Economic Optimization of Offshore Windfarm Substations and Collection Systems

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***Abstract*—Conventional utility design practices often have limited applicability to offshore windfarm collection systems, thus each aspect of design must be carefully evaluated from an economic basis. Three economic evaluation factors can be derived which condense the complexities of the windfarm business model into a form that can be conveniently used to optimize substation and collection system design for maximized profitability.**

This paper reviews the basics of offshore windfarm substation and collection system economics, highlighting the differences from conventional utility practice, explains the derivation of three economic evaluation factors, and illustrates their application to a range of design choices.

I. Introduction

Conventional utility design practices often do not yield economically preferable designs for the medium voltage collection system, offshore substation, and high-voltage transmission line of an offshore windfarm; collectively referred to as the windfarm electrical system. This is due to substantial differences in purpose and economics of the respective applications. For example, the economic incentives for a windfarm are measured by availability, while utility designs focus on reliability. The cost of physical space in an offshore windfarm substation is orders of magnitude greater than onshore land area. Due to subsidies provided to windfarm production, the economic penalties of inefficiency in an offshore windfarm are often substantially greater than those applied to a typical utility application.

To optimize an electrical system design for an offshore windfarm application, each aspect and typical assumption must be challenged and carefully evaluated. The challenge in the evaluation has been determining the life-cycle economic implications of aspects such as lost availability, losses at full load, and no-load losses so they can be included in the design process. Three economic factors condense the complexities of the windfarm business model into a form that can be conveniently used in simple spreadsheet calculations to optimize electrical system design for maximized profitability. These factors can be determined from the unique economic characteristics of the specific project, including wind regime, cost of money, tax treatment, and expected project return on investment.

This paper identifies some of the key aspects driving the unique characteristics of offshore windfarm electrical system design philosophy. The derivations of the economic evaluation factors are provided, and their application is illustrated in several examples. These examples show that optimized electrical system design can yield incremental rates of financial return equal to, or better than, the expected return on investment for the windfarm as a total project.

II. Key Differences in Design Philosophy

An offshore windfarm electrical system is not simply the same as a utility power delivery system, operated in reverse-flow mode, and adapted to the marine environment. Unique functional requirements result in substantial differences in the configuration of the system and the selection of the equipment [1].

A. Availability and Reliability Considerations

Utility substation and infrastructure designs focus on maintaining continuous power flow, which translates to redundancy and automatic transfer concepts that recognize faults, clear them, and reconfigure the system appropriately. The solutions that provide reliability require large initial investments, increase the land area required for the design, and can increase system losses. These initial investments are justified by the value of uninterrupted capacity to the energy consumers. Disruptions as brief as a few seconds can be devastating to manufacturing operations, and therefore a premium is attached to continuity of service (i.e., reliability).

Transmission lines, in the utility context, are critical to preserving the integrity of the grid. In addition to interruption of power delivery to a specific area, outage of key transmission lines can cascade to cause system breakup and blackout of a large area. Even where transmission lines are radial to a specific conventional generating plant, the continuity of operation is critical to providing the capacity benefit of that plant to meet system generation requirements.

The variability of the wind forces the windfarm to operate as a source of energy, with a limited capacity value. Thus, the electrical infrastructure of a windfarm is solving an entirely different problem. The utility electrical infrastructure is designed to maintain a continuous, relatively predictable, power flow while the windfarm infrastructure must be designed to efficiently deliver energy (i.e., availability).

A design for availability would not necessarily include redundancy and automatic transfer schemes mentioned earlier. Short durations of inoperability lasting a few minutes do not greatly affect the revenue generation of a windfarm. Simpler infrastructure designs that require manual, or manually directed reconfigurations can provide nearly equivalent energy production with substantially lower initial and operating costs.

Electrical system outages that constrain or eliminate windfarm output have a strong economic penalty, as available energy cannot be delivered to the marketplace and can never be recovered. Measuring the initial cost equivalent of that penalty has been the difficult part of the calculation, but the economic factors defined in this paper greatly simplify the analysis.

B. Cost of Substation Physical Size and Weight

New utility substations are most typically located far enough from dense urban areas for the cost of land to be negligible compared to the cost of the equipment placed on that land. Thus, a typical utility design does not place a great emphasis on substation footprint, as the equipment is the key driver of cost. Larger designs increase the total cost only by a small amount, for additional grading, ground grid, and fencing. This is not entirely true for substations in dense urban areas where land costs can be an element that requires consideration.

The cost of space on an offshore platform is far higher than even that of a dense, urban area. Every square meter of space has a defined cost to the platform manufacturer in steel and concrete. Thus, the offshore windfarm design must consider not only the cost of the equipment but the cost of the platform it will be mounted on as well.

Gas insulated switchgear (GIS) is necessary for both considerations of space and the marine environment. Because of the higher cost of GIS, relative to open-air buswork used in most onshore substations, there is a strong incentive in offshore systems design to avoid redundancy designs (e.g., ring buses, breaker-and-a-half schemess, etc.) if they do not contribute sufficient incremental energy availability to justify their use. Again, the economic factors simplify decision-making.

C. Maintenance and Repair

Maintenance cost is one element of total lifecycle cost where utility and offshore substation designs share a common goal. But even here, the cost of an offshore substation maintenance event is considerably higher than an onshore event. Routine maintenance at the offshore substation requires a person to endure the travel to and from the substation platform, possibly in rough seas. Travel to offshore wind turbine towers can be even more difficult, and more constrained by sea conditions, due to the difficulty in using helicopters to reach the towers. In addition to the time spent maintaining the equipment, cost of transport vessel or helicopter, travel time, safety training, and delays in waiting for sea or weather conditions to improve must be added to the equation. Worse yet is the cost of an unplanned maintenance event brought on by major equipment failure. Consider the huge additional expense of a barge, crane, and associated crews to transport the replacement equipment to the platform and place it into position. Heavy lift operations are more tightly constrained by sea state than personnel transportation, and these lifts may not be feasible during long periods of the year due to prevailing sea conditions. Lifecycle energy availability is significantly decreased with all or a substantial portion of windfarm production lost for a lengthy period.

Thus, equipment requiring reduced maintenance, or equipment that allows condition-based maintenance can be a solid investment; yielding much greater returns than application of similar equipment in onshore systems. An example is a transformer monitoring system that trends the health of the offshore substation transformer, allowing corrective action or pre-emptive replacement at an opportune time such as when sea conditions are sufficiently calm to perform the operation and necessary support equipment and crews can be scheduled well in advance.

D. Value of Wind Energy

Energy generated by wind is often more valuable per kWh than conventionally generated energy. This is due to various incentives, subsidies, and special "green power" markets based on wind energy's positive environmental characteristics. Because the energy delivered to the grid is more valuable, there is a greater incentive to reduce electrical system losses that decrease the energy delivered to the revenue meter.

III. Economic Evaluation

Utility electrical design practices have been developed and incrementally optimized over the last century. As the preceding discussion indicates, however, there are substantial differences in the key requirements and application considerations for offshore wind electrical systems. Offshore wind technology is a new application that is evolving rapidly. The electrical system designer does not have the benefit of a century's worth of industry experience with similar applications to guide decisions.

Wind generation electrical system decisions are driven by economics, not necessity. The electrical system must have the lowest possible total lifecycle cost for the project to maximize its economic potential. A specific design choice may have a complex effect on the project financial performance, affecting capital costs, taxes, insurance, energy revenue, maintenance costs, and government subsidies. A method is required to simplify the calculations so that alternate design proposals may be compared and an optimal solution chosen based on the specific economic factors of the particular windfarm.

Other than future maintenance costs, the future financial impacts of an electrical system design choice can be characterized as forms of energy, or revenue, loss. There are three unique types of energy losses, each affecting the revenue model of a windfarm in a different way. These are:

1. Fixed losses, which do not vary with windfarm production output. These losses are primarily transformer excitation losses.
2. Variable load losses, which vary according to the square of output. These losses are ohmic losses in cables and transformers.
3. Energy not generated due to a constraint imposed by electrical system unavailability (for example, a cable failure).

The three types of losses lead to the definition of three economic evaluation factors, to translate lost energy production into an equivalent initial capital cost. This identifies the capital cost that would be justified, at the desired rate of annual return on investment, to avoid one unit of energy loss.

It should be noted that the methodology for the fixed and variable loss factors is based on established practice, widely used by US utilities [2], and specifically adapted for the wind application in this paper. The unavailability factor is a new concept introduced in this paper, but has a conceptual basis in common with the other factors.

This paper introduces each economic factor and the type of energy loss it quantifies in the economic measurement of currency. All economic factors and calculations are shown in U.S. dollars ($). It is important to note that all calculations are the same for any type of currency, provided it is used consistently through the entire analysis. Some details of the derivations are based on the particularities of the U.S. income tax codes. However, the concepts can easily be modified to address the tax and wind incentive rules of any country.

A. Fixed Loss Factor

The fixed loss factor is commonly denoted in the U.S. as the "A factor". The A factor translates total no-load losses incurred by the windfarm into an equivalent initial capital cost value. Its units are $/kW, and it means that if an initial incremental capital investment of A yields reduction of no-load losses by 1 kW, then that incremental investment provides the rate of return used in calculating the A factor.

No-load losses are present at all times, when the windfarm is generating energy and when it is not. When the windfarm is not in production, such as when the wind is calm, energy must be purchased to supply the windfarm's no-load losses. Often, the price and terms of purchased power are different than the prices the windfarm obtains for sold power, and can include a demand charge. Complexities of the windfarm's price of purchased power must be considered when evaluating no-load loss costs.

The derivation of the A factor is based on the equality of the present value of annual costs associated with the capital investment to save 1 kW of no-load losses, with the present value of the impact on net revenue and purchased energy costs. This is shown symbolically in Equation (1).

$$PV_{cap} = PV_{rev}$$

The annual costs of a capital investment include amortization, property taxes, insurance, and the effects of asset depreciation on income taxes. Often, the present value of annual costs associated with a capital investment is less than the initial investment itself, due to the tax impacts of depreciation. Equation (2) shows the calculation of the present value of annual costs associated with a capital investment A. Note that the costs of depreciation, property tax, and insurance are deductible from income tax, per U.S. tax code.

$$PV_{cap} = A - A \cdot T \cdot \sum_{n=1}^{life}\left[\left(\frac{p}{f}\right)_n^i \cdot D(n)\right] + A \cdot \left(\frac{p}{a}\right)_{life}^i \cdot (1-T) \cdot P \tag{2}$$

where:

A = Initial capital investment

T = Income tax rate

$\left(\frac{p}{f}\right)_x^y$ = Present value of a future cash flow in year x using the compound interest rate y

$D(n)$ = Tax depreciation of capital asset in near n

$\left(\frac{p}{a}\right)_x^y$ = Present value of a uniform set of future cash flows from year 1 until year x, at a compound interest rate y

P = Property tax rate

$life$ = Economic life of windfarm

i = Desired after-tax return on investment

Because the capital investment is made with after-tax money, it is correct to equate the present worth of capital with the present worth of net after-tax revenue. Equation (3) calculates the present worth of net after-tax revenue increase caused by a 1 kW decrease in no-load loss.

$$PV_{rev} = \left(\frac{p}{a}\right)_{life}^i \cdot \left[H_o \cdot C_{ep} + (8760 - H_o) \cdot C_{ew} + C_{dem}\right] \cdot (1-T) + \left(\frac{p}{a}\right)_{life\_ptc}^i \cdot (8760 - H_o) \cdot C_{ptc} \tag{3}$$

where:

H_o = Hours per year with no generation

C_{ep} = Cost per kWh of purchased energy

C_{ew} = Selling price per kWh of wind generation

C_{dem} = Demand (capacity) charge for purchased power per kW_{peak} per year

C_{ptc} = Production tax credit, per kWh of wind generation

$life\_ptc$ = Duration of production tax credit incentive

Substituting equations (1) and (2) into (3), and solving for the value A, yields the no-load, or fixed, loss evaluation factor.

B. Load Loss Factor

The load loss factor is commonly denoted in the U.S. as the "B factor". The B factor translates load-dependent losses, measured at rated load, to an initial capital cost equivalent. Its units are \$/kW, and it means that an incremental capital investment of B to reduce rated load loss is justified at the rate of return used in calculating the B factor. Unlike the A factor, the B factor depends on the windfarm production-duration curve such as shown in Figure 1. Because it is assumed that load loss represents reduced output and not a requirement for purchased power, the B factor is not affected by demand charges.

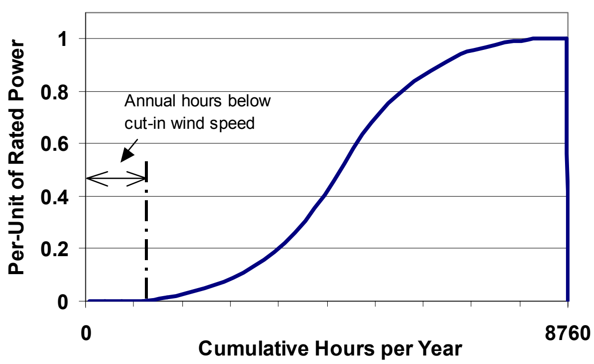

Figure 1 – Typical offshore windfarm production-duration curve.

A first step to evaluating load loss is to calculate the loss factor. The loss factor K_{loss} is the ratio of average losses divided by the losses at rated production. Note that this is not the same as the windfarm capacity factor because ohmic losses are proportional to the square of current. Equation (4) shows that the loss factor is the time-integral of the square of the per-unit production duration curve. The loss factor is always less than the capacity factor, and it cannot be determined from the capacity factor alone. For the example production-duration curve shown in Figure 1, the capacity factor is 51% but the loss factor is 41%.

$$K_{loss} = \frac{1}{8760} \cdot \int_{0}^{8760} \overline{P(t)}^{2} \cdot dt \qquad (4)$$

where: $\overline{P(t)}$ = Per-unit power output of the windfarm at hour t

If a capital investment B is substituted for A in Equation (2), Equation (5) is obtained. Equation (6) provides the present worth of annual after-tax net revenue increase caused by reducing the load loss at rated power by one kW. Substituting Equations (5) and (6) into Equation (1), and solving for B yields the load loss factor.

$$PV_{cap} = B - B \cdot T \cdot \sum_{n=1}^{life}\left[\left(\frac{p}{f}\right)_{n}^{i} \cdot D(n)\right] + B \cdot \left(\frac{p}{a}\right)_{life}^{i} \cdot (1-T) \cdot P \qquad (5)$$

where: B = Initial capital investment

$$PV_{rev} = \left(\frac{p}{a}\right)_{life}^{i} \cdot 8760 \cdot K_{loss} \cdot C_{ew} \cdot (1-T) + \left(\frac{p}{a}\right)_{life\_ptc}^{i} \cdot 8760 \cdot K_{loss} \cdot C_{ptc} \qquad (6)$$

where: K_{loss} = Loss factor

C. Unavailability Factor

Lost energy production can be caused by various events, including maintenance, equipment failure, and capacity limitations. The unavailability factor, or "C factor" provides a simple way to convert any form of annual expected lost energy production into an initial capital cost equivalent. Its units are \$/kWh/yr, and its meaning is that an incremental capital investment of C to avoid an expected 1 kWh per year of lost energy production is justified at the rate of return used to calculate the C factor.

Substituting a capital investment C for A in Equation (2) yields an expression for the present worth of annual costs associated with the capital investment, as shown in Equation (7). Equation (8) provides the present worth of the annual change in net revenue provided by avoiding one kWh per year of lost energy production. Substituting Equations (7) and (8) into Equation (1), and solving for C, yields the expression for the unavailability factor.

$$PV_{cap} = C - C \cdot T \cdot \sum_{n=1}^{life}\left[\left(\frac{p}{f}\right)_{n}^{i} \cdot D(n)\right] + C \cdot \left(\frac{p}{a}\right)_{life}^{i} \cdot (1-T) \cdot P \qquad (7)$$

where: C = Initial capital investment

$$PV_{rev} = \left(\frac{p}{a}\right)_{life}^{i} \cdot 8760 \cdot K_{cap} \cdot C_{ew} \cdot (1-T) + \left(\frac{p}{a}\right)_{life\_ptc}^{i} \cdot 8760 \cdot K_{cap} \cdot C_{ptc} \qquad (8)$$

where: K_{cap} = Windfarm capacity factor

IV. Application Examples

In the remainder of this paper, illustrative examples use A, B, and C factors to optimize parts of an offshore windfarm electrical design. Parameters such as failure rates, time to repair, and costs are assumed, hypothetical values chosen purely to illustrate the concepts. These parameters should not be used as a reference for typical values.

A. Collector Cable Optimization

The length of cable in each section of the collection system does not affect the optimal cable conductor size for that section, except in the unusual case that the cable is of sufficient length to make voltage drop a cable size constraint. The calculation is thus simplified to the process of defining the best cable for each current level.

Total evaluated lifecycle cable cost is the sum of the installed cable cost plus the loss evaluation, which is the loss at full load multiplied by the B factor. Note that the effects of load variation are already incorporated into the B factor, so its use greatly simplifies the calculation.

Figure 2 graphs the evaluated lifecycle cost of different submarine cable sizes as a function of the full load current. The upper end point of each plot indicates the maximum current capacity of each cable size (except the 240 mm^2 size, for which the maximum is outside of the plot range). At each current level, the cable size with the minimum total cost is the economic optimum. The current range over which a cable size yields the lowest evaluated cost is the economic application range of that cable. With the relatively high loss evaluation factors typical of an offshore windfarm application, the economic current range is typically well below the thermal limit for the cable. For example, the 95 mm^2 cable is the optimum for maximum load currents ranging from 106 A to 127 A, while t he maximum thermal current limit for this cable size is 183 A. Although the economic range may differ from application to application, selection of collector cables based on thermal rating alone usually does not yield an economically optimal collector system design.

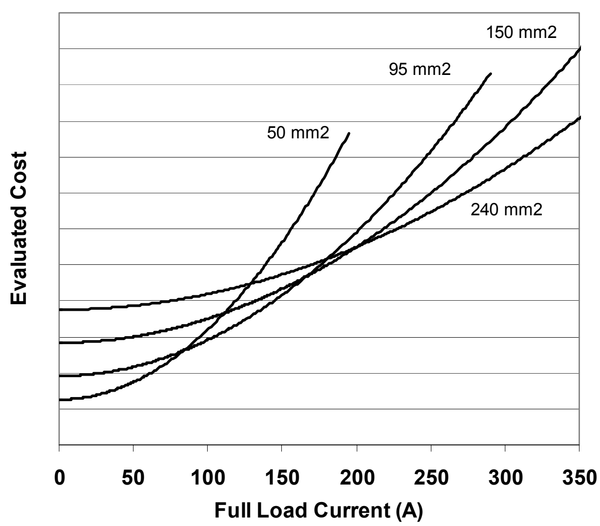

Figure 2 – Evaluated total life cycle costs for different submarine cable sizes as a function of the full-load current.

B. Transformer Selection

The evaluated cost of a transformer is the sum of the initial cost plus the no-load loss and load loss penalty costs throughout its service life. The no-load loss penalty is the no-load loss of the transformer multiplied by the A factor. The load loss penalty is the load loss when the wind farm is at rated output, multiplied by the B factor. Note that if the transformer is not loaded to its nameplate capacity at maximum windfarm loading, then the transformer's rated load loss must be multiplied by the square of the ratio between the maximum transformer loading divided by the transformer nameplate capacity. This is summarized in Equation (9).

$$Cost_{evaluated} = Cost_{initial} + A \cdot P_{nl} + B \cdot P_{ll} \cdot \left({P_{full}}/{P_{nameplate}} \right)^2 \quad (9)$$

where: P_{nl} = Transformer no-load loss, in kW.

P_{ll} = Load loss at nameplate loading in kW

P_{full} = Transformer loading in kVA at full generation output

$P_{nameplate}$ = Transformer nameplate rating, in kVA

It is not unusual for the evaluated cost of a transformer to be several times greater than the initial cost alone. This is particularly true for the smaller transformers used for wind turbine unit step-up applications. Figure 3 shows the relative contribution of initial, load loss and no-load loss costs for a transformer applied in a windfarm.

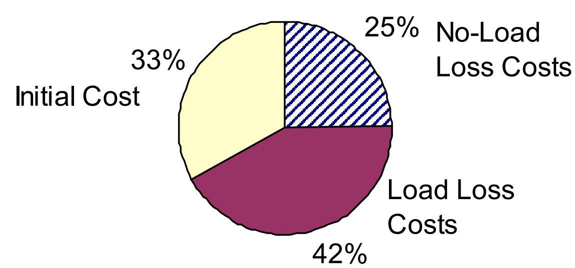

Figure 3 – Contributions of initial cost, no-load loss cost, and load loss costs to the total evaluated lifecycle costs of a typical windfarm transformer.

There are many transformer design tradeoffs that can be made between initial cost, load-losses, and no-load losses. The factors in these tradeoffs are not accessible to the windfarm electrical system designer, so it is preferable that the A and B factors be communicated to the transformer manufacturer, allowing the manufacturer to perform the transformer design optimization using the economic parameters specific to the particular application. When multiple manufacturers are considered for the transformer supply, the evaluated life-cycle costs using the formula shown in Equation (9) can be used to compare offerings.

C. Transmission Cable Redundancy

The transmission cable system between an offshore windfarm substation and the utility grid is obviously of vital importance. If a single cable is used, a cable failure can result in a lengthy period without windfarm revenue. Two cables, each rated to carry the full windfarm output, provide redundancy and nearly eliminate this possible cause for lengthy unavailability. The cable cost is approximately doubled, but this is offset by reduced ohmic losses. Table I summarizes the calculations for this example, which indicate the single cable option is preferred. With several factors affecting the transmission cable design, it is fortunate that the A, B, and C factors greatly simplify identification of the proper decision.

TABLE I
EXAMPLE EVALUATION OF TRANSMISSION CABLE REDUNDANCY

	Windfarm Parameters			Economic Parameters	
Windfarm Rating	100	MW	A	5000	$/kW
Minimum Power Factor	0.9		B	2000	$/kW
Transmission Voltage	115	kV	C	0.5	$/kWh/yr
Total Current	558.5	Amps			
	Cable Parameters				
Resistance	0.080	ohm/km			
Dielectric loss	1.0	kW/km			
Route length	10.0	km			
Failure rate	0.001	1/km/yr			
Mean time to repair	90.0	days			
Installed Cost	500.0	$/m			
	One Cable Option			**Two Cable Option**	
Installed Cost	5000	k$		10000	k$
Load Loss	749	kW		374	kW
Evaluated Load Loss (x B)	1497	k$		749	k$
Dielectric Loss	10	kW		20	kW
Evaluated No-Load Loss (x A)	50	k$		100	k$
Annual Transmission Outage	21.60	hr/yr		0.22	hr/yr
Lost Energy per Year	2160000	kWh/yr		21600	kWh/yr
Evaluated Unavailability Cost	1080	k$		10.8	k$
Total Evaluated Cost	**7627**	**k$**		**10859**	**k$**

D. *Redundant Substation Transformer*

To determine if a redundant transformer design best meets the needs of the project, one must evaluate the potential improvement in energy production against the increased costs of a redundant transformer. This requires application of all three economic factors, and the definition of one new quantity.

The designer must select the size of the transformers to initiate the analysis. The level of redundancy may be iterated as preliminary results are determined. For this example, a single 100 MVA transformer is compared to two, 50 MVA transformers. (Another option, not analyzed here, is two transformers somewhat larger than 50 MVA.) Initial costs of these transformer designs and associated installation expenses have been estimated for the example.

A single, full sized transformer generally has lower no load and load losses than two, half sized transformers. As before, multiplying the total no load losses in kW by the A factor and load losses by the B factor yields the cost of the losses.

One would expect the redundant transformer option to be justified by increased energy production through the life of the windfarm operation. The "constrained capacity factor" is introduced to quantify the energy that can be delivered by the electrical system when one transformer is unavailable. This is not calculated by applying a ratio to the normal capacity factor, but is derived by applying an upper limit to the windfarm production duration curve and calculating a new capacity factor for the constrained condition. This concept is illustrated in Figure 4. Constraining windfarm output to an upper limit of 50% reduces the capacity factor from 51% to 33%,. The constrained capacity factor is considerably greater than 50% of the normal capacity factor. As the capacity limitation is varied, the constrained capacity factor also changes.

Using the constrained capacity factor, the energy lost during a transformer outage can be calculated by Equation (10).

$$E_{Lost} = P_{farm} \cdot MTTR \cdot \left(K_{cap} - K_{ccf}\left(P_{Limit}\right)\right) \qquad (10)$$

where: P_{farm} = Windfarm rated power capacity

K_{cap} = Windfarm capacity factor

$MTTR$ = Mean time to repair or replace (hours)

$K_{ccf}(P_{limit})$ = Capacity factor with windfarm output constrained to less than P_{limit}

The expected value of annual energy production caused by transformer unavailability is obtained by multiplying the energy loss of a single outage by the transformer failure rateand the number of transformers. Finally, one can multiply the C factor by the expected lost production of each option to determine the evaluated cost.

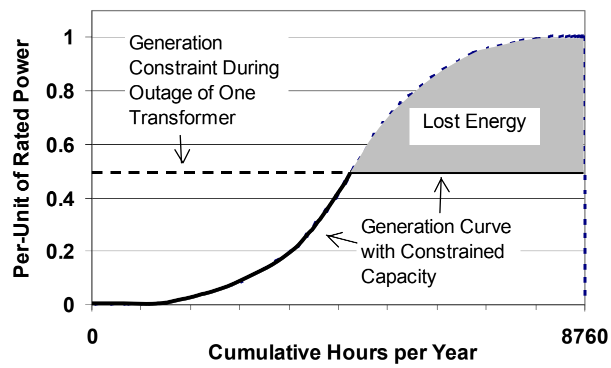

Figure 4. Illustration of constrained capacity.

Summing all evaluated costs indicates that the double transformer solution is the preferred economic decision for this illustrative example. We have not, however, yet included the cost of incremental platform space. The space for two half-size transformers will be greater than for the single full-size unit. The designer now has the knowledge that the double transformer is the better design decision if the incremental cost of platform space is less than 555k$.

TABLE II
EXAMPLE EVALUATION OF TRANSFORMER REDUNDANCY

	Windfarm Parameters			Economic Parameters	
Windfarm Rating	100	MW	A	5000	$/kW
Normal p.f.	1.0		B	2000	$/kW
Capacity Factor	0.51		C	0.5	$/kWh/yr
Constrained Capacity Factor*	0.33				
Loss Factor	0.41				
Transformer Failure Rate	0.02	per yr			
Repair/Replace Time	10	months			
	One Trafo Option			**Two Trafo Option**	
Transformer Rating (each)	100	MVA		50	MVA
Installed Cost (each)	1000	k$		700	k$
Total Installed Cost	1000	k$		1400	k$
No-Load Loss (each	55	kW		32	kW
Total No-Load Loss	55	kW		64	kw
Evaluated No-Load Loss (x A)	275	k$		320	k$
Rated Load Loss (each)	300	kW		170	kW
Total Load Loss	300	kW		340	kW
Evaluated Load Loss (x B)	600	k$		680	k$
Lost Energy During Outage	367200	MWh		129600	MWh
Expected Annual Lost Energy	7344	MWh/yr		5184	MWh/yr
Unavailability Cost (xC)	3672	k$		2592	k$
Total Evaluated Cost	**5547**	**k$**		**4992**	**k$**

*Constrained Capacity Factor in this example is the capacity factor which can be obtained when the windfarm capacity is limited to 50% of rating due to the outage of one half-rated substation transformer.

E. Other applications

The preceding examples of transmission cable and substation transformer redundancy highlight the use of a combination of economic factors to assist with a variety of design decisions. They allow a range of design alternatives to be evaluated with a common criterion: investment value. There are many other offshore windfarm electrical design decisions which can be aided by the approach presented in this paper. Some additional examples are briefly discussed below.

The value of a spare transformer or spare cable is the reduction it provides in outage duration resulting from a failure. Because power transformers and cables are custom equipment with lead times on the order of ten months, and which require special equipment and favorable sea conditions for installation, the designer should invest the time to diligently perform the analysis of spares.

The evaluated cost of the collection cable system is a large part of the overall windfarm cost. Thus, modifications to its design can have a large impact on windfarm profitability. We have shown how the B factor allows the designer to determine the best cable size for each connection. That analysis can be expanded to identify decisions in the turbine interconnections, where system availability and load losses are both in play.

Turbine availability can be improved by using a loop configuration in the collection system design. That allows any cable failure to be isolated without reducing the ability to deliver energy to the grid. There is a secondary benefit, as all cables might be sized for a greater current, reducing load losses. The B and C factors, and assumptions on failure probability, allow the designer to quickly evaluate the net value of the loop configuration.

V. Conclusion

With offshore windfarms emerging as a new, rapidly evolving application, proper electrical system design decisions are critical to project success. The drivers of design decisions for offshore windfarm electrical systems are quite different from those of utility systems, so conventional design practices are not necessarily applicable. The designer needs a simple method to evaluate options against the requirements of the windfarm and ensure the proper economic decisions are made.

By using the expected windfarm percent return on investment (ROI) in the calculations for the windfarm economic factors (A, B, and C), design alternatives shown to be favorable by these factors inherently have a greater ROI than the initial windfarm design. Hence, the factors assist both the designer and the investor. The designer may use these factors to evaluate the investment value of various options, and the investor may review decisions with the same criterion and be comfortable that the design is created to provide the best financial returns.

VI. References

[1] P. Gardner, L. M. Craig G. J. Smith, *Electrical Systems for Offshore Windfarms*, Proceedings of the 1998 Twentieth British Wind Energy Association Wind Energy Conference.

[2] Edison Electric Institute, *A Method for Economic Evaluation of Distribution Transformers*, EEI Task Force Report, April, 1981.

VII. Biographies

Reigh Walling received his Bachelor's and Master's Degrees in Electric Power Engineering from Rensselaer Polytechnic Institute in 1974 and 1979, respectively, and is a registered Professional Engineer. He is a Principal Consultant for GE Energy and is involved in a wide range of distribution and transmission technologies, as well as wind generation systems. He currently is directing the design of the collection systems and offshore substations for a large-scale offshore wind project. He was a co-developer of GE Energy's unique windfarm voltage and reactive power control system.

He is a Fellow of the IEEE®[1], has authored over twenty-five papers, and has been awarded two U.S. patents.

Tom Ruddy received a BSEE degree from Lafayette College in 1992, a MSEE degree from Virginia Tech in 1994, and an MBA from Virginia Tech in 2001. He started with GE in 1993 and has worked in the industrial drives and power generation businesses. Tom is currently the Product Line Leader for GE's windfarm substation business, leading system development and marketing efforts. He participates in efforts to optimize windfarm electrical systems for onshore and offshore applications. Tom has presented new technology topics at two shipping industry conferences and holds two U.S. patents.

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