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# Improving the Value of Wind Energy Generation Through Back-up Generation and Energy Storage

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## Abstract

This white paper evaluates the use of back-up generation and energy storage for improving the economic performance of wind generation. Since wind is an intermittent resource, a generator cannot be assured of producing the power levels as bid in any given hour. Under a Firm Capacity contract, a generator will be penalized for under-generation and will not be able to sell excess power when there is over-generation. Both back-up generation and energy storage can, in principle, reduce the under-generation and storage can provide a way to sell excess power. This analysis examines the economic performance of these approaches. For both approaches the optimal operating procedures and system configurations are developed assuming operation under a Firm Capacity contract. The rate of return on investment in back-up generation and storage are then determined. These are compared to the financial performance of a wind generator operating under an Intermittent Resources contract (which has no penalties for under or over-generation). Since the addition of storage or back-up generation will improve the reliability of wind generation, such arrangements may qualify for capacity payments. The financial benefits of such payments are also evaluated. It is found that, even under fairly optimistic assumptions, the energy storage approach is unlikely to perform as well as operating under an Intermittent Resources contract. Under some optimistic assumptions, the back-up generation approach does approach the rate of return for operation under and Intermittent Resources contract. However, it may be difficult to realize these assumptions in practice. Adding capacity payments also provides significant financial benefits, if they can be made available. In both cases, the analysis has assumed that there is unconstrained access to the grid. Therefore the prices for electricity reflect grid-wide conditions. There can be locations on the grid with constraints resulting in congestion. This would change the electricity prices, possibly improving the financial viability of these approaches in a local area.

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# Improving the Value of Wind Generation Through Back-up Generation and Energy Storage

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# 1. Introduction

Wind turbine generators are emerging as a competitive renewable resource for electrical generation. As the capital costs have decreased and reliability has increased the cost of energy from wind turbines has declined to the range of $0.0288 to 0.0495/kWh [Wiser and Kahn]. On a cost per kWh generated, this is fairly competitive with other sources of electric power. However, wind generators are intermittent generators. Unlike conventional generators which reliably deliver a committed level of power, wind generators are dependent on wind speed which cannot be predicted exactly from hour to hour. As is discussed below, this can incur additional costs for the operating of the electric grid and complicates the correct structuring and financial compensation for wind generators. The reliability of wind generation can be improved by operation in conjunction with a back-up generator or with an energy storage system. Operating this way can improve the revenue to the wind generator, but at the cost of installing and operating the additional capacity. This study evaluates the potential for overall improvement of the financial performance of a wind generator using back-up generation or energy storage.

## Improving the economic value of wind generation

The economic viability of wind generation may be improved by designing a system that ensures that the wind generator provides the maximum possible value to the overall system and ensures that the owner of the generator is compensated for the value that he provides.

The value provided by a generator can be measured by the "system marginal cost" (SMC). This is the cost of increasing the system's power generation by a small increment. At the same time, it is generally equal to the savings due to decreasing generation by a small amount [Stoft]. When a wind generator comes on line, it reduces the load on the other generators and the system marginal cost measures the saving due to that reduction. In principle, the SMC is the amount that a wind owner should be compensated for generation. In these analyses we have used a grid-wide marginal cost (or price) to make the evaluations. It should be noted that the system marginal cost, in fact, varies from place to place on the grid since it is partly determined by conditions on the transmission system. Often local conditions of congestion will cause the marginal value of electricity to be larger than the grid-wide value in that local area. In such cases, the value of either back-up generation or storage can be greater than that found in this study. Such local phenomena would have to be evaluated on a case-by-case basis.

The value of an intermittent generator is reduced by the fact that its power is not "firm"—it is intermittent so that the wind generator output will often deviate from the committed level (either greater than or less than). Wind forecasting can reduce, but not eliminate these deviations. The system operator must manage these deviations by maintaining reserves and by dispatching other generators as the power from the wind generator deviates from the committed level. In theory, this extra cost should be borne by the wind generator to the extent that it is incurred. At low levels of wind penetration, this is not a substantial problem since the amount of variation due to the wind generators is similar to the amount of variation in demand that the system operator must already take into account. At higher levels of penetration (say, above 15% of total capacity [Watson et al]) the variability of the wind may require that additional costs be incurred. As is discussed below, some contracts that wind generators operate under penalize the generators for generating less than the power level committed. This penalty in part compensates for the cost of dealing with the intermittent output and in part is intended to encourage generators to meet their commitments.

Two approaches to improving the value of wind generation are explored here. Both approaches aim to improve the reliability of the wind generator by ensuring that its power output is closer to the level that it bids each hour. The first approach uses a back-up generator (typically a fossil generator) that will start producing if the wind power drops below the bid level. Conceivably with a suitably priced generator it could be possible to provide enough back-up power to avoid most of the penalties. The second approach uses energy storage to increase the reliability of the wind generator. The storage system can provide power in those hours when the wind generator fails to meet its bid. It has the added possibilities of taking in excess wind for sale later and arbitrage between low value and high value hours.

Both storage and back-up generation improve the reliability of wind generation. If reliability is improved sufficiently, wind generators may qualify for capacity payments. This report evaluates the potential financial benefits that capacity payments might have. However, it is beyond the scope of this report to determine whether or not capacity payments would actually be provided.

## Overview of the report

The next two sections of the report describe the environment within which a wind generator must operate. A key issue is the type of contract. In this study we consider the "Intermittent Resource" and the "Firm Capacity" contracts. Since the contract determines the way that the generator is compensated, it also determines the way that the generator is structured and operated in order to maximize return to the generator. Each of the subsequent analyses examines the optimal configuration, operation, and financial return given a specific form of contract.

The "Intermittent Resources" contract was designed recently to accommodate intermittent resources such as wind. After the discussion of the types of contracts, the report evaluates the financial performance of a wind generator under this contract. This provides a benchmark for evaluating each of the other approaches to improving the wind generation.

After evaluating the Intermittent Resources contract, the report evaluates the use of back-up generation and storage to improve wind generation performance under a Firm Capacity contract. In each case we first explore the optimal operation and configuration of the system to maximize the return to the owner of the wind generator. We then assess the financial performance of several configurations, including the optimal configuration.

The sections on back-up generation and storage pay particular attention to the financial viability of those approaches. A number of optimistic assumptions are made to determine if there are some plausible configurations that are financially viable in the sense of having an acceptable financial return. In addition, the financial performance of the approaches are compared to the financial performance of the intermittent contact. If the proposed configurations cannot meet the financial performance of the Intermittent Resources contract, they are unlikely to be adopted.

# 2. Contract types for wind generation

A key consideration in evaluating ways to increase the value of wind is the form of the contract under which the wind is compensated for its energy. The design and operation of the system and its economic evaluation take into account the terms of the contract. This analysis considers the "Firm Capacity" contract and the "Intermittent Resources" contract as used by the California Independent System Operator (CAISO). These are outlined below.

## Firm Capacity contract

Under the Firm Capacity contract the owner of the wind generator bids a power level each hour. If the actual generation is less than the bid amount, the generator is assessed a penalty. If the actual generation is greater than the bid, the generator is not paid for the excess generation.

The penalty to be assessed is determined by rules established by the ≈ CAISO. The penalty is intended to ensure that the generator has a strong incentive to meet the power level bid each hour. The penalty is set as a fraction of the value of the electricity that was not generated. A penalty of 25% has recently been proposed [CAISOa]. In these analyses, the form of the penalty has been structured as described in [CAISOa]. Under this structure, the generator is paid for the amount of energy bid each hour. If the actual generation is less than the bid, the generator is assessed a penalty equal to (1.25 * energy shortfall * electric value). Under this scheme, the generator is effectively not paid for the amount of energy less than the bid, and is assessed an additional penalty equal to 25% of the value of the energy.

Although these analyses assume that the wind generator would be allowed to operate under the rules that are assumed in the analysis, it is quite possible that the behavior of the wind generator would be unacceptable to the CAISO and the rules would be revised to prevent this sort of operation.

The Firm Capacity contract was originally developed for merchant energy plants that are dispatchable such as fossil fueled or hydroelectric generators. Such plants can control their output to be close to the bid amount. The provisions that there is no payment when the generator over-generates and a penalty when the generator under-generates are intended to encourage the generator to operate close to its bid power level. It should be noted that any under or over-generation creates operational problems for the CAISO. The rules penalizing under-generation are intended to (strongly) encourage generators to meet the bids that they make. They encourage the owner to keep the equipment in good working order and discourage gaming the market.

These analyses explore ways that either storage or back-up generation could be used to improve the financial performance of a wind generator. They explore possible opportunities for improvement when operating under a Firm Capacity contract. These analyses have made favorable assumptions about the Firm Capacity contract to see whether or not the financial performance can reach the level of the Intermittent Resources contract. If the financial performance cannot reach the level of the Intermittent Resources contract under the favorable assumptions made here, it is unlikely to reach the performance of the Intermittent Resources contract under more realistic assumptions.

## Intermittent Resources contract

The Firm Capacity contract has worked to the disadvantage of wind generators because of wind's intermittency. To the extent that the wind generators are not compensated for their over-generation, they are not receiving the compensation for the benefit they provide. It has been proposed that intermittent resources such as wind, be allowed to sell power under an "Intermittent Resources" contract. This contract recognizes that intermittent resources cannot be sure of their power output from hour to hour and thus it is not realistic to penalize them for missing their bid amounts. It also recognizes that when they exceed their bid amounts, they do provide benefits to the system to the extent that the excess power allows the system operator to back down more expensive generators.

Under the Intermittent Resources contract, the intermittent resource agrees to bid its expected power each hour using forecasts provided by the CAISO [CAISOa, CAISOb]. The generator is paid for its bid amount at the system price for each hour. The net discrepancies of energy over and below the bid amounts are accumulated. Since the forecasts are designed to be unbiased, the cumulative net discrepancies are expected to be small. The accounts are settled up monthly and the generator is charged or credited the value of the cumulative net discrepancy times the average system cost over the period in question.

Assuming that the system prices each hour do represent the value of additional generation, the Intermittent Resources contract should approximately compensate the wind generator for the value provided to the system.

# 3. Assumptions used in this study

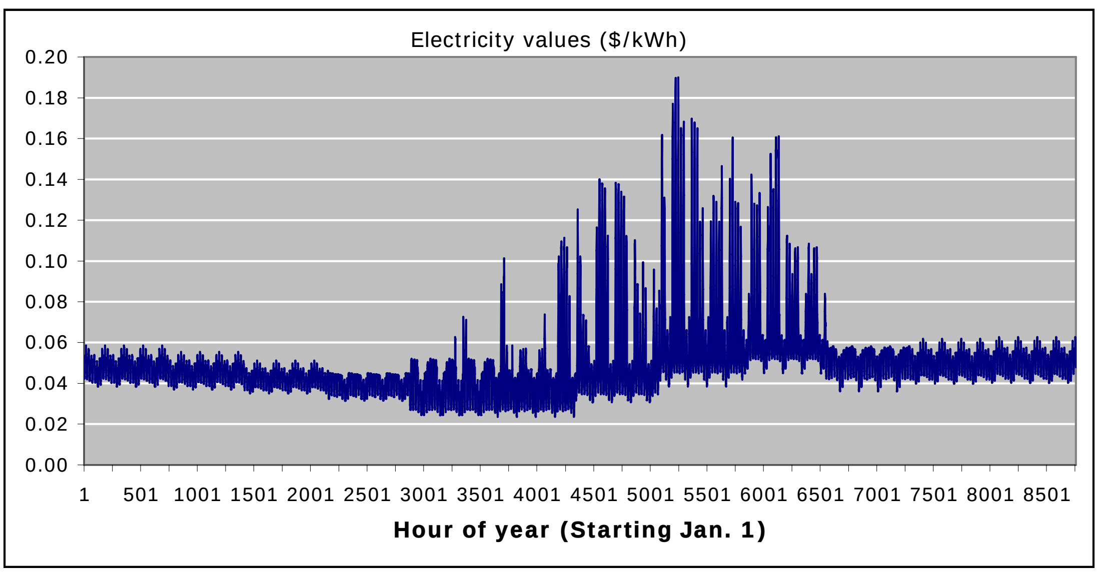
Several assumptions have been used throughout the analyses. Table 1 lists the financial assumptions that have been used.

*Table 1: Assumptions used throughout the analysis.*

| **Parameter** | **Value** |
|---|---|
| Average electricity value | 0.05 $/kWh |
| Interest rates | 5 and 10% |
| Penalty factor for under-generation | 0.25 |
| Capital cost of wind turbine | 850 $/kW |
| Operating cost of wind turbine | 0 $/kWh |
| Equipment life for computing rate of return | 20 yrs |

In this analysis we will use projections of future hourly SMC developed for the California Energy Commission (CEC) by Pacific Gas and Electric Company [PG&E]. These values are used for both the back-up generator analysis and the storage analysis. The values provided by the CEC do not set the average value of electricity. Here we have assumed an average value of $0.05/kWh. Figure 1 illustrates the electricity values used for these analyses.

*Figure 1: Electricity values (system marginal costs) used for these analyses.*

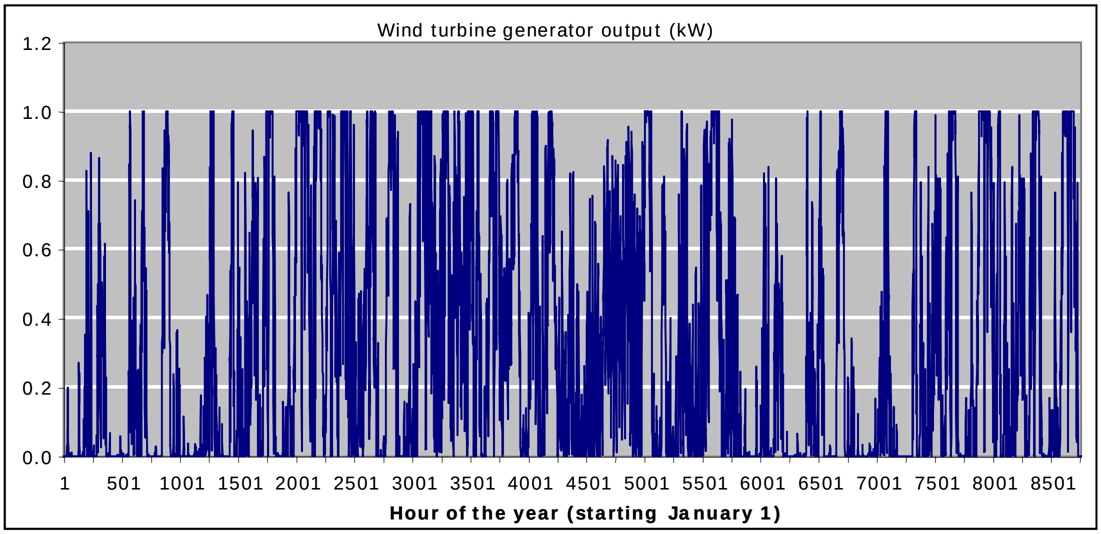



*Note: The average value has been set at $0.05/kWh*

The current analysis uses a year of actual hourly data from a wind turbine generator in the area of the Tehachapis that has been scaled to a rated power of

1 kW for a 70 meter diameter turbine in a wind speed regime of 6 m/sec [Jackson]. The output power pattern per kW of capacity is shown in Figure 2

*Figure 2: Wind generator power output for 1 kW of capacity.*




*Note: This case is for a 70 m diameter turbine in a 6 m/sec wind regime in the Tehachapi wind resource area.*

# 4. Financial performance of a wind generator under the Intermittent Resources contract

The Intermittent Resources contract provides a benchmark for evaluating other approaches. If another approach cannot achieve the financial performance of the Intermittent Resources contract, there is no incentive for using the other approach. Under this form of contract, the wind generator is in principle compensated for the value of the energy at the time that it is generated.

The analysis is straightforward: the value of the wind energy generated each hour is computed based on the energy produced and the electricity value (SMC) prevailing each hour. Given the assumptions of the analysis the following results are obtained for a 1 kW wind generator:

*Table 2: Financial performance of Intermittent Resources contract for wind generator.*

| Financial Item | Value |
|---|---|
| Total annual revenues ($) | 128.9 |
| Life (yrs) | 20.0 |
| Annual capital cost of generator @10% ($) | -99.8 |
| Annual net revenue @10% ($) | 29.1 |
| Annual capital cost of generator @5% ($) | -68.2 |
| Annual net revenue @5% ($) | 60.7 |

The rate of return for the generator is 14.1% under the Intermittent Resources contract. This is the interest rate that just makes the discounted net present value of the revenue stream equal to the initial capital investment.

For much of this analysis the rate of return on investment is the key indicator of financial viability. This will be compared to the rates of return for wind systems combined with back-up generation or storage to determine whether or not those approaches can improve the financial performance of the wind generator.

# 5. Use of back-up generation to firm power under a Firm Capacity contract

Under the back-up generation approach, the wind generator owner uses a conventional, fossil fueled generator when the wind output is less than the bid amount. Here we evaluate two scenarios. First, the back-up generator could be an on-site generator owned by the same party that owns the wind generator. In that case the owner would have to bear the capital and operating costs of the back-up generator. In an effort to find some sort of arrangement that could be as favorable as possible to the wind generator, we have explored a second scenario under which the wind owner makes an arrangement with another owner of a generator to provide energy when needed (up to some maximum output power). For this case it is assumed that the wind generator might pay a relatively high amount for energy from the back-up generator, but not explicitly pay a charge for the capital costs of the back-up generator. The owner of the back-up generator would recover capital and operating costs from the higher energy price. In both cases, we seek to identify the optimal amount of back-up generation by running a sequence of analyses which vary the amounts of back-up capacity available to the wind generator.

## Bidding strategies under Firm Capacity contract

The financial performance of a wind generator depends on its bidding strategy each hour. Under the Intermittent Resources contract, the strategy is specified: the wind generator always bids expected power using a model developed by the CAISO. However, when operating under a Firm Capacity contract, the owner can choose the level to bid. The bidding strategy has a substantial impact on the financial performance of the system. The financial performance of a generator operating under a Firm Capacity contract can only be accurately assessed by taking into account the bidding strategy.

In this section, the optimal bidding strategy is described. As we will see, it can lead to situations where the owner bids a power level greater than the expected power. This could lead to a larger number of hours where the generator under-generates. Such a behavior could be unacceptable to the system operator (CAISO). This analysis does not attempt to determine the acceptability of such behavior. Rather, it simply evaluates the financial potential for this sort of strategy. If there is a high potential for the strategy, then it could be worth further investigation. Conversely, if the financial performance even under the optimal strategy is not encouraging, then it is probably not productive to pursue the issue.

In each hour, the owner chooses a level of power to bid. The owner of the wind generator should bid so as to maximize expected profit from the system. The profit depends on the value of the electricity generated, the likelihood that there will be over-generation (for which the generator will not be paid), and on the penalties if there is under-generation.

One plausible strategy is to bid the expected power each hour. However, this does not necessarily maximize the revenues, particularly when there is a back-up generator available.

An optimal strategy takes into account the rewards each hour for generating power (i.e., the value of the electricity generated), the penalties if there is under-generation, and the probability distribution over the wind during the hour. If the price is high in a given hour the owner has an incentive to bid a high output since he will only be paid for the amount of the bid and a high bid will allow him to capture a larger amount of revenue. Without a back-up generator, the expected rewards when the electricity price is high have to be balanced against the fact that the penalty for under-generation is also high. However, if there is a back-up generator, the penalty has a ceiling—it will be no greater than the cost of the back-up energy. In the extreme case where the cost of the back-up energy is less than the value of the electricity, the owner should bid the maximum capacity since he cannot lose: the owner will be paid for this bid at the system value of electricity and any under-generation will cost less than he is paid for the energy.

The optimal bid is derived mathematically in Appendix 1, taking into account the electricity values, the probability distribution over the wind, the cost of back-up generation, and the penalties for under-generation. The result is a simple procedure:

- First we compute the ratio of the value of the electricity (SMC) to the penalty of under-generation (which is either the SMC with a penalty factor applied, or the cost of back-up generation). This is a ratio that can be less than or greater than or equal to 1.0. If it is greater than 1.0, it is set to 1.0.

- Then we examine the probability distribution over the wind power. The optimal amount of power to bid is the level such that the probability of generating less than that level is equal to the ratio of electricity value to penalty value.

For example, if there is no back-up generation and the penalty factor for under-generation is 0.25, then the ratio of electricity cost to penalty cost is 1/(1+0.25) = 0.80. The wind owner should bid a level of power such that there is an 80% chance that the actual realized power will be less than the level that was bid. That is, the bid should be the 80th percentile of the wind distribution. As a second example, assume there is a back-up generator that can generate at a cost of $0.06/kWh and that the electricity value is $0.08 in a given hour. Then the ratio is 0.08/0.06 = 1.3. Since this is greater than 1.0 we set the value to 1.0. Now the owner should bid a power level such that there is a probability of 1.0 that the actual power will be less than that level. In other words, he should bid the peak power of the generator since the probability that the actual power will be less than (or equal to) the peak is 1.0. This makes intuitive sense since the owner cannot lose (unless the capacity of the back-up generator is insufficient). If the wind generation is less than the bid, the cost of covering the shortfall with the back-up generator is still $0.02/kWh less than the amount the owner will be paid for the electricity.

The bid depends on a statistical model of the wind. The model used here is discussed in Appendix 2.

## Analysis of use of back-up generator to firm capacity

Several sets of cases were analyzed to explore the possible ways that a back-up generator might be used to improve the financial performance of the wind generator. It is assumed that the back-up generator will be similar to a natural gas fired combustion turbine with a capital cost in the order of $300/kW capacity. One set of cases is run with a higher capital cost of $400/kW in order to represent the case of a more efficient generator such as a combined cycle, although this cost is probably optimistic for a combined cycle generator.

Natural gas costs in the order of $4/MMBtu or $0.0136/kWh (i.e. energy cost of the fuel input to the generator) [EIA]. Since a combustion turbine would have an operating efficiency of around 25%, the fuel cost of electricity generated would be about $0.055/kWh. A combined cycle generator would have an efficiency approaching 50% with a fuel cost would be around $0.027/kWh. In the analyses below operating costs ranging from $0.06 to $0.03/kWh are used.

A number of cases are analyzed below to cover a range of assumptions about bidding strategy, back-up capacity and back-up costs. These cases are summarized in Table 3 below. In all these cases the wind generator peak capacity is 1 kW and the back-up capacity is varied from 0 to 1 kW.

*Table 3: Descriptions of cases analyzed for the back-up generation analysis.*

| Case | Contract type | Bid strategy | Back-up capacity, kW | Back-up capital cost, $/kW | Back-up operating cost, $/kWh |
|---|---|---|---|---|---|
| A | Intermittent Resources | NA | 0 | NA | NA |
| B | Firm capacity | Expected power | 0 to 1.0 | 300 | 0.06 |
| C | Firm capacity | Expected power | 0 to 1.0 | 300 | 0.04 |
| D | Firm capacity | Expected power | 0 to 1.0 | 0 | 0.06 |
| E | Firm capacity | Optimal | 0 to 1.0 | 300 | 0.06 |
| F | Firm capacity | Optimal | 0 to 1.0 | 300 | 0.04 |
| G | Firm capacity | Optimal | 0 to 1.0 | 0 | 0.06 |
| H | Firm capacity | Expected power | 0 to 1.0 | 400 | 0.03 |
| I | Firm capacity | Optimal | 0 to 1.0 | 400 | 0.03 |

The rationale for evaluating each of these cases is as follows:

Case A: This is the reference case for the Intermittent Resources contract.

Case B, C: These cases use a strategy of bidding expected power. It provides a measure of the advantage of using the optimal bidding strategy.

Case D: This case uses a strategy of bidding expected power and contracts with another generator to provide back-up power. It is assumed that the wind generator does not explicitly pay for capital cost of the back-up generator but pays a relatively high price for the back-up energy.

Cases E, F: These cases demonstrate the financial performance that could be expected when the wind owner purchases and operates a back-up generator, and uses an optimal bidding strategy. These cases assume different levels of operating cost for the back-up generator.

Case G: This case uses an optimal bidding strategy and contracts with another generator to provide back-up power as in Case D.

Cases H, I: These cases examine the financial performance of the optimal bidding strategy and the expected wind bidding strategy under optimistic assumptions about the cost of the back-up generator. At $0.03/kWh the operating cost is closer to what one would expect for a combined cycle. Accordingly the capital cost has been set at \$400/kW (although this may still be an optimistic value for a combined cycle generator).

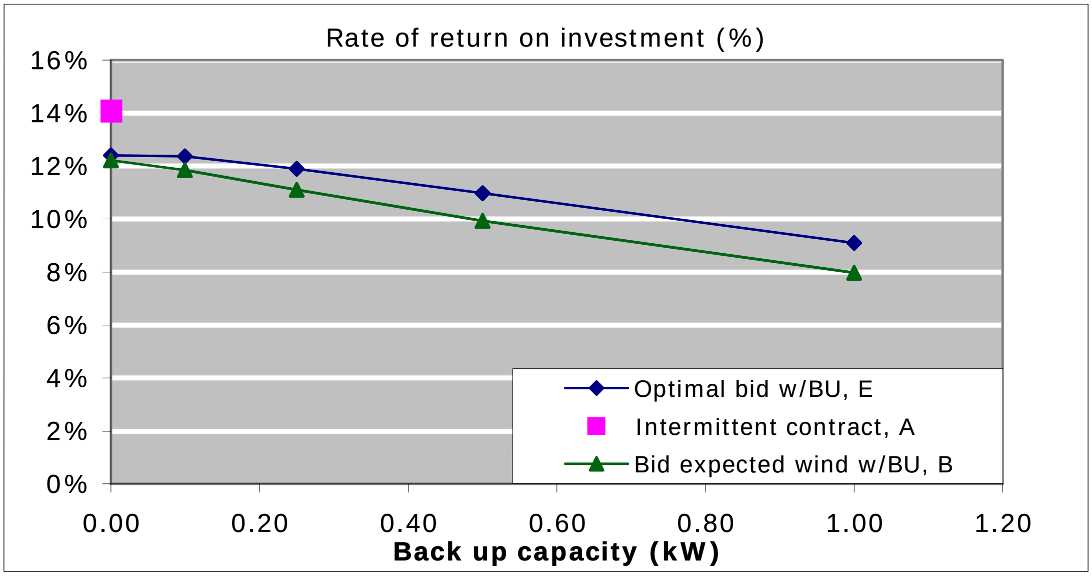
In evaluating these cases we note that the revenue and the capital investments are different from case to case. To make a meaningful financial comparison the rate of return on investment is computed for each case. These are computed assuming a 20 year life for each of the projects.

In each of the figures below we show the performance for a generator using an optimal bidding strategy and the performance for one bidding the expected wind each hour. We note that with zero back-up capacity, the two strategies perform nearly the same—the optimal strategy shows a slight advantage over the expected value strategy. However, as more back-up capacity is added, the relative costs of under-generation change enough so that the optimal strategy shows a marked improvement over the expected value strategy.

As was pointed out above, a wind generator operating under an Intermittent Resources contract would earn a 14.1% return on the total investment. Each of the figures below shows this result as a benchmark for comparison to the other cases.

Figure 3 shows the results for the case of a generator costing \$300/kW with an operating cost of \$0.06/kWh. These are the costs that might be expected from a relatively expensive combustion turbine. The back-up strategies do not perform nearly as well as the Intermittent Resources contract. In the case of the optimal bidding strategy, adding a small amount of back-up capacity neither helps nor hurts the financial performance. For the expected value bidding strategy, adding back-up capacity degrades financial performance.

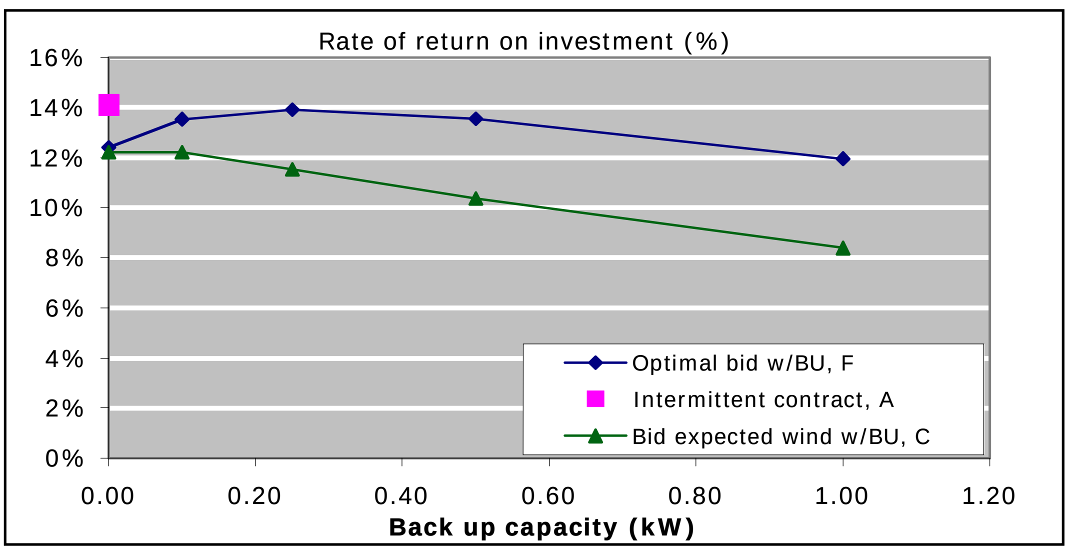
*Figure 3:     Back-up generation Cases A, B, E.*




*Note:  Capital costs are $300/kW, operating cost is $0.06/kWh, wind generator capacity is 1kW.*

Figure 4 shows a case for a combustion turbine that could plausibly be installed with a capital cost of $300/kW and an operating cost of $0.04/kWh.  In this case the optimal bidding strategy with about 0.25 kW of back-up capacity nearly equals the financial performance of the Intermittent Resources contract.

*Figure 4:     Back-up generation Cases A, C, F.*

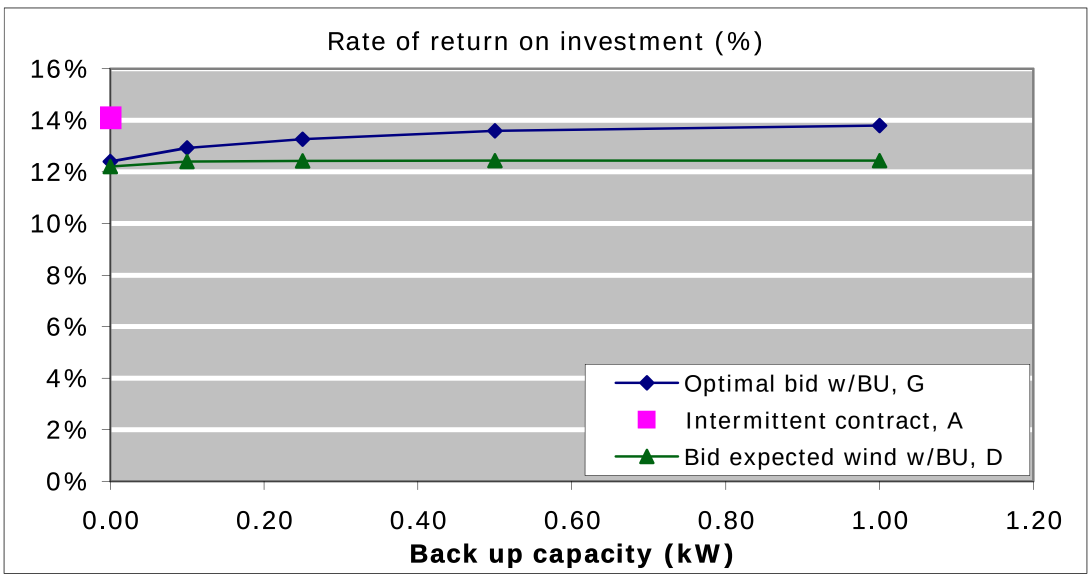



*Note: Capital costs are $300/kW, operating cost is $0.04/kWh, wind generator capacity is 1kW.*

Figure 5 evaluates the case in which a wind generator contracts for back-up energy.  The wind generator pays nothing for capital costs, but pays a relatively high cost for the back-up energy.  Here the level of back-up capacity is the maximum power that the wind generator is allowed to take from the back-up generator. Allowing the wind generator to use about 0.5 kW of back-up capacity yields a financial performance nearly equal to the Intermittent Resources contract (adding more back-up capacity only improves the return slightly). This analysis does not investigate the financial desirability of this arrangement for the owner of the back-up generator. It is only observed here that such an arrangement can nearly equal the performance of the Intermittent Resources contract.

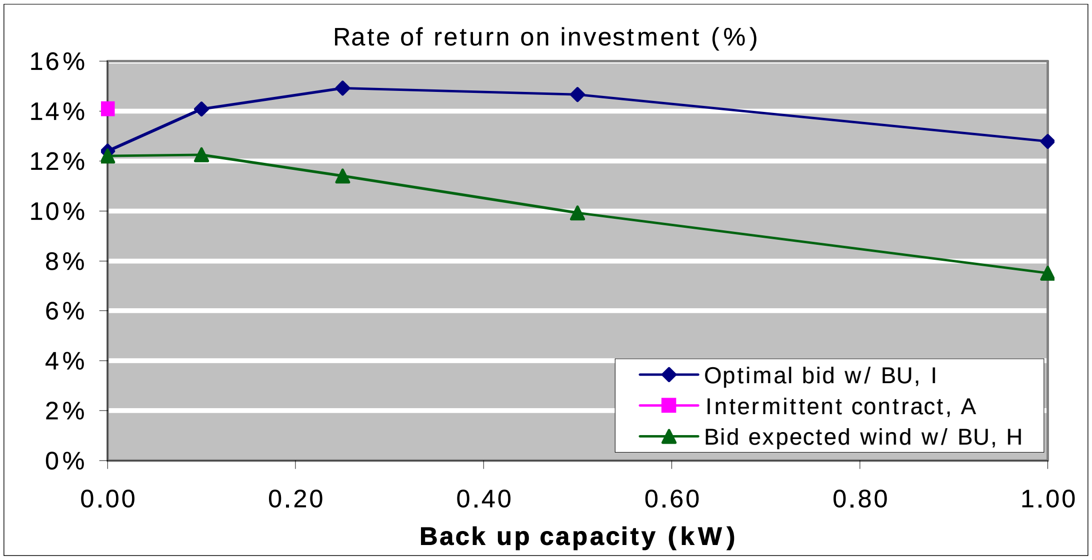
As part of this study we have sought assumptions under which the back-up generator could outperform the Intermittent Resources contract. Figure 6 shows such a case. The efficiency of the back-up generator is assumed to be relatively high (about 50%, as compared to 25% for a natural gas fired combustion turbine). This is more in the range of efficiency of a combined cycle generator. Correspondingly, the capital cost of the back-up generator is assumed to be $400/kW. This is higher than in the previous cases, although it is an optimistic value for a combined cycle generator. Under these assumptions, the use of 0.25 kW of back-up generation does outperform the Intermittent Resources contract.

*Figure 5: Back-up generation Cases A, D, G.*




*Note: Capital costs are $0/kW, operating cost is $0.06/kWh.*

*Figure 6: Back-up generation Cases A, H, I.*




*Note: Capital costs are $400/kW, operating cost is $0.03/kWh, wind generator capacity is 1kW.*

These analyses indicate that it is difficult for a wind generator with a back-up generator to match the financial performance of an Intermittent Resources contract. Case I does show, at least, a possibility that the back-up generator could outperform the Intermittent Resources contract, but the assumptions used are optimistic.

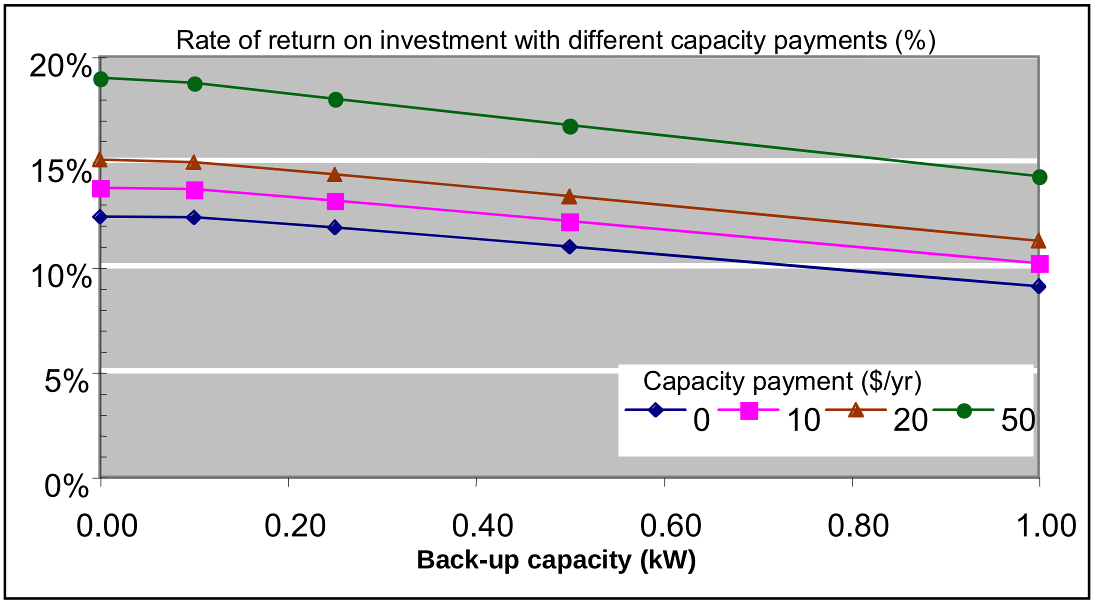
## Potential benefits of capacity payments for wind with back-up generation

With the addition of back-up generation a wind generation installation will improve its reliability. It has been suggested that reliability may improve to the point that wind generators with back-up could qualify for capacity payments under a firm capacity contract. It is beyond the scope of this study to determine whether or not such an installation would actually qualify for capacity payments. However, we do explore the financial impacts of such payments.

The figures below show the rates of return for the wind generator plus back-up generator under hypothetical capacity payments of 0, 10, 20, and 50 dollars per year, per kW of installed wind capacity. These calculations are similar to those above, except that the amount of the capacity payment has been added to the annual net revenue of the generator. Results are shown corresponding to cases E, F, G, and I. These are all of the cases with a firm capacity contract and optimal bidding. In each graph, the rates of return for capacity payment of zero is the same as the corresponding graph in the previous figures.

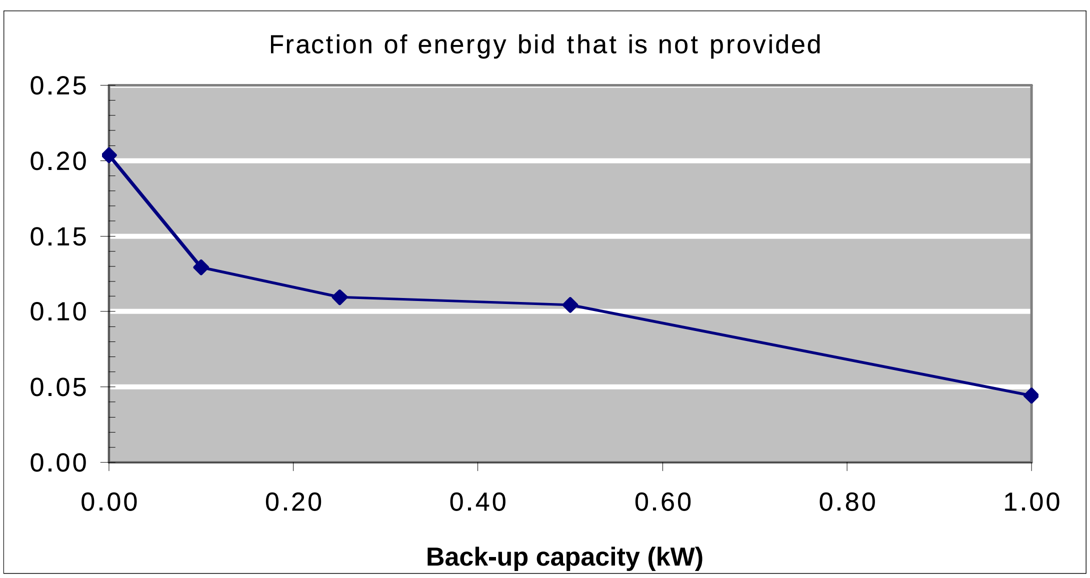
Although this report cannot determine if such payments would be warranted, to provide some context for interpretation the figures below also provide data on the reliability of the wind plus back-up generator. The net under generation is shown as the fraction of the total amount bid that is not provided by either the wind generator of the back-up generator.  This is shown in the graphs as a function of the capacity of the back-up generator.

*Figure 7:     Rates of return for Case E with capacity payments*



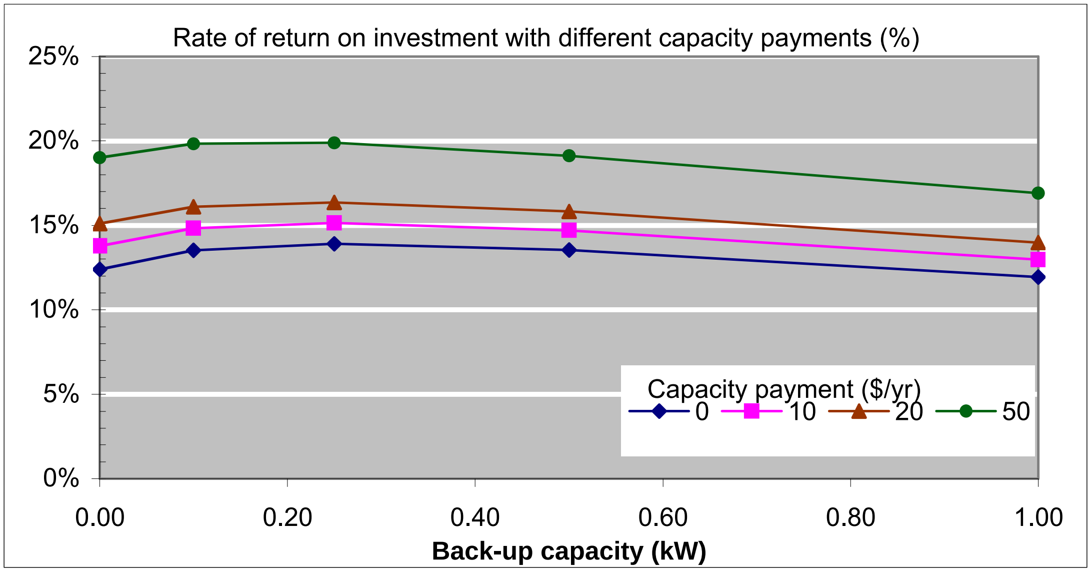

*Note:  Capital cost is$300/kW, operating cost is $0.06/kWh*

*Figure 8:     Reliability for Case E as function of back-up capacity*




In Figure 8 the fraction of net under generation does not go to zero as the back-up capacity goes to 1.0 kW (which is the capacity of the wind generator) due to the fact that the operating cost of the back-up is quite high.  In a number of hours of the year it is cheaper for the owner to accept the penalty for not generating and not run the back-up generator to cover the under generation.

*Figure 9: Rates of return for Case F with capacity payments*




*Note: Capital cost is$300/kW, operating cost is $0.04/kWh*

*Figure 10: Reliability for Case F as function of back-up capacity*

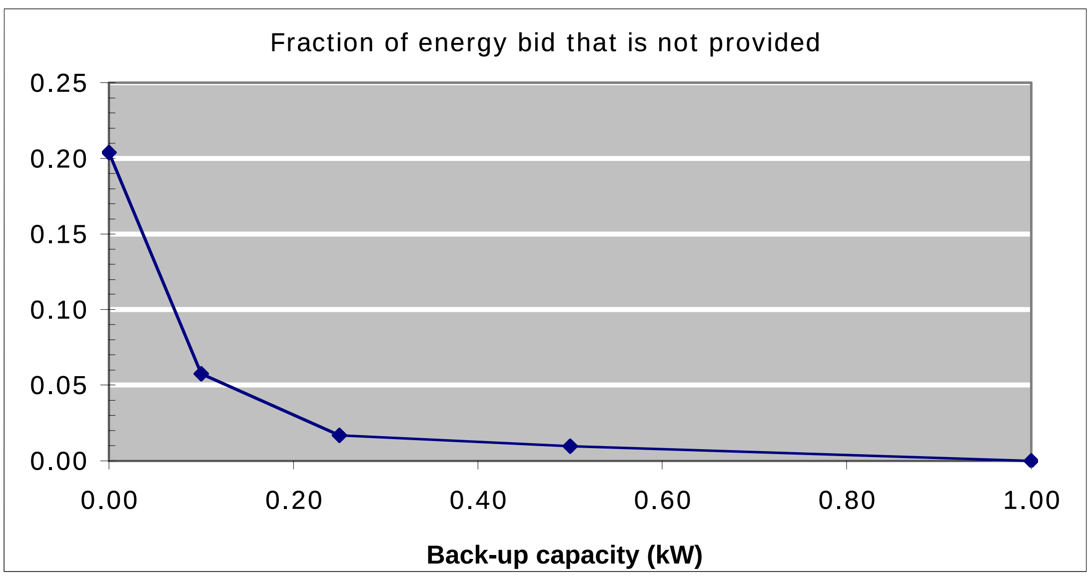
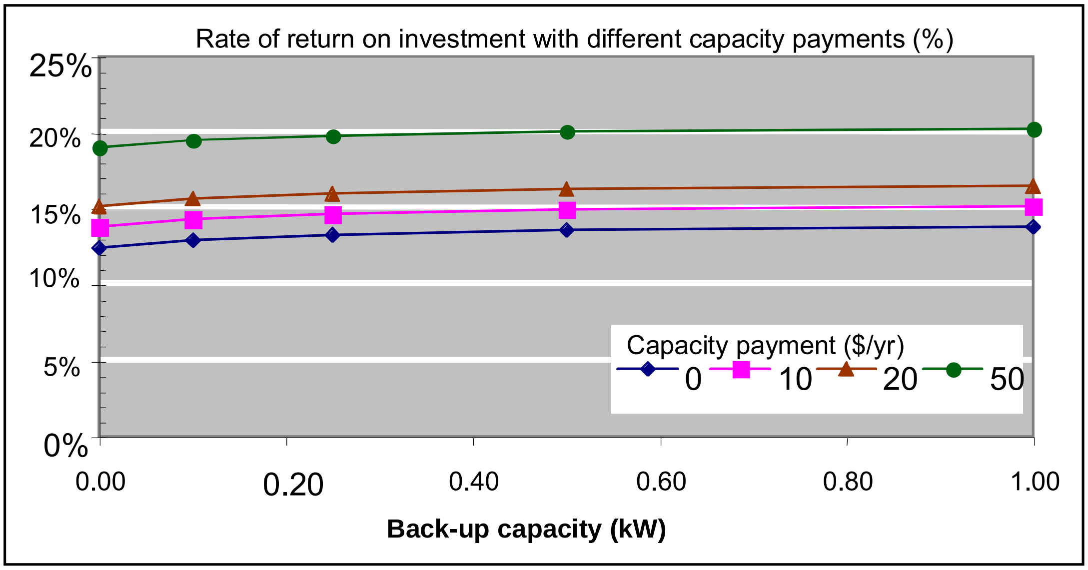
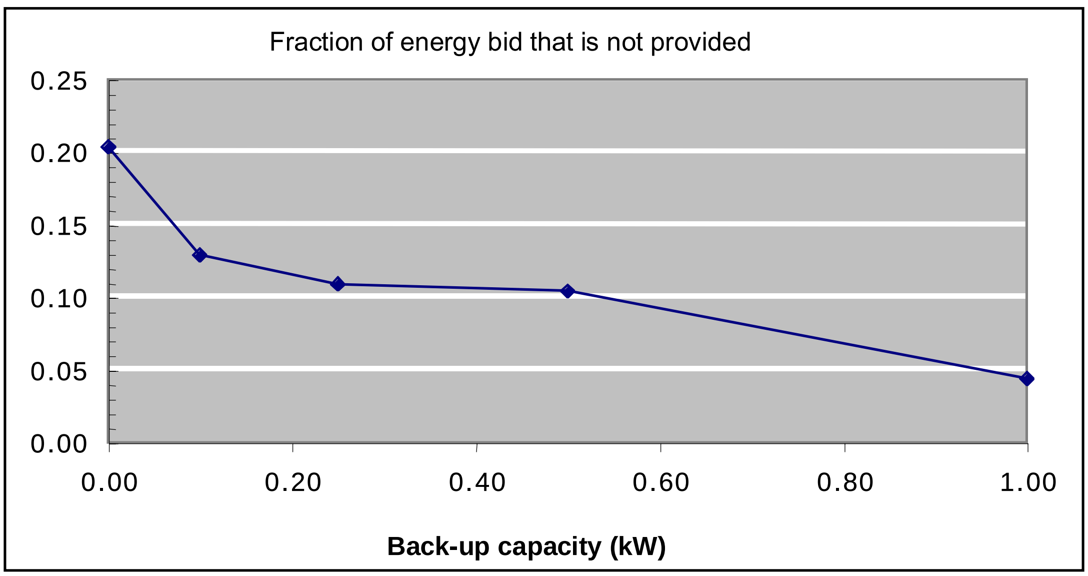


*Figure 11: Rates of return for Case G with capacity payments*



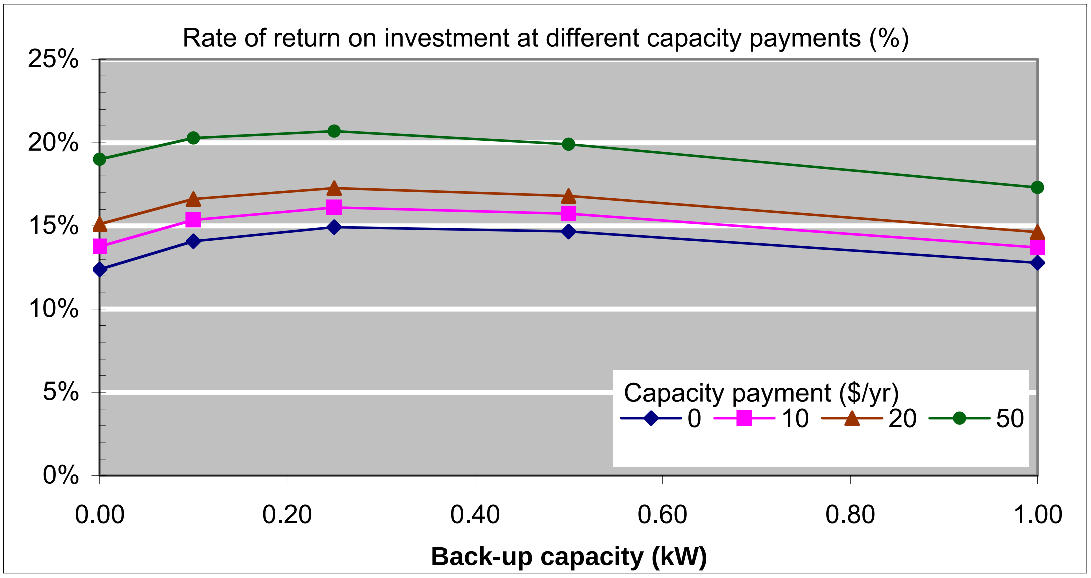

*Note: Capital cost is $0/kW, operating cost is $0.06/kWh*

*Figure 12: Reliability for Case G as function of back-up capacity*



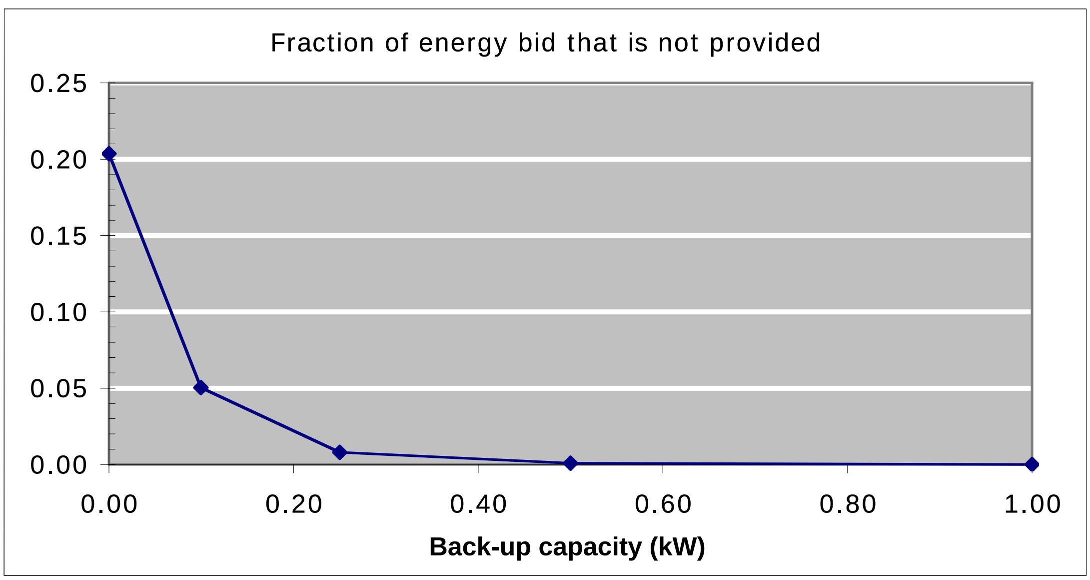

As in Case E, the net under generation for Case G does not go to zero as the back-up capacity goes to 1.0 due to the assumed high operating cost of the back-up generator.

*Figure 13: Rates of return for Case I with capacity payments*




*Note: Capital cost is $400/kW, operating cost is $0.03/kWh*

*Figure 14: Reliability for Case I as function of back-up capacity*




These cases show the potential for reasonable rates of return even with annual capacity payments of $10/kW. However, the total undergeneration tends to be a few percent of the total amount bid. Further discussion and analysis of reliability would be required to determine whether or not capacity payments could be provided.

# 6. Operation of wind generation in conjunction with storage

Adding storage to the generation system allows several benefits. First it can provide arbitrage between low value and high value hours ("buy low, sell high"). Second, when coupled with a wind generator operating under a Firm Capacity contract, it can provide a buyer for the generator's excess energy and can provide some back-up power when the generator does not meet its bid. Third, such facilities may relieve congestion on the grid and/or allow for grid upgrade deferral. This analysis evaluates the first two benefits. The value of storage in relieving congestion is not addressed here since those situations should be evaluated on a case-by-case basis.

We note that the combination of the generator and storage systems can help both systems, so the analysis must be structured to capture all of the financial effects, without double counting. Here the analysis is structured so that the wind generator is left in the same financial situation with and without the storage. We then can evaluate the financial performance of the *storage* system with, and without, the operation with the wind generator. These analyses evaluate the revenues and costs of the storage system and compute the rate of return of an investment in storage. The rate of return for an investment in storage can be compared to the rate of return from other investments such as additional investments in wind. While a bit indirect, this approach allows us to clearly define the financial effects of combining the two systems.

## Overview of the storage analyses

The sections below develop a series of analyses of storage under different conditions. The next section describes the approach used to analyze storage and assess its financial viability. This is followed by a discussion of the basic assumptions used and a discussion of technology costs used for the analyses.

Following the discussion of technology costs, we analyze the behavior and performance of a stand-alone storage system. This is a system that is not operated in conjunction with a wind generator and fundamentally arbitrages between low cost and high cost hours. Two cases of stand-alone systems are considered. The first case assumes that there is a charge for transmission and losses (T&L) while the second case assumes that the T&L charge is zero. This second case assumes that the storage operator could (conceivably) negotiate a purchase contract with little or no charge for T&L.

After the analysis of the stand-alone system, we consider the case of a storage system working with a wind generator operating under a Firm Capacity contract. We find that in this situation, the size of the storage system matters, so both small and large systems are evaluated.

At the end of the storage analysis we discuss the differences in behavior between the storage system operating as a stand-alone system and one operating in conjunction with a wind generator. We find that the way that they are operated and the role that they play in the system are quite different, which helps explain the differences in financial behavior.

## Optimization and financial analysis of storage system operation and configuration

These analyses are developed from the point of view of the owner of a storage system. The owner can earn a return from buying and selling energy and by cooperating with a wind generator (which, of course, may also be owned by the storage system operator). To maximize the return from the system, both the configuration of the system (i.e. the capacities of the devices) and the operation of the system (i.e. when and how much energy to buy and sell) must be optimized. The first part of this section describes the components of a storage system and the approach used to optimize the system.

The analysis has been structured to provide some overall insight into the interaction between system component costs, optimal configuration, and revenue. In the sections evaluating storage systems, two sets of results are provided. The first set shows financial results that are not dependent on assumptions about the costs of the technology or the interest rate. These technology-neutral results can be used to evaluate the financial viability of any technology, given the costs of the technology and the interest rate. The second set of results uses the technology-neutral results along with specific data on storage technologies to evaluate the financial viability of those technologies by computing their internal rates of return for the investment period. The discussion below describes the steps in this series of analyses.

Again, this analysis is intended to seek out applications for storage which have the potential to improve the financial performance of wind generation. To that end, these analyses use the optimistic assumption that the storage device is perfectly efficient. If a storage system is not financially viable given this assumption, it would likely not be viable in a more realistic scenario .

### *Components of storage system*

A storage system consists of three basic components:

- Charging device that takes energy in, e.g., a pump in pumped hydro storage, an electrolyzer in a hydrogen system, or the internal wiring and electrodes in a battery.
- Storage vessel, e.g., a reservoir in a pumped hydro storage system, a hydrogen tank in a hydrogen system, or the electrodes and electrolyte in a battery.
- Discharging device that returns energy to grid, e.g., a turbine in a pumped hydro storage system, a fuel cell in a hydrogen system, or the internal wiring and electrodes in a battery.

To maximize the return to the owner, the storage system should be optimally structured to match the patterns of energy prices, availability, and demand. In general, one would optimize the capacities of all three devices. In practice, we can simplify the optimization by assuming that one of the devices has a fixed capacity and optimizing the relative sizes of the other two. In most of the analyses below, we assume that the charging device has a capacity of 1 kW and we optimize the rest of the storage system relative to that.

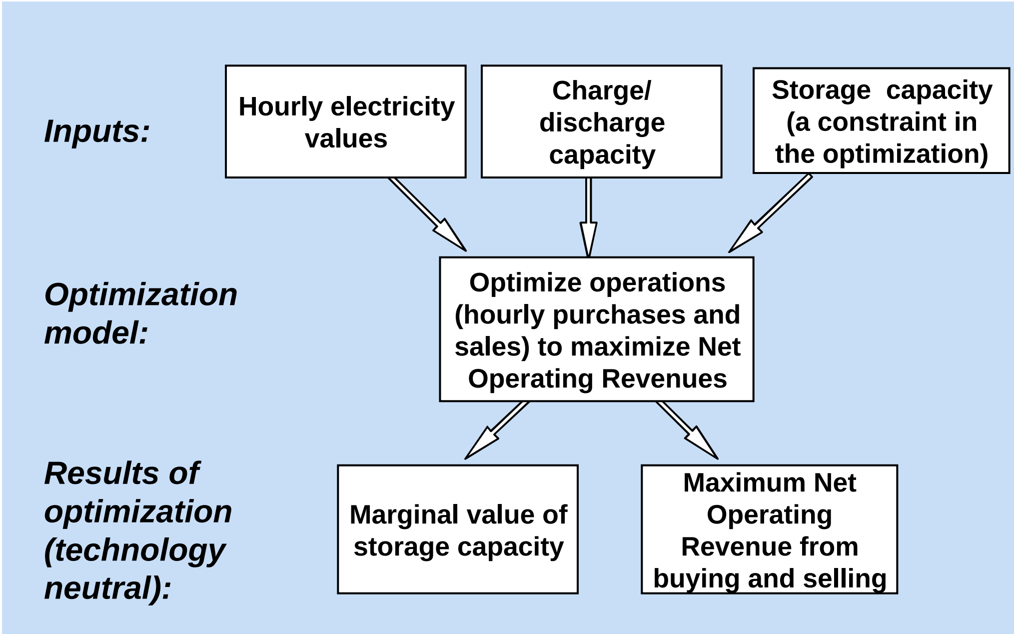
The charging and discharging devices are often the same physical device. In that case the analysis is simplified further. The capacity of the charge/discharge device is fixed (e.g., at 1 kW) and the capacity of the storage device is optimized. It is not necessary to assume that the charging and discharging capacities are equal, just that they have a fixed ratio to each other. Here, however, it has been assumed that they are equal.

### *Optimization of operation to derive technology-neutral results*

As a first step, the analysis derives a set of results for storage that are technology-neutral. These results simply reflect the total net revenue and the marginal revenues for the system and make no assumptions about the costs of technologies or interest rates. Once derived, however, these results can be used to calculate results for specific technologies given the technology costs and interest rates.

Figure 15 illustrates the sequence of inputs, calculations and outputs for this stage of the analysis. Given the charge/discharge capacity of the system, the hourly electricity values, and the storage capacity of the system we can optimize the hourly purchases and sales of energy to maximize the net operating revenue (the revenue from selling energy minus the cost of purchasing it). The net operating revenue must be sufficient to cover the annualized capital cost and operation and maintenance costs of the charge/discharge device and the storage devices. The optimization tells us the maximum net operating revenue that can be derived from a given set of charge/discharge and storage capacities.

*Figure 15: Computations in developing the technology neutral results.*




*Note: In the later analyses of a storage system operating with a wind generator under a firm capacity contract, there are additional inputs such as the amount of under-generation each hour that must be covered by the storage and the penalty for under-generation.*

In these analyses the charge/discharge capacities are fixed. However, the storage capacity must be optimized relative to the charge/discharge capacity. This can be done by specifying the storage capacity as a constrained decision variable in the optimization problem rather than as a parameter. The optimization procedure then calculates the "marginal value" of storage capacity. This is independent of the particular storage technology. However, it can be used to determine the optimal storage capacity for a specific technology, given its capital cost, life, and the interest rate.

The following paragraphs describe the optimization model and the calculation of the marginal value of storage capacity.

The owner of a storage system would naturally wish to optimize both its operation and configuration in order to maximize the return on investment. As is indicated above, the optimization of the system requires optimization of the capacities of the charge/discharge and the storage capacity.

If an operator has a storage installation with a given capacity for charging/discharging and storing energy (i.e., the configuration is fixed), his objective is maximization of annual net operating revenue (total revenue from selling energy minus the cost of buying it). This is done by buying at the lowest price hours and selling at the highest price hours. The first part of the discussion will cover the maximization of net operating revenue. We can then extend the analysis to consider the optimization of net operating revenue plus the capital costs of the storage equipment.

To maximize net operating revenue, we set a "buy strike price" (buy price) and a "sell strike price" (sell price). In any hour that the purchase price (SMC +

T&L) falls below the buy price, the storage buys energy, provided it has available storage capacity[1]. When the SMC rises above the sell price, the storage sells, provided it has energy in storage. The buy price and sell price are decision variables in the optimization problem. The general pattern of prices varies over the year, so the optimal buy and sell prices are not uniform over the year. In this model we have divided the year into 9 periods of about 1000 hours each. These roughly bracket portions of the year with characteristic price behaviors. In each period, we optimize the buy and sell prices. This part of the optimization encompasses 18 variables.

The next step is optimization of the storage capacity. This analysis uses a "marginal value" approach based on optimization theory. In these analyses we only need to compute the marginal value of storage capacity, but the same general concepts would apply to an analysis of charge/discharge capacity. In the optimization model as formulated here, storage capacity is a decision variable, but is constrained to be less than a specific value (the analysis is repeated for a series of values). If we constrain the capacity, we constrain the total amount the system can earn. With a little more storage capacity, the system could buy a little more at the cheapest hours and discharge more at the highest price hours. For each capacity analyzed, the optimization software computes the amount that the net operating revenues (sales revenues minus cost of purchase) could increase with a small increment of additional capacity. This is known as the "marginal value" of additional capacity.

The marginal value of capacity is independent of the technology used. However, we can use that information to determine whether or not it is financially advantageous to change the capacity of a specific technology in a system. To take a concrete example, assume that when the system is configured with, say, 0.8 kWh of storage capacity, we determine that adding 0.01 kWh of capacity would increase gross operating revenues by $5/yr. From this we know that if adding 0.01 kWh of additional capacity costs less than $5/yr, we could increase our total net revenue (not just the net operating revenue) by adding that increment of 0.01 kWh. That is, if the annual cost of storage capacity is less than $500/kWh-yr, it is advantageous to add capacity. Note that the annual cost is a function of the capital cost of the capacity, its life, and the interest rate.

When the capacity of any component is very small, its marginal value could be quite high—often it is high enough to justify the addition of some capacity. As more capacity is added, the marginal value of capacity tends to decrease. Eventually, the marginal value of capacity decreases to the point that it is just equal to the marginal (annualized) cost of capacity. That is the economic optimum capacity—adding any more capacity will not increase the total return. Of course, it is possible that even when capacity is very small its marginal value

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[1] In this particular formulation, the amount of energy purchased is partly a function of the magnitude of the difference between the buy price and the purchase price. If the purchase price is just slightly below the buy price, the storage only buys a small amount. If the purchase price is well below the buy price, the storage buys a larger amount, up to its charge capacity. This sort of rule is reasonable in itself. It is also necessary in order to make the purchases and sales of energy a continuous function of the buy and sell prices. Without continuous functions the optimizer used here cannot find an optimal solution.

is less than its cost. In that case we can conclude that the system is just not economically viable.

In this analysis we compute the marginal values of storage capacity using the Solver function in Microsoft Excel™. We make a series of runs constraining storage capacity to different values.

### *Use of technology-neutral results to evaluate specific technologies*

The technology-neutral results can be used to evaluate the economic viability of any specific technology. Two approaches can be used. The first approach, discussed in this section, assumes an interest rate and determines whether or not the technology is viable. One can also determine the optimal configuration at that interest rate. The second approach, described in the next section, determines the return on investment that can be achieved and the configuration that will maximize the return on investment.

As an example, consider the results shown in Figure 16 and Figure 17. Figure 16 shows the net operating revenue from a system as a function of the storage capacity (the charge/discharge capacity is set at 1 kW). If the storage capacity is 1 kWh, the system can only earn about $4/yr. As storage capacity is added, the net operating revenue increases until it reaches a level of about $28/yr at around 12 kWh of capacity. After that, adding additional storage capacity does not increase revenues significantly (i.e., its marginal value goes to 0).

To be financially viable, the net operating revenue of the system must be high enough to cover the annualized capital cost of the system—both the charge/discharge capacity and the storage capacity. As an initial screening question, we can ask if the maximum net operating revenue can cover the capital cost of 1 kW of charge/discharge capacity alone. In some of the examples that follow, the net revenue is insufficient to cover the charge/discharge capacity. Such a result indicates that the technology is not viable since it cannot support the investment in the charge/discharge capacity, much less the investment in the storage capacity.

If the maximum net revenue can support the charge/discharge capacity, it is straightforward to determine if the net operating revenue can support both the charge/discharge capacity and the annualized cost of the storage capacity since the storage capacity determines the total annualized cost of the system.

The marginal value of storage capacity shown in Figure 17 can also be used to quickly screen for financial viability. Here the maximum marginal value of storage capacity occurs at low values of capacity. In this example the maximum value is around $4/kWh-yr. If the annualized cost of storage capacity is greater than this, the technology will not be financially viable since no amount of storage capacity can be economically added to the system.

Finally, we can use the marginal values shown in Figure 17 to determine the amount of storage capacity that would be optimal. As noted earlier, the optimal level of capacity occurs when the marginal value of capacity is equal to its marginal cost. If in this example, the marginal cost of storage capacity were, $2/kWh-yr, then the optimal amount of capacity would be 8 kWh.

In the cases studied below, we use these types of analyses to evaluate the financial viability of each technology.

### *Calculation of internal rate of return to evaluate specific technologies*

The methods described above assume a given rate of interest and determine financial viability at that rate of interest. Another way of looking at the issue is to calculate the internal rate of return for an investment in storage. This is the interest rate that just makes the discounted net present value of the revenue stream equal to the initial capital investment. Since this still takes into account the initial capital investment and the life of the technology, it is technology specific.

For each of the cases below, the internal rate of return is calculated for a case of battery storage and for pumped hydro storage. For both technologies, we use the results for the annual net operating revenue to calculate the internal rate of return as a function of storage capacity. For any given level of storage capacity, we can read off the internal rate of return. That is the rate of return that would just make the project viable (i.e., make that level of storage capacity financially viable).

There is no guarantee that the internal rate of return is positive. In many of these cases it is negative. This simply indicates that the project is not financially viable.

The maximum rate of return is also shown in the curves. If this rate of return is acceptable—for example, if it is greater than the cost of funds—the project will be financially viable. We can also compare the rate of return to alternative investments such as additional wind generation.

## Assumptions about storage operation and storage technology costs

This section describes the basic assumptions made about the operation of the storage system and provides example data regarding the costs and technical characteristics of storage technologies.

### *Basic assumptions about configuration and operation of storage system*

The analyses below make the following assumptions about the configuration and operation of the storage system:

- The storage system can sell to the grid. When it sells energy, it receives the SMC as payment.
- The storage system can buy from the grid. When it buys, it must pay the SMC plus a charge for transmission and losses, if any.
- In some configurations it is assumed that the storage system is collocated with a wind generator. In that case the storage device

can buy directly from the generator without paying for transmission and losses. The cost of energy to the storage device is SMC since that is the revenue that the generator must give up in order to sell to the storage device.

- The storage system is assumed to be perfectly efficient. Some systems approach this efficiency (e.g., flywheels). In general, of course, the round trip efficiency may only be in the 80 to 40% range. This would substantially affect profitability. By assuming perfect efficiency, we can determine an optimistic upper bound on the economic viability of the system. If the system is not viable under these assumptions, it is likely not viable at more realistic efficiencies.

The absolute size of the storage system is not critical in analyzing the stand-alone system. The storage system can buy as much energy from the grid as it wishes each hour (this is only true up to the point where the presence of the storage systems begins to affect the SMC). Because of this, it can be assumed that the charge/discharge device has a capacity of 1 kW, and the size of the storage device can be determined relative to that.

### *Storage technology costs*

There are a wide variety of storage technologies that could potentially be used. Two possibilities considered here are batteries and pumped hydro. Since these two technologies have very different capital cost structures, it is instructive to examine the economics of both of them. Some illustrative values are shown in Table 4.

Batteries can be easily placed on-site for operation in conjunction with a wind generator. Pumped hydro would typically be developed at some other location. For this analysis, it will be assumed that pumped hydro is located near the wind generator.

Some of the analyses below require information about the marginal (or “incremental”) cost of capacity for each of the storage system components. Table 5 shows the incremental costs derived from the data in Table 4, assuming interest rates of 10% and 5%.

*Table 4: Cost and performance parameters for example storage technologies.*

| **Cost or Performance Item** | **Technology/region** | |
|---|---|---|
| | **advanced battery** | **conventional pumped hydro, Northeast** |
| Technology number in Technology Assessment Guide | 85.1 | 87.1 |
| plant size (no units X unit size, MW) | 1x20 | 3x350 |
| storage size, hrs | 3 | 10 |
| **Capital costs, $/kW** | | |
| power charge/discharge | 153 | 854 |
| storage for hours given above | 366 | 143 |
| total plant cost | 519 | 998 |
| allowance for batteries (200 cycles per yr, 30 yrs) | 79 | na |
| **Operation & Maintenance Cost** | | |
| fixed, $/kW-yr | 0.5 | 4.6 |
| variable, mills/kWh | 7.1 | 4.6 |
| consumables, mills/kWh | 0.0 | 0.0 |
| **energy requirements, kWh in/kWh out** | | |
| full load | 1.23 | 1.33 |
| 75% load | 1.14 | 1.36 |
| 50% load | 1.06 | 1.46 |
| 25% load | 1.10 | na |
| | | |
| unit life, yrs | 30 | 50 |

*Source: Electric Power Research Institute, Technology Assessment Guide for 1989 [EPRI]. These use the cost data from 1989 inflated to 2002 values using the Bureau of Labor Statistics inflator Total Manufacturing Industries, 22% [BLS].*

*Table 5: Incremental cost of storage capacity and charge/discharge capacity.*

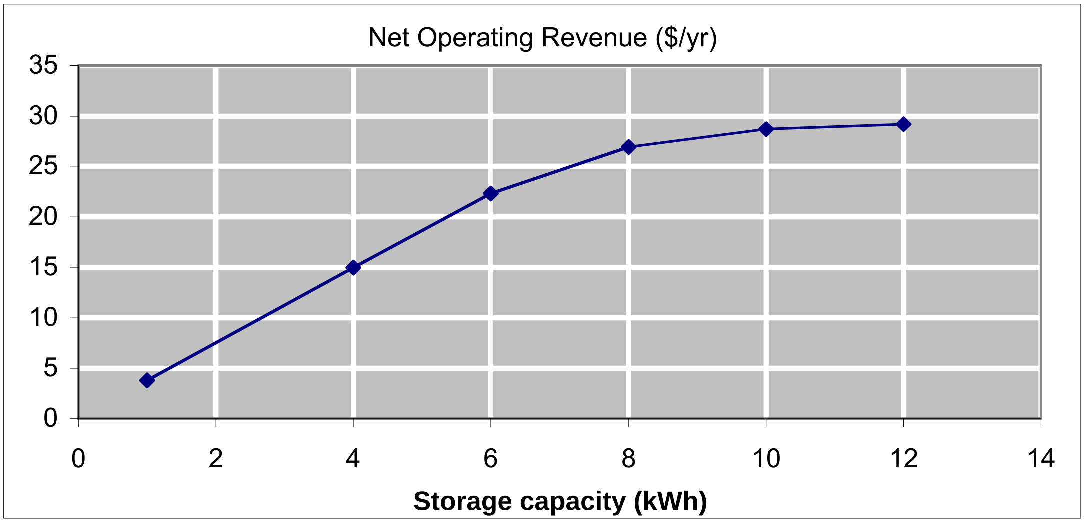
| Cost Item | advanced battery | conventional pumped hydro, Northeast |
|---|---|---|
| ***Incremental capital costs*** | | |
| Incremental cost of storage capacity, $/kWh | 148.4 | 14.3 |
| Incremental cost of charge/discharge capacity, $/kW | 152.5 | 854.0 |
| ***Incremental annualized costs*** | | |
| storage capacity, $/kWh/yr @10% | 15.75 | 1.44 |
| charge/discharge capacity, $/kW/yr @ 10% | 16.18 | 86.13 |
| | | |
| storage capacity, $/kWh/yr @5% | 9.66 | 0.78 |
| charge/discharge capacity, $/kW/yr @ 5% | 9.92 | 46.78 |

## Evaluation of stand-alone storage system

As a baseline, we have first analyzed a stand-alone storage device that simply buys and sells energy from the grid. Such facilities have been proposed for arbitrage, reducing peak generation, and for relief of congestion on the grid. This analysis will consider arbitrage. Reduction of peak generation and relief of congestion are highly localized phenomena and each locale would need to be evaluated separately. However, the approach used here could, in principle, be extended to evaluation of congestion relief, provided that the value of additional electricity supply is known for periods of high congestion or peak demand.

Figure 16 and Figure 17 show the total net operating revenue and the marginal value of storage capacity for a stand-alone storage system that must pay a charge for Transmission and Losses of 1¢/kWh.

*Figure 16: Net operating revenue of stand-alone storage system as a function of storage capacity (with T&L charges).*



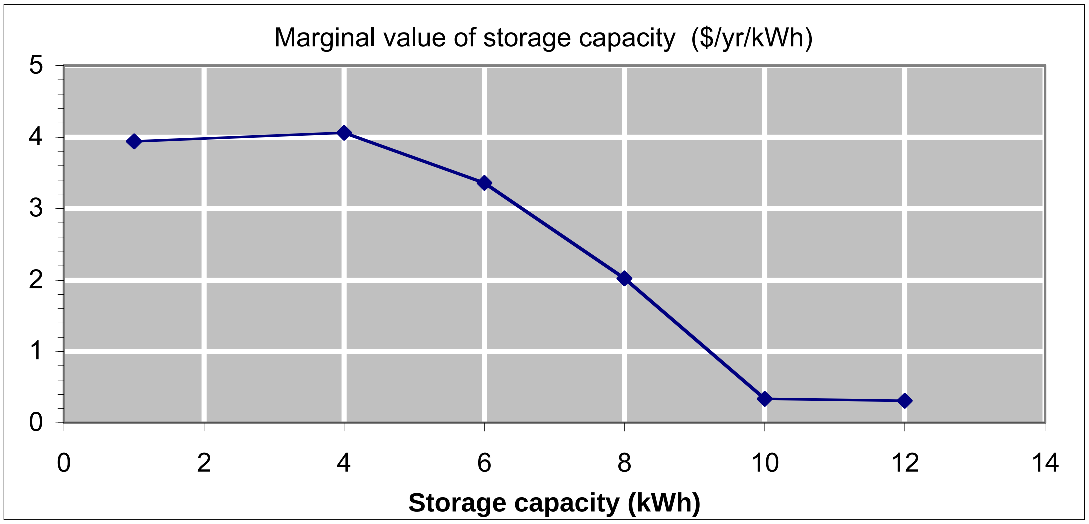

*Note: Assumes a 1¢/kWh charge for transmission and losses. Charge/discharge capacity is 1 kW.*

From these we can assess the optimal storage capacity to be used, given the pattern of prices assumed. In Figure 16 we see that the annual net operating revenues reach a maximum of about $30/yr (with a 1 kW charge/discharge capacity). Thus, if the annual cost of charge/discharge capacity plus storage capacity is greater than $30/yr, the system is clearly uneconomical. For example, at the 10% interest rate, the annual cost of one kW of charge/discharge capacity of the pumped hydro is $86.13/yr as shown in Table 5. From Figure 16 we can see that this cost cannot be met and pumped storage is not viable.

The most favorable case is the battery system at a 5% interest rate as shown in Table 5. Here we see that the annual cost of one kW of charge/discharge capacity is $9.92/yr. Figure 16 shows that this much revenue is earned at a storage capacity of approximately 2.5 kWh, suggesting the possibility that the battery system could be feasible. However, the annual marginal cost of storage capacity is $9.66/kWh and 2.5 kWh of capacity would have an annual cost of $24.15 making the total annual cost $34.05, far more than the revenue at 2.5 kWh of capacity.

From Figure 17 we see that the annual marginal value of storage capacity is never greater than about $4/kWh, much less than the annual cost of battery storage capacity. Consequently, the battery storage system is not viable.

*Figure 17: Marginal value of storage capacity for a stand-alone storage system.*



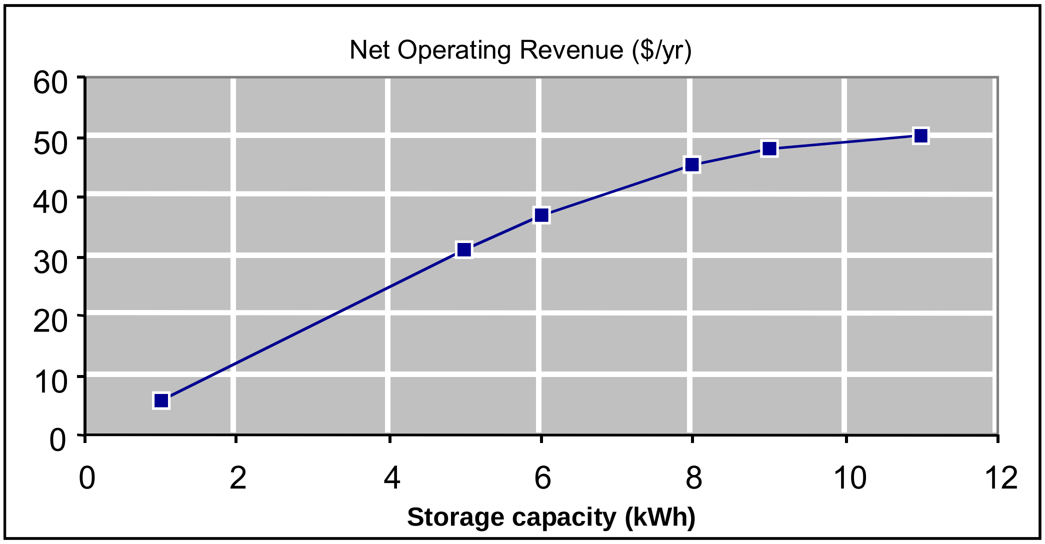

*Note: Assumes a 1¢/kWh charge for transmission and losses. Charge/discharge capacity is 1 kW. The slight increase in marginal value from 1 kWh to 4 kWh is caused by slight differences in the optimization solutions.*

## Stand-alone storage system without charges for transmission and losses

The previous section indicates that a stand-alone storage system would not be economically viable when there is even a small charge for transmission and losses . It is conceivable that a storage system owner could negotiate a contract for energy with little or no charge for T&L. This section evaluates a stand-alone storage system that does not pay T&L charges.

Figure 18 and Figure 19 show the net operating revenue and marginal value of storage capacity for a system operated without T&L costs. Here the net operating revenue rises to about $50/yr and the maximum marginal value of storage capacity is about $6/kWh-yr.

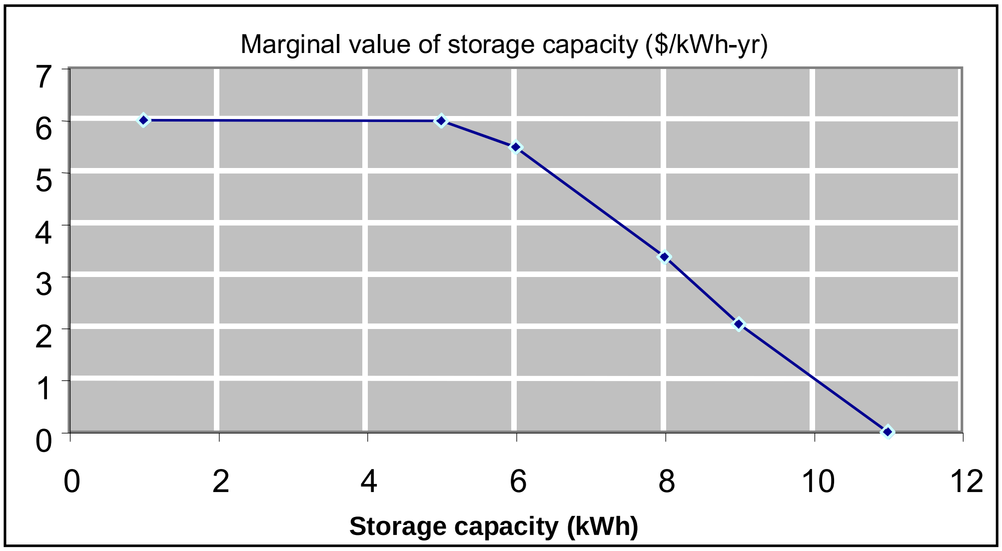
*Figure 18: Net operating revenue of stand-alone storage system as a function of storage capacity (without T&L charges).*




*Note: Assumes a 0¢/kWh charge for transmission and losses. Charge/discharge capacity is 1 kW.*

For this case the battery storage system is not viable even at 5% interest rate. However, at 5% interest, the pumped storage system approaches viability. At a storage capacity of about 8.5 kWh the net operating revenues are sufficient to pay for the annual cost of the charge/discharge capacity ($46.78/yr from Table 5). Figure 19 indicates that at 8.5 kWh of storage capacity, the marginal value of storage capacity is still somewhat greater than $2.50/yr—much greater than the marginal cost of storage capacity ($0.78/yr from Table 5). However, at 8.5 kWh of storage capacity, the net operating revenues are not sufficient to cover both the cost of the charge/discharge device and the storage capacity. As more capacity is added, the situation does improve, but it never quite reaches breakeven. Even at 10 kWh of storage the marginal value of storage capacity has dropped to about $1.00/yr which is close to the marginal cost of storage capacity ($0.78/yr), indicating that this is nearly the optimal amount of storage capacity. However, at 10 kWh of storage the total system cost would be ($46.78 + 10*$0.78) = $54.58 which is still greater than the net operating revenue at 10 kWh of storage capacity (≈$50/yr).

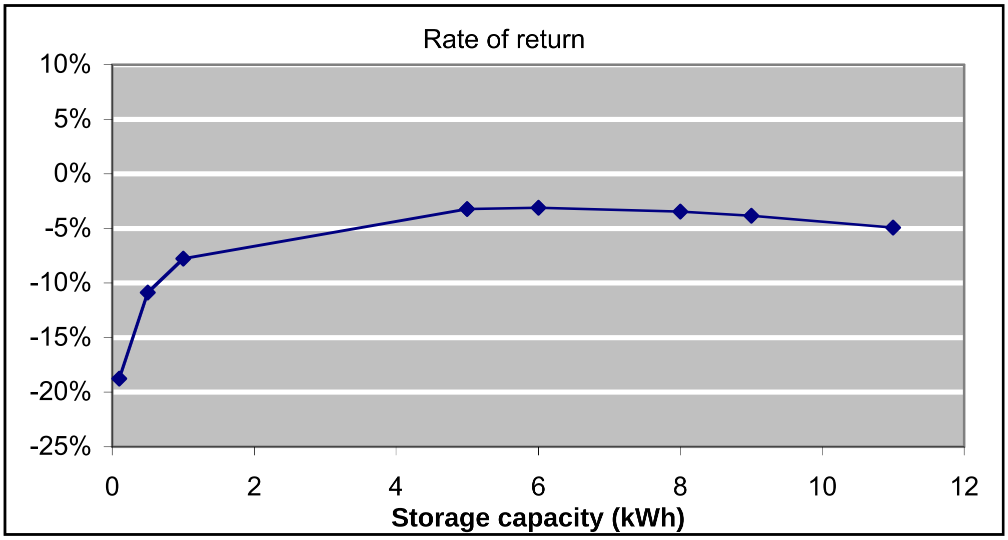
*Figure 19: Marginal value of stand-alone storage capacity without a charge for transmission and losses.*




*Note: Assumes a 0¢/kWh charge for transmission and losses. Charge/discharge capacity is 1 kW.*

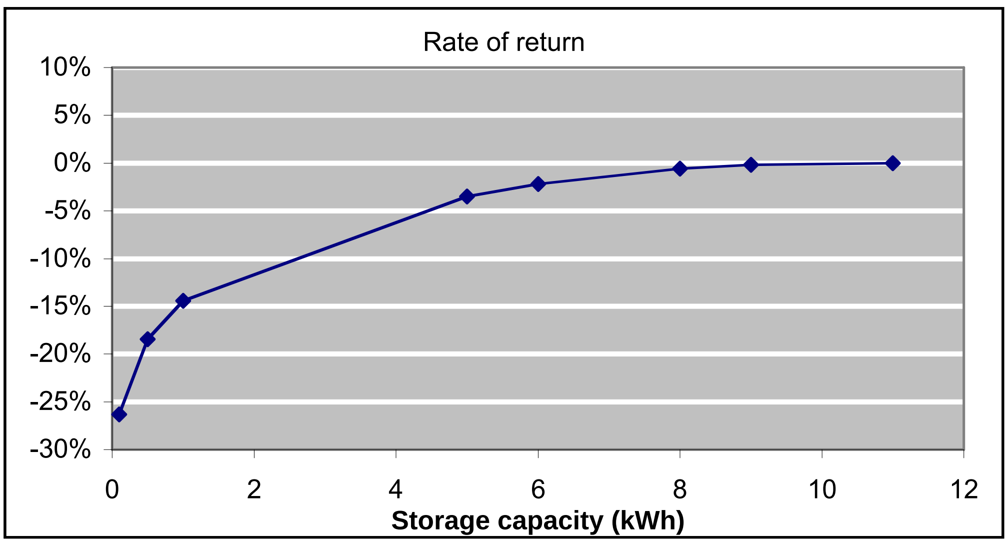
These same conclusions can be drawn by examining the annual rates of return for both battery and pumped storage systems. These are shown in Figure 20 and Figure 21. For the battery storage the rate of return is consistently negative reaching a maximum of about –3.5% at around 6 kWh of storage. The rate of return of the pumped hydro does reach 0% as we approach 11 kWh of storage, but otherwise is negative.

*Figure 20: Rate of return for stand-alone storage system using batteries.*




*Note: Charge/discharge capacity is 1 kW. No charge for transmission and losses.*

*Figure 21: Rate of return for stand-alone storage system using pumped hydro.*




*Note: Charge/discharge capacity is 1 kW. No charge for transmission and losses.*

In all of these cases the rate of return for the stand-alone systems is negative or barely positive. Note that these analyses are made using fairly optimistic assumptions, particularly the high efficiency of the storage system. Under more realistic assumptions the financial performance would be worse[2].

[2] Although these analyses suggest that stand alone storage is not financially viable, we do see large pumped storage facilities in California that are apparently financially viable–for example the Helms facility in the PG&E area. These facilities do not necessarily buy energy using the price schedule used here (in Figure 1). Under the price schedule used here the purchase price of

## Evaluation of storage operating with wind under Firm Capacity contract

Operating storage in conjunction with a wind generator under a Firm Capacity contract has potential benefits that could improve the economics of the combined system. When a wind generator operates under a Firm Capacity contract, any excess energy generated is not paid for. The wind generator must also pay a penalty for any under-generation. Operating the wind with a storage system can reduce these problems by taking the excess energy and selling it later. The storage system can also cover at least some of the under-generation so as to avoid some of the penalty charges. This section analyzes the effect of these benefits on the economics of the storage system.

As discussed earlier, combining storage with the wind generator can help the economics of both systems. To evaluate the effect of combining the two without double counting benefits, the energy flows and payments in the analysis have been structured so that the wind generator is left in the same financial position as it is when operating by itself and all of the financial benefits accrue to the storage system. We can evaluate the benefits of the combination by evaluating the total costs and revenues of the combined system.

Figure 22 illustrates the energy flows and payments for this analysis. Appendix 3 describes in detail the rules and decision procedures used in the analysis to determine the energy flows and payments.

In contrast to the stand-alone storage system, using storage with the wind generator implies that the size of the storage system, including the charge/discharge capacity and the storage capacity, must be sized to match the capacity of the wind generator. This is due to the fact that the excess energy available and the power output needed to cover under-generation by the wind generator are functions of the wind generator capacity. The sections below compare the financial performance of a small system, with 0.1 kW of charge/discharge capacity, and a larger system with 1.0 kW of charge/discharge capacity.

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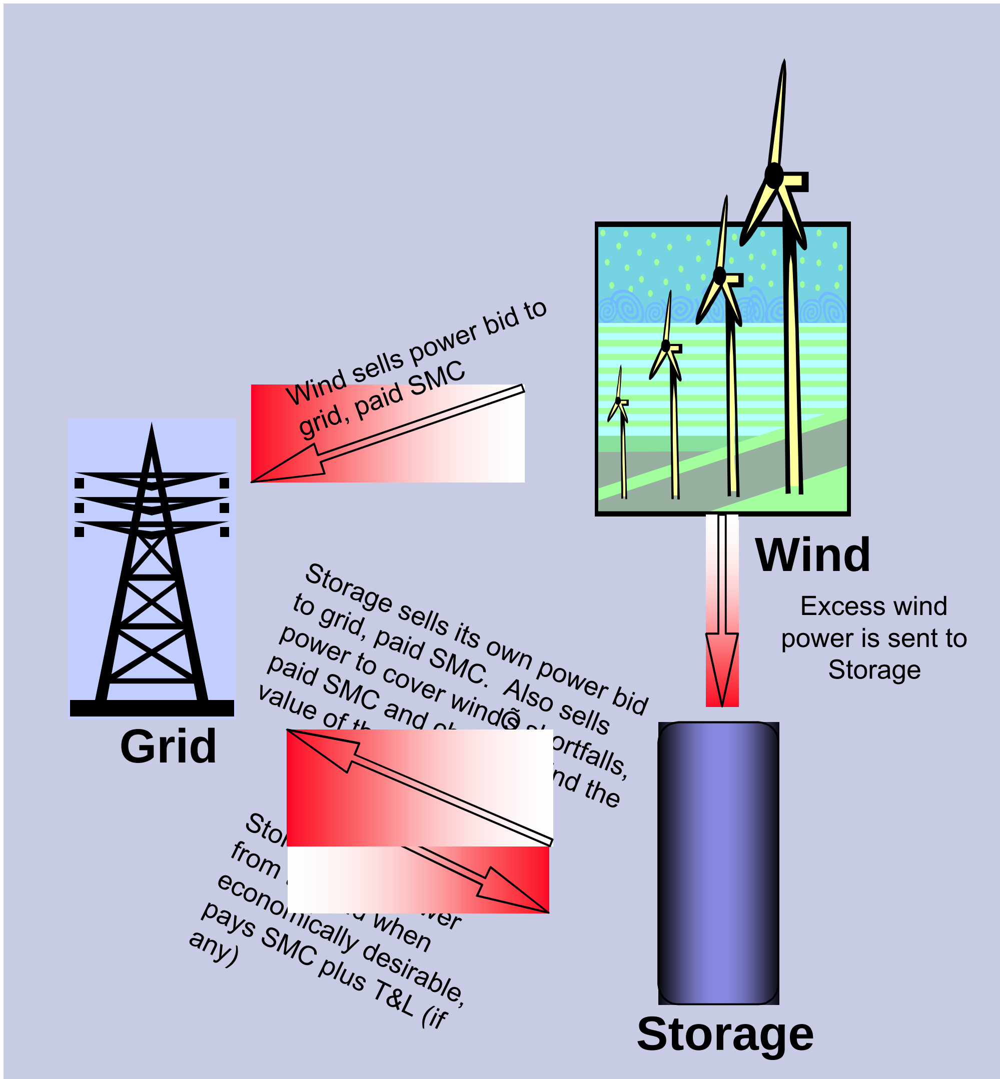
energy is never below $0.02/kWh, while energy has been available to pumped storage units at prices that are considerably lower. In addition, a large pumped storage unit that can reliably generate at peak hours would receive a substantial capacity credit.

*Figure 22: Energy flows and payments for storage system operating with wind generator under a Firm Capacity contract.*

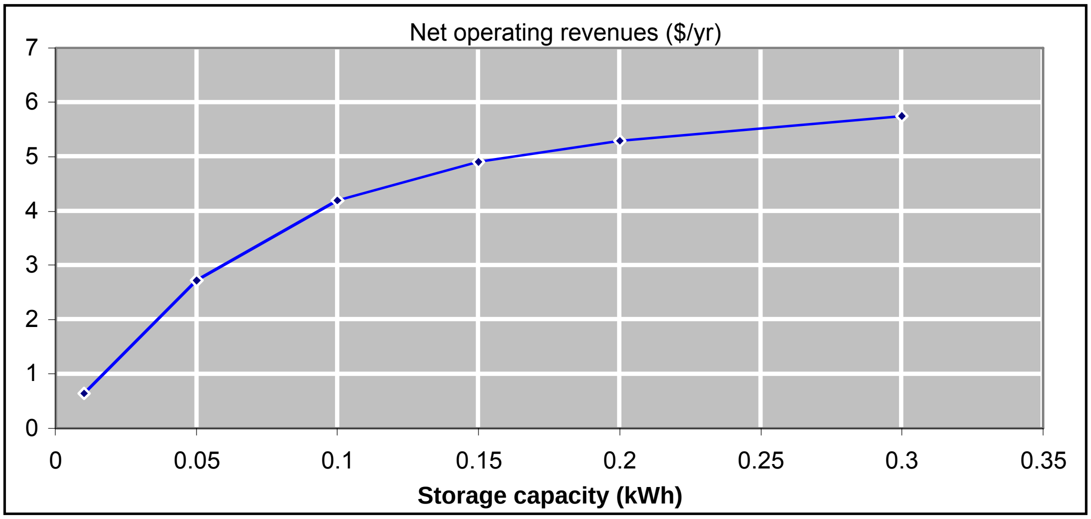



## Evaluation of smaller storage system (0.1 kW charge/discharge capacity)

The financial performance of the smaller capacity system is shown in Figure 23 and Figure 24. In this case the charge/discharge capacity is set at 0.1 kW while the storage capacity is varied.

From Figure 23 we see the total net operating revenue approaches $6/yr as storage capacity is increased. We can compare this to the annual cost of charge/discharge capacity to determine whether or not there is a possibility that the small storage system will be financially viable. The annualized capital cost of 0.1 kW of charge/discharge capacity ranges from about $1/yr (for the case of the battery at 5% interest rate) to $8.60/yr (for the pumped hydro at 10% interest rate). The revenue is sufficient to cover the costs of the charge discharge capacity for any of the cases except pumped hydro at 10%.

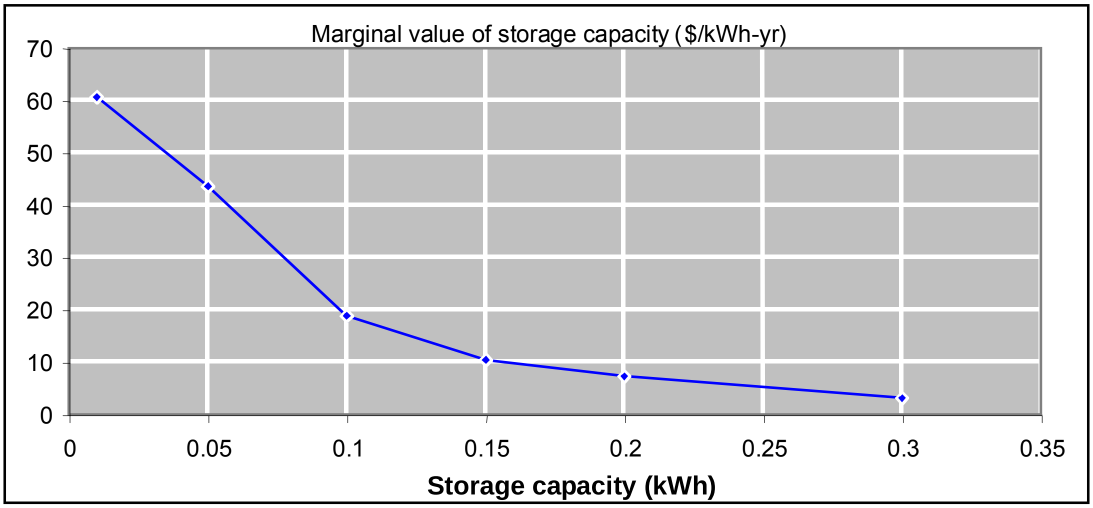
*Figure 23: Net operating revenue of storage system as a function of storage capacity operating with a wind generator under Firm Capacity contract.*




*Note: Wind generator capacity is 1 kW while the charge/discharge capacity of the storage system is 0.1 kW. Assumes a 0¢/kWh charge for transmission and losses.*

Figure 24 shows that the marginal value of storage capacity starts out at around $60/yr. This is far greater than the marginal cost of storage for any of the technologies and interest rates. The highest marginal cost of any of the storage cases is $15.75/yr for the battery technology at 10%. The marginal value of storage capacity declines to this level when there is around 0.12 kWh of storage capacity. This implies that a storage capacity of at least 0.12 kWh could be justified.

*Figure 24: Marginal value of storage capacity as a function of storage capacity operating with a wind generator under a Firm Capacity contract.*

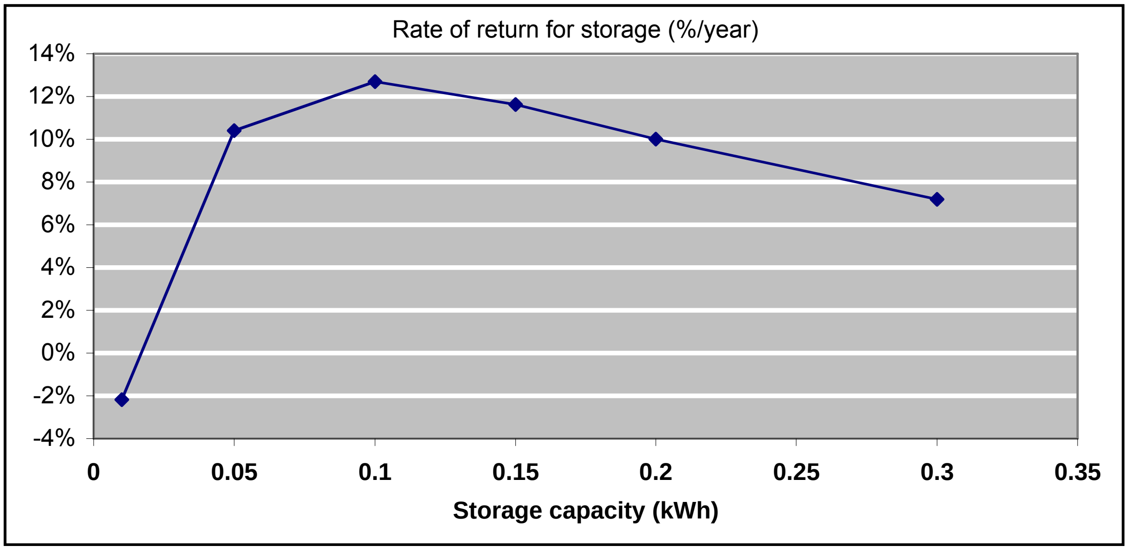



*Note: Wind generator capacity is 1 kW while the charge/discharge capacity of the storage system is 0.1 kW. Assumes a 0¢/kWh charge for transmission and losses.*

Figure 25 and Figure 26 show the rates of return for the battery system and pumped storage systems. For the battery system, the rate of return reaches a maximum of about 12.5% at around 0.1 kWh of storage capacity. This is a fairly respectable rate of return and is comparable to the rate of return for the wind generator itself. We have to keep in mind that this uses optimistic assumptions about the costs and performance of the storage system.

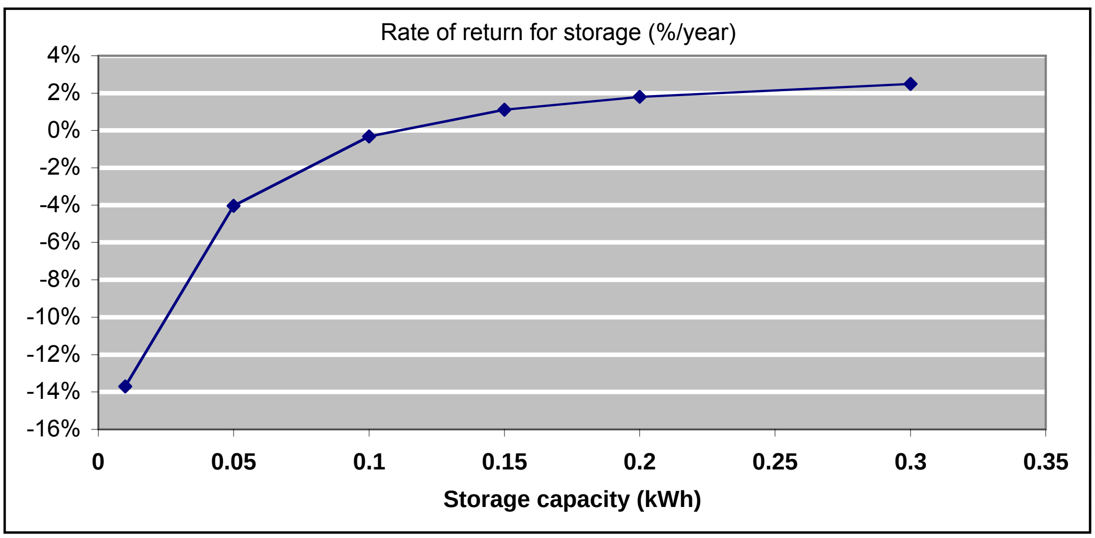
Figure 26 shows the rate of return for the pumped storage system. Here the rate of return rises to somewhat above 2%. This not really financially viable, particularly considering the optimistic assumptions that have been made.

Figure 25: Annual rate of return for investment in battery storage.




*Note: Charge/discharge capacity is 0.1 kW. Wind generator capacity is 1 kW. Assumes a 0¢/kWh charge for transmission and losses.*

Figure 26: Annual rate of return for investment in pumped hydro storage.




*Note: Charge/discharge capacity is 0.1 kW. Wind generator capacity is 1 kW. Assumes a 0¢/kWh charge for transmission and losses.*

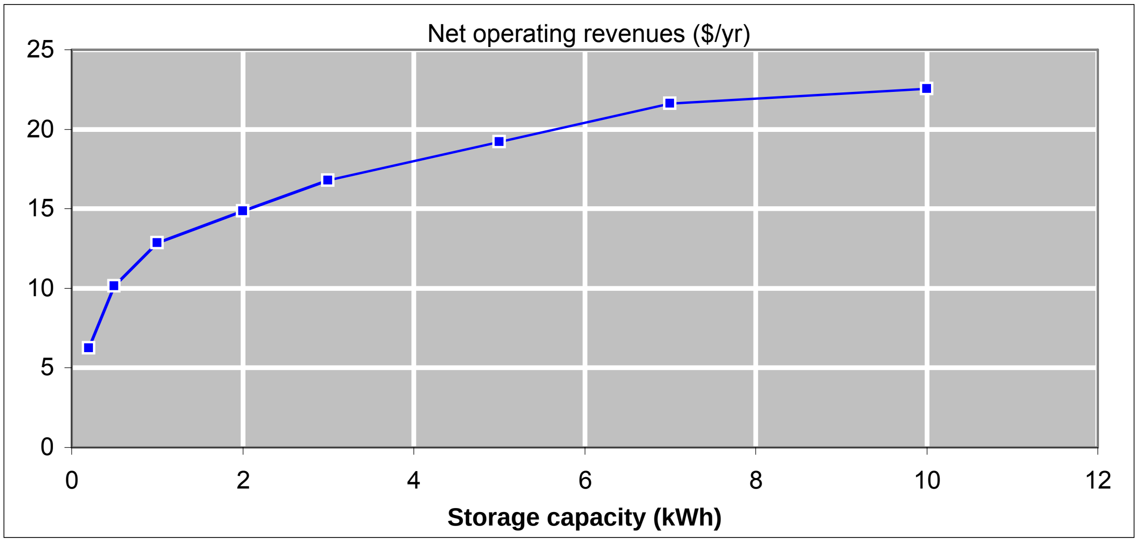
These analyses indicate that a small storage system may be viable when operated in conjunction with a wind generator operating under a Firm Capacity contract.

***Evaluation of larger storage system (1 kW charge/discharge capacity)***

This section evaluates a larger system with 1.0 kW of charge/discharge capacity. In Figure 27 we see that the net operating revenue rises to about

$22/yr as the storage capacity is increased. This is insufficient revenue to cover the annual cost of 1 kW of charge/discharge capacity for the pumped storage system, even at 5% interest rate. Thus the pumped storage system can be ruled out. The revenue is sufficient to cover the charge/discharge capacity of the battery system.

*Figure 27: Net operating revenue of storage system operating with a wind generator under Firm Capacity contract.*

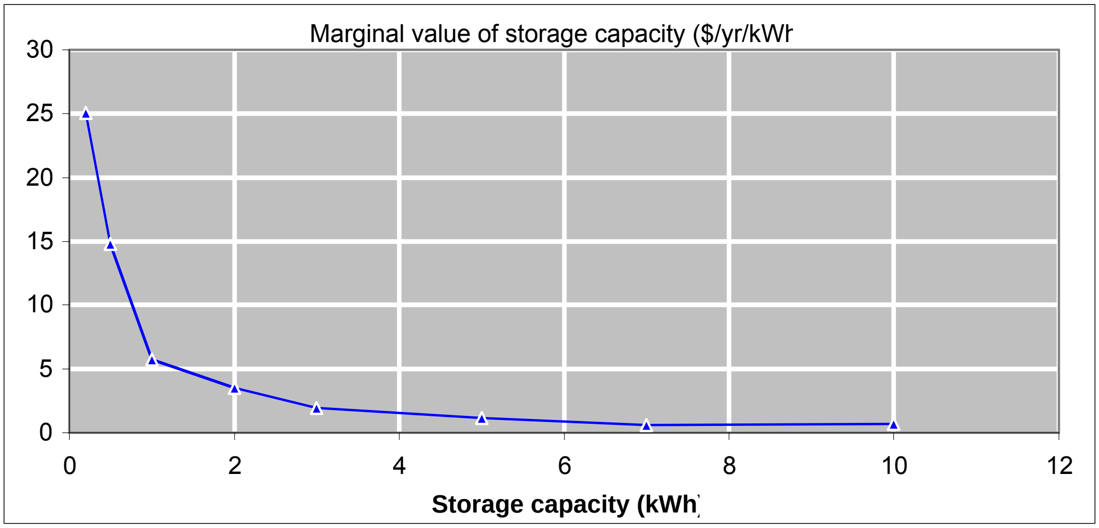



*Note: Wind generator capacity is 1 kW while the charge/discharge capacity of the storage system is 1.0 kW. Assumes a 0¢/kWh charge for transmission and losses.*

Figure 28 shows the marginal value of storage capacity for this system. Although the marginal value of storage capacity is very high initially, it drops rapidly as capacity is added. At 10% interest rate the annual cost of storage capacity for the battery system is $15.75/yr. From Figure 28 we see that the optimal storage capacity of this system would be around 0.5 kWh. This is small compared to the discharge capacity of 1.0 kW, implying that the storage system would have a minor impact on operations. Even at a 5% interest rate the optimal storage capacity would still be less than 1 kWh leaving the storage system with less than an hour of discharge capacity.

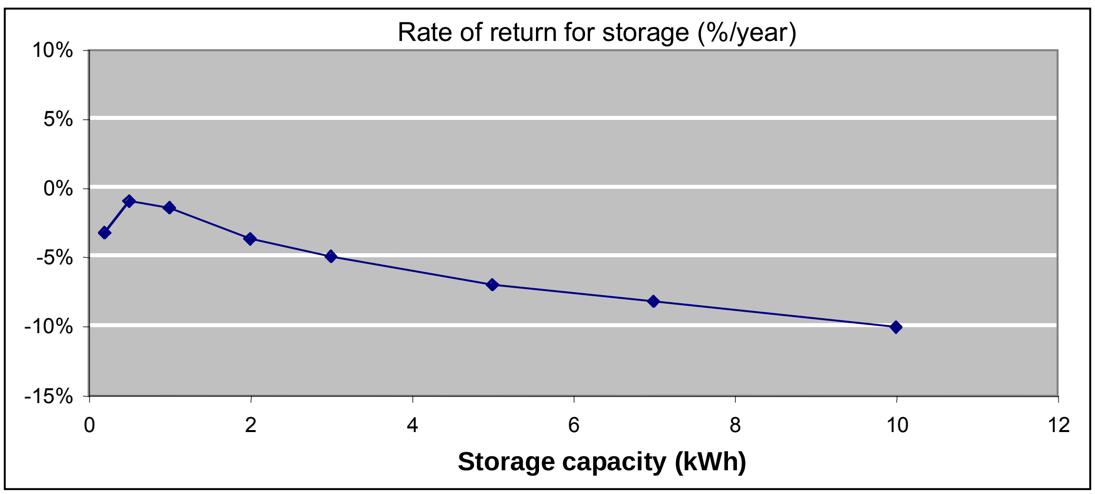
Examining the rates of return for both the battery system and the pumped hydro system indicates that neither one is financially viable. For the battery system, shown in Figure 29, the maximum rate of return is negative but approaches 0% at around 0.5 kWh of storage capacity. For the pumped storage, shown in Figure 30, the rate of return increases as storage capacity is added, but it remains negative, only reaching a level of –7% in this analysis.

*Figure 28: Marginal value of storage capacity for storage system operating with a wind generator under Firm Capacity contract.*



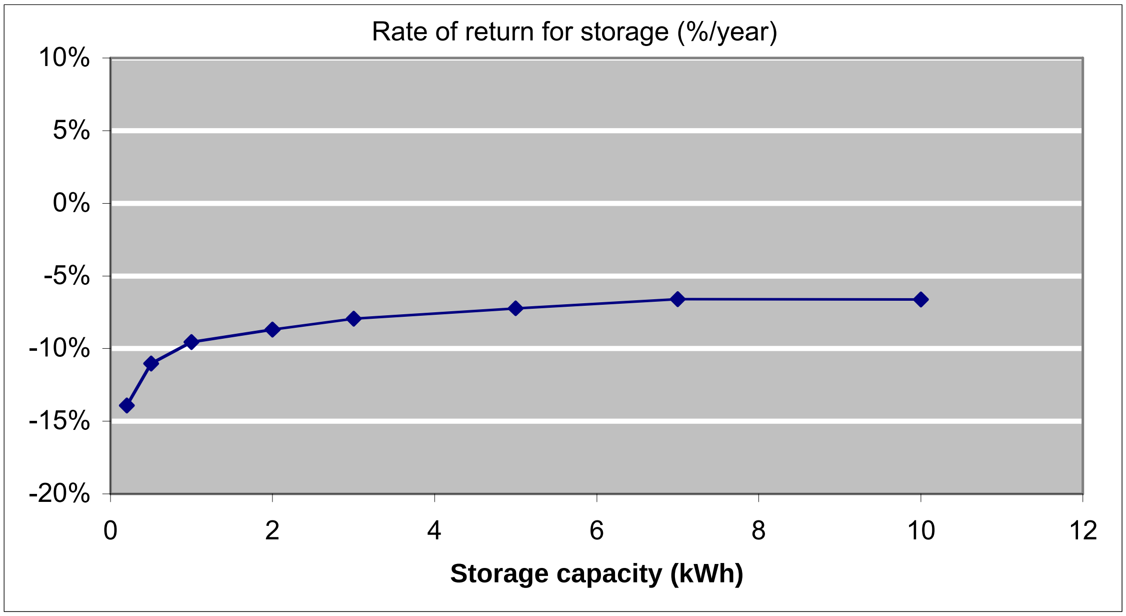

*Note: Wind generator capacity is 1 kW while the charge/discharge capacity of the storage system is 1.0 kW. Assumes a 0¢/kWh charge for transmission and losses.*

*Figure 29: Rate of return for an investment in battery storage.*




*Note: Charge/discharge capacity is 1 kW. Wind generator capacity is 1 kW. Assumes a 0¢/kWh charge for transmission and losses.*

*Figure 30: Rate of return for an investment in pumped hydro storage.*



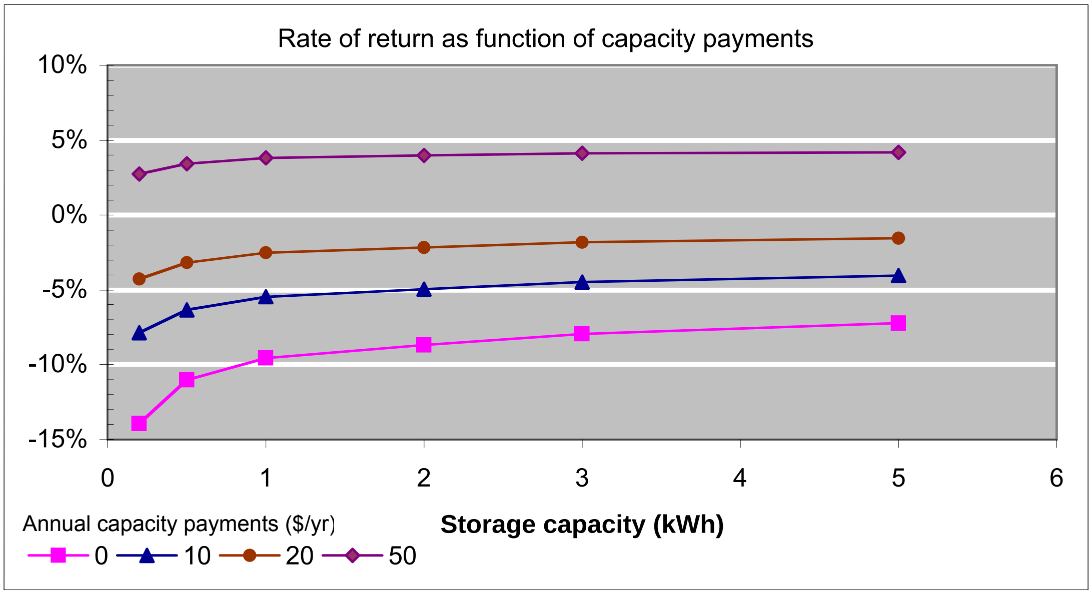

*Note: Charge/discharge capacity is 1 kW. Wind generator capacity is 1 kW*

## Potential financial benefits of capacity payments for a 1 kW storage system

As in the case of wind generation with back-up generation, the use of storage will improve the reliability of generation. This suggests the possibility that capacity payments could be made. This section examines the impact that capacity payments might have on the rate of return. Similar to the case of back-up generation, the impact of storage on reliability is also discussed. In this analysis we consider the case of the storage system with a 1 kW charge/discharge capacity (equal to the wind generation capacity). Although the discussion above shows that a system with a smaller capacity has a larger rate of return and might be a more favorable system from a financial point of view, its impact on system operations is probably not very useful.

Figure 31 shows the effect of capacity payments on rates of return for a pumped hydro storage system. Adding storage capacity improves the rate of return since storage capacity is quite inexpensive. However, increasing storage capacity beyond 1 or 2 kWh (i.e. 1 or 2 hours of discharge capacity) provides very little additional benefit. The maximum rates of return, even with a fairly high capacity payment, do not reach 5%, suggesting that even with capacity payments pumped hydro storage would not be viable.

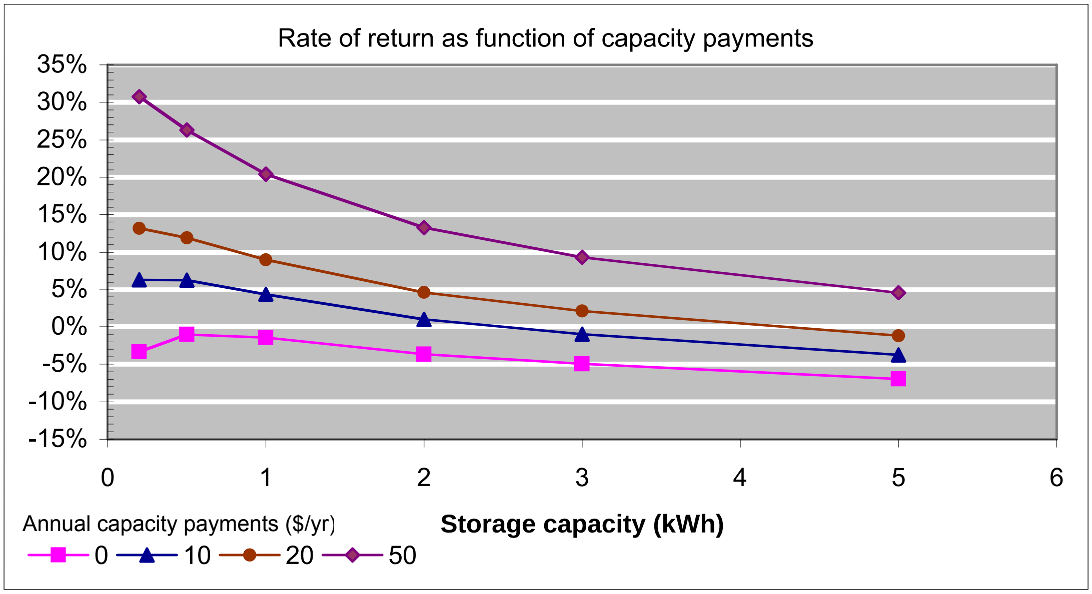
*Figure 31: Rates of return for wind generation with pumped hydro storage for different capacity payments*




*Note: charge/discharge capacity is 1kW*

In contrast to pumped hydro storage, adding storage capacity to a battery storage tends to reduce the rate of return due to the high cost of battery storage capacity. At low levels of storage capacity the potential rate of return seems to be viable. However, as is shown below, at low levels of storage capacity the reliability of the system is not high—possibly not high enough to justify capacity payments.

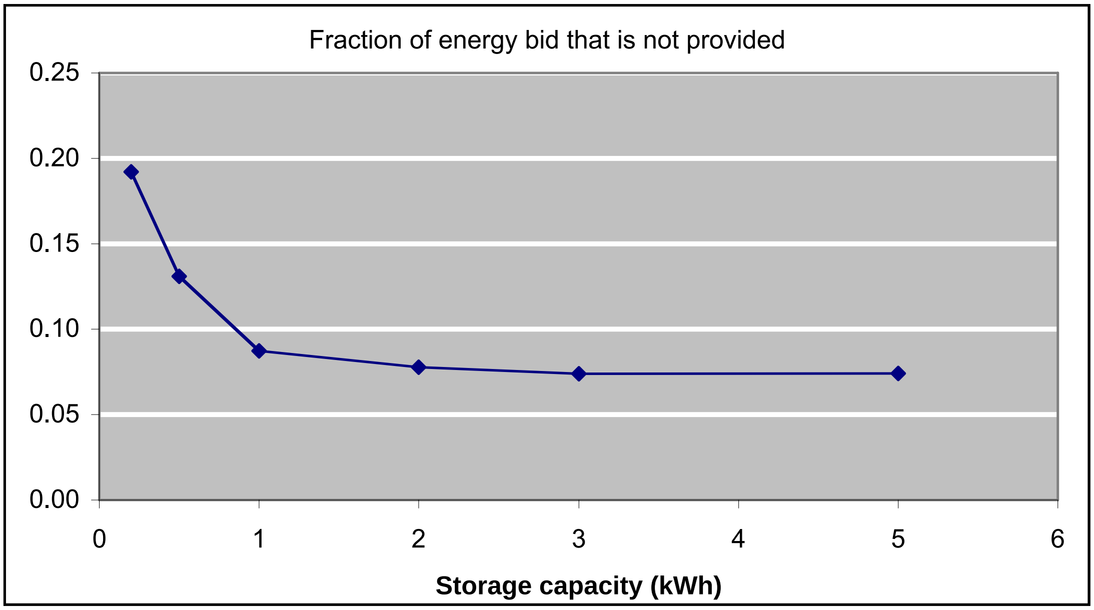
*Figure 32: Rates of return for wind generation with battery storage for different capacity payments*



*Note: charge/discharge capacity is 1kW*

The reliability of the storage system is shown in Figure 33. The addition of 1 to 2 kWh of storage capacity reduces the fraction energy bid but not provided to around 7% of the total amount bid. Further additions of storage capacity do not improve reliability significantly.

*Figure 33: Reliability of wind generation plus storage*




## Comparison of operations between stand-alone storage system and storage system operating with wind generator

The stand-alone storage system arbitrages between low value and high value hours, much as one would expect. When we examine the buy and sell prices from the optimization, they lie between the daily minimum and maximum values. This corresponds to the strategy of buying when the price is low and selling when the price is high.

However, when we examine the operation of a storage system operating with a wind generator operating under a Firm Capacity contract we find a qualitatively different behavior. In these cases the optimal buy and sell prices are very high. Generally they are equal to or higher than the daily maxima. The fact that the buy and sell prices are very high implies that: a) the storage system nearly always wants to buy energy (the SMC is always below the buy price), and b) the storage system seldom wants to sell energy (the SMC is generally below the sell price). On reflection, this behavior is actually reasonable. Recall that the rules are established so that the storage system always sells energy to cover the wind generator's under-generation, if there is energy in storage. There are many hours when there is at least a small amount of under-generation and thus the storage is called on frequently to provide some energy. Whenever the storage provides some energy, it is credited with the cost of the under-generation penalty that the wind generator would have paid. The under-generation penalty is a fraction of the energy value. Here the fraction is 0.25. Thus the storage purchases energy at, say, $1, it can usually resell that energy quickly for $1.25. In this way the storage earns a little revenue from nearly every transaction, often regardless of the price that it paid for the energy.

The fact that the storage system receives the value of the penalty for most transactions is legitimate. From the point of view of the wind generator, the penalty is a real cost and the storage system helps to avoid that cost. From the point of view of the larger grid, if the penalty represents a true cost of having to cover the wind's under-generation, then the storage system is helping the overall system avoid that cost and the storage system should be compensated for that.

This behavior explains why smaller storage systems are favored when the storage is connected with a wind generator under a Firm Capacity contract. This strategy is only useful as long as the storage system is helping the wind generator cover under-generation. The amounts of under-generation are not large so a small discharge capacity on the storage system is sufficient to cover most of them. If the storage system's discharge capacity is large, much of that capacity is not used and the capital investment is idle. A very small storage system would have the best possible return on investment. Unfortunately, a very small storage system would also have a negligible impact on the economics of the overall system.

# 7. Conclusions

This white paper has examined the use of back-up generation and energy storage to make wind generation more financially viable when operating under a Firm Capacity contract. It has examined the possibility that the use of back-up generation or storage can improve the financial performance of the wind generator. Since wind generators can operate under an Intermittent Resources contract, the key question is whether or not the use of back-up generation or storage can exceed the financial performance obtained under the Intermittent Resources contract.

Because these analyses are seeking possibilities for improving the financial performance of wind energy, they make consistently optimistic assumptions about the back-up and storage technologies. For reference, Appendix 4 tabulates the optimistic assumptions used. If the approaches do not appear financially viable under these optimistic assumptions, they are unlikely to improve under more realistic assumptions.

Neither the back-up nor the storage strategies seem particularly promising. Back-up generation can *approach* the performance of the Intermittent Resources contract. We did identify assumptions about the cost of a back-up generator that would allow the back-up strategy to exceed the performance of the Intermittent Resources contract, but the case is probably overly optimistic.

Storage strategies do not appear to be particularly useful. Even under the optimistic assumptions used here we find that the rates of return for investment in storage are either negative or small. The only exception was the use of a small battery storage operating with a wind generator under a Firm Capacity contract. The rate of return for this small storage approaches the rate of return for a wind generator under an Intermittent Resources contract. However, this rate of return only occurs for small storage systems. For larger systems, the rate of return drops substantially. Thus, although this case has a viable rate of return, its impact on the system as a whole is negligible. The value of storage can be greater in situations where there is congestion on the grid. However, that has not been addressed here since such situations should be individually evaluated.

Capacity payments would improve the financial performance for the both back-up generation and the storage approaches. However, the benefit appears to be greater for the back-up generation approach than it is for the storage approach. In either case, it is not clear that the level of reliability obtained by adding storage or back-up generation would be sufficient to justify capacity payments.

# 8. References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# Appendix 1: Derivation of optimal bid for wind generator

Each hour, the wind generator needs to bid a specific power level (B) into the market. Here we assume that the generator will be paid for power that is bid at the electricity price for that hour ($p_e$). However, if the wind power that actually materializes (W) is less than the bid, a penalty will be assessed that is calculated as a price ($p_p$, \$/kWh) times the energy shortfall (B–W). This penalty will generally be more than 100% of the electricity price (e.g., 125%). In this way, the generator is paid for the bid amount, but the revenue from the shortfall is subtracted away and a penalty is assessed. Alternatively, the wind generator can cover the shortfall by running another generator. Running the generator or paying the penalty are similar strategies in that they simply represent a penalty cost for the shortfall. In the derivation below, we will simply represent the penalty cost as $p_p$, but this could be either the penalty to be assessed or the cost of replacing the power with the back-up generator. If the wind power that materializes exceeds the bid, the generator will only be paid for the amount of energy (power) bid.

The wind generator also has some information about the likely wind power that will materialize. This is described as a probability distribution over the wind power, P(W).

The generator's problem is to make a bid that will maximize expected net revenue during the hour, taking into account the penalty for under-generating, the price to be paid for electricity generated, and the probability distribution over the wind power.

We can write the total expected net revenue as a function of the power level bid as the sum of two integrals. The first term represents the expected net revenue when the wind is below the bid. The second term is the expected net revenue if the wind is above the bid. If the wind is above the bid, the revenue to the generator is just equal to the bid amount times the price of electricity—that is, the generator is not paid for any generation above the bid amount.

$$ENR = \int_0^B \left[p_e \bullet B - p_p\left(B - W\right)\right] \bullet P(W) \bullet dW + \int_B^{Capw} p_e \bullet B \bullet P(W) \bullet dW$$

where:

| | | |
|---|---|---|
| ENR | = | expected net revenue |
| B | = | amount of power bid |
| $p_e$ | = | price of electricity for the hour ($/kWh) |
| $p_p$ | = | penalty cost for under-generating or the cost of running an alternate generator ($/kWh) |
| W | = | wind energy actually available. Since we are considering 1 hour time period, the wind power and wind energy are numerically equivalent. |
| P(W) | = | Probability distribution over the wind |
| Capw | = | The maximum wind capacity |

To find the maximum we differentiate the ENR with respect to B and set the derivative to 0. The derivative is

$$\frac{dENR}{dB} = (p_e - p_p)\int_0^B P(W)dW + p_e \int_B^{Capw} P(W)dW$$

Setting the derivative to zero gives

$$p_e - p_p \int_0^B P(W)dW = 0$$

or

$$\frac{p_e}{p_p} = \int_0^B P(W)dW$$

We note that $p_p$ is generally (not always!) greater than $p_e$. Therefore the ratio of $p_e$ to $p_p$ is generally less than 1.0. The equation above gives us the rule that the bid should be set so that the probability that the wind will be less than the bid is equal to the ratio of $p_e$ to $p_p$. For example, in hours when the price of electricity is very small compared to the penalty or alternate generator price, the owner of the wind generator has little incentive to bid a large amount. If the wind power is high, the owner will earn very little money because the electricity price is low. But, if there is a shortfall, he will pay a large penalty. On the other hand, if the price of electricity is large and the ratio approaches 1.0, there is a substantial amount to be earned and the cost of the penalty for any shortfall is small. It is even possible, with a back-up generator, that the price of electricity will exceed the cost of the penalty (the penalty being the cost of running the back-up). In that case, the wind generator cannot lose money unless the capacity of the back-up generator is exceeded. Even if the back-up generator has to be run, it will earn more than its cost. In that case, the wind generator should bid full capacity.

In applying the equation derived here, care must be taken to ensure that the correct value for penalty or back-up generation cost is used. For example, if one were to use the back-up generation cost in the equation and obtained a bid amount that was greater than the back-up capacity, the result would be invalid. Consequently, in the actual analysis each condition is checked to ensure that the correct form is used in calculating the optimal bid.

# Appendix 2: Statistical model for wind forecasts

The statistical forecasting model provides a probability distribution over the wind power in one hour based on observations of the wind in the previous hour. This provides a statistical basis for bidding power an hour ahead.

The method used here makes note of the difference between the expected wind and the actual wind in the current hour. We then assume that this same difference will persist. Essentially this assumes that the deviation between the actual and expected wind is a one step random walk. This provides the basis of the statistical forecast.

The basic steps to prepare the model are:

1. Divide the data into sets of hours: There is one set for each different hour of the day for each month. For example one set includes all the 1AM hours in January. There are 12 x 24=288 sets.
2. Estimate average wind power value for each set. For month m and hour of the day h, this is denoted as $\overline{w_{m,h}}$. As an example, $\overline{w_{1,1}}$ is the average wind power over all the hours from midnight to 1AM in January.
3. In each hour of the year we can compute the difference between a) the actual wind in that hour and b) the average for the set that includes that hour. Let us call this difference $\Delta$.

To apply the model we observe the $\Delta$ in one hour. We assume that the expected value of the Δ in the following hour will be the same. That is, the expected *change* in the Δ is 0. For example, if the Δ at 2AM on January 12 was 0.3 kW, then the expect value of the Δ at 3AM on January 12 will also be 0.3 kW. This gives us the expected value of the wind for the next hour based on observations for the current hour. Mathematically this is:

$$E\left(w_{m,d,h}\right) = \overline{w_{m,h}} + \left[w_{m,d,h-1} - \overline{w_{m,h-1}}\right]$$

*or*

$$E\left(w_{m,d,h}\right) = \overline{w_{m,h}} + \Delta_{m,h-1}$$

*where*

$w_{m,d,h} =$ the actual wind during month m, day d, and hour of the day h

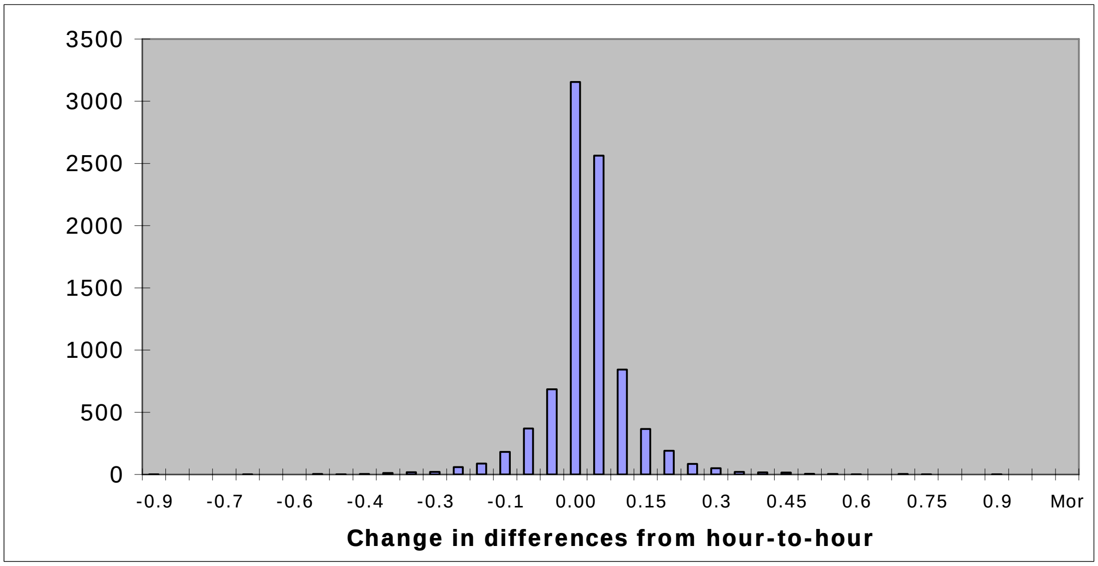
$\overline{w_{m,h}} =$ the average wind over all the days in month m, at hours (of the day) h

$\Delta_{m,d,h} = w_{m,d,h} - \overline{w_{m,h}} =$ the deviation

We assume the change in Δ between the current hour and the next will be normally distributed (with a 0 mean, as noted above). To complete the model, we need to estimate the standard deviation of the change in Δ. In this analysis we have simply compiled the hour-to-hour changes in Δ within the data set and computed the standard deviation. This was actually done for each of the sets of hours (288 standard deviations were computed).

The assumptions were checked empirically for reasonableness. Within the data set, the changes in Δ from one hour to the next ranges from 0.87 to –0.93 kW. The average change in Δ, however, is 0.00003 kW. Thus the assumption that the expected change in deviation is 0 seems reasonable. A histogram of the changes in Δ is shown in Figure 34.

*Figure 34: Histogram of the hour-to-hour changes in the differences between actual and average winds.*




These appear to be roughly symmetric and plausibly normal, justifying the normality assumption.

It should be noted that in this model, the standard deviations were estimated from the data set. This estimate was then used to make predictions *with the same set of data*. Generally, this is not regarded as good practice since it leads to an overly accurate prediction. One should estimate the parameters on one data set and then apply them to another. However, in this case there is only one year of data available. In addition, throughout these analyses we have consistently made optimistic assumptions on the principle that if the approaches to improving the wind value are not economically feasible under these assumptions, then they are likely not feasible under more reasonable assumptions.

# Appendix 3: Procedures for operating storage in conjunction with wind generator operating under Firm Capacity contract

When a wind generator operates in conjunction with a storage system, there are a number of energy exchanges possible each hour. Each energy exchange involves a payment of some type, even if the exchange is between two systems owned by the same owner. In order to correctly account for the benefits of the storage system, the payments have been defined so that all of the changes in economic benefits and costs accrue to the storage system and the generator is left in exactly the same situation as when it operates alone. The sections below outline the energy exchanges and payments for the analysis. Figure 35 shows the decision process for using and transferring energy at each hour.

## Procedure for purchasing energy

- Storage calculates the amount that it would buy given the Buy Price for that hour and the current system marginal price.
- Wind bids power. Bid is B.
- We observe the amount of wind power available that hour. This is W.
- If W>B then there is excess energy. Storage takes this energy, up to its charging capacity.
- Storage then considers the amount that it planned to buy. It buys an amount that is the lesser of: a) the amount that it planned to buy, or b) the difference between its charging capacity and the amount of excess that it is already being taking in from the wind generator.
- Storage pays zero for the excess energy. Leaves wind in the same financial condition.
- Storage pays SMC (plus charge for T&L, if any) for energy purchased from the grid.

## Procedure for selling energy

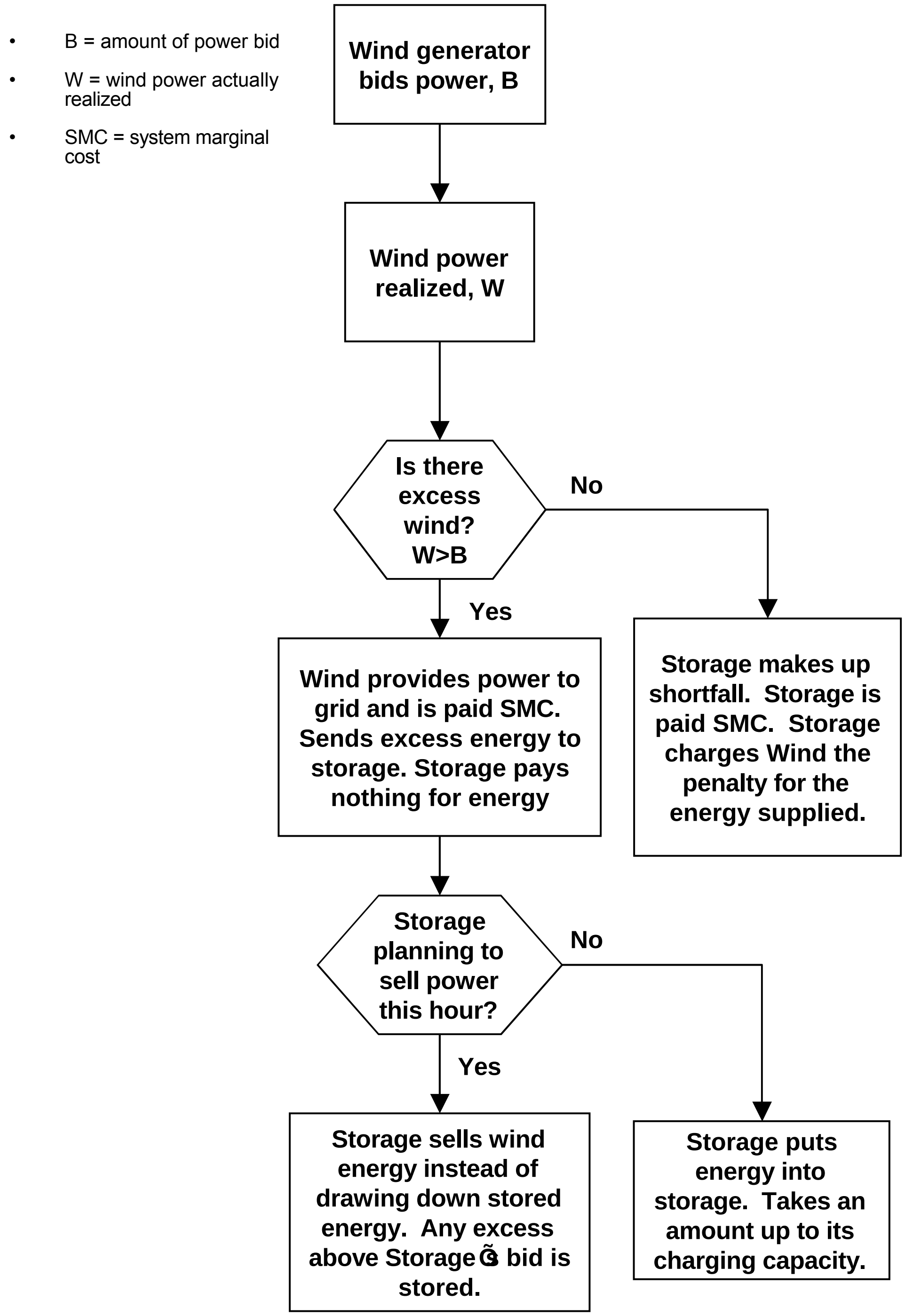
- Storage calculates the amount that it will sell based on prices. This is S.
- If W<B there is a shortfall. Storage makes up the difference if it has enough energy in storage, up to its discharge capacity. It is paid SMC. It charges wind the penalty that wind would have paid to the system, leaving wind in the same financial situation.

- Storage then sells to the grid the amount that it had planned to sell, provided that it has enough energy in storage. The total amount that it can sell is limited by its discharge capacity. It is paid SMC.

## Case when Storage would be selling, and there is excess wind

- The wind generator cannot sell the excess.
- It would not be appropriate for Storage to take the excess and sell it directly to the grid since the excess wind is an unexpected amount and we are assuming that we are operating based on bids that are made prior to the hour in question. For Storage, it would be inefficient to take the energy into storage and then sell it. It would make sense to use the excess as part of its sales, releasing less from storage.

*Figure 35: Decision procedure for operating storage in conjunction with a wind generator operating under a Firm Capacity contract.*



# Appendix 4: Optimistic assumptions made in the analysis

As is mentioned at various points in the main body of the report, the analyses have used several optimistic assumptions. These are highlighted in the table below:

*Table 6: Tabulation of optimistic assumptions made in the analyses.*

| Assumption | Discussion |
|---|---|
| Perfectly efficient storage | Real storage devices would have a round trip efficiency in the range of 40% to 80%. |
| Wind forecast model is applied to the same data used to calibrate model | This assumption will cause the wind forecast model to perform better in this analysis than such a model would in actual operation. |
| Operation and maintenance costs not explicitly accounted for | This reduces the costs of the back-up generator and the storage systems. However, the range of operating costs used will allow for some operation and maintenance costs. |
| Charge for Transmission and Losses is zero | It is possible that a purchase contract could be negotiated with a zero charge for transmission and losses. This would be situation specific. |
| Relatively low capital cost ($400/kW) for a 50% efficient back-up generator | A 50% efficient generator might cost up to $600/kW. However, the actual cost would depend on size of the generator purchased and thus the size of the wind farm that it serves. |
| Pumped hydro can be used as storage device although it is not colocated with the wind turbine | Generally, it would be required that the wind turbine and the storage device be colocated. Also the analysis does not include possible losses due to transmitting power to and from the pumped hydro site. |