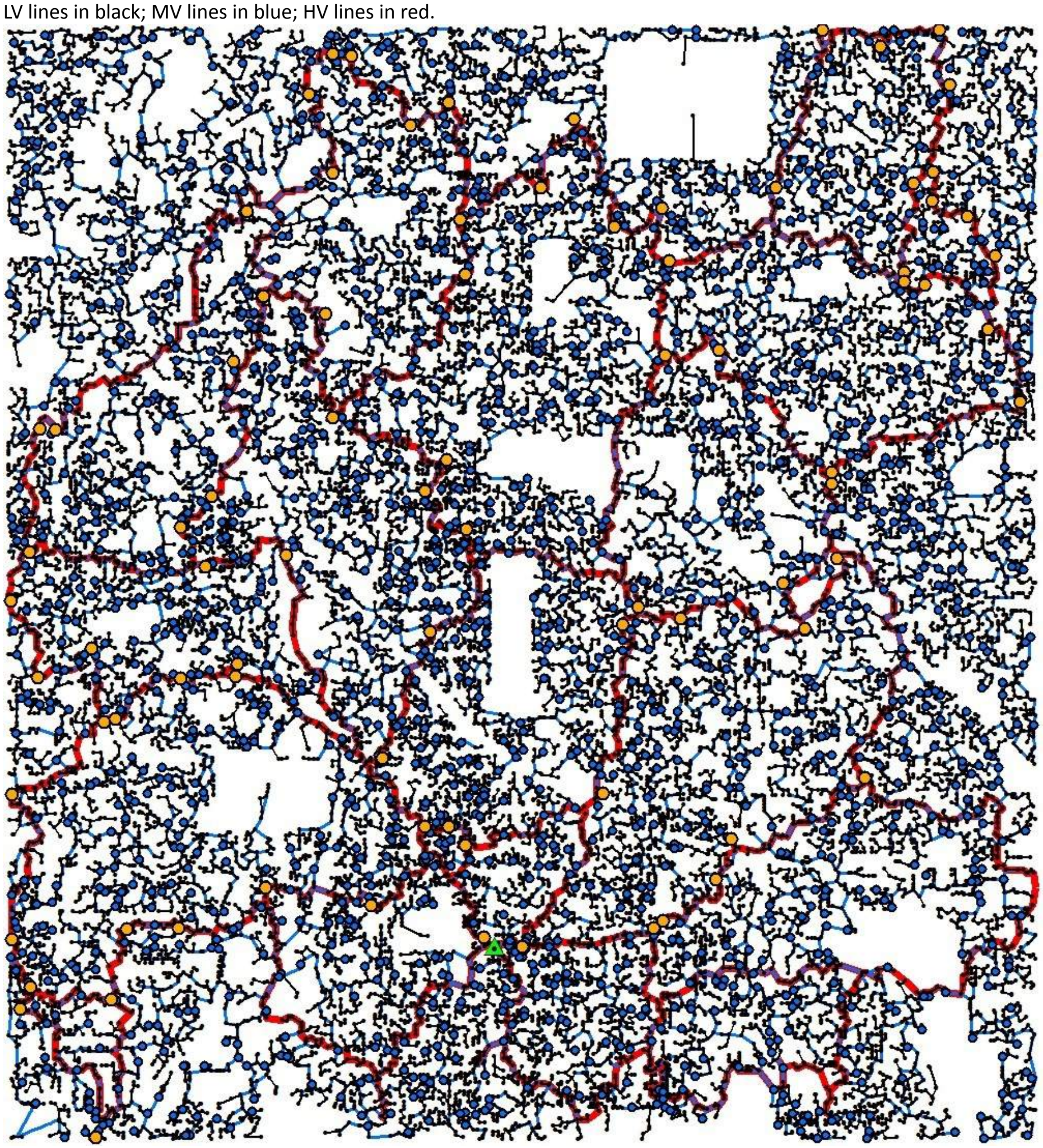
	New Network Investment	New Quality Equipment	Total New Network Investment	Preventive Maintenance	Corrective Maintenance	Total Maintenance
Network components	**Overnight costs (US$)**			**Annual costs (US$)**		
LV feeders	$50,096,168	$0	*$50,096,168*	$792,654	$620,343	*$1,412,997*
LV/MV transformers	$22,706,658	$0	*$22,706,658*	$1,332,445	$60,829	*$1,393,274*
MV feeders	$120,526,302	$18,746,320	*$139,272,622*	$703,912	$618,606	*$1,322,517*
MV/HV substations	$147,384,000	$0	*$147,384,000*	$2,127,960	$589	*$2,128,549*
HV lines	$58,589,781	$0	*$58,589,781*	$211,176	$12,987	*$224,163*
Transmission substation	$0	$0	*$0*	$0	$0	*$0*
Total	**$399,302,909**	**$18,746,320**	***$418,049,229***	**$5,168,147**	**$1,313,354**	***$6,481,501***

2.1.3 - Simulating network expansion scenarios

Next, several network expansion scenarios are simulated for use in demonstrating the proposed regulatory process. These scenarios capture a range of possible evolutions in network use, including variations in load growth and DER penetration. For both load and PV, three forecasts are generated: a central forecast, and both high and low sensitivity scenarios capturing the range of likely deviation from the central forecast (see Table 5). Projected load growth is specified as both "vertical" load growth – i.e., a percentage increase in demand at each load point during the regulatory period – and "horizontal" load growth – i.e., a number of new load points at each voltage level connected to the system during the regulatory period. Finally, to account for the impact of DER penetration on distribution networks, the forecast includes projected penetration of solar photovoltaic (PV) generators at each voltage level. Nine network expansion scenarios are then constructed covering all possible combinations of the low, central, and high forecasts for load growth and PV penetration.

FIGURE 7: THE BASE SIMULATED NETWORK FOR DENVER, COLORADO

LV lines in black; MV lines in blue; HV lines in red.



Insert: zoomed-in view of the portion of the network in vicinity of the primary transmission substation.

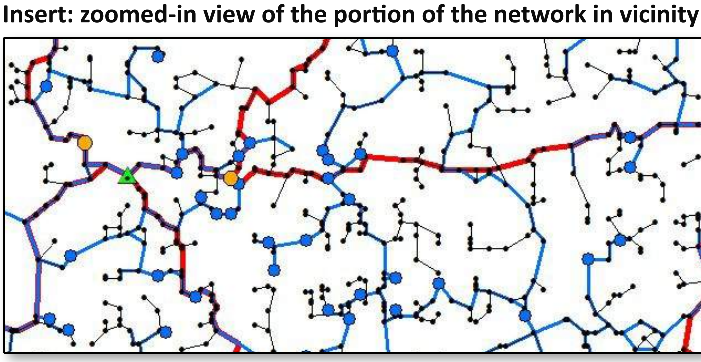


TABLE 5: FORECASTED EVOLUTION OF NETWORK USES (LOAD GROWTH AND PV PENETRATION)

Vertical load growth (% increase from base system)				
	LV	**MV**	**HV**	**Approx. total load (million kWh/year)***
Base system	-	-	-	2,100.7
Low forecast	3.5	3.5	3.5	2,212.5
Central forecast	4.0	4.0	4.0	2,232.5
High forecast	4.5	4.5	4.5	2,252.5
Horizontal load growth (# of new load points / kW peak)				
	LV	**MV**	**HV**	**Approx. total peak demand (kW)***
Base system	-	-	-	467,610
Low forecast	450 / 2,700	35 / 3,500	2 / 2,000	492,460
Central forecast	500 / 3,000	40 / 4,000	3 / 3,000	496,710
High forecast	550 / 3,300	45 / 4,500	4 / 4,000	500,980

* Note: Total values include combined impact of both horizontal and vertical load growth

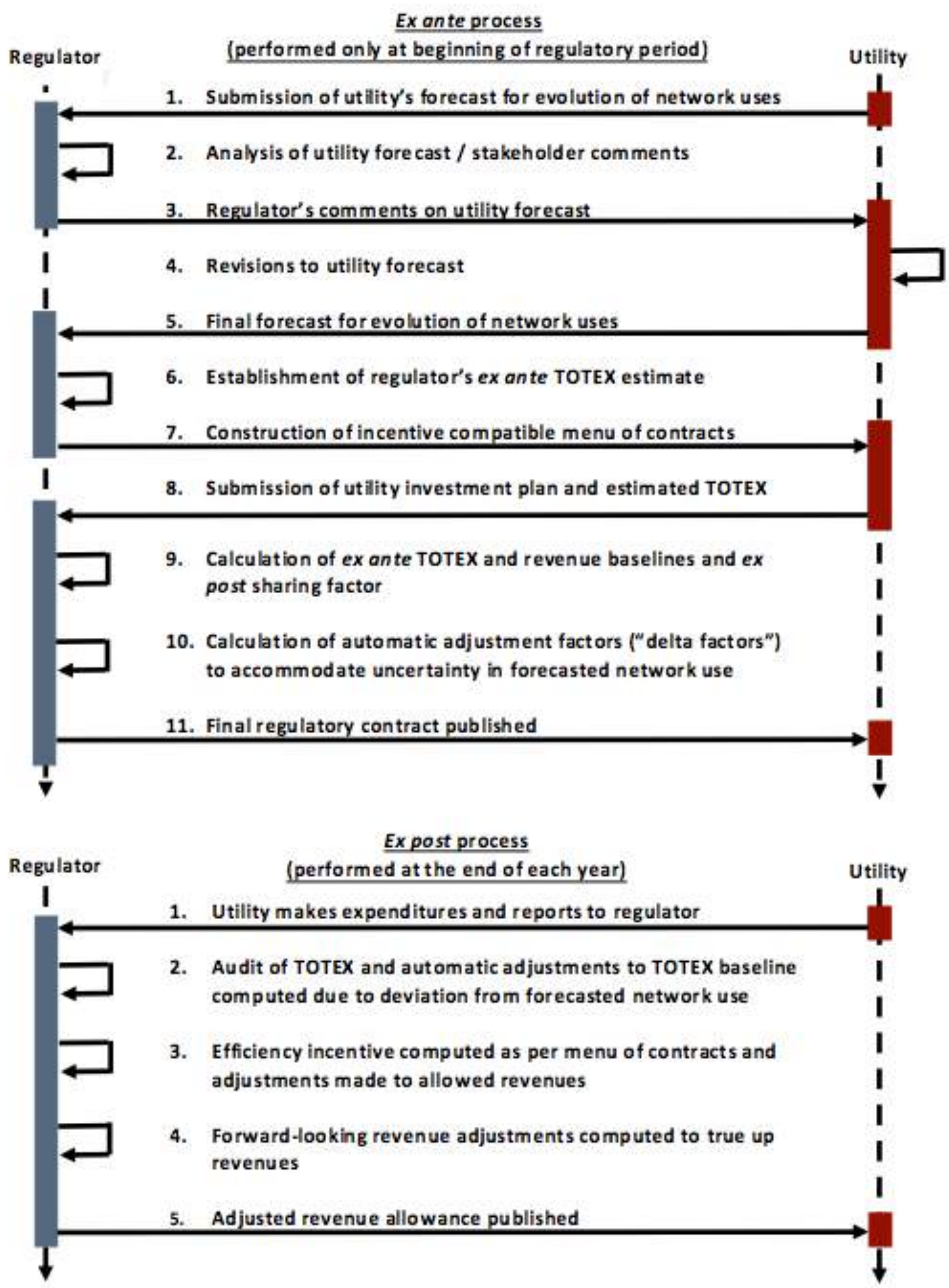
PV penetration (# of new PV connections / kW peak)				
	LV	**MV**	**HV**	**Approx. total peak generation (kW)**
Base system	-	-	-	-
Low forecast	1,875 / 22,500	270 / 54,000	5 / 10,000	86,500
Central forecast	2,083 / 25,000	300 / 60,000	6 / 12,000	97,000
High forecast	2,292 / 27,500	330 / 66,000	7 / 14,000	107,500

New load points and PV generators are assigned to eligible connection points and 48-hour power profiles using the same methods described in Section 2.1.1. In addition, power demand at each hour is increased at all load points (existing and new) as per the appropriate vertical load growth in each scenario. To ensure consistency across cases, the set of new load points and PV generators (and their locations and load profiles) used in the high forecast cases contains the full set of loads and PV generators in the central forecast cases, and the set in the central forecasts cases includes the full set of loads and generators in the low forecast cases. That is, for each load $l_i \subset L_{low} \subset L_{central} \subset L_{high}$ *and* $l_j \subset L_{central} \subset L_{high}$ and for each PV generator $g_i \subset G_{low} \subset G_{central} \subset G_{high}$ *and* $g_j \subset G_{central} \subset G_{high}$. The RNM is then run in brownfield mode to determine efficient total network costs necessary to accommodate load growth and DG penetration in each scenario.

2.3. Introducing and Demonstrating a Novel Regulatory Method for Establishing the Allowed Revenues of Distribution Utilities

The novel regulatory process proposed herein is summarized in Figure 8, and the key stages of the process are demonstrated in the remainder of this section.

FIGURE 8: THE PROPOSED REGULATORY PROCESS FOR THE REMUNERATION OF ELECTRICITY DISTRIBUTION UTILITIES



2.3.1. Forecasting the Evolution of Network Uses

The *ex ante* regulatory process begins with the utility submitting to the regulator a detailed year-by-year forecast of the evolution of network uses over the upcoming regulatory period (Step 1). This forecast should at minimum 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.[22] The regulator then critically reviews this forecast (Step 2). This review may also include a period of open comment on the preliminary forecast by stakeholders. At the conclusion of this review, the regulator will 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).

While in practice, this forecast would be created through several important, iterative steps involving the utility, regulator, and key stakeholders, this demonstration of this regulatory method utilizes the forecasted evolution of network uses described in Table 5 above, which is meant to represent the end-product of Steps 1-5. While a real forecast would involve expected changes in load profiles beyond a simple increase in average demand (vertical load growth) and would encompass a variety of new DER network users in addition to solar PV, this simplified forecast will suffice to demonstrate the basic application of the regulatory process.

2.3.2. Establishment of Regulator's Ex Ante Estimate of Efficient Expenditures

Next, the regulator next employs a reference network model (RNM) to construct 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 (i.e., a period of 3-5 years) (Step 6). An RNM is a large-scale distribution network planning tool that emulates the practices of an efficient utility. The model will produce an estimate of efficient expenditures to expand and maintain a network to serve a specified set of network users at prescribed quality levels (i.e., maximum statistical probability of network disruptions, voltage limits, etc.) and considering incentives for reduction of network losses. The RNM described in detail in Domingo et al. (2011) and summarized in Section 2.1.2 above will be used throughout this thesis to demonstrate application of this method, but any suitably rigorous RNM could be employed.[23]

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22 It is important to note that the utility may have an incentive to engage in strategic behavior during the construction of this forecast (Cossent & Gómez, 2013; Ofgem, 2010b). The utility may believe that inflating estimates of load growth or DER penetration will lead to an increase in ex ante allowed revenues. This is an important concern, but is mitigated through a variety of means. First, critical review of the preliminary forecast by the regulator and comment by stakeholders provides an opportunity to illuminate any strategic inflation in expected cost drivers. Second, use of automatic adjustment factors to account for departures from the final forecast over the regulatory period for each key cost driver minimizes the incentive to engage in strategic behavior: if forecasted load growth is inflated and realized load is much lower, for example, the ex post automatic adjustment accounting for departures of load from the final forecast will reduce final allowed revenues accordingly.

23 Note that the current implementation of the RNM used herein does not model active system management, dynamic network reconfiguration or other novel approaches to reduce network costs. This is appropriate for regulatory purposes at this stage, as the regulator should establish economic incentives for these novel practices to become commonplace. However, as these techniques become part of the utility's normal repertoire, the RNM should be regularly updated to ensure the efficient frontier estimated by the model aligns with industry best-practices.

As a regulatory benchmarking tool, the RNM should be used in a "brownfield" or network expansion mode in order to take into account the established layout of the network and sunk investments in network components (Cossent & Gómez, 2013). 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 DG); the layout, impedance, and capacity of the electrical lines and protection devices; and the capacity and location of transmission interconnection substations, substations and transformers. 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.[24] See Domingo et al. (2011) for a full description of input requirements for this particular RNM.[25]

As an RNM can be designed to accommodate expected changes in network use, technology performance and cost, and network management practices, these models equip the regulator with a forward-looking method to benchmark efficient total network expenditures (TOTEX), reducing the uncertainty and information asymmetries facing the regulator.[26] In effect, the RNM gives the regulator a tool with which to "peer into the future," a crucial ability in *ex ante* regulatory approaches. 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. For example, RNMs have already been applied to assess the impact on distribution planning and costs due to large-scale deployment of DG, active network management, and electric vehicle penetration (Cossent, et al., 2011; Fernández et al., 2011; Olmos et al., 2009; Vergara, et al., 2014). Additionally, as a reference network is constructed for each utility, RNMs can capture the heterogeneity of utility networks, a particularly important feature as DER penetration is likely to increase the heterogeneity between distribution networks.

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24 This catalog of network components is used by the model to plan necessary network investments and 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, see Cossent & Gómez, 2013; Cossent, 2013).

25 These information requirements can be significant. However, similar requirements have been successfully implemented in Spain, Chile, and Sweden, each of which employ 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.

26 Note that as with any other benchmarking method, the cost figures produced by the RNM should not be used directly to establish the utility's allowed revenues. The RNM is a model that simplifies reality and, as a result, generally produces a network solution that is less expensive than an efficient real-world utility is likely to achieve. For example, the RNM can plan the network with perfect foresight given the input forecast, while utility planners may have to adjust plans over time, incurring sunk costs as real-world conditions change. Other constraints faced by a real utility company may also be ignored by the RNM. Regulators should therefore adjust the cost estimates produced by the RNM accordingly. The RNM's performance can be benchmarked by running it against several real world efficient network cases with known expenditures to estimate an appropriate correction factor, or the regulator can employ consultants to 'spot check' the estimates produced by the RNM.

For demonstration of this regulatory process, the realistic, large-scale urban distribution network simulated in Section 2.2 will be used as the base network in place of the real network layout that would be provided to regulators in a real regulatory proceeding. This network corresponds to a roughly 120 km-sq portion of Denver, Colorado, and is parameterized to closely simulate realistic conditions, including geographic distribution of network users using a real street map as a "scaffold" to constrain locations, use of thirty realistic load profiles (ten each for industrial, commercial, and residential users), and a specification of load power density and distribution of load points among user types (industrial, commercial, and residential) and voltage levels that closely matches the real distribution of retail electricity sales in Denver. Likewise, the range of forecasts for the evolution of network uses described in Table 5 will be used in place of the forecasts that would be developed in Steps 1-5 of the regulatory proceeding. The location, size, and profiles of new load points and PV generators in each forecast case are specified using the simulation methods detailed in Section 2.1.

Table 6 summarizes the efficient network expenditures estimated by the RNM for the central forecast case for our simulated network. New network investments necessary to accommodate forecasted changes in network use (load growth and PV penetration) are divided into primary network investments and quality-related equipment (protection devices, voltage regulators, etc.) chosen by the RNM to optimize quality of service. This yields the total incremental network investment required over the regulatory period, expressed as overnight capital costs. Note that these incremental network investments do not include any investments necessary to replace existing network assets. Replacement investments are calculated separately below.

TABLE 6: ESTIMATED EFFICIENT NETWORK EXPENDITURES IN CENTRAL FORECAST SCENARIO

	New Network Investment	New Quality Equipment	Total New Network Investment	Preventive Maintenance	Corrective Maintenance	Total Maintenance
Network components	**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**
Transmission substation	$0	$0	**$0**	$0	$0	*$0*
Total	$12,488,262	$74,100	**$12,562,362**	$5,356,768	$1,342,403	**$6,699,171**

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

The efficient investment and annual maintenance expenditures estimated in Table 6 must then be converted to the regulator's *ex ante* estimate of total network expenditures (TOTEX) for the regulatory period. Table 7 depicts these calculations.

First, the overnight cost of incremental investments is converted into an annual investment schedule by dividing the annual overnight investment cost computed by the RNM into even annual investments across the regulatory period. These overnight cost figures are then adjusted for inflation to current year dollars by applying the producer price index (PPI).

In addition to incremental investments 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.[27] To accommodate network replacement costs, regulators commonly allow the utility an investment allowance equal to the full replacement value of the assets in the expiring vintage. 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 dug, 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 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. This demonstration assumes an extended lifetime factor of 66.7%. Overnight replacement costs are then adjusted to current year costs by applying the PPI.

Annual network maintenance costs (in non-inflation-adjusted terms) are estimated from the RNM. The maintenance costs at the start of the regulatory period equal the expected total maintenance costs for the base network simulated (Table 4), while the costs for the final year of the regulatory period correspond to the expected total maintenance costs for the expanded network that corresponds to the central forecast scenario (Table 6). Annual values for the interim years are imputed by assuming a compound annual growth in maintenance costs over the regulatory period. These values are then adjusted for inflation by applying the PPI.

27 In a real regulatory proceeding, the value of retiring assets would be obtained from audits of the firm's booked assets. To demonstrate the regulatory process, this paper makes the simplifying assumption that the gross asset value of booked network assets at the start of the regulatory period corresponds to the replacement value of the base network simulated in Section 2.1 (see Table 4), and that the gross asset value is divided evenly into 40 annual vintages (assuming a 40 year average lifespan for network assets). The oldest vintage in the gross asset base will be fully depreciated each year, and assuming the financial life of assets corresponds to the physical useful life of these assets, this vintage will need to be replaced with new or refurbished assets, to maintain the functionality of the network.

The regulator's estimate of efficient TOTEX is thus the sum of inflation adjusted CAPEX (including incremental and replacement investments) and OPEX (network maintenance).[28]

TABLE 7: REGULATOR'S EX ANTE ESTIMATE OF EFFICIENT TOTAL NETWORK EXPENDITURES

Assumes 5 year regulatory period and straight-line depreciation of RAV over 40 year average asset life; base network assets are evenly divided among vintages for computation of average age of network assets and gross asset value; pre-tax return on equity is 10%; cost of debt is 5.5%; gearing ratio is 35% equity, 65% debt and W.A.C.C. is 7.08%; inflation is 2.5%; discount rate is 6.5%; extended lifetime factor for replacement investments is 0.67.

	Year 0	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
CAPEX (million $)		**Annual cost (current year dollars)**					**NPV**
Incremental investment		*Total overnight cost (incremental network cost from RNM):*					*$12.56*
Overnight cost		$2.51	$2.51	$2.51	$2.51	$2.51	
Inflation adjusted		$2.64	$2.71	$2.77	$2.84	$2.58	$11.22
Replacement investments		*Total gross asset value (base network cost from RNM):*					*$418.05*
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 $)		**Annual cost (current year dollars)**					**NPV**
Network maintenance Base value, 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**
FAST AND SLOW MONEY (% of TOTEX)							
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 regulator can also determine the expected portion of TOTEX associated with both CAPEX and OPEX. These shares should be used to implement a TOTEX-based approach to capitalizing expenditures into the regulated asset value (RAV) in order to equalize incentives for

28 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.

cost savings in both categories of expenditure.[29] Under this approach, introduced by Ofgem (2009), the regulator sets ex ante 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 allowances are calculated). The remainder of realized TOTEX is designated as "fast money," which is fully expensed annually. The share of slow and fast money can be established based on the regulator's ex ante estimates of CAPEX and OPEX, respectively, in total expenditures. As such the share of CAPEX and OPEX in actual utility expenditures during the regulatory period is free to depart from this expected share without impacting the utility's return on equity. Thus, cost-saving tradeoffs between both types of expenditure can be fully exploited by the utility (see Ofgem, 2009, p. 117-120, and Ofgem, 2013b, p. 30-32 for more). Equalizing incentives for efficiency across both CAPEX and OPEX is particularly important given the heightened tradeoffs between these expenditures, as discussed in Section 1.2.3.

2.3.3. Construction of an Incentive Compatible Menu of Contracts

The next step involves creation of an incentive compatible menu of profit-sharing regulatory contracts for the utility (Step 7).[30] A menu of contracts specifies an *ex ante* regulatory allowance as well as clear rules 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 via use of the RNM in Step 6. 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 construction of the menu of contracts can be tuned by the regulator to appropriately balance incentives for X-efficiency and manage uncertainty while maintaining "incentive compatibility"—that is, a profit-maximizing firm will always be better off (i.e., 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 thus 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.

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

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29 Under a TOTEX-based approach, both OPEX and CAPEX savings will face the same efficiency incentives—that is, a dollar of OPEX savings and a dollar in CAPEX savings will earn the utility the same efficiency-related income. In contrast, 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 shareholders. This decline in net profit will offset some portion of the efficiency-related income, distorting tradeoffs between OPEX and CAPEX and potentially encouraging over-investment.

30 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, this general approach has been successfully implemented by the Ofgem 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 theoretically framework for a menu of contracts is discussed in Laffont & Tirole (1993).

1. The weight placed on the regulator's estimate of efficient network expenditures relative to the utility's estimate, $\boldsymbol{\omega}$. 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), $\mathbf{SF_{ref}}$, which corresponds to the case where the utility's estimate of future expenditures aligns with the regulator's estimate ($\mathbf{R}_{\textit{ex ante}}$ = 1.0). This value can be set to establish the strength of efficiency incentives faced by utilities in order to manage tradeoffs between incentives for efficiency and rent extraction taking into account the degree of uncertainty about future costs and demand.[31] 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.

3. The rate of change in the profit-sharing factor is the ratio between the utility's estimate and the regulator's estimate changes, $\mathbf{SF_{roc}}$. 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.[32]

4. The reference value for the additional income payment, $\mathbf{AI_{ref}}$, 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 ($\mathbf{R}_{\textit{ex ante}}$ = 1.0). The selected value can be used to tune expected profit margins for the utility.

See Appendix A for the formulas to use these four discretionary parameters to calculate the remaining initialization parameters necessary to construct a menu of contracts. Appendix A also describes the formulas to compute the appropriate *ex ante* regulatory contract and *ex post* efficient incentive, the portion of realized over- or under-spend shared with the utility's shareholders. An example menu of contracts is shown in Table 8 below,[33] demonstrating the incentive compatibility of the menu.

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31 See Ofgem (2010b) at p. 84-87 for further discussion of regulatory considerations in establishing the sharing factor or incentive rate. In general, under lower levels of uncertainty, a higher profit-sharing factor (i.e., the firm is exposed to most of the risks and rewards of cost savings) performs better, while a lower profit-sharing factor (which shares most risks and rewards with ratepayers) performs better under higher levels of uncertainty (Schmalensee, 1989).

32 Note that the regulator may wish to set this value to ensure that the sharing factor does not fall below a certain value (a lower bound of 0.3 for example). If the sharing factor is too low, a company may not face enough exposure to the costs of overspending and could face perverse incentives to increase their spending unnecessarily to increase their regulated asset value (RAV) and allowed revenues (for more, see Ofgem, 2010b, p. 85-86). As a rule of thumb, the sharing factor should not fall below the risk-adjusted rate of return the utility would be expected to earn by increasing their regulated asset value (i.e. their allowed returns on equity invested plus depreciation adjusted for relative risk), and it may be advisable to ensure the sharing factor stays a healthy margin above this rate.

33 Note that while this table shows discrete values in each column, a continuous menu of contracts can be calculated using the formulas in Appendix A.

TABLE 8: EXAMPLE INCENTIVE COMPATIBLE MENU OF PROFIT-SHARING CONTRACTS

Shaded cells correspond to those for which the ex ante utility 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 the matrix), the utility will earn the greatest revenues in the case where their realized cost matches 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). This menu uses the following discretionary parameters: ω = 0.66; SFref = 0.7 SFroc = -0.01; AIref = 1.0.

Ratio of firm's cost estimate to regulator's cost estimate [%]	$\mathbf{R}_{ex\ ante}$	90	95	**100**	105	110	115	120
Allowed revenues *ex ante* [% of regulator's cost estimate]	$\mathbf{X}_{ex\ ante}$	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 *ex ante* estimate [%]	$\mathbf{R}_{ex\ post}$	Final *ex post* adjustment to allowed revenues [% of regulator's *ex ante* estimate]						$\mathbf{A}_{ex\ post}$
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

Employing an incentive compatible menu of contracts can help regulators address both the heightened information asymmetry and uncertainty expected as distribution networks evolve to accommodate new DERs and employ new smart grid capabilities (see Section 1.2). First, the incentive compatible nature of the menu elicits accurate estimates of expected costs from the utility and removes incentives to inflate estimated costs (i.e., engage in strategic behavior). Second, the combination of *ex ante* revenue determination with clear *ex post* adjustment rules promotes efficient network investments while minimizing the regulatory uncertainty that can deter investment.[34] Finally, the discretionary parameters used to construct the menu of contracts give the regulator flexibility to tune the strength of incentives to mitigate the impacts of uncertainty. For example, the weight placed on the regulator's estimate of network costs and the strength of the efficiency incentive (the sharing factor) can be reduced in the face of greater uncertainty or increased as the regulator becomes more confident in forecasts.

2.3.4. Calculation of Ex Ante *TOTEX and Revenue Baselines and Sharing Factor*

With the regulator's estimate of efficient network expenditures and menu of contracts on 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 utility's annual TOTEX estimates are compared to the regulator's estimates produced in Step 6 and the *ex ante* TOTEX baseline for each year in the regulatory period is established as per Equation 1:

34 Regulatory certainty is further improved when this menu of contracts is combined with the automatic adjustment factors discussed below.

(1) $X_{ex\ ante} = X_{regulator} \times \omega + X_{firm} \times (1 - \omega)$

Where:

$X_{baseline}$: annual total network expenditures baseline
$X_{regulator}$: regulator's *ex ante* estimate of efficient total network expenditures
X_{firm}: firm's *ex ante* estimate of efficient total network expenditures
ω: weight placed on regulator's estimate

Next, the ratio between the total net present value (NPV) of the utility's TOTEX estimate and the regulator's TOTEX estimate determines the sharing factor and additional income allowances as defined by the menu of contracts produced in Step 7.

Finally, the *ex ante* allowed revenue baseline for the regulatory period is calculated as per Equations 2-8:

(2) $Slow\ Money = X_{ex\ ante} \times Slow\ Money\ Share$

(3) $Gross\ Assets_y = Gross\ Assets_{y-1} - Expiring\ Assets + Slow\ Money_y$

(4) $RAV = \frac{Life - Age}{Life} * Gross\ Assets$

(5) $Fast\ Money = X_{ex\ ante} - Slow\ Money$

(6) $Depreciation = \frac{Gross\ Assets}{Life}$

(7) $Cost\ of\ Capital_y = RAV_{y-1} \times WACC$

(8) $Revenue\ Baseline = Fast\ Money + Depreciation + Cost\ of\ Capital + Additional\ Income$

Where:

$Slow\ Money$: notional CAPEX allowance (capitalized into RAV)
$Slow\ Money\ Share$: regulator's expected share of CAPEX in TOTEX
$Gross\ Assets$: total gross value of in-service assets
$Expiring\ Assets$: gross value of assets reaching end of useful life
y: current year in the regulatory period
RAV: regulated asset value (gross value of assets less depreciation)
$Life$: regulatory life of assets
Age: average age of assets
$Fast\ Money$: notional OPEX allowance (expensed annually)
$Depreciation$: annual capital depreciation allowance
$Cost\ of\ Capital$: annual allowance for repayment of debt and equity
$WACC$: weighted average cost of capital
$Additional\ Income$: additional income allowance from menu of contracts
$Revenue\ Baseline$: *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 clear incentives for efficient management of network costs. Table 9 computes an example revenue allowance for a case in which the utility's estimate of TOTEX is higher than that of the regulator (ratio = 1.2).[35]

TABLE 9: EXAMPLE OF TOTEX AND REVENUE BASELINE CALCULATIONS

ω = 0.66; SF_{ref} = 0.7 SF_{roc} = -0.01; AI_{ref} = 1.0; Slow Money Share = 59%; WACC = 7.09%; Avg asset life = 40yrs

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	NPV
TOTEX ESTIMATES							
Regulator's estimate		$16.40	$16.81	$17.24	$17.67	$18.11	$71.44
Utility's estimate		$19.69	$20.18	$20.68	$21.20	$21.73	$85.73
TOTEX BASELINE AND MENU OF CONTRACTS PARAMETERS							
TOTEX baseline		$17.52	$17.96	$18.41	$18.87	$19.34	$76.30
Ratio	1.2	**Sharing Factor**		50%	**Additional income**		-$3.14
REVENUE BASELINE CALCULATIONS							
Capitalization							
Slow money		$10.38	$10.64	$10.90	$11.18	$11.46	
Gross asset value	$418.05	$417.98	$418.16	$418.61	$419.34	$420.34	
Average age of assets (yrs)	19.50	19.50	19.49	19.47	19.44	19.40	
Regulated asset value	$214.25	$214.18	$214.36	$214.81	$215.52	$216.50	
Cost allowances							
Fast money allowance		$7.14	$7.32	$7.50	$7.69	$7.88	$31.11
Depreciation allowance		$10.45	$10.45	$10.45	$10.47	$10.48	$43.47
Cost of capital allowance		$15.16	$15.15	$15.17	$15.20	$15.25	$63.09
Additional income		-$0.72	-$0.74	-$0.76	-$0.78	-$0.80	-$3.14
Revenue baseline		**$32.03**	**$32.18**	**$32.37**	**$32.58**	**$32.82**	**$134.5**

35 For these calculations, the total replacement value of the base network simulated in Section 2.1 is used as the initial gross asset value, while assets are divided equally and assigned to 40 annual vintages. Each year, the oldest vintage of assets is fully depreciated, and thus removed from the gross asset value, while new investments (both incremental and replacement investments) made that year are added to the gross asset value as a new vintage. The average age of assets is tracked each year, and expressed as a dollar-weighted average of the age of each vintage in the gross asset base.

2.3.4. Calculation of Automatic Adjustment Factors to Manage Uncertainty

While the use of an RNM and menu of contracts produces a clear revenue determination for each utility taking into account the expected cost of capital, evolution of network uses, and network component costs, the *ex ante* nature of this regime means there will always be uncertainty regarding the accuracy of these estimates. This uncertainty can lead to both benchmark errors and forecast errors (see Section 1.2.2), and the longer the regulatory period, the more substantial the effects of uncertainty can be on utility cost recovery or rent extraction (Ofgem, 2010b, 2013e).

The sharing factor established by the menu of contracts can help mitigate the impacts of benchmark error, as utilities and ratepayers share risks associated with divergences in realized costs from the *ex ante* benchmark. In particular, the impact of benchmark error on utility returns declines as the sharing factor declines (and *vice versa*), as anticipated by Schmalensee (1989) and demonstrated by Jenkins (2014, p. 85-87). The regulator can thus select the strength of the sharing factor based on their confidence in the benchmark.

A range of additional uncertainty mechanisms designed to manage the impacts of forecast error have also been proposed and adopted by regulators, including indexing mechanisms, full or partial cost pass-throughs, revenue triggers, mid-period reviews, and re-opener thresholds. For a discussion of uncertainty mechanisms available for *ex ante* regulatory approaches, see Ofgem (2010b, 2013e) and Jenkins (2014, p. 74-76).

This paper focuses on the *ex ante* calculation of automatic adjustment factors, or "delta factors," simple formulas which 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 DG penetration (Step 9). Using delta factors minimizes the impact of forecast error and thus reduces the risk that the revenue determination will need to be re-opened during the regulatory period, increasing regulatory certainty. These delta factors also reduce incentives for the utility to slow interconnection of 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 across a set of uncertainty scenarios that capture the likely range of potential evolution of load, DG penetration, or other important and uncertain cost drivers. To demonstrate this process, nine uncertainty scenarios are constructed corresponding to all possible permutations combining the three forecasts for load growth and three forecasts for DG penetration in Table 5 (the low, central, and high forecasts for each). The RNM is then run in brownfield mode to calculate the efficient network costs under each of these uncertainty scenarios. Table 10 illustrates the difference in investment and maintenance costs and efficient TOTEX for the simulated Denver network, as estimated by the RNM, under each of the uncertainty scenarios as compared to the central forecast scenario, as well as the difference in load and PV penetration.

TABLE 10: DIFFERENCE IN ESTIMATED EFFICIENT NETWORK COSTS, LOAD, AND PV PENETRATION ACROSS UNCERTAINTY SCENARIOS

	Load	PV penetration	Total New Network Investment	Total Network Maintenance Costs	Efficient TOTEX
		Difference from Central Case			NPV
Scenario	(kWh)	(kW)	(US$ Overnight Cost)	(US$ Annual Cost)	(M$)
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**
Central Load, Low PV	0	-10,241	-$520,576	-$6,670	**$70.97**
Central Load, Central PV	0	0	$0	$0	**$71.44**
Central 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, Central 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**

By performing a two-factor linear regression on the resulting estimated TOTEX for each scenario, the regulator can determine the relationship between deviations in cost driver values and efficient network costs. In this demonstration, regression coefficients are obtained describing the change in TOTEX as a function of the divergence in load (in kWh) and PV (in kW) from the central forecast. These coefficients, which this paper calls "delta factors," prescribe simple formulas to adjust the estimated TOTEX baseline *ex post* based on the realized evolution of network uses. Table 11 shows delta factors for the simulated Denver network, along with the R-square values for the regression. As the table illustrates, this regression is quite robust.

TABLE 11: REGRESSION COEFFICIENTS AND DELTA FACTORS FOR LOAD GROWTH AND PV PENETRATION

	Regression Coefficients / Delta Factors (NPV Efficient TOTEX)
Load growth	**$0.078/kWh**
PV penetration	**$36.20/kW**
R-square value	0.998

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 regulatory method thus provides a high degree of regulatory certainty and clear incentives for utilities to improve X-efficiency (minimizing the moral hazard problem). In addition, this method improves allocative efficiency and mitigates the impact of uncertainty (i.e., benchmark or forecast errors) through the use of both profit-sharing factors and delta factors, which help align revenues with realized costs. In addition, combining the use of an RNM with an incentive compatible menu of contracts substantially reduces information asymmetry by equipping the regulatory with a powerful, forward-looking benchmarking tool and incentivizing the utility to submit accurate, high-quality estimates of future network expenditures.

2.3.5. The Ex Post Regulatory Process: Applying Annual Corrections

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) (Step 1).

Next, the regulator will audit these reports to ensure their accuracy, and then compute 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 (Equation 9) for each of the key network uses 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 remaining years in the regulatory period (Equation 10).

$$(9)\quad Adjustment_{NPV} = Delta\ Factor \times \left(Deviation_y - Deviation_{y-1}\right)$$

$$(10)\quad Adjustment_i = \left(Adjustment_{NPV} \times \frac{1}{R}\right) * (1 + Discount\ Rate)^i$$

Where:

$Adjustment_{NPV}$: total adjustment to TOTEX baseline (in NPV$)

Delta factor: delta factor for network use (in NPV$/kWh for load, NPV$/kW for PV)

$Deviation_y$: difference between realized and forecasted network use in year y (in kWh for load and kW for PV)

$Deviation_{y-1}$: cumulative deviation from forecast through year y–1

y: current year in the regulatory period

$Adjustment_i$: annual adjustment to allowed revenues in year *i* where $i = y{:}y+(R\text{-}1)$

R: number of years remaining in the regulatory period

Discount Rate: regulatory discount rate

Table 11 provides an example of the annual adjustments to the TOTEX baseline for a deviation in load growth from the forecast, as applied over each year of the five year regulatory period. The same calculations would be employed for any deviations in the penetration of PV or other DERs as per the delta factors defined in the *ex ante* regulatory contract. The sum of all such annual adjustments will then be added to each year of the *ex ante* TOTEX baseline to arrive at the adjusted *ex post* TOTEX baseline.

TABLE 11: EXAMPLE OF ANNUAL EX POST ADJUSTMENTS TO TOTEX BASELINE DUE TO REALIZED LOAD GROWTH

Delta factor for load is $0.078/kWh; regulated discount rate is 6.5%

Year	**1**	**2**	**3**	**4**	**5**
NETWORK USE: LOAD (M kWh)					
Forecasted	2,186.5	2,212.3	2,238.3	2,264.8	2,291.5
Realized	2,182.7	2,204.6	2,226.7	2,249.1	2,271.6
Deviation	-3.80	-7.67	-11.64	-15.69	-19.82
ADJUSTMENT TO TOTEX BASELINE (M NPV $)					
Adjustment	-$0.30	-$0.32	-$0.35	-$0.38	-$0.41
ADJUSTMENT TO TOTEX BASELINE (annual streams, in M $)					
Year 1	-$0.06	-$0.07	-$0.07	-$0.08	-$0.08
Year 2		-$0.09	-$0.09	-$0.10	-$0.10
Year 3			-$0.12	-$0.13	-$0.14
Year 4				-$0.20	-$0.22
Year 5					-$0.44
Cumulative Adjustment	**-$0.06**	**-$0.15**	**-$0.29**	**-$0.51**	**-$0.98**

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 the efficiency incentive is calculated (Step 3) as per Equation 11. 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. The *ex post* allowed TOTEX is thus the utility's realized TOTEX less this efficiency incentive, as in Equation 12.

$$(11)\ Efficiency\ Incentive = Sharing\ Factor \times \left(TOTEX_{realized} - TOTEX_{adjusted}\right)$$

$$(12)\ TOTEX_{allowed} = TOTEX_{realized} - Efficieny\ Incentive$$

Where:

$Efficiency\ Incentive$: portion of over/under-spend shared by utility shareholders

Sharing Factor: the sharing factor specified in the *ex ante* regulatory contract

$TOTEX_{adjusted}$: adjusted TOTEX baseline

$TOTEX_{realized}$: total network expenditures realized by the utility

The regulator next 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 2.3.4).

Since revenues have already been collected over the course of the recently concluded year, the regulator must adjust the utility's revenue allowance in future years to "true up" the collected revenues and the *ex post* revenue allowance computed above (Step 4), as in Equation 13. 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, rather than a single lump sum correction, so as to smooth the impact on rates and avoid discontinuous rate increase/decreases.[36]

$$(13)\ True\ Up_K = \frac{Allowed\ Revenues - Collected\ Revenues}{N} \times (1 + Discount\ Rate)^{K-y}$$

Where:

$True\ Up_K$: annual adjustment to allowed revenues in year K where $K = y{+}1{:}y{+}N$

$Allowed\ Revenues$: *ex post* revenue allowance for y

$Collected\ Revenues$: revenues collected in year y

y: current year in the regulatory period

N: the number of years in the regulatory period

Tables 12 and 13 demonstrate the full application of the ex post annual adjustment process and formulas described above. In this hypothetical example, the utility initially estimates a higher efficient cost than the regulator (ratio 1.1), but ultimately achieves a reduction in costs bringing realized TOTEX below the adjusted TOTEX baseline (ratio 0.9). Load ends up growing slower than forecasted, while PV penetration grows more rapidly. This case therefore demonstrates the computation of adjustments to the TOTEX baseline due to realized network use as well as the adjustments to the revenue allowance to account for efficiency incentives and the additional income allowance specified by the *ex ante* regulatory contract.

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36 Note that as allowed revenues are adjusted for the next N years, where N is the length of the regulatory period, a portion of the true up corrections will be applied during the next 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.

TABLE 12: EXAMPLE OF EX POST ANNUAL CORRECTIONS TO ALLOWED REVENUES

Ex ante ratio = 1.1; Sharing factor = 60%; Additional income = -1.54%; Slow money share = 59%; WACC = 7.08.

Year	*NPV*	1	2	3	4	5
DEVIATION IN NETWORK USE FROM FORECAST						
Load deviation (M kWh)		-3.80	-7.67	-11.64	-15.69	-19.82
PV deviation (kW)		+2,193	+4,385	+6,578	+8,770	+10,963
TOTEX (M $)						
Regulator's estimate	*$71.4*	$16.4	$16.8	$17.2	$17.7	$18.1
Utility's estimate	*$78.6*	$18.0	$18.5	$19.0	$19.4	$19.9
Realized cost	***$63.2***	**$14.51**	**$14.88**	**$15.25**	**$15.63**	**$16.02**
EX ANTE TOTEX AND REVENUE BASELINES (M $)						
TOTEX baseline	*$73.9*	$17.0	$17.4	$17.8	$18.3	$18.7
Revenue baseline	*$135.3*	$32.3	$32.4	$32.6	$32.7	$33.0
CUMULATIVE ADJUSTMENT TO TOTEX BASELINE DUE TO DEVIATIONS FROM FORECASTED NETWORK USE (M $)						
Adjustment: load	*-$1.54*	-$0.06	-$0.15	-$0.29	-$0.51	-$0.98
Adjustment: PV	*+$0.40*	$0.02	$0.04	$0.08	$0.13	$0.25
Adjusted TOTEX baseline	***$72.7***	**$16.9**	**$17.3**	**$17.6**	**$17.9**	**$18.0**
CALCULATION OF EFFICIENCY INCENTIVE AND EX POST ALLOWED TOTEX						
Total over/under-spend	*-$9.52*	-$2.40	-$2.40	-$2.36	-$2.26	-$1.97
Efficiency incentive	*-$5.71*	-$1.44	-$1.44	-$1.42	-$1.36	-$1.18
Ex post allowed TOTEX	***$68.9***	**$16.0**	**$16.3**	**$16.7**	**$17.0**	**$17.2**

TABLE 13: EXAMPLE OF EX POST ANNUAL CORRECTIONS TO ALLOWED REVENUES (CONTINUED)

Year	*NPV*	1	2	3	4	5	6	7	8	9	10
CORRECTION OF REVENUE ALLOWANCE (M $)							Adjustments applied in next regulatory period				
Ex post allowed revenues	*$132.8*	$31.9	$31.9	$32.0	$32.0	$32.1					
Revenue correction	*-$1.57*	**$0.00**	**-$0.09**	**-$0.18**	**-$0.28**	**-$0.39**	**-$0.51**	**-$0.43**	**-$0.34**	**-$0.24**	**-$0.13**
Final revenue allowance	***$132.8***	**$32.27**	**$32.22**	**$32.20**	**$32.19**	**$32.18**	**-$0.51**	**-$0.43**	**-$0.34**	**-$0.24**	**-$0.13**

Table 14 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 7.5% for the regulatory period, above the target return on equity of 6.5%.

TABLE 14: FINAL FINANCIAL POSITION OF THE UTILITY
Cost of debt = 5.5%; gearing ratio = 35% equity / 65% debt; tax rate = 35%

Allowed revenues	**$132.8**
Allowed costs	$103.0
Fast money allowance	$28.1
Depreciation allowance	$43.3
Cost of debt	$31.6
Efficiency incentive income	$5.7
Earnings before interest & taxes	$35.6
Taxes	$12.4
Net profit	**$23.1**
After-tax return on equity	**7.5%**

3. Conclusions: Advantages of the Proposed Regulatory Process

The novel regulatory process proposed in this paper offers several important advantages for the economic regulation of electricity distribution utilities, especially under increasing penetrations of distributed energy resources and smart grid technologies.[37]

First, the regulatory regime proposed herein *helps overcome information asymmetry* by equipping the regulator with a reference network model, which emulates the network planning practices of an efficient utility and can help the regulator develop more accurate estimates of efficient network costs given the expected evolution of network uses. 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 thus *eliminates 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 systemic uncertainty.* The RNM gives the regulator a tool with which to "peer into the future" and *create a forward-looking benchmark* for efficient network expenditures that accommodates expected evolutions in network use, technology costs, and network management practices. 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. The RNM can also be used to explore a range of possible scenarios for the evolution of network uses (i.e., load growth and DER penetration). The model 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 forecasts 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 X-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

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37 For a quantitative evaluation of the performance of this method, including proof of the incentive compatibility of the overall process, equalized incentives for cost savings in OPEX and CAPEX, the ability of the process to accommodate uncertainty in the evolution of network uses, and the performance of the framework if the regulator errs in establishing their ex ante TOTEX baseline, see Jenkins (2014, p. 83-87).

parameters). The “slow money/fast money” 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 innovative contractual arrangements with the owners of distributed energy resources. Removing this distortion and equalizing cost-saving incentives across both categories of network expenditures is thus an important step to encouraging cost-saving active system management approaches and encouraging an evolution in the distribution utility business model.

Fourth, 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 X-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 X-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 the resulting regulatory contract 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 (2013a), Gomez (2013a), 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 pass-through), output-based incentives (financial incentives for adoption rates 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).

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Appendix A. Formulas for Construction of an Incentive Compatible Menu of Contracts

Symbol	Description	Formula/constraint
DISCRETIONARY INITIALIZATION PARAMETERS		
$\boldsymbol{\omega}$	Weight on regulator's estimate [p.u.]	[0,1]
$\mathbf{SF_{ref}}$	Reference value for sharing factor [p.u. share of over/under-spend retained by firm]	[0,1]
$\mathbf{SF_{roc}}$	Rate of change of sharing factor with ratio	<0
$\mathbf{AI_{ref}}$	Reference value for additional income [% of regulator's estimate]	-
CALCULATED INITIALIZATION PARAMETERS		
$\mathbf{AI_{int}}$	Intercept of additional income	$AI_{ref} - 100 * SF_{ref} *(\omega - 1) + 10^4 * SF_{roc} *(\omega - 0.5)$ $= AI_{ref} - 100*\alpha - 100^2*\beta$
$\boldsymbol{\alpha}$	1st order factor of additional income formula	$SF_{ref} *(\omega - 1) + 100* SF_{roc} *(1 - 2*\omega)$
$\boldsymbol{\beta}$	2nd order factor of additional income formula	$SF_{roc} *(\omega - 0.5)$
EX ANTE PARAMETERS		
$\mathbf{X_{firm}}$	Firm's *ex ante* TOTEX estimate [$]	Submitted by firm
$\mathbf{X_{regulator}}$	Regulator's *ex ante* TOTEX estimate [$]	Calculated by regulator using RNM
$\mathbf{R_{\textit{ex ante}}}$	Ratio of firm's estimate to regulator's estimate [%]	$X_{firm} / X_{regulator}$
$\mathbf{X_{\textit{ex ante}}}$	*Ex ante* allowed TOTEX baseline [% of regulator's estimate]	$\omega *100+(1 - \omega)*R_{\textit{ex ante}}$
SF	Sharing factor [p.u. share of over/under-spend retained by firm]	$SF_{ref} + (R_{\textit{ex ante}} - 100)* SF_{roc}$
AI	Additional income [% of regulator's estimate]	$AI_{int} + \alpha *R_{\textit{ex ante}} - \beta *R_{\textit{ex ante}}^2$

Symbol	Description	Formula/constraint
EX POST PARAMETERS		
$\mathbf{X}_{ex\ post}$	Realized *ex post* TOTEX [$]	Submitted by firm and audited by regulator
$\mathbf{R}_{ex\ post}$	Ratio of realized *ex post* TOTEX to *ex ante* allowed TOTEX baseline [%]	$X_{ex\ post}$ / $X_{regulator}$
$\mathbf{EI}_{ex\ post}$	*Ex post* efficiency incentive [share of over-under-spend retained by firm as % of regulator's estimate]	$(X_{ex\ ante} - X_{ex\ post})$*SF / $X_{regulator}$
$\mathbf{A}_{ex\ post}$	Final *ex post* adjustment to allowed revenues [% of *ex ante* regulator's estimate]	$EI_{ex\ post}$ + AI