MANAGING RISK USING RENEWABLE ENERGY TECHNOLOGIES

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ABSTRACT

This paper investigates the potential of owning renewable energy technologies to mitigate risk faced by the electric utility industry. It considers the effect of market structure on the plant ownership decision and how the attributes of renewable energy technologies can help to manage risk. Explicit consideration is given to the renewable energy technology's attributes of fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility. It concludes that renewable energy technologies, particularly the modular technologies such as photovoltaics and wind, have the potential to provide decision makers with physical risk-management investments.

1. INTRODUCTION

Regulatory and technical forces are causing electric utilities to move from a natural monopoly to a more competitive environment. Associated with this movement is an increasing concern about how to manage the risks associated with the electric supply business. There are several approaches to managing these risks. One approach is to purchase financial instruments such as options and futures contracts. Another approach is to own physical assets that have low risk attributes or characteristics. This research investigates the potential of mitigating risk by owning renewable energy technologies.

Two groups that would consider owning renewable power plants for risk-management purposes are power consumers and power generators. Power consumers need power to operate their businesses or residences and power generators operate their businesses to make power. Power generators include investor-owned utilities (IOUs), municipal utilities, independent power producers (IPPs), and other market segments that can use generation to satisfy multiple requirements such as within a distributed generation configuration.

The decision to own a renewable power plant is influenced by a number of economic issues. Some of these issues depend on market structure while others depend on the technology's attributes. The second section of the paper considers the effect of market structure on the plant ownership decision. The third section discusses how the attributes of renewable energy technologies can help to manage risk from various ownership perspectives. Explicit consideration is given to the attributes of fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility.

The research concludes that renewable energy technologies, particularly the modular technologies such as photovoltaics and wind, have the potential to provide decision makers with physical risk-management investments. The use of these investments and their risk-mitigation value depend upon the ownership perspective.

2. MARKET STRUCTURE

This section considers some of the issues affecting the plant ownership decision associated with market structure. Two issues upon which market structure has a dominant influence are to whom the plant owners are allowed to sell their output and the contractual relationships between plant owners and output purchasers.

2.1 Output Sales

One issue of concern to plant owners is to whom they can sell their output, an issue that is affected by the structure of the electric utility market. The current market structure is composed of a group of integrated utilities and IPPs as shown in figure 1.[1] The thick lines correspond to the transmission system and the thin lines correspond to the distribution system.

Under this structure, renewable power plants can be owned by IPPs, by IOUs and municipal utilities (either as central station or distributed generation), and by power consumers. IPPs are limited under this structure to selling their output to the utilities who supply power to power consumers, while the latter are limited in their ability to own plants depending upon whether or not the plants can be physically located on their premises.

[1] The following three figures are based on Hyman (1994).

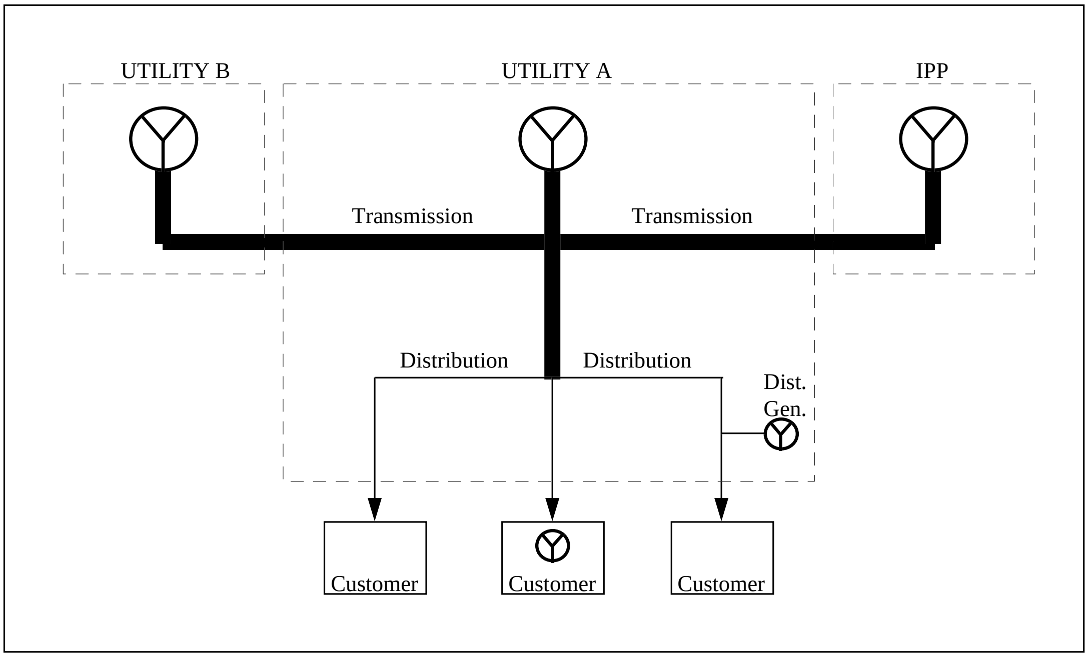

Figure 1. The current system.

Although the electric utility industry is becoming more competitive, there is likely to be a transition period as this occurs. Figure 2 suggests that this transition will provide greater contractual freedom between generators and consumers. While the physical characteristics of the electric supply system may not change, the dashed lines with arrows in the figure indicate that IPPs can sell their output directly to power consumers in addition to selling to utilities. The power flows through the same electrical wires but the payment flows directly from the consumer to the generator with some charge going to the utility that manages the transmission and distribution system. This opens up an additional market for renewable technologies that are not physically located on customer premises.

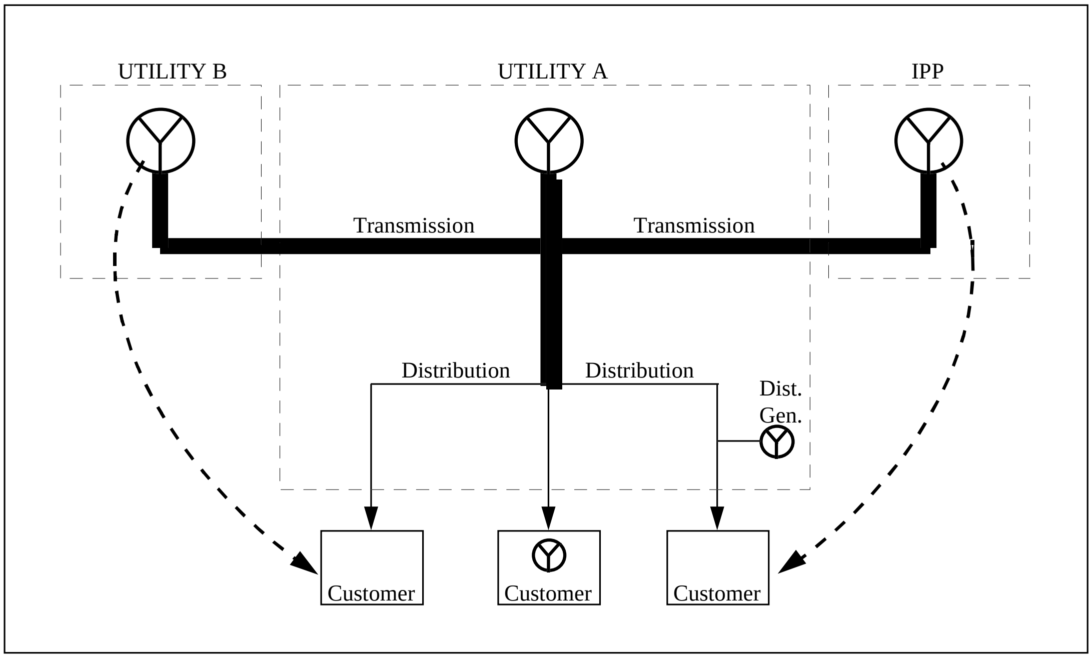

Figure 2. The transitional system.

Full-scale competition is likely to result in structural change in the industry. In particular, the generation market will probably become fully competitive and separate transmission and distribution utilities will distribute the power. As shown in figure 3, it is likely that generation will not be owned by the same companies that operate the transmission and distribution systems to avoid conflicts of interest. Power generators might sell their output to a transmission utility or power pool, to local distribution utilities, or directly to consumers.

In addition to this increased access, greater competition is likely to encourage the market for distributed generation IPPs. First, IPPs could serve a group of consumers but use only a portion of the distribution system. This reduces the IPPs' costs associated with using the transmission and distribution system (if the IPP is central generation) and the transaction costs associated with siting many small plants on customers' premises.

Second, the IPPs could sell their output to the high value consumers at the times when they are consuming power and then have access to the transmission and distribution system to sell their excess output when the consumers do not need the output.

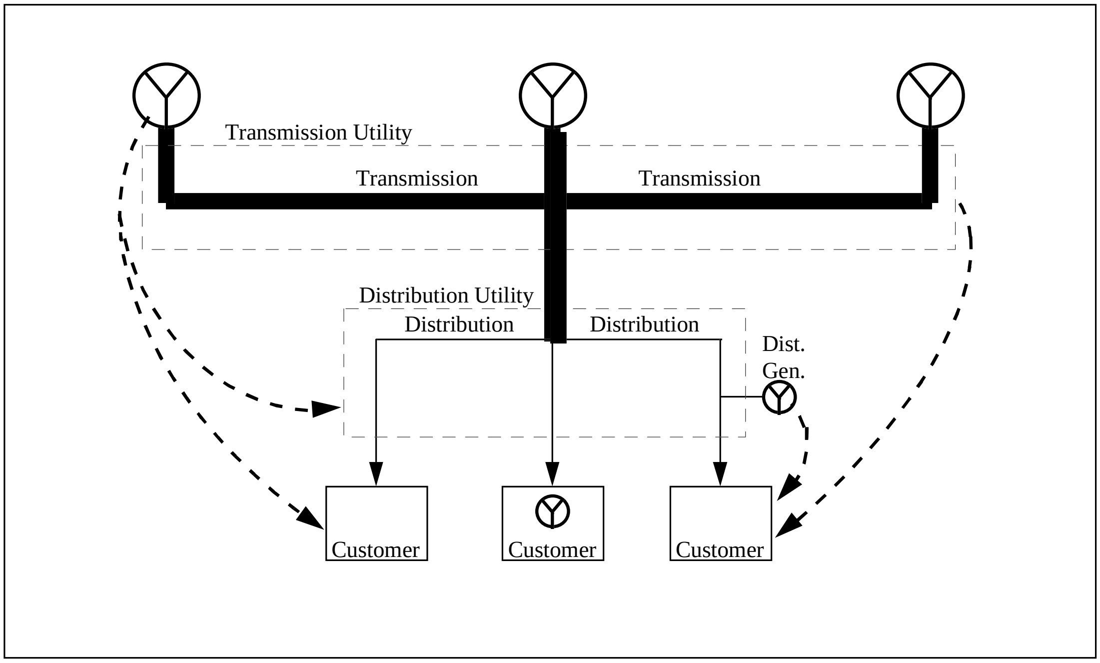

Figure 3. The competitive system.

Power marketers are potentially very important and can serve as an intermediary between the plant owner and the output purchaser in each of the three scenarios described above. Hamrin and Rader (1994) suggest that a specific type of power marketer may be a renewable power marketing authority (also called renewable aggregator). Such a power marketer aggregates, firms, and transmits renewable resources and then sells the power. Hamrin and Rader suggest that this is necessary to enable renewables to participate in a wholesale commodities market because it allows intermittent renewable resources to be mixed together and then be packaged as a commodity and marketed in sizes that reduce transactional costs. That is, renewable aggregators would help to solve the intermittent output and marketing problems associated with renewable technologies.

Another possible type or role of a renewable aggregator might be to obtain more attractive financing for renewable power plants. A renewable aggregator might be able to attract the financial capital from individual investors who are interested in promoting the use of renewable energy by investing their funds in such plants. A renewable aggregator would aggregate demand for capital from renewable project developers rather than demand for electricity from power consumers.

2.2. Sales Contracts

A second issue of concern to power plant owners is the contractual relationship between the renewable plant owner and the customer to whom the output is sold. There is no need for a contract if the renewable plant owner consumes the output itself. The terms and conditions of the contract (if one exists) become very important, however, when the plant owner and the output consumer are not the same party.

Utilities have historically operated as if they had long-term sales contracts with their customers even though no contracts existed. Utilities set their rates with the oversight of public utility commissions and the customers' only options were to pay the rates or to leave the system. This structure has not offered much choice to customers with regard to contractual relationships for future power needs.

This structure has, however, been the basis for the long-term power purchase agreements that utilities have offered IPPs, agreements that have been essential to the development of the IPP market, particularly for capital-intensive renewable energy technologies. According to the wind-generating manufacturer Kenetech Corporation

(1994), for example, sales of wind turbines fall into the general categories of power purchase agreements, direct sale to a utility, and equipment sales. Under the power purchase agreements category, Kenetech arranges for third-party financing based on the value of the particular power contract. Fully three-quarters of Kenetech's installed base, three-fifths of Kenetech's 1,114 MW of wind plants currently under construction or in the contracting process, and all of the 945 MW of wind plants that were proposed in the California Biennial Resource Planning Update are in the power purchase agreements category.

The changing electricity supply environment is affecting long-term contracts in several ways. First, public utility commissions are moving away from traditional rate making to performance based rate making.[2] This encourages utilities to be more cost conscious and to exercise great care about the contracts that they sign. For example, many utilities are currently financially exposed due to long-term power purchase contracts. Southern California Edison Company (1994, pp. 1, 9) and Pacific Gas and Electric Company (1994, p. 40), for example paid an average of $0.080/kWh and Niagara Mohawk Power Corporation (1994, p. 23) paid an average of $0.065/kWh for purchased power in 1994. The two west coast utilities estimate that the market price of electricity at the generation level in a competitive environment would be closer to half of what they paid in 1994.

[2] Under traditional rate making, revenue equals cost (as calculated by the utility) plus profit (as determined by the public utility commission). Under performance based rate making, profit equals revenue (as determined by the public utility commission) minus cost (based on the utility's performance).

Second, utilities also recognize that there are no guarantees that customers will remain in the system. Hyman (1994) suggests that this may result in the situation where utilities need more protection from customers rather than vice versa. In the future, utilities may have to move toward a system of commercial contracts with large customers to protect themselves.

These and other changes make it unclear what the future will hold in terms of the types of contracts that will exist between generators (IPPs and utilities) and consumers. This is of concern to those interested in the development of renewable energy because a key to the success of the renewable power industry has been the ability to obtain long-term contracts.

While IOUs may be shying away from long-term power purchase contracts, there is no reason to believe that all parties in the market will do likewise. As stated earlier, the current electric utility structure does not offer most customers choice with regard to the type and duration of contracts that they enter into. In a more competitive market, it is likely that some customers will be willing to enter into long-term contracts. This desire may be further increased if a competitive market results in highly volatile electricity prices. Other commodity markets, for example, abound with risk-management tools such as forward and futures contracts (i.e., agreements between two parties to buy or sell an asset at a certain time in the future for a certain price), and swaps (i.e., the exchange of a fixed income stream for a variable income stream; swaps can be regarded as portfolios of forward contracts).

Moreover, other competitive industries commit to long-term capital improvements instead of continuing to manage short-term variable costs. Consider, for example, the manufacturing sector and automated machines versus labor intensive machines. Renewable energy technologies are comparable to automated machines and fossil-based technologies are comparable to labor intensive machines. Specifically, renewable energy technologies have high up front costs but require no fuel (automated machines have high up front costs but require little labor) while fossil-based technologies have lower up front costs but require fuel (labor-intensive machines have lower up front costs but require more labor). Substantial investments have been made in automated machines to replace labor-intensive machines in competitive manufacturing industries. This is a source of strategic competitive advantage for some firms.

The question is who wants to purchase electricity under long-term contracts and how long is long-term? A possible role for renewable aggregators in markets where generators have direct access to consumers is that of negotiating long-term contracts between consumers and renewable power producers. A renewable aggregator would make sense in this situation if it could more successfully lower transaction costs or secure contracts to sell renewable power than a single producer.

3. RENEWABLE ENERGY TECHNOLOGY ATTRIBUTES

The previous section discussed some of the important issues associated with market structure from a plant owner's perspective. This section describes the particular attributes of renewables that can be used to mitigate risks and ownership scenarios that benefit from these attributes. The attributes considered include: fuel costs, environmental costs, modularity, lead time, location flexibility, availability, initial capital costs, and investment reversibility.

3.1. Fuel Costs

One of the most often stated positive attributes of renewable technologies is that they have no fuel costs. As a result, there is no uncertainty associated with the future fuel costs to operate a renewable power plant. All ownership scenarios mentioned earlier can benefit from this attribute. Different ownership scenarios, however, will benefit to a different degree with those experiencing the most uncertainty realizing the greatest benefit. Currently, this includes IPPs and power consumers because fluctuations in fuel costs (or electricity prices) directly affect the profit of IPPs, the profit of commercial and industrial users of electricity, and the well being of residential consumers who use power for their residential needs. IOUs and municipal utilities that generate power realize less of a benefit from a reduction in fuel cost variability because they currently pass this uncertainty on to customers through fuel adjustment clauses. In a more competitive environment, however, it is unlikely that this practice will continue.

When comparing renewable to fossil-based plants, the absence of fuel cost uncertainty must be added as a benefit of the renewable plant or counted as a cost of the fossil-based plant. Cost analysis for fossil-based plants typically projects a stream of expected fuel costs, discounts the results, and considers the present value cost as part of the cost of the plant. This analytical approach, however, improperly converts the uncertain stream of future fuel costs into a stream of certain costs without accounting for uncertainty.

One way to account for this uncertainty is to determine the cost of entering into a long-term, fixed price fuel contract, such as a natural gas contract (e.g., Awerbuch, 1995). Entering into such a contract is comparable to taking out a loan and should, as such, be considered a form of debt financing. Taking this approach has a direct cost and an indirect cost. The direct cost equals the present value cost of the fuel contract discounted at the firm's cost of debt. The indirect cost equals the increased cost of future investments due to the fact that entering into the contract changes the firm's capital structure. Hoff (1996) presents the details of how to calculate the indirect cost.

3.2. Environmental Costs

Another attraction of renewables is that they produce low or no environmental emissions. Quantifying the value of this benefit, however, is controversial. A good part of the debate stems from the fact that the various participants in the process may have vastly different valuations.

The perspective taken in this paper is that of the plant owner, including investors in IPPs, utilities, or power customers. Plant owners can incur two types of costs associated with emissions. First, there is the additional cost of building the plant to comply with current environmental standards. This cost, which is minimal when environmental standards are low, is usually included in evaluating all types of plants, both fossil-based and renewable.

Second, there is the cost associated with future environmental standards that have not yet been established. As Swezey and Wan (1995) point out, "prospective environmental cleanup costs of fossil-fuel-based plants are never considered up-front when generation investment decisions are made." These future costs have the potential to be quite high. Pacific Gas and Electric Company (1994, p. 20), for example, estimates that compliance with NOx emissions rules for its existing power plants could require capital expenditures of up to $355 million over the next ten years. It is likely that these costs were not anticipated by Pacific Gas and Electric Company when the plants were initially constructed. Power plants that are considered to be very clean according today's standards (e.g., natural gas based generation) may fare very poorly in five years.

A conceptual framework that can be used to view this future cost is that the decision to build any polluting generation source includes the plant owner's decision to give a valuable option to the government. The option gives the government the right (but not the obligation) to change emissions standards or impose externality costs (i.e., environmental taxes) associated with environmental damages at any time and require that all generators meet the standards. The result of this is that there is a positive probability that the plant owner will incur costs in the future. The cost of this option must be accounted for when comparing fossil-based to renewable plants. Either fossil-based plant owners require compensation for the option that is given to the government or renewable plant owners need to be given a credit. The benefit of low or zero future environmental costs depends upon who owns the plant, since some owners are more likely to incur environmental costs. For example, utilities and IPPs are likely to experience more stringent regulation than power consumers that own plants.[3]

This idea is similar to stock options that are given to company executives as part of their compensation; while there are no costs associated with the options when they are given, the cost will be incurred at some future time if the option is exercised, thus diluting the stock's value. This represents a cost to stockholders and a value to the executives to whom the compensation is given.

3.3. Lead Time

IOUs and municipal utilities are still considered to be regulated natural monopolies, which requires them to serve all customers regardless of whether or not it is profitable to do so. The interaction between demand uncertainty, plant lead time, and capacity additions is of concern to these utilities. The smaller the utility is in size, the greater the concern. For this reason, municipal utilities might be particularly concerned about demand uncertainty at the generation system level.

The following example illustrates the interaction between demand uncertainty, lead time, and capacity additions. Figure 4 presents capacity and demand for a hypothetical utility generation system. The heavy lines correspond to historical data and the light lines to projected data. The current year is 1995. Actual peak demand (heavy solid line) increased in 1992, remained constant in 1993 and 1994, and increased in 1995. System capacity (heavy dashed line) remained constant during this period.

A typical approach to incorporating demand uncertainty is to project high, average, and low demand scenarios (e.g., Price, Clauhs, and Bustard 1995). The average projected demand is depicted in figure 4 by the light solid line and the high and low projected demands by the light dashed lines.

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[3] This does not imply that consumers do not place a high value on the absence of emissions as illustrated by the success of green pricing. Rather, it is that consumers are less likely to be required by the government to clean up a generation source than an entity whose primary business is power generation.

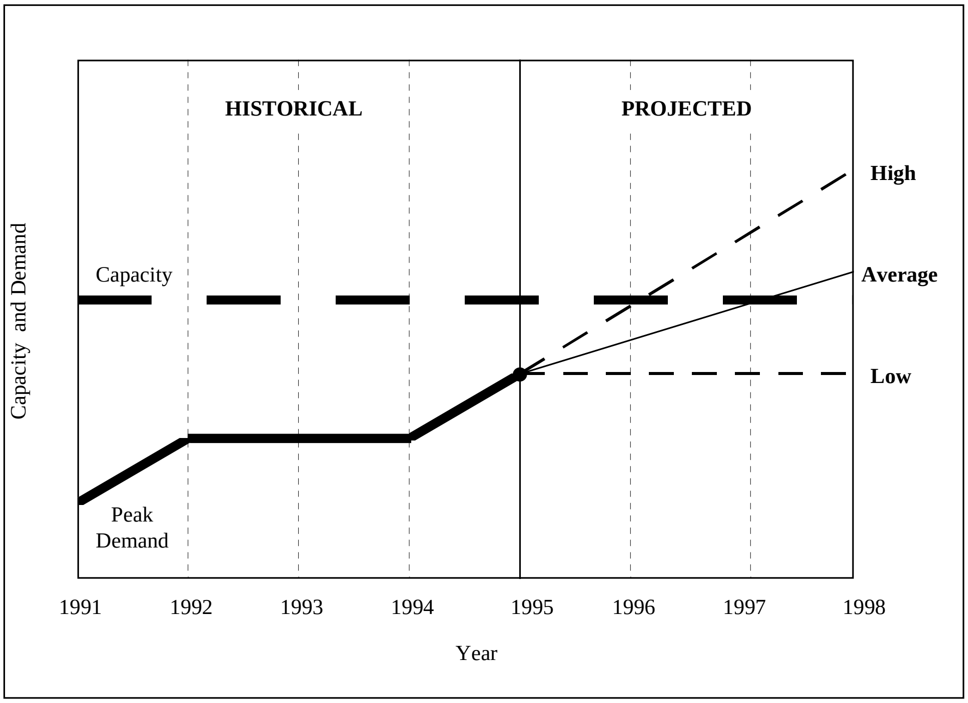

Figure 4. Demand growth and system capacity (high, average, and low scenarios).

The utility is faced with the decision to invest in either one of two plants. The plants are identical except for their lead time and capital cost: one plant requires a one year lead time and costs C^1 (it is assumed that the full cost is incurred when construction begins) and the other requires no lead time and costs C^0. The utility must decide whether to choose the plant with a one year lead time or the plant with no lead time. The real discount rate is r.

One solution to this problem is to assume that the utility must satisfy average projected demand (i.e., the light solid line in figure 4), calculate the discounted cost of each alternative, and compare the results.[4] This approach suggests that the plant with a one year lead time be built in 1996 at a present value cost of $C^1/(1+r)$ and the plant with no lead time be built in 1997 at a present value cost of $C^0/(1+r)^2$. The utility is economically indifferent between the two alternatives if $C^0/(1+r)^2$ equals $C^1/(1+r)$, which reduces to C^0 equal to $C^1(1+r)$.

This approach to incorporating demand uncertainty, however, does not capture the dynamic nature of demand growth. Demand growth can change over time so that demand can grow or not grow at each point in time as represented by the small solid circles in figure 5. For example, peak demand might increase in 1996 (point B) and then not increase in 1997 (point D) and 1998 (point F).

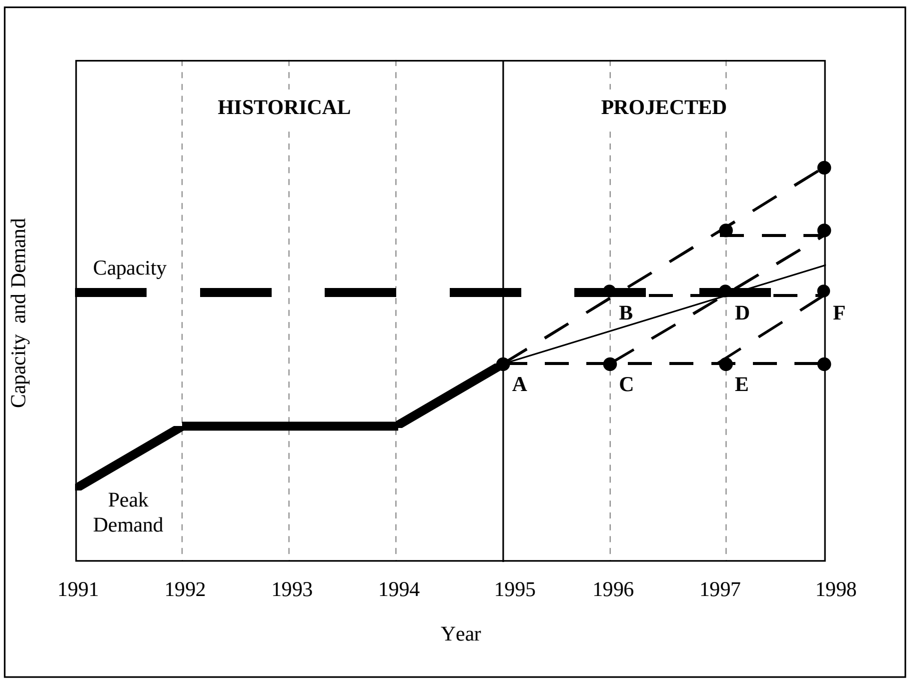

Figure 5. Demand growth and system capacity (dynamic evaluation).

The utility has the obligation to have sufficient capacity to satisfy peak demand the first time it occurs. Figure 5 suggests that construction of the plant with a one year

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[4] Relative plant costs are unchanged if it is assumed that the utility must satisfy the high projected demand rather than the average projected demand.

lead time must begin in 1995 (point A) because there is a 50 percent probability that additional capacity will be needed in 1996 and it takes one year to build the plant.[5] Construction of the plant with no lead time, by comparison, can be postponed until at least 1996. The plant will be built in 1996 if demand increases (point B), otherwise construction will be postponed if demand does not increase (point C); it will be built in 1997 if demand increases (point D), otherwise construction will be postponed if demand does not increase (point E), etc.

The present value cost of the plant with a one year lead time is C^1 because the cost is incurred in 1995. The expected present value cost of the plant with no lead time equals the probability that the plant will be needed (i.e., the first time demand reaches capacity, or points B, D, and F) times the discounted cost of the plant. This equals $C^0/(1+2r)$.[6]

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[5] The possible projected demands are based on the historical observation that system peak demand has a 50 percent probability of increasing and a 50 percent probability of staying at its current level in any given year.

[6] The expected cost is calculated by determining the probability of the cost occurring and multiplying this by the discounted cost. Figure 5 indicates there is a $(1/2)$ probability that the plant will be built in the first year at a discounted cost of $C^0/(1+r)$, a $(1/2)^2$ probability that the plant will be built in the second year at a discounted cost of $C^0/(1+r)^2$, etc. The expected cost of the expenditure equals $\sum_{t=1}^{\infty}\left(\frac{1}{2}\right)^t \frac{C^0}{(1+r)^t}$, which simplifies by reducing the infinite series to an expected cost of $C^0/(1+2r)$.

In general, the expected present value cost of the plant with no lead time equals the probability of needing the plant at time $k+L$ times the discounted cost summed over all time periods. That is, $E[Cost]=\sum_{k=0}^{\infty}\left[\binom{k+L-1}{L-1}(p)^L(1-p)^k\right]\left[\frac{C^0}{(1+r)^{k+L}}\right]$ where k is the number of years, L is the number of years of lead time associated with the alternative (L must be a positive integer), $\binom{k+L-1}{L-1}$ is the number of possible combinations of $(k+L-1)$ objects taken $(L-1)$ at a time, The utility is economically indifferent between the two alternatives if $C^0/(1+2r)$ equals C^1, which reduces to C^0 equal to $C^1(1+2r)$.

While the first approach indicates that the plant with no lead time can cost a factor of r more than the plant with a one year lead time, the dynamic approach indicates that the plant with no lead time can cost a factor of $2r$ more than the plant with a one year lead time. Suppose, for example, that the plant with a one year lead time costs $1,000,000 and the discount rate is 10 percent. The plant with no lead time can cost $100,000 more using the first approach and $200,000 more using the dynamic approach.

3.4. Location Flexibility

IOUs and municipal utilities have historically satisfied customer demand by generating electricity centrally and distributing it through an extensive transmission and distribution network. As demand increases, the utility generates more electricity. The capacity of the generation, transmission, and distribution systems can become constrained once demand increases beyond a certain level. The traditional utility response to these constraints is to build new facilities.

Utilities, however, are beginning to consider alternative approaches to dealing with transmission and distribution capacity constraints (Weinberg, Iannucci, and Reading 1991), such as using photovoltaic and other distributed generation technologies or reducing demand through targeted demand side management programs (Orans, et. al.

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p is the probability that demand will increase, r is the real discount rate, and C^0 is the current cost of the plant with no lead time. This expected cost simplifies to $E[Cost] = C^0\left(\frac{1}{1+r/p}\right)^L$.

1992). These investments can reduce a utility's variable costs and defer capacity investments as illustrated in figure 6.

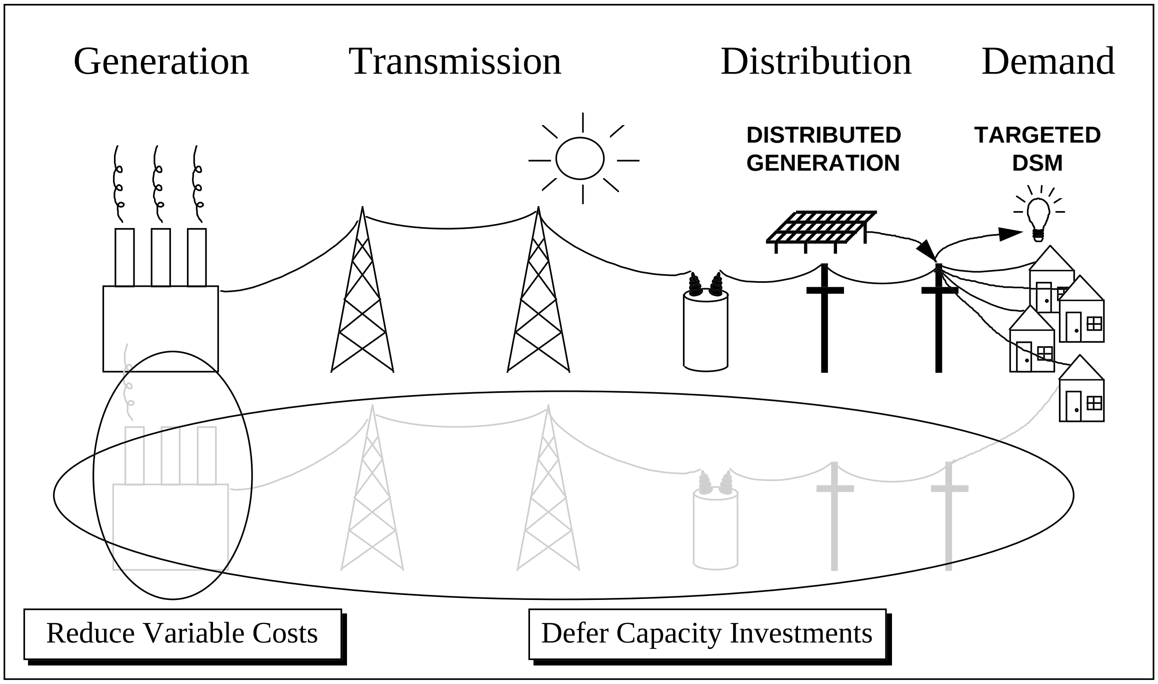


Figure 6. The benefits of distributed generation to the utility system.

A special case of the value of modularity and short lead time occurs within this distributed generation setting due to the location flexibility associated with the modular generation technologies. The analysis from the previous subsection can be applied to the transmission and distribution system in addition to the generation system in the case of distributed generation. That is, rather than determining the value of short lead time for the generation system, the value of short lead time is determined for the transmission and distribution system.

The value of short lead time when combined with location in a distributed generation setting is probably of greater value to IOUs than to municipal utilities. The reason for this is that municipal utility systems tend to be highly concentrated in urban areas (and thus are highly interconnected) while IOUs have systems that are more spread out.[7]

3.5. Availability

Plant modularity also affects plant availability, which is of interest under all ownership scenarios. Modular plants are likely to begin producing power (and thus revenue for utilities and IPPs or cost-savings for power consumers) earlier than non-modular plants. In addition, modular plants have less variance in their equipment availability than non-modular plants.

3.5.1. Earlier plant operation

A modular plant can begin operation as each segment of the plant is completed. This availability means that a modular plant will begin to produce revenue earlier than a plant that is not modular or is lumpy. Using a hypothetical example, suppose that a utility wants to build a 500 MW facility. A modular alternative can be constructed in 50 MW increments with each increment having a 6 month lead time (i.e., it takes 5 years to complete the plant). A 500 MW non-modular plant, by contrast, is built in one segment and has a five year lead time. If it is assumed that each plant or portion of the plant has a 20 year life beginning at the point when the equipment starts operating (i.e., one horse shay depreciation) then the modular plant begins earning revenue six months after the start of construction while the non-modular plant produces no revenues until the fifth

[7] Location is also very important to power consumers who own their own generation facilities. This is not for reasons of risk and uncertainty but because, under the current market structure, the generation facility must be physically located on the customer's premises in order to self-generate. This restriction will become less important as the access to the T&D system becomes more open.

year. As illustrated in figure 7, the plants have identical capacities between 2000 and 2015 while the modular plant has higher capacity between 1995 and 2000 and the non-modular plant has higher capacity between 2015 and 2020.

Assume that revenues (*R*) for the full plants are constant in real terms over the life of the plants and that they are proportional to plant capacity (e.g., a plant with 10 percent of its capacity on-line receives 10 percent of *R*). The present value of the revenues from the modular plant equals $\sum_{i=1}^{10}\frac{(i/10)R}{(1+r)^{i/2}}+\sum_{i=11}^{40}\frac{R}{(1+r)^{i/2}}+\sum_{i=41}^{50}\frac{[(50-i)/10]R}{(1+r)^{i/2}}$ and the present value of the revenues from the non-modular plant equals $\sum_{i=11}^{50}\frac{R}{(1+r)^{i/2}}$; *r* is the real discount rate and *i* corresponds to six-month time periods. If it is assumed that a 500 MW plant has revenues of $50,000,000 every six months and the discount rate is 10 percent, the present value revenues of the modular plant are $710,000,000 while the present value revenues of the non-modular plant are $540,000,000.

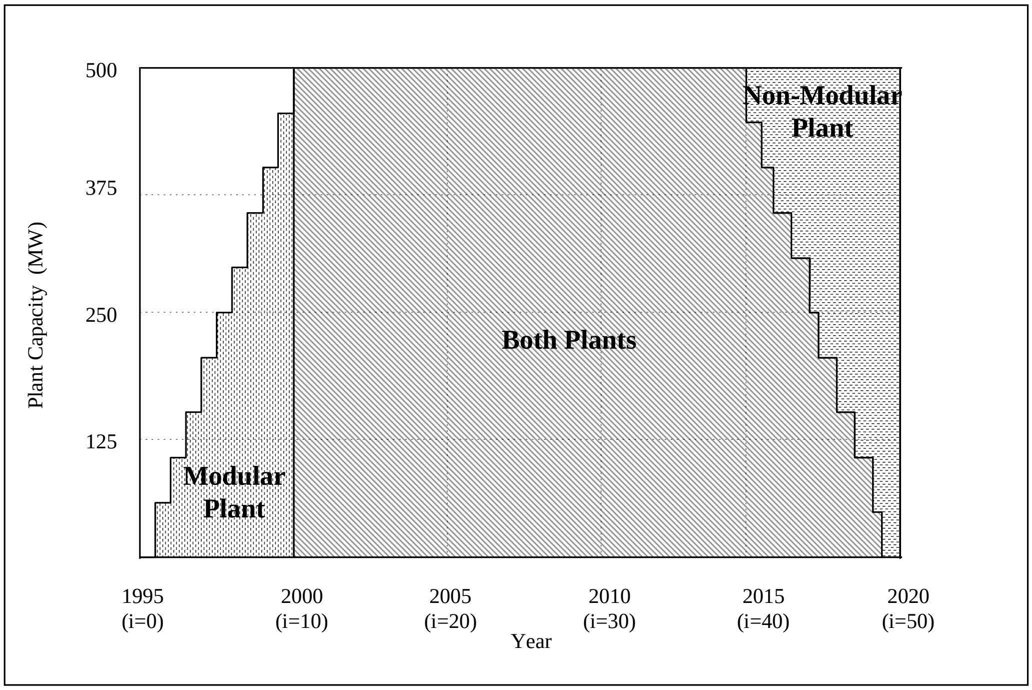


Figure 7. Modular plant produces revenue sooner than non-modular plant.

An interesting extension occurs when the modular plant is infinitely divisible (i.e., the steps in figure 7 turn into straight lines). Let L be the number of years to complete the full plant, T the life of each part of the plant once completed, and r the continuous time real discount rate. Analogous to the discrete time case, the present value of the revenues from the modular plant equals (for $T > L$; and for T, L, and $r > 0$)

$\int_0^L (x/L)(R)\exp(-rx)dx + \int_L^T (R)\exp(-rx)dx + \int_T^{T+L} [(T+L-x)/L](R)\exp(-rx)dx$; this

simplifies to $[R]\left[\frac{1-\exp(-Tr)}{r}\right]\left[\frac{1-\exp(-Lr)}{Lr}\right]$. The present value of the revenues from

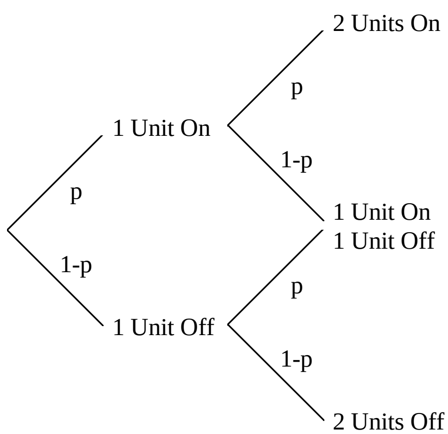
the non-modular plant equals $\int_L^{T+L} (R)\exp(-rx)dx$; this simplifies to

$[R]\left[\frac{1-\exp(-Tr)}{r}\right][\exp(-Lr)]$.

The ratio of the revenues from the modular plant to the non-modular plant is $\left[\frac{\exp(Lr)-1}{Lr}\right]$. Notice that the only variables in this equation are the real discount rate and the number of years it takes to complete the plant; that is, the life of the plant is not relevant.

3.5.2. Reduced variance of equipment availability

Modular plants have less variance in their equipment availability than non-modular plants when equipment failures in the modular plant are independently distributed. A non-modular plant can be considered to be either operating or not operating. If its forced outage rate is (1-*p*), it has full availability with probability *p* and is unavailable with a probability of (1-*p*). Modular plants, by contrast, can have partial availability. For example, a modular plant with two identical segments has three possible levels of availability as depicted by the probability tree in figure 8: the plant is 100 percent available if both segments are functional; it is 50 percent available if either the first or the second segment is functional (thus the 2 in the probability distribution in figure 8); and is unavailable if both segments are non-functional.



Availability	Probability
100%	p^2
50%	2p(1-p)
0%	$(1-p)^2$

Figure 8. Distribution of plant availability for modular plant.

The mean or expected availability of a plant regardless of the number of segments is one minus its forced outage rate. Since the forced outage rate is (*1-p*), the mean availability is *p*. Variance for a non-modular plant is $\left[p(1-p)^2 + (1-p)(0-p)^2\right]$, which simplifies to $p(1-p)$.[8] Variance for a modular plant with two segments equals $\left[p^2(1-p)^2 + 2p(1-p)(\tfrac{1}{2}-p)^2 + (1-p)^2(0-p)^2\right]$, which simplifies to $p(1-p)/2$. In general, it can be shown by using either an iterative repetition of the variance calculation above or by an application of the Central Limit Theorem (Ross 1988) that the variance for

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[8] The variance of a random variable *X* is $Var(X) = E\left[(X-\mu)^2\right]$, where *E* is the expectation and μ is the mean.

a plant with n independent identical segments equals $p(1-p)/n$. That is, variance decreases as the number of segments increases.

Consider a specific example where the non-modular plant and the segments of the modular plant have a 10 percent forced outage rate and the modular plant has 10 segments. The variance for the non-modular plant is 9 percent (standard deviation equals 30 percent) but the variance for the modular plant is much smaller: less than 1 percent (standard deviation equals 10 percent). This indicates that the plant's availability is more predictable.

3.6. Initial Capital Costs

Projects with short lead times tend to have greater certainty associated with their installed cost due to fewer cost overruns and less lost revenue due to plant delays. This is of interest to any party that is responsible for plant construction, although it is most significant for IPPs since utilities and power consumers frequently install generation facilities through a contracting procedure, thus shifting the construction risk away from themselves to the contractor. Two other benefits associated with modular technologies are that modular plants tie up fewer capital resources during construction and that modular plants have off-ramps so that stopping the project is not a total loss

3.6.1 Fewer capital resources are tied up during construction

A modular plant ties up fewer capital resources during the construction of the total plant. The project developer only needs enough working capital to finance one segment at a time. Once the first segment is completed, the unit can be fully financed, and the proceeds used to finance the next segment.

Figure 9 presents the unrecovered capital costs for both the non-modular and the modular plants based on the example in the previous subsection assuming a linear investment rate. The developer building the modular plant requires at most one-tenth of the total project cost at any one time. This could translate to a lower risk of default and thus, more attractive financing. This benefit is likely to be of particular interest to companies with limited financial resources, such as IPPs.

This benefit is similar to the benefit realized by a developer that chooses to build single-family dwellings rather than an apartment building. The full financial resources are tied up in the apartment building before it is sold while the single family dwellings can be sold as they are completed, thus requiring less working capital.

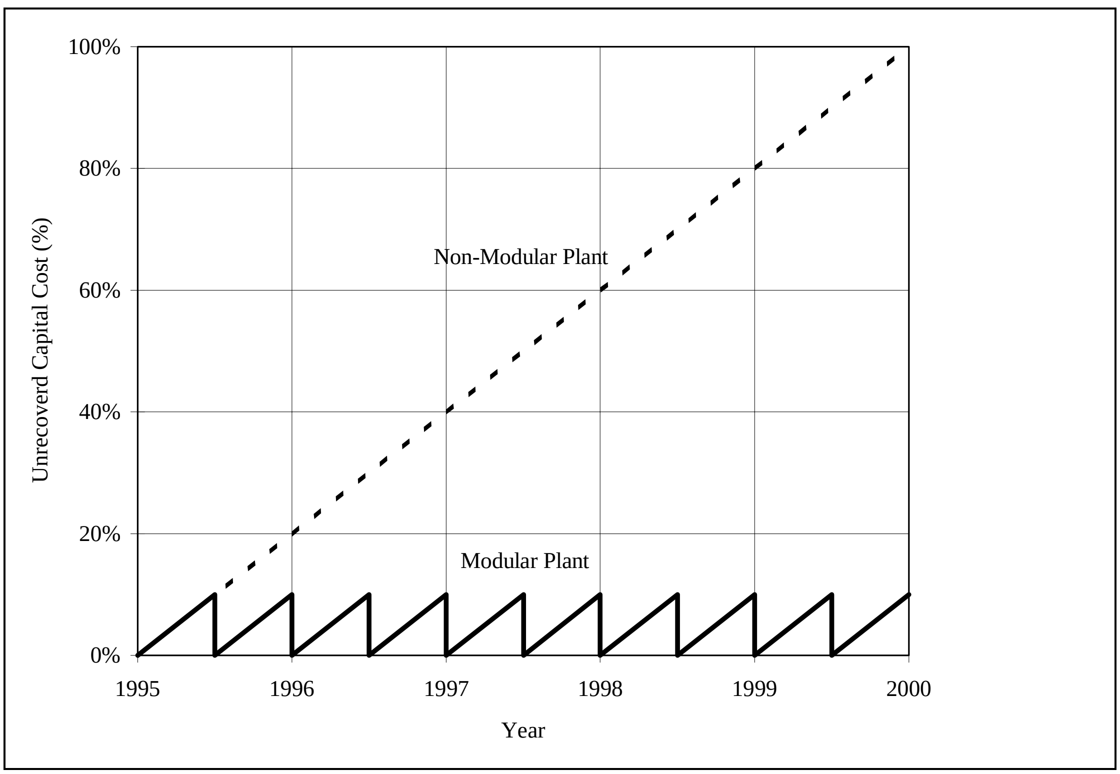

Figure 9. Unrecovered capital costs of modular and non-modular plants.

3.6.2 Project off-ramps

Modular plants have off-ramps so that stopping the project is not a total loss. Figure 10 presents a simple example for a plant that is composed of two identical segments. It is assumed that there is no market for the uncertainty associated with capital costs. The squares and circles in the figure correspond to decisions and uncertainties, respectively. The only uncertainty is what the cost of construction will be for each segment. This uncertainty is resolved after the first segment is completed and before the decision to build the second segment is made. If construction cost is high for the first segment it will be high for the second segment as well. Likewise, if construction cost is low for the first segment it will be low for the second segment as well. Cost will be high with a probability p and low with a probability (1-p).

The figure presents the net benefits associated with the completed plant for a modular and a non-modular plant after all decisions are made and cost uncertainty is resolved. It is assumed that the costs are proportional to the completed project for both plants. The difference between the modular and non-modular plants is that the modular plant has value after the first segment is completed while the non-modular plant has value only after both segments are built. That is, half of the value minus cost is obtained for the modular plant if only one segment is completed while there is only a cost for the non-modular plant if only one segment is completed. It is assumed that the plants have no salvage value.

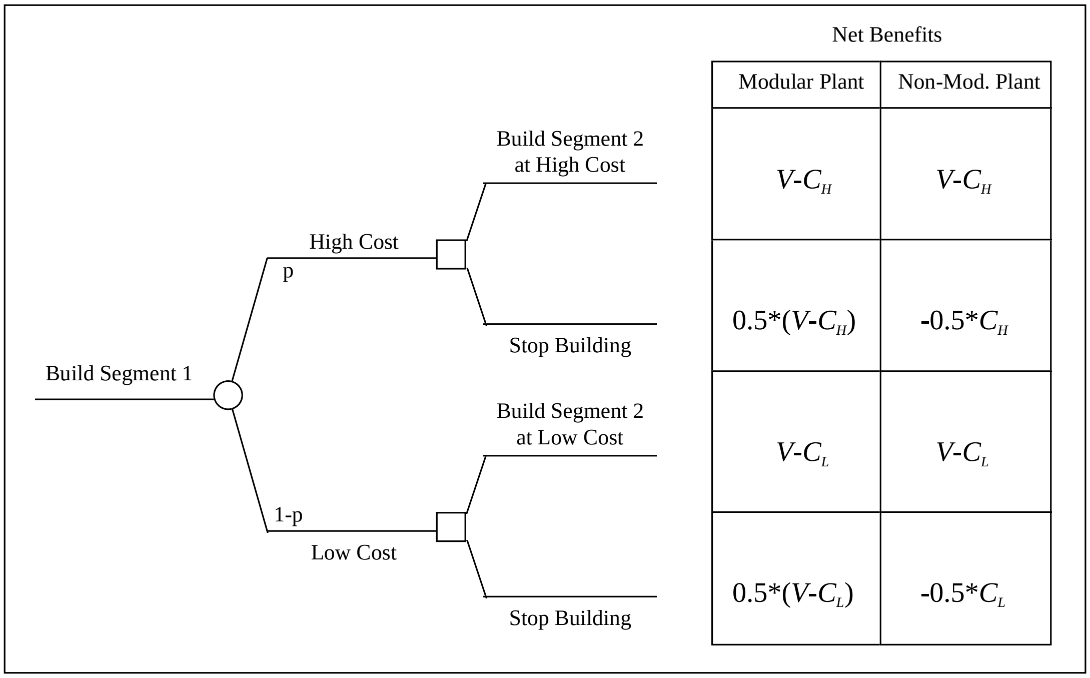

Figure 10. Modular plants can be halted without a total loss.

To illustrate the difference in net benefits between the modular and non-modular plants, consider the following example. Suppose that the value of the completed plant is \$1,000,000, high cost is \$1,500,000, low cost is \$500,000, and the probability of high cost, *p*, is 0.5. It can be shown by working backwards through the tree in figure 10 that both segments will be built whether the cost is low or high for the non-modular plant while only one segment will be built if costs turn out to be high for the modular plant. The expected net benefit for the non-modular plant is \$0 while the expected net benefit for the modular plant is \$125,000. Thus, while modularity provides value to utilities who want to control demand uncertainty, it is also of value to investors who are funding an IPP and are unsatisfied with the project's progress.

3.7. Investment Reversibility

Investment reversibility is the degree to which an investment is reversible once it is completed. This is of interest because a plant owner has the right (but not the obligation) to salvage a plant should its value become low in the particular application. Modular plants are likely to have a higher salvage value than non-modular plants because it is more feasible to move modular plants to areas of higher value or even for use in other applications. The degree of reversibility is a function of the difficulty and cost in moving the technology to another location and the feasibility of using it in different applications. Given that the uncertainty associated with the plant's future value is spanned by market traded assets, the value of this option is similar to an American put option on a dividend paying stock. Details of the evaluation approach can be found in Hoff (1996).

To illustrate this concept, suppose that a utility is accepting bids for a 50 MW battery facility. Two IPPs submit bids with identical prices proposing two technologies with identical efficiencies, lifetimes, and maintenance requirements. The only difference is that one plant is a single, 50 MW battery while the other plant is 50,000 automobile batteries (rated at 12 volts and 83.3 amp-hours).

Now suppose that in the future, due to technological breakthroughs in Superconducting Magnetic Energy Storage or other storage technologies the battery plant may become obsolete. The automobile battery plant could be salvaged for use in cars, while the 50 MW battery would have few other uses and may have to be sold as scrap. This makes the modular plant superior to the non-modular plant because the plant has a higher salvage value under an assumption of technological progress.

This value is not merely hypothetical. Consider, for example, the 6 MW Carrisa Plains photovoltaic plant facility in California, whose original owner, Arco Solar, sold the plant for strategic reasons to another company. This company dismantled the plant and the modules were resold at a retail price of $4,000 to $5,000 per kilowatt at a time when new modules were selling for $6,500 to $7,000 per kilowatt (Real Goods, 1993). That is, the investment was reversible, partially due to the modularity of the plant.

4. CONCLUSIONS

Regulatory and technical forces are causing electric utilities to move from a natural monopoly to a more competitive environment. Associated with this movement is an increasing concern about how to manage the risks associated with the electric supply business. This paper investigated the risk-mitigation potential of renewable energy technologies from several ownership perspectives. Specific attention was given to the effects of market structure and to the attributes of fuel costs, environmental costs, modularity lead time, location flexibility, availability, initial capital costs, and investment reversibility.

Table 1 summarizes the ownership scenarios that benefit from the attributes of renewable energy technologies; X denotes some benefit and XX denotes much benefit. The conclusion of this research is that renewable energy technologies, particularly the modular technologies such as wind and photovoltaics, have attributes that may be attractive to a variety of decision makers depending upon the uncertainties that are of greatest concern to them.

Table 1. Important attributes under various ownership scenarios.

	Consumers	IOUs	Municipals	IPPs
Fuel Costs	XX	XX	XX	XX
Environmental Costs	X	XX	XX	XX
Lead Time		X	XX	
Location Flexibility		XX	X	
Availability	X	X	X	X
Initial Capital Costs				XX
Reversibility	X	X	X	XX

The next step of this research is to develop a set of representative case studies for each of the types of decision makers in table 1 and to numerically quantify the economic risk-mitigation value of the various attributes described in this paper. Analytical approaches to be used in the analysis include risk-adjusted discount rates within a dynamic discounted cash flow framework, option valuation, decision analysis, and future/forward contract comparisons. The analytical approaches will be selected based on the available information and how well they demonstrate the value of the various attributes of the renewable energy technology given the specific requirements of the decision maker making the investment decision.

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