Quantitative Analysis of Decoupling, Distributed Generation, and Net Energy Metering

by

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Abstract

Rapidly declining costs of rooftop solar systems and government incentives are helping to put increasing amounts of electricity generation on the customer side of the meter. Deployment of customer owned distributed generation (DG) such as rooftop photovoltaics (PV) fundamentally upends the traditional utility business model. It forces utilities to buy electricity from their customers and therefore reduces their electricity sales and their revenue. In the past, some regulated utilities have managed revenue loss from reduced sales due to implementation of energy efficiency programs through a regulatory policy known as *decoupling*, which severs the link between retail sales and revenues through an alternative rate setting procedure. Could decoupling also make a utility indifferent to reduced sales due to high penetration distributed photovoltaic generation? In this study, a computer simulation model represents a generic utility from 2012 through 2035, to explore the effects of increased DG penetration with and without decoupling. The model outputs utility financial performance, ratepayer costs and benefits, and environmental emissions performance. Results suggest that under growing penetration of distributed PV generation, decoupling does protect utility financial performance compared with traditional ratemaking. However, in the long run it cannot inure the utility against loss of market share and rate base erosion. While PV imposes increased costs on the grid, ratepayers are better off due to deferral of investments in supply side energy and possibly capacity assets. Emissions of greenhouse gasses and criteria pollutants are reduced with high penetration PV. The study highlights the challenges ahead for updating the traditional utility business model for the 21st century should current trends continue to put customer owned generation within reach.

1.0 INTRODUCTION

By 2013, most investor owned electric utilities and their regulators have at one time or another grappled with the issue of decoupling, the "regulatory business model" by which utility revenues are delinked from retail sales. Decoupling is a regulatory policy that changes the way price regulated utilities are allowed to set volumetric rates for their customers to neutralize the incentives to maximize retail sales in order to maximize profits. While there are business reasons why a utility might wish to move to a decoupled environment, such as minimizing risk of lower than expected sales, decoupling is primarily understood as a critical pillar of an alternative regulatory business model that enables utilities to fully embrace aggressive energy efficiency programs that would otherwise erode revenues.

The effect of decoupling on utility financial performance as well as ratepayer costs and benefits in the context of energy efficiency has been studied in the consulting and academic literature, especially by Eto et al (1997), the National Action Plan for Energy Efficiency (2007), the Regulatory Assistance Project (2011), Cappers and Goldman (2009), Satchwell and Cappers (2011), and others. However, little attention has been paid to the effect of high penetrations of distributed generation (DG) as enabled by Net Energy Metering (NEM), perhaps because DG and NEM have yet to impact the electricity sector in a substantial way. This appears to be changing. Rapidly decreasing prices of solar panels coupled with NEM incentives and state mandates to stimulate renewable energy are building momentum towards a future of much higher penetrations of customer-owned distributed generation and consequently, reduced utility sales. Does the possibility of increasing DG support the business case for decoupling? Do ratepayers lose or benefit from this scenario?

This paper attempts to provide some insight into these questions by applying the framework used by Cappers and Goldman (2009) to study the costs and benefits of alternative regulatory business models to the question of high penetration DG and NEM. They use a modeling approach that constructs a hypothetical utility and projects the costs and benefits of an aggressive energy efficiency portfolio. For this analysis, we have built a model of a hypothetical vertically integrated electric utility located in an environment that resembles the Midwestern states of the U.S. The Midwest was chosen so as to investigate an area with very low to non-existent DG penetration as a counterfactual. It also has the benefit of not closely resembling a policy area where interest in DG is high, such as California, thereby avoiding particular policy details and rather demonstrating broader principles about DG, NEM, and decoupling. For this analysis, we only evaluate rooftop solar, which comprises the vast majority of NEM accounts.

We find that decoupling is in the business interest of an electric utility faced with a high penetration of distributed photovoltaic resources connected to the grid with NEM tariffs. Compared with traditional ratemaking, decoupling limits the losses a utility incurs due to reduced sales and stabilizes shareholder return. However, decoupling does not immunize a utility against long-term rate base erosion due to reduced need to build centralized supply-side assets. Ultimately, a growing penetration of distributed PV introduces competition to what was previously a natural monopoly. Instead, the utility becomes a “regulated monopsony”, forced to buy DG at retail prices. Reduced market share means reduced earnings and a smaller utility. While high penetration distributed PV adds cost to the grid that ratepayers must bear, including integration costs and a net energy metering subsidy, we find that due to the deferral of investment in supply-side assets, PV is of net benefit to ratepayers. We also find that a high penetration of distributed PV would reduce greenhouse gas emissions and criteria pollutants although we do not calculate the cost of abatement. We conclude that distributed generation resources pose a fundamental challenge to the regulatory bargain that has been the dominant utility business paradigm for a century. A distributed utility becomes more of a manager of the grid rather than supplier of electrons. Consequently, utilities and their regulators would need to develop a transition strategy that fairly compensates utility shareholders for their investment in grid infrastructure while also supporting distributed generation and guarding against cross subsidies the unfairly penalize less affluent ratepayers.

This paper is organized as follows. Section 2 reviews the theory of decoupling in the context of a comprehensive approach to an alternative regulatory regime that aligns the underlining incentives for utility managers to maximize investment in the lowest cost resource; whether that is efficiency, DG, or new utility generation. Section 3 discusses distributed generation, primarily rooftop solar, and how the net energy metering tariff incentivizes it. Section 4 describes the data gathered and the modeling approach. Section 5 describes the analysis, including a number of sensitivity cases to observe the effects of variation in key parameter estimates as well as test the impact of key uncertainties such as PV penetration and peak demand coincidence. Section 6 concludes with a discussion of the implications for utility business leaders and policymakers. Key assumptions and modeling inputs are included in the Appendix.

2.0 THEORY OF REVENUE DECOUPLING FOR ELECTRIC UTILITIES

Traditional "cost-of-service" regulation has been the dominant business model for vertically integrated electric utilities since Samuel Insull's Commonwealth Edison pioneered the form in the 1920s. Under this model, prices are capped between rate cases and utilities bear the risk of lower sales of electricity relative to projections. Revenue decoupling flips this dynamic by assuring the utility receives its required revenue regardless of the amount of actual sales. Decoupling, as part of a comprehensive redesign of the utility business model, has important consequences for how the utility behaves towards public policy driven efforts to conserve energy (National Action Plan for Energy Efficiency, 2007).

2.1 The Traditional Cost of Service Regulatory Model

Electric utilities are characterized by very high investment costs in fixed assets such as power plants and transmission infrastructure and relatively low marginal costs such as cost of fuel or purchased power. The "natural monopoly" occurs when long run average costs decrease rapidly, duplicative infrastructure is infeasible, and consequently the most efficient solution is for one firm to supply the entire market (Brown 2010). Since a monopolist will constrain production in order to maximize profits, government price regulation and a legal requirement to provide universal service is necessary.

The utility and regulators go about the complex and often contentious process of setting the electric tariffs designed to recover costs and earn a return for investors in the rate case. Typically the utility initiates a rate case proceeding with a requested rate increase and a justification based on current or projected under recovery of revenue. Rate cases are held in an administrative law setting, where utility executives provide testimony and outside groups such as consumer advocates, industrial interest groups, and environmental organizations may intervene. Ultimately, public utility commissioners rule on two key numbers: the revenue requirement and the allowed return on rate base. The revenue requirement is the amount of revenue the utility needs to collect in order to meet costs of production, such as operations and maintenance expenses, taxes, depreciation and interest on debt. These items are to be recovered at cost. Capital investments on the other hand are booked into the rate base, a balance sheet asset upon which utilities earn a return. In a general rate case, the Public Utility Commission (PUC) will rule on what a utility may collect as profit to return to shareholders, based on considerable judgment about what investors will require and comparison with other utilities in similar jurisdictions.

Table 1: Summary of Traditional Ratemaking Formula Variables

Variable	Description
RR	Revenue requirement
O	Operations and maintenance
D	Depreciation
T	Taxes
I	Interest
R	Return
t	Test year
U	Cost of service

Variable	Description
k	Customer class
Rb	Rate base
ARR	Allowed rate of return
P	Plant in service
AD	Accumulated depreciation
RR	Retail rates
D	Revenue
S	Retail sales

The traditional cost of service regulatory formula is as follows:

$$RR_t = O_t + D_t + T_t + I_t + R_t \quad Eq. 1$$
$$R_t = Rb_t \times ARR \quad Eq. 2$$

That is, revenue requirement is the sum of operations expenses, depreciation, taxes, interest, and return, where return is the rate base multiplied by the allowed rate of return. Most jurisdictions use a historic test year (t) to determine the values for each of the revenue requirement components. As rate cases are legal proceedings that can take a year or more to complete, utility rates experience "regulatory lag" in that rates based on last year's cost structure will go into effect sometime next year. Rate base is defined as the difference between total physical plant in service in the test year (P_t) and accumulated depreciation in the test year (AD_t).

$$Rb_t = P_t - AD_t \quad Eq. 3$$

Rates must be designed to collect the revenue requirement. In order to avoid cross subsidization, the revenue requirement is more or less divided into revenue requirements by customer class, such as industrial, commercial, and residential, and charged according to their cost of service.[1]

$$Rb_t = \sum_{k=1}^{n} Rb_k \quad Eq. 4$$

Rate base by customer class is a function of the size of the total rate base and the relative cost to serve that customer class or RB_k= f(Rb_t, U_k). Retail rates, indexed by test year and customer class (RR_{tk}), include a fixed customer charge to recover billing and some fixed costs of service, a fixed or block volumetric rate ($/kWh), and a demand charge for high demand classes of consumers ($/kW). Within the customer classes, the volumetric portion of the retail rates is determined by dividing the amount of revenue to be collected through the volumetric rate by the test year retail sales. Once rates are set, they are fixed until the next rate case ruling. Thus,

[1] Generally, residential customers are more costly to serve due to their low consumption relative to the high cost of physical assets required to serve them. Commercial is next costly and industrial is the least costly to serve.

for any given year n, the actual revenue D received by the utility is actual retail sales multiplied by the last adopted rate structure.

$$D_n = Rr_{kt} \times S_{kn} \quad Eq. 5$$

If prices cannot change, the utility maximizes profits in two ways: minimizing costs without customer discrimination and maximizing retail sales whenever marginal revenues are greater than marginal costs. This is known as the "throughput incentive" (Moscovitz 1989). The typical utility business model vastly under recovers its fixed costs with the fixed charge but makes up the difference in the volumetric rate. In other words, actual variable costs are only a fraction of the $ per kilowatt price customers see on their electric bill. This means that for most hours in a given year, the utility's marginal cost is significantly below the price charged, which sets up a strong disincentive to encourage efficiency, conservation, or self-generation. This is especially pronounced in jurisdictions that have fuel adjustment clauses, which directly expense fuel and purchase power costs in real time, thereby passing all fuel risk onto the ratepayer.

2.2 Alternative Utility Business Models

Advocates of alternatives to the traditional regulatory business model cite decoupling as a critical component of a "three-legged stool" (National Action Plan for Energy Efficiency, 2007). The goal is to restructure the regulatory policy such that the utility is always incentivized to procure the lowest cost asset to meet demand (Moscovitz 1989). The underlying assumption is that "negawatts" or reductions in demand from efficiency and demand response are often the most efficient energy resource from a welfare theory perspective but are not aligned with utility shareholder incentives under traditional cost of service regulation. By this logic, severing the link between sales and utility revenues makes the utility indifferent to a reduction in sales because they are guaranteed to recover their revenue regardless. The other two legs of the "stool" include guarantees of cost recovery related to administration of energy efficiency programs and shareholder incentives that represent foregone return from investment in supply side assets. The details and consequences of program cost recovery and shareholder incentives are out of the scope of this paper. Rather, we take a closer look at decoupling and model the performance of a utility under traditional and decoupled regimes.

2.3 The Mechanisms of Decoupling

There are three primary mechanisms to decouple revenues from sales. The first is to simply charge a fixed fee per customer in line with their cost of service. A small volumetric rate would be added to collect variable costs of fuel and purchased power. This system, known as straight-fixed variable pricing, has found little enthusiasm, as it is highly regressive when charged to low income and low usage customers. The second system is known as Lost Revenue Recovery Mechanism (LRAM), where a utility gets reimbursed from the PUC based on an estimate of lost revenues due to energy efficiency programs. This method has been tried, but has lost favor due to highly contentious monitoring and evaluation requirements (Sullivan et al 2011). The third, and the focus of this paper, is revenue per customer decoupling (RPC).

RPC links revenue recovery to customer growth rather than retail sales and allows for automatic rate adjustments at regular intervals (e.g. yearly, quarterly, monthly, etc.). Customer growth is less variable than sales, which are highly sensitive to weather, economic conditions, and investment in energy efficient or self-generation capital stock. Furthermore, the number of customers is a more reliable indicator of cost incurred by the utility to serve a territory, as fixed costs to set up new connections or build peak capacity dominate total utility costs.

In a decoupled environment, the formula for calculating revenue requirement during a rate case remains the same, but decoupling does change the way rates are calculated in between rate cases. Let C_t equal the number of customers in the test year t. The RPC metric set at the rate case is as follows:

$$RPC_t = \frac{RR_t}{C_t} \quad Eq. 5$$

For any given time interval m after the rate case the revenue requirement is calculated as follows:

$$\mathrm{RR_m} = \mathrm{RPC_t} \times \mathrm{C_n} \quad \mathrm{Eq.\,6}$$

That is, the revenue requirement in any given time tranche is equal to the revenue per customer calculated in the test year multiplied by number of actual customers in the current year. The rate is then the revenue required in the current year divided by actual retail sales.

$$\mathrm{Rr_{nk}} = \frac{\mathrm{RR_{nk}}}{\mathrm{S_{nk}}} \quad \mathrm{Eq.\,7}$$

A utility found to be under collecting in a previous time period will have an automatic rate adjustment to bring revenues back in line. However, the converse is also true. A utility that over collects will have to reduce rates and essentially refund ratepayers (Lesh, 2009).

Decoupling therefore insulates the risk of under-collecting revenue for any reason, including aggressive efforts to reduce consumption through efficiency, conservation, or DG. On the other hand, the utility loses any benefit from unexpected increases in retail sales due to spurts of economic growth. Thus, historically, utilities with growing costs but stagnant sales have been most receptive to decoupling. This was the case with the natural gas transmission industry, which like the electric power industry was traditionally regulated but faced flat and declining retail sales (Sullivan & Bennett, 2011). Critics point to potential change in management behavior that makes them less likely to respond quickly to avoid sales disruptions. For example, Brennan (2012) notes that after Hurricane Isabel, the electric utility may have been slow to respond because they knew they would receive their revenue requirement regardless of whether their sales took a hit from the storm. He also cites an assessment from the Electricity Consumers Resource Council (ELCON), which states that decoupling “promotes mediocrity” by eliminating efficiency incentives, when profits become independent of use (ELCON 2007). By the same line of reasoning, utilities are also effectively passing risk onto consumers and diluting the incentive for utilities to aggressively manage costs.

Also, some have concluded that decoupling should be combined with a reduction in allowed rate of return due to the reduced risk of under recovery. Decoupling makes the utility business much less risky, and as such investors should not be allowed to receive returns commensurate with much riskier classes of investments (Weiss 2008). When decoupling implies a reduction in allowed return, utilities are more likely to balk and fight decoupling in the political process. Thus, some see decoupling as a political give away to a powerful stakeholder in exchange for non-interference in public policy objectives of promoting greater amounts of energy efficiency.

2.4 Decoupling and Energy Efficiency: Who Wins and Who Loses?

Studies on decoupling typically focus on how energy efficiency programs affect utility financial performance and rates. Advocates of energy conservation generally point to decoupling as a necessary tool to neutralize utility resistance to policies that mandate deep investment in energy efficiency, such as Energy Efficiency Resource Standards. Various studies have attempted to model the costs and benefits for those who participate in energy efficiency plans and the vast majority of ratepayers who do not. We have seen from these studies for regimes with decoupling, program cost recovery, and shareholder incentives, that energy efficiency programs are essentially a wealth transfer from the non-participant ratepayer, who must bear increased rates in order to pay for efficiency programs, to the participant, who installs subsidized efficiency upgrades (Croucher 2012).

The utility with decoupling is inured to reduced sales from energy efficiency because their revenue requirement is decoupled from retail sales. They also may make money on the negawatts they "generate" from investment in efficiency if a shareholder incentive plan such as Shared Savings or Performance Incentives are in place. The ratepayer on the other hand gets a mix of costs and benefits. On the benefits side, if a utility invests in EE, they differ the need to build physical assets such as power plants and increased transmission capacity, which translates to lower revenue requirements and lower rates. The costs side include the cost of running the energy efficiency program, including millions of dollars for incentives, program administration, marketing, implementation, monitoring and evaluation. These program costs, in a regime of guaranteed program cost recovery such as EE bill riders, mean that those costs are passed directly into increased rates shared by all ratepayers. For those who participate, the net benefit is clearly positive, as savings from EE exceed costs of increased rates. Non-participants see increased rates, which are somewhat offset by lower rates *than otherwise would be* from capital deferment. Thus, how much EE can differ utility CapEx is a key factor in apportioning costs and benefits. The balance of risk, costs and benefits between utility, participant, and non-participant is a highly contentious issue amongst various parties when these issues come before PUCs.

2.5 Decoupling, Distributed Generation, and Net Energy Metering

This analysis departs from previous studies in that we wish to evaluate the balance of costs and benefits between utility, ratepayer, and environment in a scenario of high penetration of distributed generation under net energy metering tariffs. Distributed generation is simply customer owned generation connected to the distribution grid. The most well-known example of DG is rooftop PV, but other examples include combined heat and power engines, fuel cells, and micro-wind turbines (Thornton & Monroy, 2011). In this paper, we will only refer to rooftop PV, which is the focus of our analysis. Many states incentivize customer generation as an environmental policy to promote renewable energy technologies and reduce greenhouse gas emissions. For example, the State of California's Million Solar Roofs program aims to spend $2.17 million to support installation of 1,940 MW of distributed PV capacity by 2017 (CEC 2013). Some see DG as part of a growing trend towards a more decentralized virtual power plant approach that combines smart grid, storage, distributed generation , and efficiency that could in theory be balanced to form a self-sustaining energy ecosystem (Pudjianto, Ramsay, & Strbac, 2007).

A common approach to provide an ongoing incentive to install PV is a net energy metering (NEM) tariff. NEM tariffs allow customers to use excess generation put onto the grid as a credit for times in which power is withdrawn from the grid. Credits can roll over from month to month in a twelve-month period. While the sun is shining, generation covers onsite load and excess is put onto the grid. Between 7 PM and 7 AM, the system is drawing power. Typically, any excess generation at the end of the twelve-month period is forfeited, although California has recently implemented legislation to roll over energy credits indefinitely or pay the customer at wholesale market prices (E3 2010) . The forfeiting of the remaining balance at year end is designed to discourage customers from oversizing systems to meet more than their annual load.

Like the EE analysis, PV and decoupling involves both costs and benefits to the ratepayer.

Table 2: Costs and Benefits of Distributed PV and NEM Tariffs

Benefits	Costs
Reduced fuel and purchased power	Increased billing costs
Deferred assets	Distribution infrastructure
Capacity value	Integration costs
Reduced T&D losses	NEM subsidy

Table 2 shows costs and benefits related to PV and NEM. On the benefits side, PV can reduce utility fuel and purchased power costs and may defer the need for capital expenditures on power plants and increased transmission capacity. PV reduces losses from transmission because energy is generated at the load, thus the system benefits from 1.07 kW for every 1.0 kW of PV due to reduced line losses (Denholm & Margolis, 2006). DG can also provide network support or ancillary services (Bayod-Rújula, 2009).

On the costs side, ratepayers bear increased utility costs associated with distributed PV and NEM tariffs. NEM tariffs are widely considered a subsidy because distributed generation increases grid and administrative costs that the remaining ratepayers must bear. Local distribution networks, which were not designed to handle generation, require upgrades to equipment such as distribution feeders (Navigant, 2010). Furthermore banking excess credits is essentially forcing utilities to procure energy at a cost equal to retail rates rather than what would otherwise be lower wholesale avoided costs, which we call the NEM subsidy. That being said, the level of the subsidy is not well understood, as PV owners put energy onto the grid nearly coincident with peak load when energy is very valuable and withdraw power off-peak when energy is cheap. Reduced retail sales coupled with these increased costs can lead to higher rates borne by ratepayers.

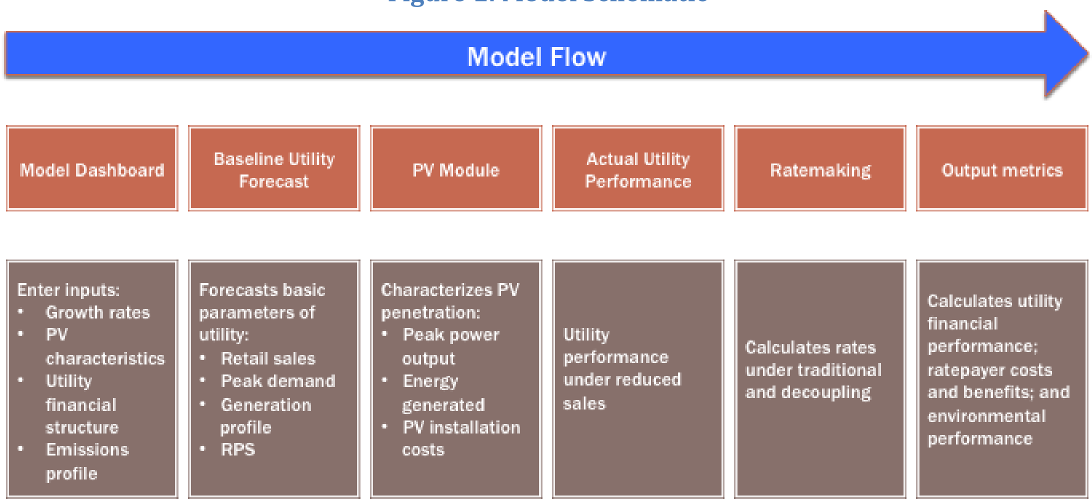
3.0 DATA AND METHODOLOGY

To begin to answer some of these questions on costs and benefits amongst various stakeholders, we developed a spreadsheet based financial model of a generic electric utility that calculates utility financial performance metrics, average retail rates, customer bills, and emissions savings. The data is stylized from real and recent information from two Midwestern utilities: Westar and Kansas City Gas and Electric. Additional data on PV was taken from the three California investor owned utilities: Pacific Gas and Electric (PG&E), Southern California Electric (SCE) and San Diego Gas and Electric (SDG&E). The goal was to characterize a believable electric utility that we can monitor from 2012 through 2035. This generic utility approach demonstrates general principles about alternative utility business models without paying excessive attention to modeling specific utilities and avoiding references to contentious politics of specific utility rate cases.

We chose to model a generic Midwestern utility because it currently has a low penetration of distributed PV, which we can approximate as zero. This allows us to set up a counterfactual of business-as-usual to compare with scenarios of high penetration of PV. Midwestern states such as Kansas also have high insolation, similar to that of the San Francisco Bay Area and the California Central Valley, which makes it an ideal environment for PV (NREL 2013). The fact that the Midwestern States are traditionally regulated makes them good laboratories for experimenting with the effects of decoupling. We chose to only monitor the effect of PV because 99 percent of NEM tariffs in California go to rooftop PV (E3 2010).

Figure 1 shows a schematic of the model architecture and a summary of major model inputs.

Figure 1: Model Schematic



The model is designed to perform a time–series simulation of utility financial performance, ratepayer costs and benefits, and environmental performance. A dashboard allows the user to vary inputs and assumptions and to generate model outputs. The major modules include utility characterization, a baseline utility forecast, a module that calculates actual utility performance, a distributed PV module, a ratemaking module, and a cost/benefit calculation module. The model simulates regular rate cases based on actual conditions faced by the utility. It has an embedded algorithm (based on a logical statement) that will build supply-side assets as needed to meet growing customer demand. As PV penetration grows, the utility adjusts its behavior accordingly.

3.1 Characterizing the Utility

The model generates a baseline utility forecast of key variables such as generation capacity, purchase power agreements, fuel costs, capacity factors, retail sales, customer counts, and peak demand; from an initial set of values and linear compound annual growth rates (CAGRs). We assume the utility needs to meet RPS standards, faces requirements for environmental upgrades on coal facilities, and needs to build transmission to accommodate new wind resources. We also characterize the financial situation of the utility by specifying gross plant value, accumulated depreciation, tax rates, and capital structure.

Actual utility performance is based on increased costs from PV and how retail sales are reduced due to increasing penetrations of DG. The model contains simple decision logic that automatically builds new supply assets based on peak demand and energy requirements. When the utility's peak capacity falls below the required reserve margin of 12 percent above peak demand, a 277 MW peaking natural gas combustion turbine is built. When the utility's generation slips below a certain percentage of total demand, the utility builds a 550 MW natural gas combined cycle plant[2]. The utility books the CAPEX required for these assets into their rate base spread evenly during the time of construction up to its in-service date. As peak demand and retail sales are reduced by PV, the utility will defer building these supply side assets, resulting in a benefit to the ratepayer. An adjusted utility forecast characterizes the utility across the time series that includes the capacity additions.

3.2 Modeling Distributed Generation

We modeled distributed rooftop PV as meeting an increasing amount of total system load. We assume zero penetration in 2012 and allow the user to decide on the achieved penetration in 2035. Key variables such as average system size,

[2] We use 12 percent as a default, which means that no more than 12 percent of load is met through wholesale power purchases. We felt this was a believable decision criteria as the utility has a financial interest in building supply-side assets if they can justify it as lower cost than purchasing power on the wholesale market. In the model the user can vary the tolerance for demand met by the wholesale market.

average capacity factor, incremental billing costs, and integration costs are entered exogenously. We estimated annual effects due to PV given average system sizes of residential (5.7 kW) and non-residential (217kW) systems, plus assumed growth rates of system size based on current trends (Interstate Renewable Energy Council, 2012).

Having increasing grid connected rooftop PV both reduces the utility's retail sales and perhaps the peak demand that the utility is responsible for meeting. The capacity value of distributed PV system is a matter of debate. While it is true that PV generally reaches maximum output in the late afternoon, it is not entirely coincident with peak. In fact, solar output exhibits a sharp drop once the sun sets but heat has not dissipated enough to reduce A/C load in the summer peak. A Navigant (2010) study for NV Energy concluded that distributed PV has no capacity value, while other estimates give it a value as high as 40 percent of peak output power (Hoke and Komor 2012). The model reflects uncertainty and variability in the level of solar capacity value and allows the user to experiment with differing percentages. With high levels of coincidence, solar will significantly reduce peak demand and thus defer the need for peaker plants. If coincidence is much less, solar may not actually contribute to much in any CAPEX deferral, making it more of a solely avoided energy cost resource. It is important to note that regardless of peak coincidence, at high penetration levels, DG from solar could increase the need for ancillary services which could in turn increase the need for investment in fast ramping generating units or energy storage. This is because with DG generation, the steepness of the net load curve (i.e. electrical load minus DG) could increase significantly, since most DG resources would reduce their power output to near zero at virtually the same time (when the sun sets). This situation is of concern in regions with high penetration of DG such as California, but can be left out of the analysis for the DG levels analyzed in this study.

How much PV energy is exported during peak periods has important consequences for environmental benefits. We assume solar at off-peak times will reduce the need for base load coal for this primarily coal based utility. Peak period solar will reduce the need for both coal and natural gas, depending on which one is on the margin. For a Midwestern utility coal is still sometimes on the margin during peaking periods depending on the season. We assume that during peak periods, coal is on the margin 40 percent of the time.

3.3 Ratemaking

The model represents two ratemaking regimes: traditional and RPC decoupling. Both are driven by a rate case logic that initiates a rate case proceeding either on a two-year cycle or by a CAPEX trigger. For the latter, the default trigger initiates a rate case if CAPEX exceeds $300 million. If a rate case is triggered, the model calculates retail rates based on the ratemaking formulas described in sections 2.1 and 2.2. Values to calculate revenue requirement are drawn from the preceding year's data because the utility uses a historic test year. The rate calculated in the rate case year goes into effect the following year, representing regulatory lag. Fuel and purchased power is expensed directly in the year it was incurred through a fuel adjustment clause. The model then combines the fuel adjustment rider and the rate from the general rate case to estimate an all-in-average retail rate for both the traditional and the decoupled utility. These rates are then used to calculate actual utility performance and customer bills.

3.4 Outputs

The model calculates key output metrics for the stakeholders of concern: utility, ratepayer, and environment, based on data calculated from the previous modules. For the utility, the all-in-average retail rates are multiplied by actual retail sales to generate revenues. Costs include fuel and purchased power, O&M, interest on debt, and taxes. Profits are divided by total equity to calculate ROE. The model calculates average retail sales by residential and non-residential accounts. Multiplying these numbers by the retail rates gives total energy expenditure per average residential and non-residential ratepayer. Energy savings calculations from the DG modules are multiplied by average emissions factors for coal and natural gas turbines to generate emissions savings of CO_2-equivalent, SO_2, and NOx.

4.0 ANALYSIS

For our analysis, we modeled a scenario where 15 percent of utility retail sales are supplied by distributed PV by 2035. We chose 15 percent based on an estimate by NREL (2010) that shows available roof space could allow between 10 and 25 percent of load to be met through PV. Very high penetrations of PV (greater than 20 percent) increase integration costs exponentially, therefore in our judgment 15 percent is a believable high penetration level that still works within our linear growth assumptions (Denholm and Margolis 2007). Table 3 lists key assumptions in our first model analysis.

Table 3: Key Model Assumptions

Input	Value	Reference
2012 percentage of load supplied by PV	0%	
2035 percentage of load supplied by PV	15%	NREL 2012
Capacity value factor	0%	Navigant 2010
Average residential system size	5.7 kW	US Solar Market Trends 2012
Average nonresidential system size	217 kW	Sunshot 2010
Incremental NEM billing costs	$9.10/account	E3 2010
Integration costs	$0.003/kWh	Hoke and Komor 2012
Customer count growth rate	2%	Energy Information Agency (EIA)
Retail sales growth rate	1.7%	EIA
Peak demand growth rate	1.5%	EIA

The following figures present the model outputs from the first simulation. The red and blue lines in the time–series diagrams represent traditional and decoupled ratemaking respectively in the base case (business as usual or BAU) with no customer owned distributed generation. The green and purple lines represent traditional and decoupled ratemaking under the 15 percent PV scenario.

Figure 2: All-in-Average Retail Rates

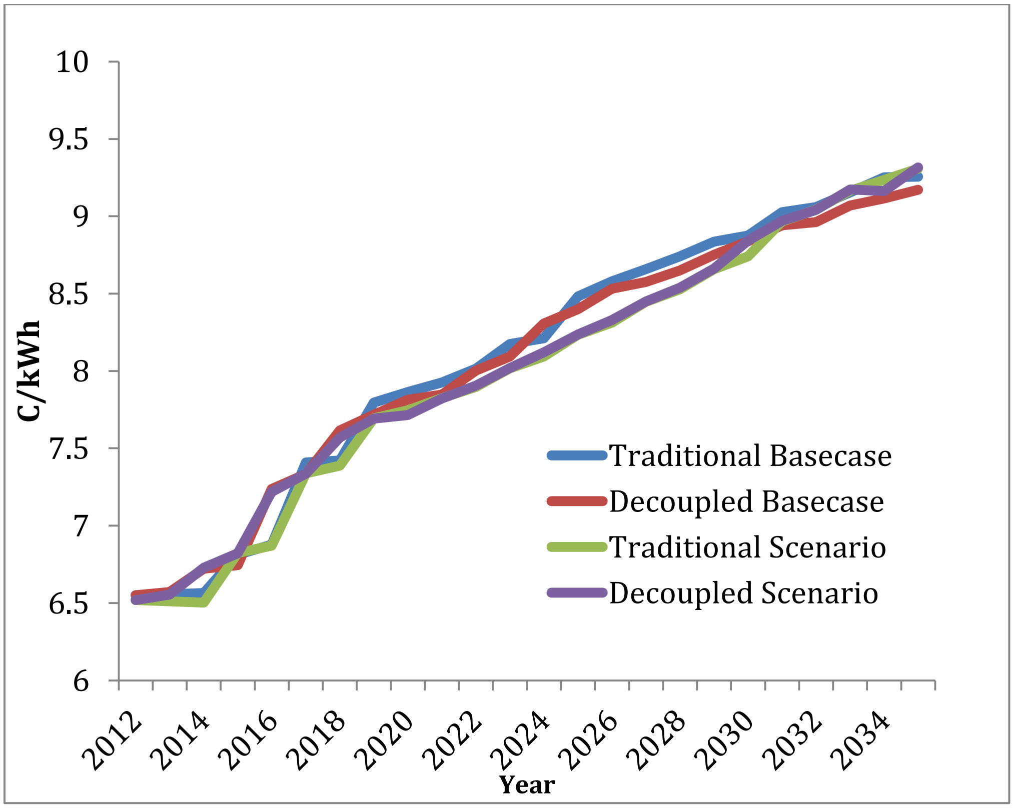
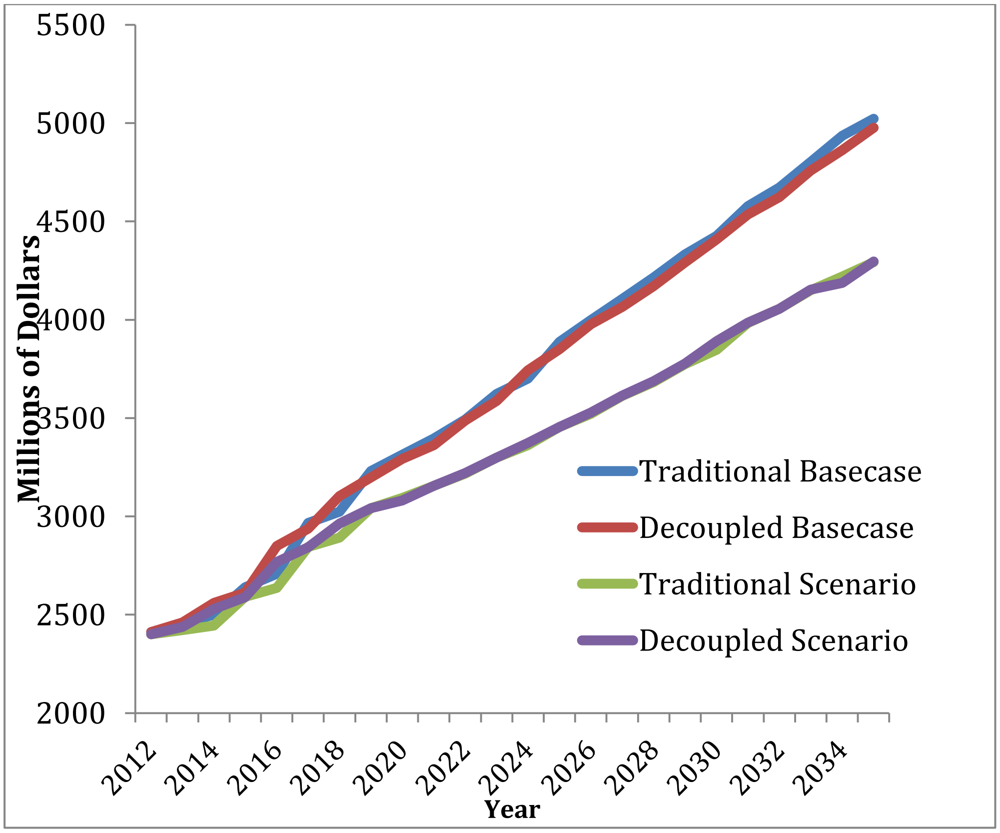


Figure 2 shows that all-in-average retail rates track closely for all cases, rising from approximately 6.5 cents per kilowatt hour in 2012 to nine cents per kilowatt hour by 2035. Retail rates are higher in the decoupled scenario in the early years. By 2020, both traditional and decoupled in the DG scenario case provide lower rates to consumers through approximately 2031.

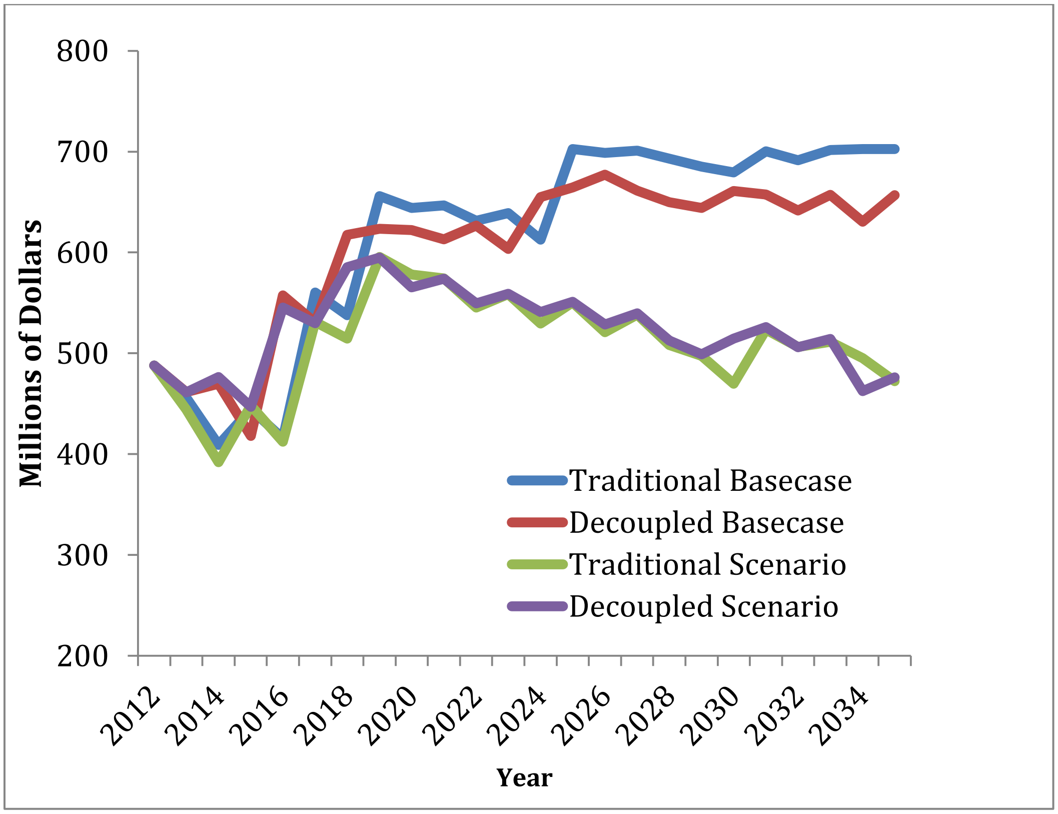
There is a significant change in trend for collected revenues, shown in Figure 3, beginning in 2016.

Figure 3: Collected Revenues



Collected revenues track closely by ratemaking type depending on the scenario. Under the 15 percent PV penetration scenario, the utility collects far fewer revenues, about 800 million less by 2035. This decrease in revenues is reflected in the utility's return shown in Figure 4.

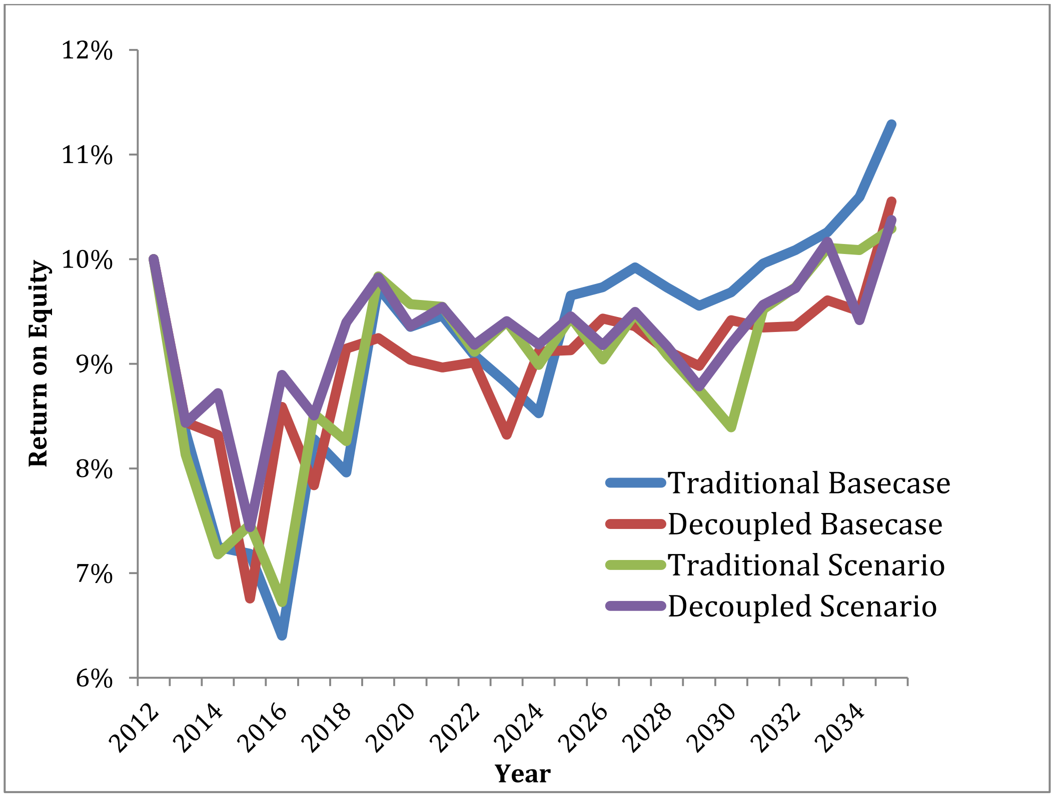
Figure 4: Utility Return



With no PV, the utility earns $500 million in 2012 and increases its earnings to between $600 and $700 million by 2035. However, with PV the utility's earnings peak in 2019 and decrease to under $500 million by 2035. The utility's return is much less volatile under decoupling in both the base case and the DG scenario. The blue and green lines which depict return under traditional ratemaking exhibit much sharper peaks both of high return and low return. Under traditional ratemaking, the average return on equity over the time period is 9.0 percent with a standard deviation of 0.9 percent. Under decoupling, our scenario shows an average return on equity of 9.3 percent with a standard deviation of 0.6 percent. These results are consistent with decoupling theory, which postulates that decoupling's automatic adjustments reduce revenue volatility and risk of under recovery.

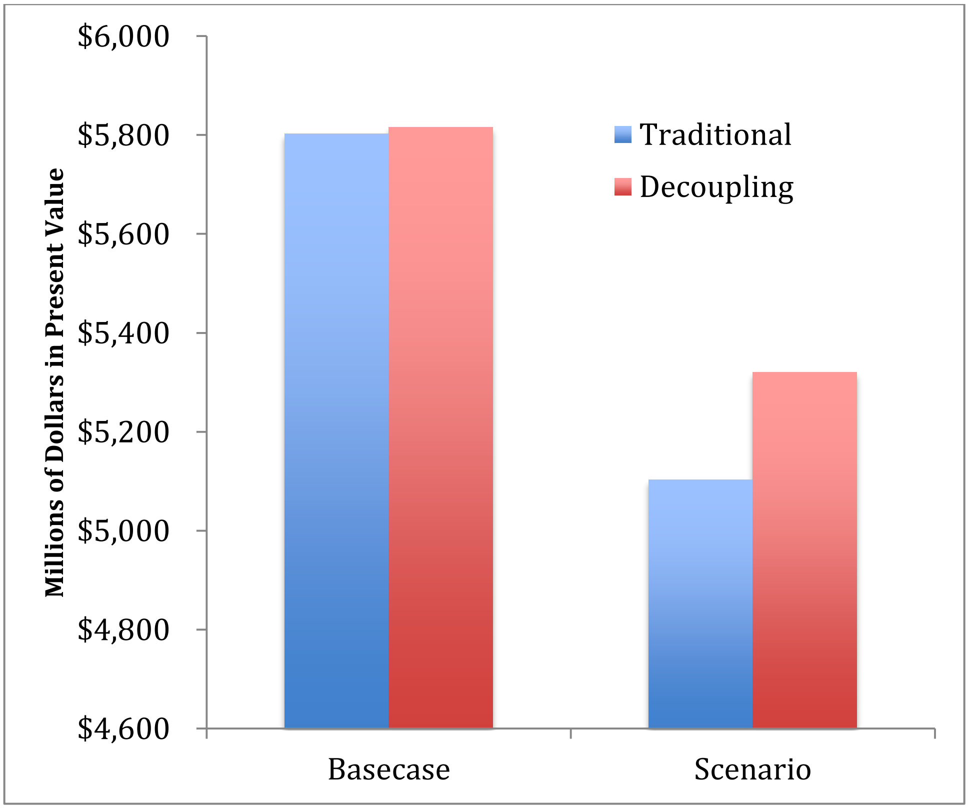
Utility financial performance in terms of return on equity, depicted in figure 5, becomes more complicated.

Figure 5: Return on Equity



Through 2035 the decoupled utility with distributed PV achieves the best performance, although all cases exhibit significantly lower achieved ROE then the allowed ROE of 10 percent in the early years. This is due to significant spending on environmental upgrades and new transmission and regulatory lag. After 2024, traditional ratemaking in the no PV scenario significantly outperforms all other cases. Figure 6 shows after-tax earnings in present value terms.

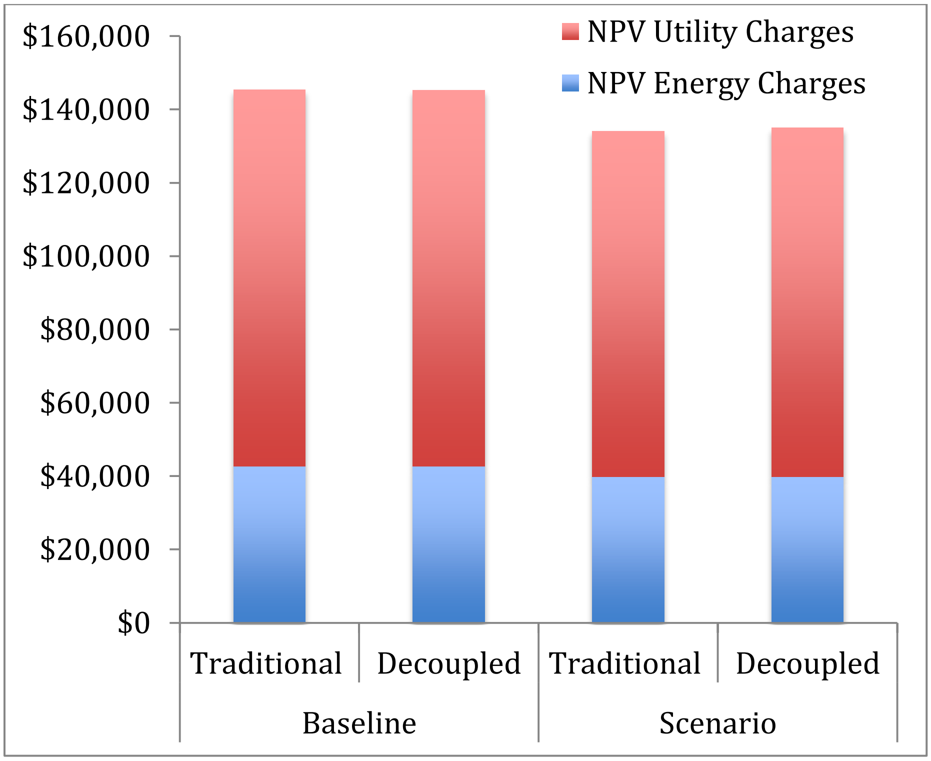
Figure 6: After Tax Earnings in Present Value



In the base case, over the entire time series traditional and decoupled ratemaking perform nearly identically. However, under the high penetration PV scenario, decoupling significantly outperforms traditional ratemaking from the utility's perspective.

Figure 7 depicts customer bills by energy and utility charge in net present value terms.

Figure 7: Customer Bills in Present Value



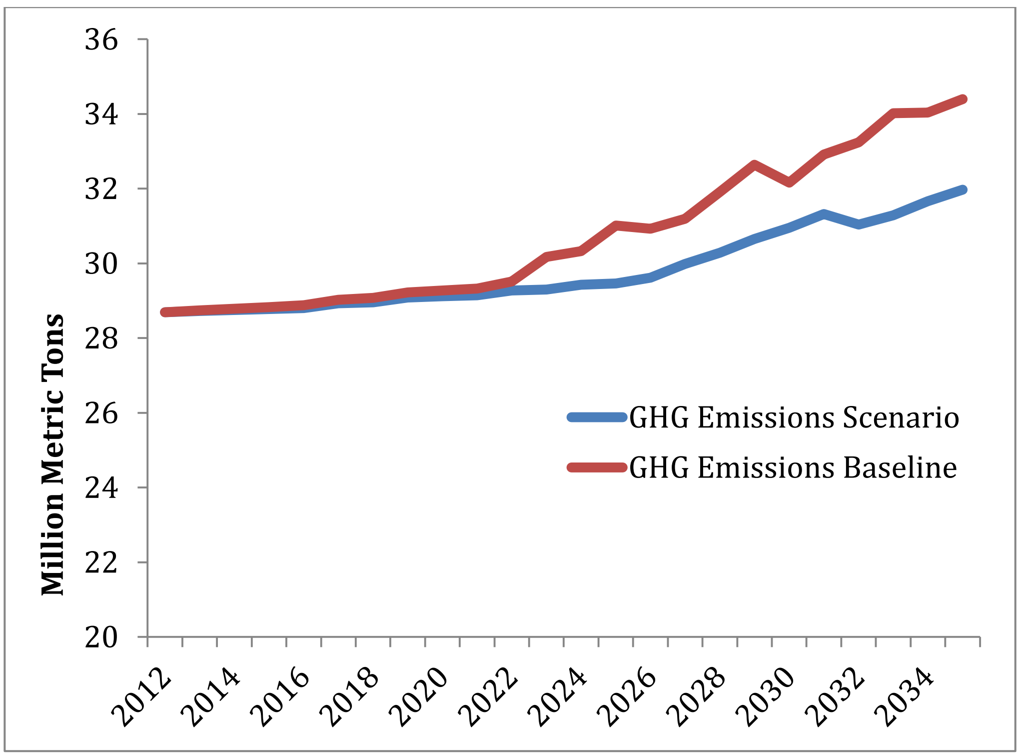
The blue bars show how much customers are paying for fuel and purchased power while the red bars show the part of their energy expenditure that is used for utility operations and capital expenditures. The figure shows that customers will pay less over the course of the time period when there is high penetration PV on the system. As shown in Table 4, while PV avoids the cost of fuel and purchased power, most of the savings come from reductions in the utility charge. This stems from the fact that PV defers the need to build supply-side energy assets to meet load and comply with the RPS standard. The utility is unable to put new equipment into rate base to keep up with depreciation. As rate base erodes, retail rates cannot increase as much as they otherwise would with no PV. This results in a direct benefit to ratepayers that exceeds the increased costs of PV integration through the NEM tariff and integration costs.

Table 4: Customer Bills

	Baseline		Scenario		Difference	
	Traditional	Decoupled	Traditional	Decoupled	Traditional	Decoupled
NPV Energy Charges	$42,703	$42,703	$39,840	$39,840	-$2,863	-$2,863
NPV Utility Charges	$102,726	$102,633	$94,312	$95,157	-$8,413	-$7,476
NPV Total Bills	$145,429	$145,336	$134,153	$134,997	-$11,276	-$10,339

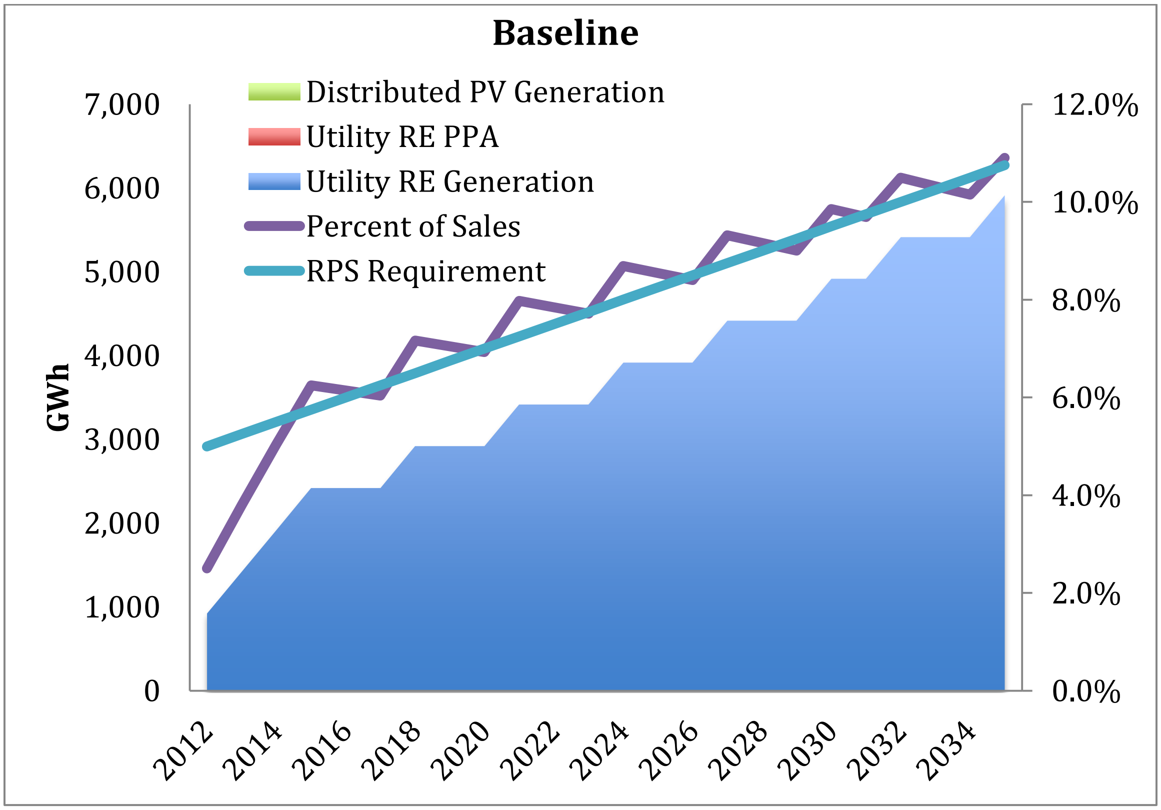
Figure 8 show the greenhouse has emissions consequences of high penetration PV.

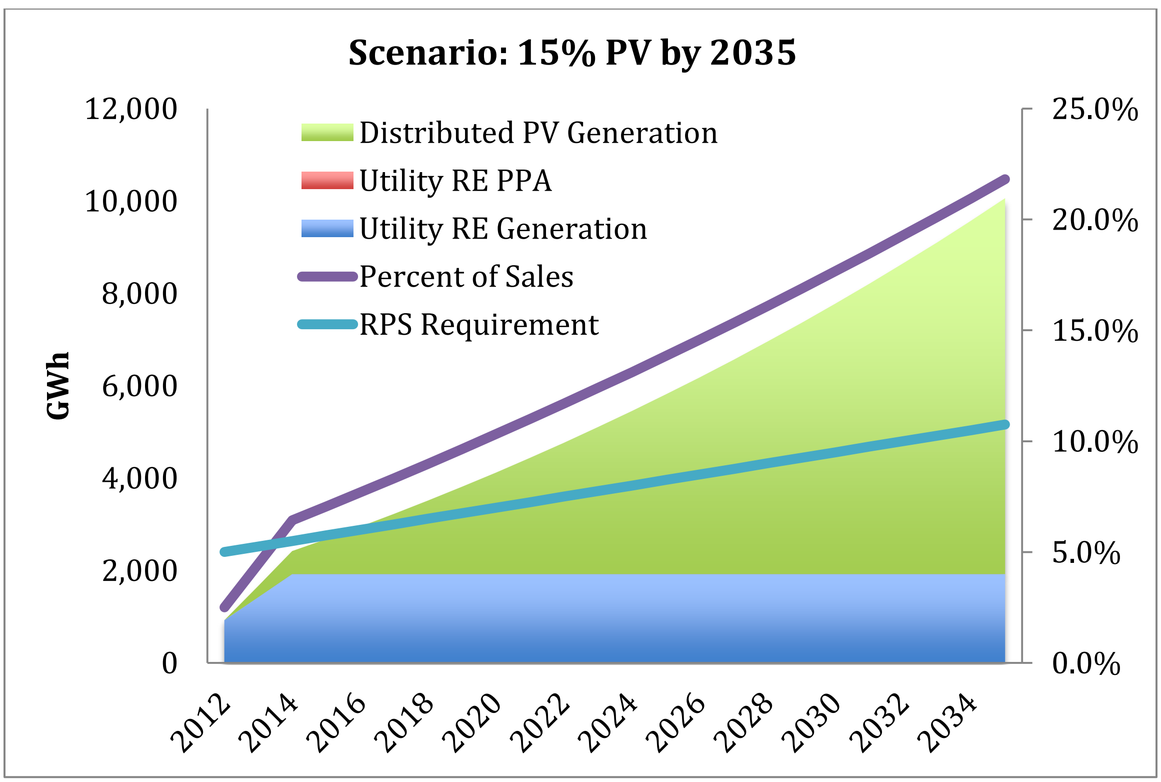
Figure 8: GHG Emissions



Significant increases in greenhouse gas emissions occur after 2022 in the baseline scenario when more fossil fuel generation is needed to meet increasing load. By 2035 our hypothetical utility is emitting just under three million metric tons fewer GHG emissions that would otherwise. Figure 9 shows renewable energy generation in the baseline and 15 percent PV penetration scenario.

Figure 9: Renewable Energy Generation





In the baseline set scenario, utility meets its RPS standard by building wind farms just in time to meet the standard. However in the PV scenario, the utility does not need to build any new wind farms after 2014 due to the distributed renewable generation on system. This also yields reduced costs for ratepayers as well as drives down GHG emissions. Due to the preexisting wind assets, 22 percent of energy delivered to the system is renewable by 2035.

4.1 Sensitivity Analyses

We ran three sensitivity analyses to observe the effects on net present value of utility earnings, and customer bills from:

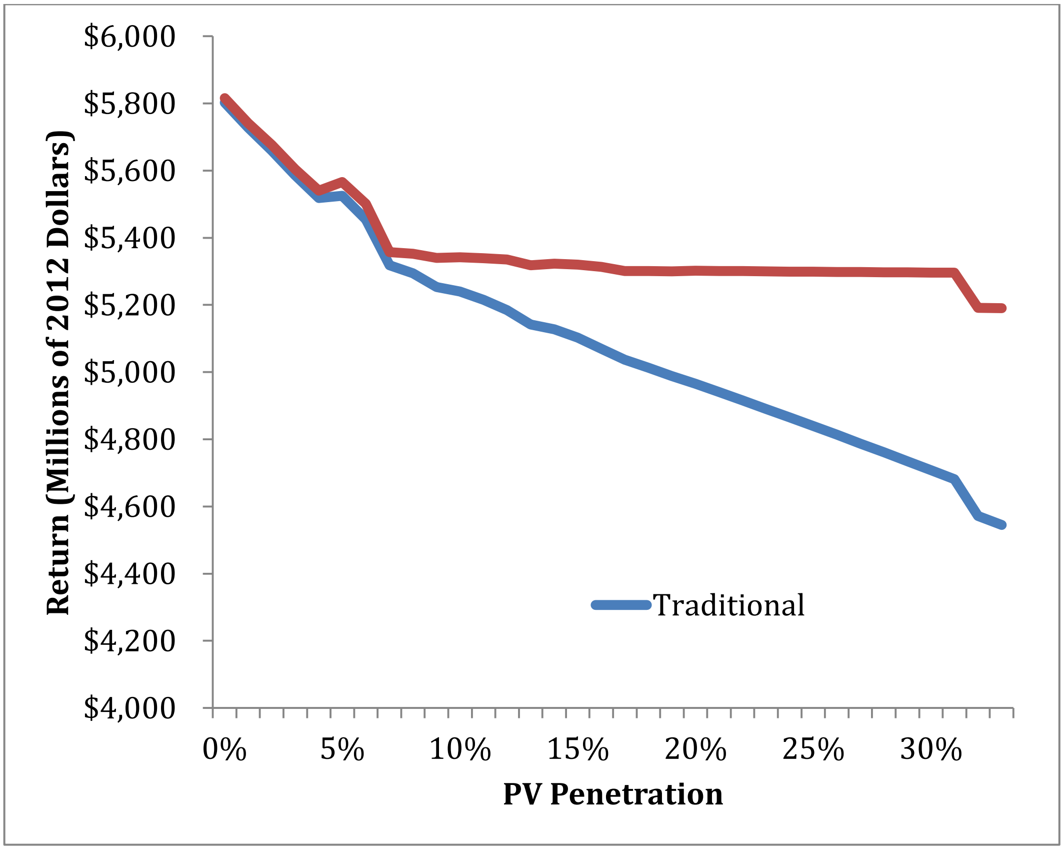
1. Variations in the penetration of PV
2. Variations in the capacity value factor of PV
3. Variations in customer count growth rates and retail sales growth rates

The results of these analyses are presented in the following sections.

4.1.1 PV Penetration

In our first sensitivity analysis, we ran a simulation to evaluate variation in PV penetration between 0 and 33 percent. Figure 10 plots the net present value of utility return against PV penetration achieved in 2035.

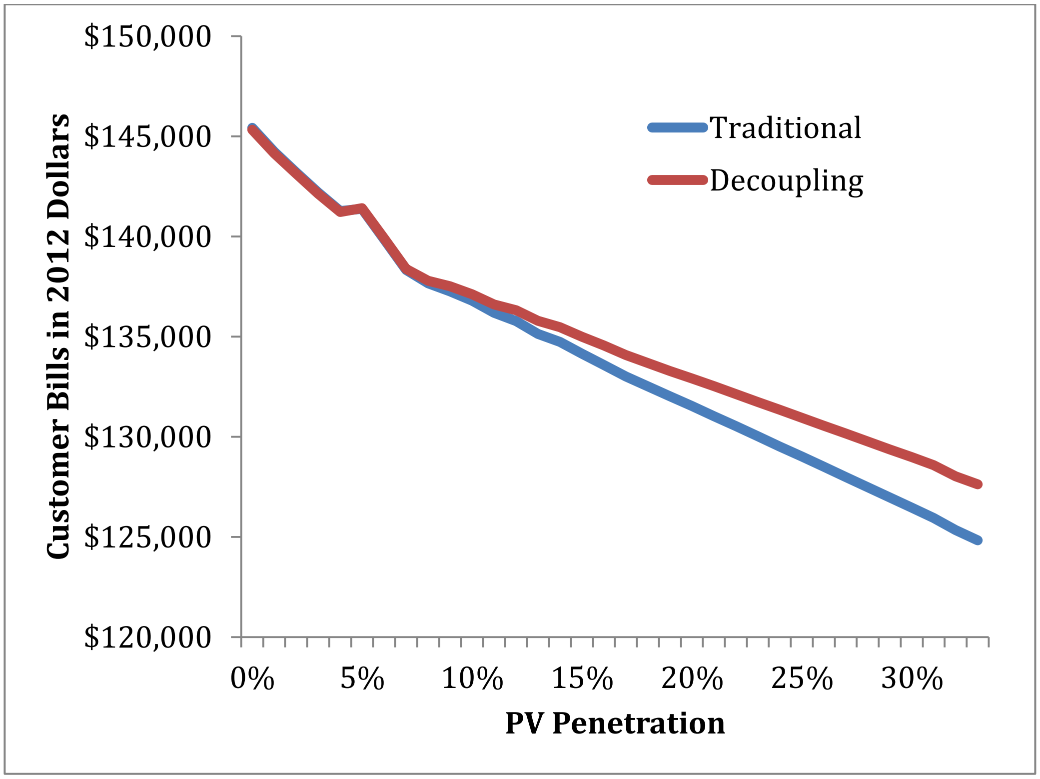
Figure 10: Net Present Value Utility Return



The chart clearly shows that after about the 5 percent penetration level, decoupling protects the utility's return until after 30 percent penetration. Decoupling is working as intended by assuring that the utility receives its required revenue despite rapid reductions in sales.

Figure 11 shows that growing penetration of PV increases what decoupled ratemaking will collect from ratepayers than traditional ratemaking.

Figure 11: Net Present Value Customer Bills



The utility's return is kept stable by extracting relatively more revenue from ratepayers than they would otherwise pay under traditional ratemaking, although it is still less in absolute terms than if there was no distributed generation at all.

4.1.2 Capacity Value Factor

Considerable uncertainty surrounds how much capacity value PV provides the utility because it is unclear how closely peak solar output is coincident with peak demand. It may be determined by geographical location, which helps explain why different studies have found different levels of peak coincidence. In our first model simulation, we assumed peak coincidence provided zero capacity value, which was found in the Navigant (2010) study for NV Energy. For the sensitivity analysis, we varied this capacity value factor between zero and 40 percent. The results of this analysis are presented in Table 5.

Table 5: Capacity Value Sensitivity Analysis

Capacity Value Factor	NPV Utility Revenues (millions)			NPV Customer Bills		
	0%	20%	40%	0%	20%	40%
Traditional	$5,103	$4,922	$4,809	$134,153	$130,106	$127,706
Decoupling	$5,320	$5,050	$4,899	$134,997	$130,564	$128,010

The table is color-coded with the strongest colors showing the best outcome for both the utility and the customer. For the utility, decoupling provides the best outcome for each capacity value factor. The utility's absolute best outcome is for the capacity value to be zero, because this allows the utility to keep building peaking natural gas plants in order to meet increasing peak demand. The construction of more plants increases the rate base and thus allows higher revenues. From a customer perspective, the highest capacity value factor provides the greatest benefit for the same reason: it defers the construction of peaking power plants. Consistent with our previous results the ratepayer is relatively worse off under decoupling, within the same scenario.

4.1.3 Customer Counts and Retail Sales

In our final sensitivity analysis, we co-varied customer count and retail sales growth rates, as these are key determinants for calculating revenue requirement in the traditional and decoupling ratemaking formulas. Tables 6 and 7 present the results of this analysis.

Table 6: NPV Utility Return

Traditional				Decoupled			
Retail Sales Growth Rate	Customer Count Growth Rate			Retail Sales Growth Rate	Customer Count Growth Rate		
	1%	2%	3%		1%	2%	3%
1%	$4,763	$4,763	$4,763	1%	$5,198	$5,303	$5,408
2%	$5,272	$5,272	$5,272	2%	$5,244	$5,349	$5,454
3%	$5,882	$5,882	$5,882	3%	$5,457	$5,565	$5,674

Table 7: NPV Customer Bills

Traditional				Decoupled			
Retail Sales GR	Customer Count Growth Rate			Retail Sales GR	Customer Count Growth Rate		
	1%	2%	3%		1%	2%	3%
1%	$140,300	$127,194	$115,924	1%	$142,275	$129,470	$118,437
2%	$151,905	$137,305	$124,775	2%	$151,575	$137,522	$125,437
3%	$169,067	$152,119	$137,621	3%	$166,781	$150,599	$136,733

The blue boxes indicate which ratemaking regime yields the higher benefit for the utility in Table 6 and the customer in Table 7. For the utility, customer growth rate has no effect on return because it has no bearing on the revenue requirement equation. The utility performs best under traditional ratemaking when retail sales growth rates are high and it performs best under decoupling when sales growth rates are low relative to customer growth. The opposite is true for the ratepayer. When the customer count growth rate is high relative to retail sales they are better off with traditional ratemaking. The ratepayer's best outcome in our analysis is a customer count growth rate of 3 percent compared with a retail sales growth of 1 percent, where there is less need to build supply-side assets and a large customer base to divide the revenue requirement. However, this is a fairly unlikely scenario in real life as customer count growth rate and retail sales growth rate are correlated.

4.2 Model Limitations and Further Research

This analysis has been supported by a highly simplified Excel model of a utility. Further work could refine this model to better approximate how the utility and ratepayer behave in the real world. One limitation is that this model is mostly deterministic and that feedbacks and nonlinearities are ostensibly ignored. An approach accounting for the uncertainties in key variables such as peak demand and retail sales could provide more insight on the expected effects of decoupling. Furthermore, this model simulates the effect of PV on a year-by-year timescale. The more sophisticated approach would model PV from 8760 perspective and a more precise calculation of rates in order to generate a better approximation of the NEM subsidy.

Additional research that would support this type of analysis would include a better approximation of integration costs of intermittent renewable resources, the level of peak demand at the solar output coincidence, and what interaction effects occur between energy efficiency and high penetration distributed PV.

5.0 CONCLUSION

In many states across the US, Public Utility Commissions and the utilities they regulate have debated the merits of alternative utility business model concepts, perhaps most importantly the idea of revenue decoupling. Many have argued that decoupling is necessary to make utilities indifferent to reduced sales due to aggressive energy efficiency programs.

We sought to learn if decoupling can also make utilities indifferent to reduced sales due to distributed generation. Using a model of a hypothetical Midwestern vertically integrated utility, we evaluated the costs and benefits of a high penetration of customer owned rooftop photovoltaic generation with net energy metering tariffs for the utility, the general ratepayer, and the environment. We found that revenue per customer decoupling does help insulate the utility against reduced sales as well as reduce overall revenue volatility. However, decoupling cannot protect the utility against long term rate base erosion due to the deferred need to build supply-side assets when customers increasingly generate their own power. With high penetration PV, customers are essentially challenging the utility's claim to a natural monopoly, as they are steadily eroding the utility's market share. The utility becomes more of a provider of energy storage and grid balancing services.

While decoupling can help soften the blow for the utility by collecting more customer revenues than otherwise under traditional ratemaking, new business models would need to be implemented to assure that the utility is fairly compensated for the grid services it provides and the investment it has made in the electricity system. Distributed generation allows us to imagine a more decentralized utility of the future that holds a natural monopoly only on the grid. This may be beneficial for reasons such as grid resiliency, lower fuel costs, and better environmental performance. In the case of energy efficiency programs, shareholder incentives compensate the utility for foregone investment in supply side assets. Perhaps some sort of shareholder compensation mechanism is appropriate for "stranded assets" during a transition period, although we will not conjecture on that question here.

This analysis does not support the conclusion that net energy metering with distributed PV is a net cost to the ratepayers, as increased costs for integration, grid upgrades, increased billing costs, and the NEM subsidy are more than compensated for by the reduction in rates due to shrinking rate base. Even when we assume capacity value of PV is zero, ratepayers still benefit significantly. If PV can be used to offset peak load, ratepayers benefit substantially more.

In the coming years, as the costs of PV modules decline, we expect utilities and regulators to become increasingly concerned about the effects to utility bottom line. Whether or not distributed generation becomes a mortal threat to the traditional vertically integrated utility remains to be seen.

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Appendix: Inputs for Model Simulation

Input	Value	Units	Source
PV Characterization			
2012 Percentage of load supplied by PV	0%		User choice
2035 Percentage of load supplied by PV	15%		User choice
% Residential Accounts	93%		E3 2010
% Non-Residential Accounts	7%		E3 2010
Incremental billing costs	$ 9.10	$/customer	E3 2010
On-peak coincidence	75%		User choice
Capacity Value Factor	0%		Navigant 2010
Average Capacity Factor	15%		Sunshot
Average Residential System Size	5.7	kW	US Solar Market Trends
Average Non-Residential System Size	217	kW	Sunshot
Residential system size growth rate	3%		US Solar Market Trends
Non-residential system size growth rate	1%		US Solar Market Trends
Integration costs	0.003	$/kWh	Hoke and Komor 2012
Utility Characteristics			
% Residential Customers	83%		Westar
% retail and PD from Res	37%		Westar
% sales met by PPAs	8%		Kansas Corporation Commission (KCC)
Capacity reserve margin req.	12%		KCC
Initial Values			
Customer Count	1,220,006	#	Westar 2011 Rate Case
Retail Sales	36,820,366	MWh	Westar 2011 Rate Case
Peak Demand	6,634	MW	KCC
Non-fuel O&M	$722.63	$M	Westar 10k
Base CapEX	$205.00	$M	Westar 10k
Compound Annual Growth Rates			
Customer Count Growth Rate	2.0%		EIA
Retail Sales Growth Rate	1.7%		EIA
Peak Demand Growth Rate	1.5%		EIA
Non-fuel O&M Growth Rate	2.5%		Westar Rate Case
Base CapEx Growth Rate	2.1%		Westar Rate Case
Initial System Capacity			
Nuclear	1100	MW	Wester,KCP&L
Coal	3975	MW	Wester,KCP&L
Natural Gas - Mid-merit	550	MW	Wester,KCP&L
Natural Gas - Peaker	2325	MW	Wester,KCP&L
Renewable	277	MW	Wester,KCP&L
Average Power Production Capacity Factors			
Nuclear	90%		EIA
Coal	68%		EIA

Appendix: Inputs for Model Simulation

Input	Value	Units	Source
Natural Gas Mid Merit	43%		EIA
Natural Gas Peaker	8%		EIA
Renewables	38%		EIA
Fuel Costs			
Nuclear	15.93	$/MWh	EIA
Coal	14.18	$/MWh	EIA
Natural Gas Mid Merit	45.53	$/MWh	EIA
Natural Gas Peaker	74.13	$/MWh	EIA
Renewables	0	$/MWh	EIA
Standard PPA	38.53	$/MWh	EIA
Renewable PPA	55.25	$/MWh	IHS Energy Research
Fuel Cost Growth Factors			
PPA Cost Growth Factor	2%		EIA
Coal Fuel Cost Growth Factor	1%		EIA
Natural Gas Fuel Cost Growth Factor	1%		EIA
Nuclear Fuel Cost Growth Factor	1%		EIA
Emissions Factors			
Coal			
GHG	1.02013045	MT/MWh	Environmental Protection Agency (EPA)
SO2	0.00589671	MT/MWh	EPA
Nox	0.00272156	MT/MWh	EPA
Natural Gas			
GHG	0.51482795	MT/MWh	EPA
SO2	4.5359E-05	MT/MWh	EPA
Nox	0.00077111	MT/MWh	EPA
Wholesale Power SPNO			
GHGs	0.894	MT/MWh	EGRID
SO2	0.00302048	MT/MWh	EGRID
Nox	0.0017418	MT/MWh	EGRID
Financial Metrics			
Proportion of CapEx that is growth related	30%		
2012 Gross Plant Level	8255	million	Westar 10k
Accumulated depreciation	3564	million	Westar 10k
Average ratebase depreciation schedule	28.6	years	
Trigger for NGCC build	12%	PPA/Deliveries	User choice
Captial Structure			
% Debt	49%		Westar Rate Case
% Equity	51%		Westar Rate Case
Cost of debt	7%		Westar 10k

Appendix: Inputs for Model Simulation

Input	Value	Units	Source
Cost of equity	10%		Westar 10k
WACC	8%		Westar 10k
Authorized ROE	10%		KCC
Initial Debt	$ 256.92	$M	Westar 10k
Tax			
Federal Tax Rate	33%		Westar 10k
State Tax Rate	7%		Westar 10k
Ratemaking			
Cycle Or Trigger?	Cycle		
Cycle Frequency of rate cases (years)	2		
Threshold for major CapEx to trigger rate case ($M)	300	Million	
Regulatory lag for new rates (year)	1		
Renewable Portfolio Standard			
RPS Strategy (percent build)	100%		
Growth rate of RPS requirement	0.25%		
Discount Rates			
Financial	8%		WACC
Social	4%		
Carbon Tax	0	$/ton	