Using Distributed Resources to Manage Risks Caused by Demand Uncertainty

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ABSTRACT

This paper presents a method to calculate the cost of satisfying transmission and distribution (T&D) system capacity needs as a function of investment modularity and lead-time. It accounts for the dynamic nature of demand uncertainty, the decision-maker's risk attitude, and the correlation between costs and firm profits. Results indicate that the modularity and short lead-times associated with distributed resources can increase their attractiveness in comparison to long lead-time, large-scale T&D investments. Results also suggest that distributed resources can operate as a type of "load growth insurance" if demand growth is positively correlated with profits (so that costs are incurred when profits are high) and if the distributed resource costs are part of a larger portfolio that cannot be diversified.

BACKGROUND

Electric utilities have become increasingly reluctant to invest in long lead-time, large-scale power generation projects for several reasons. First, facilities have often cost more and taken longer to construct than initially anticipated. Second, actual demand has often not met expectations with the result that the investments were unnecessary. Third, the investments have had a greater financial risk than initially anticipated because: a) regulatory commissions viewed them as imprudent and prevented full cost recovery in some cases; and b) competition from lower cost suppliers prevented full cost recovery in other cases. The result is that generation investments have shifted away from long lead-time, large-scale generation to short lead-time, modular generation. Sacramento Municipal Utility District's experience with nuclear power represents a good case study of some of these issues (Smeloff and Asmus 1997).

Integrated utilities are being restructured into unregulated generation companies and regulated transmission and distribution (T&D) companies. The regulated T&D companies will continue to serve the role of power delivery. Historically, a utility's revenues have been based on its assets. Given that this practice continues, these utilities may be tempted to expand the T&D system whenever there appears to be a need.

Large T&D investments as typified by new transmission facilities are somewhat analogous to large generation system investments: they are long lead-time, large-scale investments. As a result, T&D companies can learn valuable lessons from the generation investment experience and avoid some of the potential problems associated with long lead-time, large-scale investments. The lessons are as follows. First, these investments may cost more and take longer to construct than initially anticipated. Second, a careful evaluation of demand uncertainty is essential prior to committing to any long lead-time investment. Third, an accurate treatment of the financial risk associated with the

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investment is critical, even within a regulatory environment; this is particularly true when other alternatives represent a competitive threat to the utility.

OBJECTIVE

Distributed resources can enable utilities to increase system capacity without some of the drawbacks associated with large-scale, long lead-time T&D investments (Hoff, Wenger, and Farmer 1996). This paper evaluates the alternative of using distributed resources to satisfy T&D capacity needs. It presents a method to calculate the cost of a T&D capacity investment as a function of investment modularity and lead-time. The paper builds upon earlier results (Hoff 1996) by taking into account the dynamic nature of demand uncertainty, the decision-maker's risk attitude, and the correlation between costs and firm profits.

The first section uses a simple example to illustrate the value of investments that have short lead-times when one considers the dynamic nature of demand uncertainty. It compares the expected cost of a T&D investment that has a one-year lead-time with a distributed resource that has no lead-time. It then goes on to show how to incorporate a decision-maker's risk attitude into the analysis. The second section generalizes the expected cost results from the first section to account for both the investment's lead-time and modularity; an example is included of how to apply the results. Conclusions and future research needs are included in the third section. Appendix A summarizes the nomenclature used throughout the paper.

INVESTMENT LEAD-TIME

Distributed resources typically have shorter construction lead-times than large T&D investments. This provides decision-makers with flexibility regarding when to make investments. This section uses a simple example to illustrate the value of investments that have short lead-times when one considers the dynamic nature of demand uncertainty. The first subsection presents a model to characterize the dynamic nature of demand uncertainty and sets up the problem. The second subsection calculates the expected distributed generation cost. The third subsection interjects a note on investment valuation methods. The fourth subsection determines the cost when the decision-maker is risk-averse and there is only demand uncertainty. The fifth subsection determines the cost when the decision-maker is risk-averse and there is both demand uncertainty and profit uncertainty. Results between the various cases are compared in the sixth subsection.

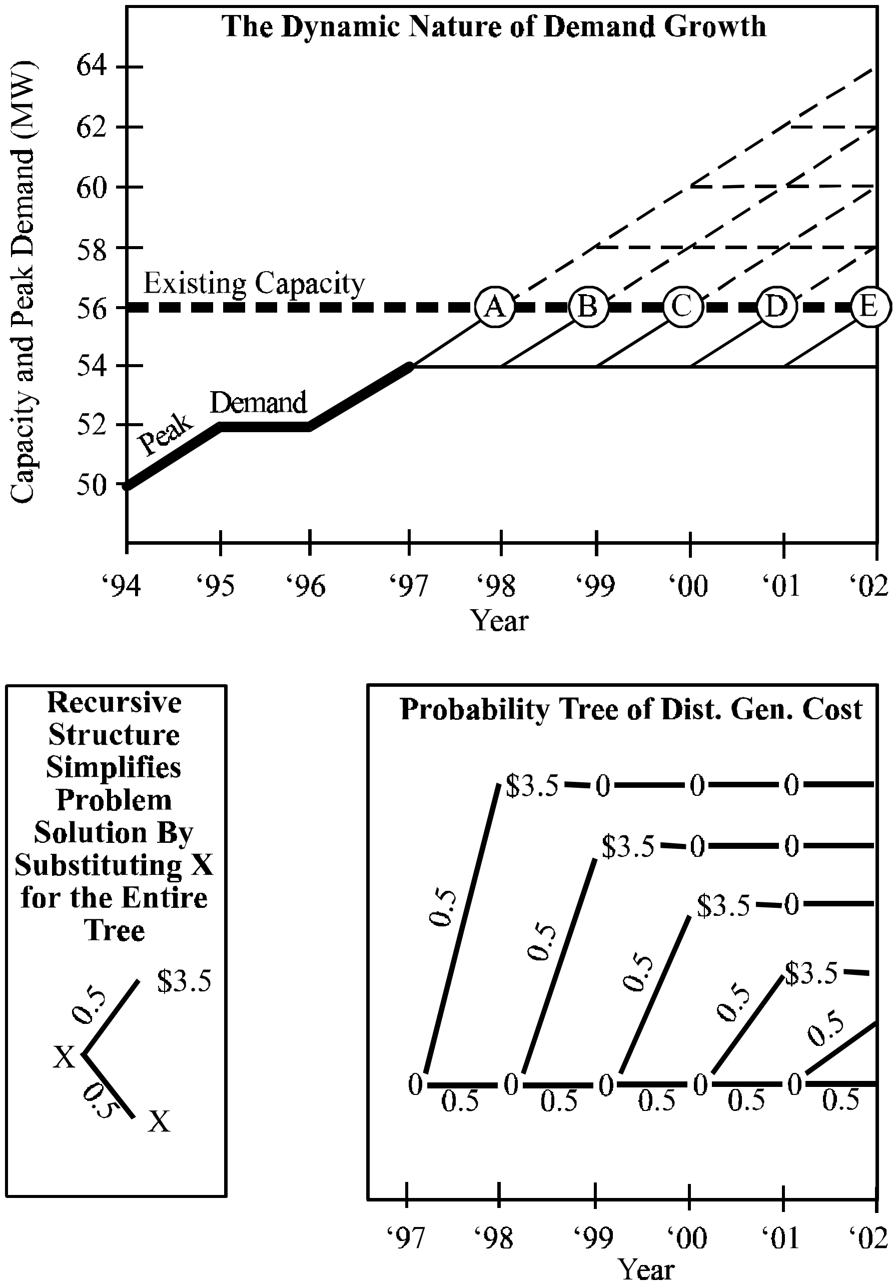
Dynamic Nature of Demand Uncertainty

Utility planners typically incorporate demand uncertainty into an evaluation by projecting high, average, and low demand growth scenarios. The weakness of this approach is that it only gives a static picture of demand uncertainty. That is, there are only three possible paths that demand can follow.

A more accurate way to capture the dynamic nature of demand uncertainty is to recognize that the rate of demand growth can change over time (Hoff and Herig 1997). Figure 1 illustrates this point for a T&D system for a hypothetical utility. The heavy solid line in the top part of the figure shows that historical peak demand increased in 1995, remained constant in 1996, and increased in 1997; the heavy dashed line shows that system capacity remained constant during this period. The light lines indicate an assumption that demand will either increase by 2 MW or remain constant in any given year (each outcome has equal chances); the light dashed lines indicate that a capacity investment is required. This results in many more than three possible paths that demand can follow with the number of possible paths increasing over time.[1]

[1] While this characterization of demand uncertainty only allows for two different states in any given time period and yearly time periods are used throughout this paper, there is nothing to prevent one from using a smaller time period in order to obtain a larger number of states as time progresses. This is similar to the concept employed in the binomial approach to option pricing (Cox, Ross, and Rubinstein 1979).

Figure 1. Simple Example.



The figure indicates that excess capacity will be eliminated if demand increases by 2 MW. The utility has decided that it will increase system capacity by either investing in a system upgrade or by investing in distributed generation. The system upgrade costs

$3.000 Million and has a one-year lead-time. The distributed generation costs $3.500 Million and has no lead-time. Both investments provide the same amount of capacity and have infinite lives. The utility has a 10 percent discount rate.

Expected Distributed Generation Cost

The expected present value cost of the system upgrade is its investment cost of $3.000 Million. This is because the upgrade must begin immediately for the utility to be prepared to satisfy peak demand the first time it occurs.

The expected present value cost of the distributed generation alternative equals the probability that the investment will be made times the investment cost, discounted to the current year. As shown in Figure 1, the investment could occur in 1998 (point A), 1999 (point B), 2000 (point C), etc. The expected cost of this is calculated using the probability tree in the lower right part of the figure.

While one can calculate the expected present value cost based on the observation that the probability distribution of the costs are binomial (Hoff 1997a), a simpler solution is to recognize that the tree has a recursive structure (see the lower left part of Figure 1; *X* is the expected present value cost). In particular, if demand remains constant in 1998, the probability tree in 1998 is identical to the tree in 1997. The expected present value cost is the probability of high demand growth times the distributed generation cost plus the probability of no growth times the expected present value cost discounted at a rate of 10 percent.

$$\overbrace{X}^{\substack{\text{Expected}\\\text{Cost}}} = \frac{\overbrace{0.5}^{\substack{\text{Prob. of}\\\text{High Growth}}} \times \overbrace{\$3.5}^{\substack{\text{Dist. Gen.}\\\text{Cost}}} + \overbrace{0.5}^{\substack{\text{Prob. of}\\\text{No Growth}}} \times \overbrace{X}^{\substack{\text{Expected}\\\text{Cost}}}}{\underbrace{1+10\%}_{\text{Discounting}}} \tag{1}$$

The result is that the expected present value cost for the distributed generation alternative, *X*, is \$2.917 Million, which is less than the \$3.000 Million cost of the system upgrade alternative. That is, the distributed generation alternative has a lower expected present value cost than the upgrade.

A Note on State Prices

Before proceeding to the cases where the decision-maker is risk-averse, it is helpful to interject a note on investment valuation methods and how these methods can be interpreted in the risk-neutral case. The field of financial economics has shown that a market-based valuation of an investment can be performed using state prices when markets are complete (i.e., when all risks can be fully hedged by entering into market transactions). State prices take into account uncertainty and discounting over time. If they exist, there is one price for each state of the world at each date. The price of an investment is the state-price weighted sum of its future payoffs (Duffie 1992). Unfortunately, this approach does not apply to this problem if one cannot purchase financial instruments to hedge risks associated with the demand uncertainty.

While this problem might appear to lend itself to a real options approach, the real options approach has some inherent limitations. In particular, Dixit and Pindyck point out in their book on real options that "there is no theory for determining the correct discount rate [to use in the dynamic programming approach that the real option approach employs when markets are incomplete]…The CAPM, for example, would not hold, and so it could not be used to calculate a risk-adjusted discount rate in the usual way (Dixit and Pindyck 1994, p. 152)." Smith and Nau (1995) similarly point out that one cannot find the correct discount rate when markets are incomplete.

In response to this limitation of the real options approach when markets are incomplete, Hoff (1997b) has shown how to extend the state price approach from financial economics to the case of incomplete markets.[2] The difference is that when markets are incomplete, the decision-maker evaluates the investment within the context of his or her own portfolio rather than the market; in a sense, the decision-maker acts like a market to find the state prices.

How does the state-price approach when markets are incomplete apply in the risk-neutral case? A state price interpretation of Equation (1) is that the state prices are the probabilities discounted at the discount rate. That is, the state-price vector is $\psi = \begin{bmatrix} 0.4545 & 0.4545 \end{bmatrix}$ and the state price weighted sum of the project costs equals:

$$X = (0.4545)(3.500) + (0.4545)X \tag{2}$$

As before, the solution to this problem is that the expected present value cost of the distributed generation investment is \$2.917 Million.

Risk-Averse Decision-Maker and Demand Uncertainty

The previous subsection assumed that the decision-maker was risk-neutral. This subsection assumes that the decision-maker is risk-averse. While one could take a typical decision analysis approach (e.g., Howard 1989) to this problem when there is only demand uncertainty, the state-price approach is employed because it will become useful in the next subsection.

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[2] Specifically, Hoff (1997b) proves that, given a time- and state-separable utility function, a decision-maker's buying price for an investment is approximately equal to the state-price weighted sum of its future payoffs; results are exact when the utility function is exponential. It is assumed throughout this paper that the decision-maker has an additive exponential utility function and that the risk-free discount rate and the risk-aversion coefficient are constant over time.

Using the same data as was presented in Figure 1, the present value cost at a given time τ-1 in state 0 (this is when demand equals 54 MW in Figure 1) equals the state price-weighted sum of the costs at time τ in states 0 and 1.

$$X_{\tau-1}^{0} = \psi_{\tau}^{1} X_{\tau}^{1} + \psi_{\tau}^{0} X_{\tau}^{0} \tag{3}$$

where X_{τ}^{1} is the discounted cost of all future cash flows at time τ in state 1 (demand equals 56 MW) and X_{τ}^{0} is the discounted cost of all future cash flows at time τ in state 0 (demand equals 54 MW),

Results from Hoff (1997b) can be used to show that, after substituting for the state prices when there is an exponential utility function, the equation simplifies as follows.

$$X_{\tau-1}^{0} = \frac{\tilde{\rho}_{\tau} \ln\left[p \exp\left(\frac{X_{\tau}^{1}}{\tilde{\rho}_{\tau}} \right) + (1-p) \exp\left(\frac{X_{\tau}^{0}}{\tilde{\rho}_{\tau}} \right) \right]}{1+r} \tag{4}$$

where the risk-aversion coefficient for all future wealth is the summation of the risk-aversion coefficients over the remaining time periods (i.e., $\tilde{\rho}_{\tau} = \sum_{t=\tau}^{T} \frac{\rho}{(1+r)^{t}}$).

The risk-aversion coefficient ($\tilde{\rho}_{\tau}$) is constant over time since the time frame is infinite so that $\tilde{\rho}_{\tau} = \frac{\rho(1+r)}{r}$. The discounted cost of all future cash flows at time τ in state 1 is $3.500 Million because no future investments occur once the distributed generation cost is incurred. The recursive structure of the tree can be exploited to find the cost at time τ in state 0. The discounted cash flows in state 0 are identical for all years. In addition, the utility functions are identical up to a scalar multiple. Thus, the cost in state 0 is the same for all times so that $X_{\tau}^{0} = X_{\tau-1}^{0}$. The subscripts and superscripts are dropped and the appropriate substitutions are made into Equation (4).

$$X = \frac{\tilde{\rho} \ln\left[(0.5) \exp\left(\frac{3.500}{\tilde{\rho}} \right) + (0.5) \exp\left(\frac{X}{\tilde{\rho}} \right) \right]}{1.1} \tag{5}$$

A simple optimization program and Equation (5) will show that the cost of this investment ranges between \$2.923 Million and \$3.182 Million depending upon which risk-aversion coefficient is selected. This is consistent with intuition because a risk-neutral decision-maker would pay the expected present value cost of \$2.923 Million (the result from Equation (1)) while a highly risk-averse decision-maker would pay \$3.182 Million (he or she would plan for the worst possible scenario even though it only has a 50 percent chance of occurring; the worst case scenario is that the \$3.500 Million cost is incurred for certain in year 1 for a present value cost of \$3.182 Million).

For purposes of illustration, assume that the decision-maker has an annual risk-aversion coefficient of \$1 Million (so that $\tilde{\rho} = 11$). In this case, the state prices are $\psi = \begin{bmatrix} 0.4605 & 0.4486 \end{bmatrix}$ and the investment cost is \$2.923 Million.

Risk-Averse Decision-Maker and Demand Uncertainty and Profit Uncertainty

Next, assume that, in addition to having a risk-averse decision-maker, both demand and the firm's profits are uncertain and neither uncertainty can be hedged by entering into market transactions. This is the case of incomplete markets. The firm's total cash flows are presented in Figure 2.

While there were only two possible states after one year in the previous cases, this case has more possible states because both demand and profits are uncertain. If it is assumed that there are two possible states of uncertainty for profits in any year (profits can be high, π^H, or low, π^L, in any year with a probability of q and 1-q respectively[3]), then there are a total of four possible states. The four states (and the associated cash flows) are: (1) high profits, high demand growth (π^H - 3.5); (2) high profits, no demand growth (π^H); (3) low profits, high demand growth (π^L - 3.5); and (4) low profits, no demand growth (π^L).

The probabilities for each of the branches are the same as those presented in the lower part of Figure 2. The probabilities in the branches are based on the joint probability distribution between *p* and *q*, where *A* is the adjustment in the probability of high demand growth *p* given the probability of high profits *q* such that the expected value and variance conditions on both distributed generation costs and firm profits are satisfied; $A = corr(I,\pi)\sqrt{p(1-p)q(1-q)}$.[4] The correlation between distributed generation costs and firm profits is the same in every year that distributed costs can occur and it equals $corr(I,\pi)$. *V* is the value of the firm without the distributed generation investment.

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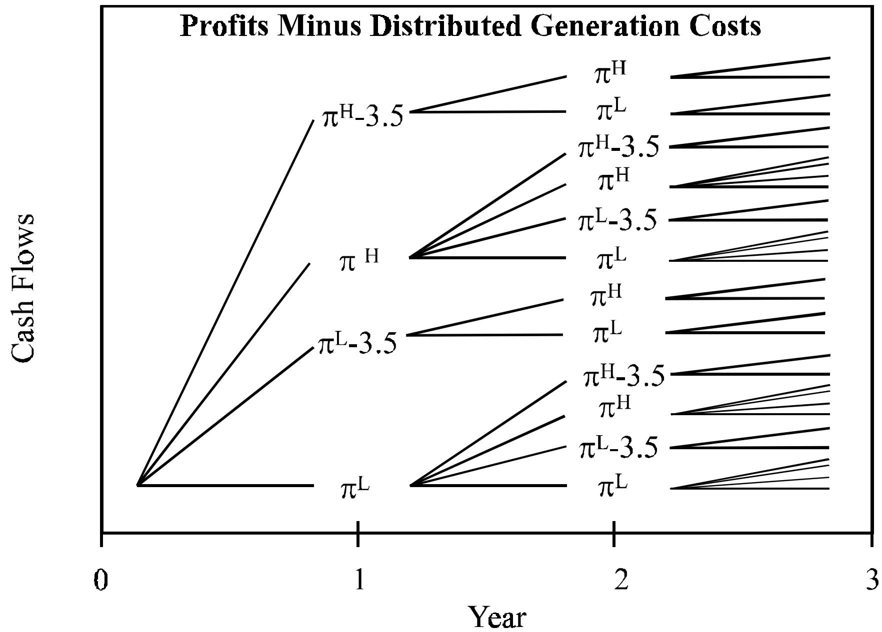
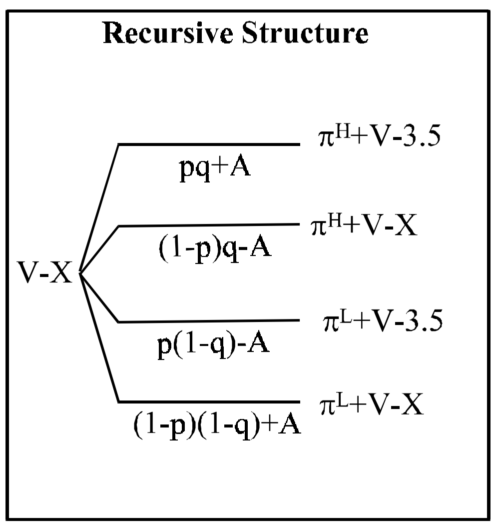
3 While this model for profits does not allow for large movements in the value of the firm, it will demonstrate the importance of the correlation between distributed generation costs and the firm's profits.

4 The limits on the correlation for a given *p* and *q* are $-\min\left(B_L, B_L^{-1}\right) \le corr(I,\pi) \le \min\left(B_U, B_U^{-1}\right)$ where $B_L = \sqrt{\frac{pq}{(1-p)(1-q)}}$ and $B_U = \sqrt{\frac{p(1-q)}{(1-p)q}}$. This ensures that all probabilities are between 0 and 1. Luenberger (1997, Section 16.4) presents an alternative way to determine the probabilities.

Figure 2. Firm's profits and distributed generation costs.





As before, the investment cost is the state-price weighted sum of the investment payoffs. In this case, however, there are four possible states that can occur at any given time. Thus, at any given time τ-1, the discounted cost in state 0 equals

$$X_{\tau-1}^{0} = \psi_{\tau}^{3} X_{\tau}^{3} + \psi_{\tau}^{2} X_{\tau}^{2} + \psi_{\tau}^{1} X_{\tau}^{1} + \psi_{\tau}^{0} X_{\tau}^{0} \tag{6}$$

where X_τ^i is the discounted cost of all future distributed generation cash flows at time τ in state i.

As was done in the previous subsection, the recursive structure of the tree both in terms of cash flows and the utility function is once again exploited. The result is presented in the lower part of Figure 2. After substituting for the state prices and simplifying (see Hoff 1997b for details), the result is that

$$X = \frac{\tilde{\rho}\ln\left[(p+P)\exp\left(\frac{3.500}{\tilde{\rho}}\right)+(1-p-P)\exp\left(\frac{X}{\tilde{\rho}}\right)\right]}{1+r} \tag{7}$$

where $P = corr(I,\pi)\sqrt{p(1-p)q(1-q)}\exp\left(\frac{rV}{\tilde{\rho}}\right)\left[\exp\left(\frac{-\pi^H}{\tilde{\rho}}\right)-\exp\left(\frac{-\pi^L}{\tilde{\rho}}\right)\right]$, and

$$V = \frac{-\tilde{\rho}\ln\left[q\exp\left(-\pi^H/\tilde{\rho}\right)+(1-q)\exp\left(-\pi^L/\tilde{\rho}\right)\right]}{r}.$$

The difference between Equation (7) and Equation (5) is that the actual probability p is replaced the probability $p+P$. This, however, can result in a vastly different solution. This is because P can be viewed as a mathematical adjustment in the probabilities based on the correlation between profits and distributed generation costs as well as the decision-maker's risk preferences.

In addition to the assumptions that a distributed generation cost of \$3.500 Million is incurred when demand increases (with probability p=0.5), that the risk-aversion coefficient in any year is \$1 Million (this implies that $\tilde{\rho}=11$), and the discount rate is 10 percent, assume that the firm’s profits will be either \$25 or \$50 Million in any given year (with a probability q=0.5). Equation (7) results in a cost of \$1.754 Million, \$2.923 Million, or \$3.153 Million, depending upon whether costs are perfectly correlated, not correlated, or perfectly negatively correlated with profits. Costs that are highly correlated with profits act as a hedge against demand uncertainty because the costs are incurred only when profits are high (P = -0.4), costs that are uncorrelated reduce to the result from the previous subsection (P = 0), and costs that are negatively correlated with profits intensify the negative aspects of demand uncertainty because costs are incurred only when profits are low (P = 0.4). The dependence of the present value cost on the correlation with profits is intensified as the decision-maker becomes more risk-averse.

The four state prices in any period can be reduced to two state prices since there are only two states of demand growth (the two states are: high demand growth/high profits plus high demand growth/low profits; and no demand growth/high profits plus no demand growth/low profits). The state prices in the perfectly correlated and perfectly negatively correlated cases are $\boldsymbol{\psi} = \begin{bmatrix} 0.0913 & 0.8178 \end{bmatrix}$ and $\boldsymbol{\psi} = \begin{bmatrix} 0.8260 & 0.0830 \end{bmatrix}$ respectively.

Comparison of Results

Table 1 compares the results from the three cases considered above. The most surprising result is that, assuming that the discount rate is the same in all cases, the risk-neutral decision-maker does not have the lowest cost. Rather, the lowest cost occurs for a risk-averse decision-maker when there is a positive correlation between profits and costs. This is because costs that are highly correlated with profits act as a hedge against uncertainty because the costs are incurred only when profits are high. Lovins and Lehmann (1997) have appropriately termed this effect as "load growth insurance."

Table 1. Comparison of Results

	Investment Cost (Millions)	State Prices	
		$3.5M Cost Incurred	$3.5M Cost Not Incurred
Risk-neutral	$2.917	0.4545	0.4545
Risk-averse			
Demand Uncertainty Only	$2.923	0.4605	0.4486
Demand and Profit Uncertainty (Positively Correlated)	$1.754	0.0913	0.8178
Demand and Profit Uncertainty (Negatively Correlated)	$3.153	0.8260	0.0830

INVESTMENT LEAD-TIME AND MODULARITY

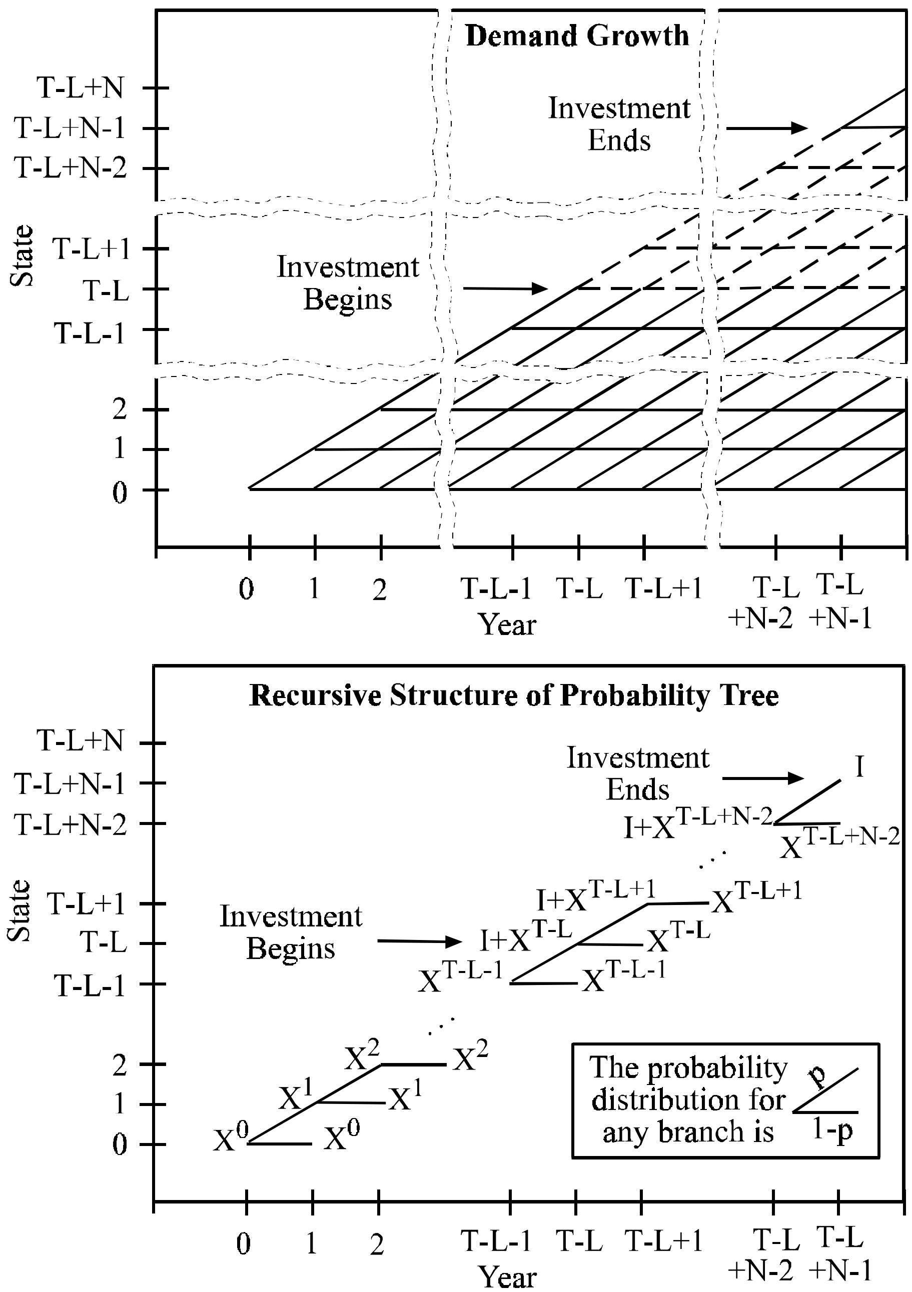
Expected Distributed Generation Cost

Distributed resources are modular in addition to having short construction lead-times. This section generalizes the lead-time result from the previous section for the risk-neutral case and incorporates modularity into the analysis.

Figure 3 presents the general problem formulation. The top part of the figure presents the possible paths that future demand can follow. The notation in the figure is as follows: I is the investment cost ($ per increment of investment); L is the investment lead-time (years); N is the number of increments of distributed generation investments that need to be made to provide the same amount of capacity as the system upgrade; T is the number of years in which excess system capacity will vanish if demand grows at the high rate for each of those years; and X^i is the expected present value distributed generation cost in state i. The utility will increase system capacity by either upgrading the T&D system with a single investment or by installing distributed generation in increments large enough to satisfy one year's worth of demand growth at the high rate.

There are three key regions of interest in the figure: 1) excess capacity exists but no investment is required (below state T-L); 2) excess capacity exists and investment is required (states T-L through T-L+N-1); and 3) all investments have been made (above state T-L+N-1). The x-axis corresponds to the year and the y-axis corresponds to the possible demand states in any given year.

Figure 3. General Formulation



The expected cost can be calculated by drawing out the full probability tree. This is the approach taken in Hoff (1997a). A simpler approach, however, is to recognize that the probability tree has a recursive structure as shown in the bottom part of Figure 3. The expected present value cost of all future expenditures at any state t is as follows.

$$X^t = \begin{cases} 0 & \text{when } t > T-L+N-1 \\ \dfrac{p\left(X^{t+1}+I\right)+(1-p)X^t}{1+r} & \text{when } T-L-1 \le t \le T-L+N-1 \\ \dfrac{pX^{t+1}+(1-p)X^t}{1+r} & \text{when t} < T-L-1 \end{cases} \tag{8}$$

Equation (8) can be simplified to

$$X^t = \begin{cases} 0 & \text{when } t > T-L+N-1 \\ \left(\dfrac{p}{p+r}\right)\left(X^{t+1}+I\right) & \text{when } T-L-1 \le t \le T-L+N-1 \\ \left(\dfrac{p}{p+r}\right)\left(X^{t+1}\right) & \text{when t} < T-L-1 \end{cases} \tag{9}$$

and then solved iteratively by beginning at t equal to T-L+N and repeating until t equals 0 to determine the expected present value cost (the following equations assume that the discount rate is positive).

$$X^0 = \overbrace{I\left(1-R^N\right)/\left(1-R\right)}^{\substack{\text{Benefit of} \\ \text{Modularity}}} \times \overbrace{R^{(T-L)}}^{\substack{\text{Benefit of Short} \\ \text{Lead-Time}}} \tag{10}$$

where I is the cost of an increment that will satisfy one year's worth of demand growth at the high rate, N is the number of increments, T is the number of years remaining until excess system capacity is eliminated if demand grows at the high rate, L is the lead-time for any increment, R is the "discount factor" and $R = \dfrac{p}{p+r}$, p is the probability that demand will grow at the high rate, and r is the real discount rate. It can be shown using an analysis similar to the one above that the real discount rate is replaced with $r' = \dfrac{r-\alpha}{1+\alpha}$

when the investment cost is changing at the rate of α per year (i.e., the time t cost is $I(1+\alpha)^t$).

Equation (10) can be further generalized by performing an analysis similar to the one above where the size of each increment of investment provides more than one year's worth of demand growth but still is modular. The results are similar to those above with the difference being the addition of a term that accounts for the degree of modularity.

$$X^0 = \overbrace{I\left(1-R^{M\times N}\right)/\left(1-R^{M}\right)}^{\text{Benefit of Modularity}} \times \overbrace{R^{(T-L)}}^{\text{Benefit of Short Lead-Time}} \tag{11}$$

where I is the cost of an increment that will satisfy M years worth of demand growth at the high rate and all other variables are the same as before.

Several comments are in order about Equation (11). First, the benefits associated with modularity and short lead-time can be explicitly identified. The modularity benefits are analogous to earlier results developed by Hoff, Wenger, and Farmer (1996) and Hoff (1996).[5] Second, there is an added benefit associated with short lead-times. Third, the expected present value cost is driven by distributed generation price and demand growth (together, these affect the cost per increment of investment), demand growth uncertainty, discount rate, distributed generation price escalation (or reduction), the degree of modularity, and lead-time. Fourth, lowering the expected rate of demand growth (by changing the probability of high demand growth by multiplying p by Y, where Y is a number between 0 and 1) has the same effect as increasing the discount rate to r/Y (i.e.,

[5] Equation (11) in this paper results in Equation (9) in Hoff (1996) when N is very large, M equals 1, p equals 1, there is no escalation in the existing capacity expansion plan cost, T equals 0, and L equals 0. Equation (11) in this paper results in Equation (2) in Hoff, Wenger, and Farmer (1996) when M goes to 0.

$R = \dfrac{pY}{pY + r} = \dfrac{p}{p + r / Y}$). Fifth, distributed generation cost decreases have a slightly greater effect on reducing the expected cost than increasing the real discount rate.

Example

To illustrate the use of Equation (11), suppose that a portion of a utility's T&D system is capacity constrained in a planning area that has stringent emissions restrictions. The utility has decided to either upgrade the transmission system or to install distributed photovoltaic (PV) systems. Historical data suggest that there are equal chances (*p* equals 0.5) of demand growth being 5 MW or nothing in any given year. Excess system capacity will be exhausted in 5 years (*T* equals 5) if demand grows at the high rate each year. The discount rate is 10 percent (*r* equals 10 percent).

The T&D upgrade will cost $25 Million, will increase capacity by 50 MW (so its per unit cost is $500/kW), and has a 5-year lead-time. Distributed PV plants will be installed in 5 MW increments, will cost $15 Million per increment and have $5 Million in system benefits per increment (thus, while the price of PV is $3,000/kW, the investment cost from the T&D system perspective, *I*, is $10 Million and the per unit cost is $2,000/kW), will have a 1-year lead-time, and there will be 10 increments to provide the same capacity of the T&D upgrade. These data are summarized in Table 1.

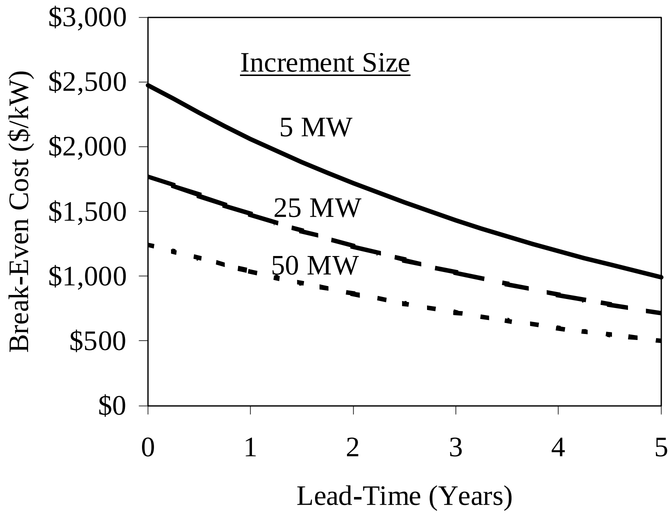
Table 1. Data for Example.

	T&D Upgrade	PV Generation
Per Unit Cost	$500/kW	$2,000/kW[6]
Increment Size	50 MW	5 MW
Years of Demand Growth (*M*)	10 years	1 year
T&D Increment Cost (*I*)	$25 Million	$10 Million
Number of Increments (*N*)	1	10
Lead-Time (*L*)	5	1
Present Value Cost	**$25 Million**	**$24 Million**

According to Equation (11), the expected present value cost of the T&D upgrade is $25 Million and the expected present value cost of the distributed PV generation alternative is $24 Million. Thus, the distributed PV generation cost is lower than the T&D upgrade cost even though the per unit cost of PV generation is four times the cost of the upgrade. Figure 4 presents the break-even cost for a range of investments as a function of their modularity and lead-time as compared to the T&D upgrade cost. The figure shows that highly modular, short lead-time investments can have a much higher per unit cost than the non-modular, long lead-time T&D upgrade and still be cost-effective.

[6] This is the total cost of the PV system minus the other benefits the PV provides to the utility. Thus, it represents the effective cost of the PV system from the T&D perspective. It is assumed that every kW of PV provides a kW of capacity to the T&D system. This cost would need to be modified as discussed in Hoff (1996) to account for a less-than-perfect match between the PV plant output and peak demand.

Figure 4. Break-even Cost as a Function of Modularity and Lead-Time.



This example assumed that the cost of PV was constant over time. In fact, PV prices have been declining at a real rate of about 9 percent per year (see Wenger, Hoff, and Pepper 1996, p. 5-2 for a plot of historical price reductions). If these price decreases continue, PV could have a current price of more than $6,000/kW[7] and still be a lower cost alternative than the T&D upgrade. This is because there will be no investment in PV for at least four years (when its cost will be reduced to about $4,000/kW).

CONCLUSIONS

This research presented a method to help utility planners and regulators to manage the risks caused by demand uncertainty in the T&D system using distributed resources. The method accounted for the dynamic nature of demand uncertainty and evaluated the relationship between demand uncertainty and investment lead-time and modularity. It

[7] As before, this is only the amount that is allocated to the T&D system; it does not include the other benefits associated with the PV system (i.e., energy value, generation system capacity value, energy loss savings, environmental benefits, etc.).

demonstrated how to incorporate a decision-maker's risk attitude into the analysis when there is both demand uncertainty and firm profit uncertainty.

Results indicate that the modularity and short lead-times associated with distributed resources can increase their attractiveness in comparison to large-scale, long lead-time T&D investments. Results also suggest the distributed resources can operate as a type of "load growth insurance (Lovins and Lehmann 1997)" if demand growth is positively correlated with profits (so that distributed generation costs are incurred when profits are high) and the distributed resource costs represent a part of a larger portfolio that cannot be diversified.

This work has only begun to address a number of the issues associated with distributed resources and uncertainty. There are several areas of future work. From a methodological perspective, there is a need to: (1) assess the empirical accuracy of the demand uncertainty model employed in this paper; (2) evaluate distributed resources that have shorter lives (e.g., some demand-side management programs); (3) examine strategies that combine distributed generation and traditional T&D investments;[8] (4) extend the analysis to non-exponential utility functions and other models of firm profits; (5) incorporate distributed resource cost uncertainty into the analysis; (6) incorporate the technical effectiveness of distributed resources at satisfying peak demand as a planning area becomes saturated and the shape of the load curve shifts; (7) evaluate the impact of eliminating the utility's obligation to have sufficient T&D capacity; (8) extend this work to an international setting; and (9) apply this work from a customer perspective. From a

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[8] Hoff (1997a) has some preliminary results using an expected cost framework. He shows that, even in cases when the distributed generation alternative cost exceeds the T&D upgrade cost, it can effectively be used to delay the upgrade until the load grows with the possibility of some cost being incurred before the upgrade is completed.

practical perspective, there is a need to: (1) design policies that give T&D utilities the option and incentive to either own distributed generation investments or to set the appropriate price signals to stimulate investment in distributed generation; (2) evaluate T&D investment decisions in the context of a competitive environment by comparing a customer's option to purchase power from either competitive generation wheeled across the utility's T&D system or directly from a distributed generator; and (3) apply the results to actual case studies.

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APPENDIX A: NOMENCLATURE AND DEFINITIONS

A	=	adjustment in the probability of high demand growth p given the probability of high profits q such that the expected value and variance conditions on both demand growth and firm profits are satisfied, where $A = corr(I,\pi)\sqrt{p(1-p)q(1-q)}$
B	=	bounds on $corr(I,\pi)$
$corr(I,\pi)$	=	correlation between distributed generation costs and firm profits
I	=	cost in $ per increment of investment
L	=	lead-time for investment in years
M	=	number of years of capacity that an increment of distributed generation will provide if demand grows at the high rate
N	=	number of increments of distributed generation needed to provide the same amount of capacity as the system upgrade
P	=	adjustment in the probabilities based on the correlation between profits and distributed generation costs in incomplete markets
p	=	probability that demand will grow at the high demand growth rate
q	=	probability that firm profits will be high
r	=	real discount rate
R	=	discount factor used in the expected cost calculation, where $R = p/(p+r)$
T	=	number of years until excess system capacity vanishes if demand grows at the high rate every year
V	=	firm value without distributed genereation costs
X	=	present value investment cost
α	=	annual rate of investment escalation
π	=	firm’s annual after-tax profits
ρ	=	risk-aversion coefficient in exponential utility function (single period)
$\tilde{\rho}$	=	risk-aversion coefficient in exponential utility function (multiple periods)
ψ	=	state price

Complete Markets:	Markets are complete if the span of the set of possible portfolio payoffs equals the number of states of uncertainty (Duffie 1992). Another way to say this is that an investor can purchase a portfolio of investments that has exactly the payoffs desired in every given state. In essence, this means that the investor can hedge any uncertain payoffs.
Incomplete Markets:	It is assumed that incomplete markets means that the decision-maker can only borrow and lend at the risk-free rate and all other uncertain payoffs cannot be fully hedged.