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Application Portfolio: East Coast Offshore Wind Farm Development

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Contents

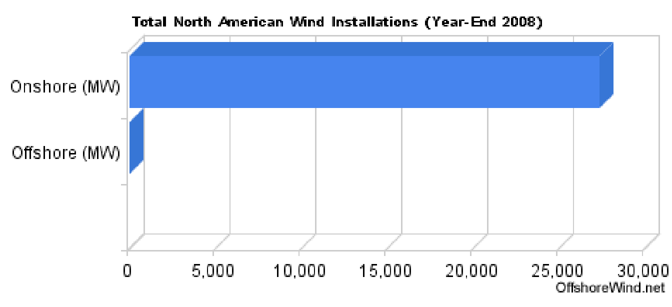
1 Abstract

This application portfolio provides an analysis of the design of a 75-turbine offshore wind farm off the East Coast of the United States. In particular it addresses the notion of designing such a wind farm in a flexible manner for the best expected economic performance over a 20-year period of time. Based on estimates of uncertain fluctuations in turbine cost, turbine efficiency, and electricity price, two system analyses were performed: decision analysis and lattice analysis. Using decision analysis, it is shown that building a wind farm in a staged approach rather than a fixed approach provides a higher expected net present value (ENPV) over the course of the wind farm. Using lattice analysis, it is shown that adding the option of shutting down turbines of the wind farm when electricity prices are low (and hence revenues are low) provides a higher ENPV than not having this shutdown option. In both analyses, a multi-criteria evaluation was also performed which showed that under almost every criterion, adding flexibility to the design provides the best possible economic outcome. The conclusion of these analyses strongly suggests that flexibility in system design is a "win-win" situation: flexibility preserves the upside economic potential when uncertain conditions are favorable and limits the downside risk when the uncertain conditions are adverse.

2 Introduction

As global carbon emissions rise and costs of traditional fossil-fuel based energy increases, the need for renewable energy sources has come to forefront of societal concerns. One important renewable energy source is wind energy, a zero-emissions vehicle of electricity generation. To harness wind energy, wind turbines translate mechanical energy used to rotate the turbine blades into electricity which can be transmitted to local municipal areas. A collection of wind turbines is called a wind farm, and a number of wind farms installations have been implemented in such areas as Alamont Pass in California and North Hoyle in the United Kingdom [1].

Wind farms can be partitioned into two categories: onshore and offshore. Onshore wind farms are land-based and have the advantage of ease of construction, ease of connection to existing power lines, and ease of maintenance [2]. Offshore wind farms are more costly to construct and maintain, however they offer the promise of greater wind speeds and hence greater power generation. In addition, offshore wind turbines are typically larger than onshore turbines, which also help to produce greater power. Due to the technological difficulties of offshore wind farms, they compromise very few of the wind farms installation in North America, as shown in the figure below [3].



Offshore wind power has made many headlines in recent years among politicians and scientists. In December 2008, Secretary of the Interior Ken Salazar suggested that offshore wind power from the

Atlantic Ocean could generate up to 1000 Gigawatts of electrical power in the United States [4]. Even more recently, in September 2009, the European Wind Energy Association (EWEA)—a European wind energy lobbying group—suggested that Europe could obtain about 10% of its total energy needs via offshore wind power by 2020 [5].

3 System Description

This project will focus on the feasibility of designing an offshore wind farm along the East Coast of the United States. Some offshore wind farms have already been planned along the East Coast, such as the controversial Cape Wind project in Cape Cod [6] and the Ocean Energy Institute in Maine [7]. However, due to unanticipated political and economic factors, such wind farms have not yet been implemented. Thus offshore wind development is a perfect candidate for a flexible design as there are a variety of uncertainties that should be considered.

The system presented includes all project construction costs and development costs of a 75-turbine offshore wind farm. It excludes the development of the land-based power network by assuming that such a network already exists. The primary metric used to evaluate the development of the wind farm is the net present value (NPV) of the project over a lifetime of 20 years and a discount rate of 12%.

An Excel model was created to calculate the NPV of alternative designs for the offshore wind farm. A snapshot of the model is shown below. For each of the 20 years of the lifetime of the wind farm there are three sections of cash flows involved: turbine construction costs, revenue generated, and maintenance costs.

Before examining the details of the NPV calculation, it must be noted that offshore wind costs are calculated based on a per Megawatt (MW) basis. For example, an average wind turbine produces 2 MW. A typical offshore wind farm consists of 10 MW to 200 MW total output power.

Year		0	1	2
Turbine construction costs				
Actual cost per turbine ($)	$ 2,520,000.00			
Turbines installed in year		75		
Down payment	$ 11,025,000.00			
Loan amount per year	$ 19,496,533.89			
Loan costs for the year		$ (11,025,000.00)	$ (19,496,533.89)	$ (19,496,533.89)
Total turbines built so far		75	75	75
Revenue generated				
Full load hours (MWh)	2500			
Electricity generated in year (MWh)			187500	187500
Price per MWh ($)	120			
Revenue from wind generation ($)			$ 22,500,000.00	$ 22,500,000.00
Maintenance costs				
Maintenance cost ($/MWh)	15			
Total maintenance cost			$ (2,812,500.00)	$ (2,812,500.00)
Total profit (revenue - cost)		$ (11,025,000.00)	$ 190,966.11	$ 190,966.11
discount rate	12%			
loan rate	9%			
PV		$ (11,025,000.00)	$ 170,505.46	$ 152,237.01
NPV		**$ (9,598,589.40)**		

<u>Turbine construction costs</u>: This section of cash flows represents the cost to purchase and install the turbines, including all labor, transport, and materials. As discussed further in later sections, it is assumed that a down payment is made in year 0 and a loan is taken out to cover the remaining costs of the construction. It is assumed the loan rate is 9%—this is less than the discount rate due to potentially favorable terms given by the federal government to incentivize alternative energy projects. A key factor to turbine construction costs is the cost per turbine—this is one of the uncertainties used to model the design.

Revenue generated: In this section cash flows represent the revenues generated during the year based on the operation of the wind turbines. Each turbine produces a certain amount of energy, in Megawatt hours (MWh) per year—this is called the full load hours of a turbine. This energy is multiplied by the current price of energy on the electricity market to generate the amount of revenue earned via electricity generation. Two important factors that control revenue generation—full load hours and price of energy—are two uncertainties in the design.

Maintenance costs: When operational, each turbine requires maintenance to keep the turbine operating at full capacity, called the yearly operations and maintenance (O&M) cost. A typical offshore windfarm in Europe has O&M costs between $12/MWh and $17/MWh [11]. In this application portfolio, a fixed maintenance cost of $15/MWh was assumed. In a more complex analysis, this number can also be considered an uncertainty.

4 Sources of Uncertainty

As mentioned previously, there are a number of uncertainties involved with the design of such a wind farm. As a general ballpark number for reference, in 2008 Delaware announced a 150-turbine offshore wind farm with a budget estimate of $1.6 billion [10]. Since such wind farms deal with billion dollar costs, a small deviation from the estimate would cause millions of dollars of loss or gain.

Three primary sources of uncertainty were analyzed in the application portfolio: cost of a turbine including installation ($), full load hours of a turbine (MWh), and the price of electricity ($/MWh).

Cost of a turbine: According to [11], written by Danish scientists, the cost of an offshore wind turbine is $1,141,000/MW and the cost of its foundation is $490,000/MW (assuming a $1.4 dollar to €1 conversion rate). These costs account for 70% of the total installation costs of the wind farm. The total installation costs for a European offshore windfarm in 2006 was $2,520,000/MW minimum, $2,940,000/MW average, and $3,360,000/MW maximum. For simplicity, it is assumed each turbine generates 1 MW and the installation costs are included in the turbine cost. Thus for the purposes of this application, the cost of a turbine, including all installation costs, is $2,520,000 minimum, $2,940,000 forecasted, and $3,360,000 maximum. These values were used in the decision analysis portion of the portfolio.

Full load hours of a turbine: A wind farm must have direct and constant wind to produce maximum power. The total yearly production output of MegaWatt hours (MWh), a unit of energy, is dependent upon the number of hours a turbine can operate at full load. According to [11], "full load hours are calculated as the turbine's average annual production divided by its rated power. The higher the number of full load hours, the higher the wind turbine production at the chosen site." For coastal areas, the number of full load hours per year for a turbine is 2700 to 2900 [11]. In this portfolio, the minimum, forecasted, and maximum full load hours are 2500, 2700, and 2900 respectively. These values were used in the decision analysis portion of the portfolio.

Price of electricity: The last uncertainty addressed in this portfolio is the price of electricity for MWh in the United States. In 2007, in the state of Massachusetts the price of electricity was $0.151 per kWh = $151 per MWh, of which price 67% was attributed to electricity generation [12]. Hence it can be roughly estimated that electricity can be sold by a wind farm on the utilities market for $101 per MWh. In this portfolio, it is assumed that the electricity price in year 0 of the project is $100 per MWh. To calculate the different parameters for lattice analysis, it is assumed that by year 6 the minimum, forecasted, and maximum price of the electricity would be $25, $120, and $200 per MWh, respectively. These values were used in the lattice analysis portion of the portfolio.

Other uncertainties not discussed in this portfolio include political and regulatory uncertainties, making it more or less favorable to develop offshore wind farms. In addition, societal concerns—such as the protest of the wind farm being developed off Cape Cod due to neighbors complaining regarding their view—were also not included in the analysis. A summary of the uncertainties and where they are used in the portfolio are shown in the table below.

Uncertainty	Measure	Where the uncertainly is applied in the portfolio
Cost of a turbine	$ per turbine	Decision Analysis
Full load hours of a turbine	MWh per year per turbine	Decision Analysis
Price of electricity	$ per MWh	Lattice Analysis

5 Fixed Base Case and Potential Flexibilities

The fixed base case of the design is the construction of a 75-turbine wind farm in year 0 with a usable total lifetime of 20 years. As described in further detail below, it is assumed a downpayment is required in year 0 to finance the loan, which has a life of 20 years and a borrowing rate of 9%.

In the decision analysis section, one flexibility will be introduced: **phased construction flexibility**, i.e. building the wind farm in a flexible, two phased approach. In year 0, a wind farm of 40 turbines will be constructed. If factors are favorable, another set of 35 turbines will be constructed in year 5.

In the lattice analysis section, another flexibility will be introduced: **shutdown flexibility**. The 75-turbine farm will be constructed in year 0, but the decision to shut down the wind farm to save on operations/maintenance costs can be made from year 1 onward.

Other flexibilities that can be implemented, but are not modeled in this portfolio, are building the wind farm in small increments in a fixed pattern, e.g. approximately 7 per year for 10 years, or 5 per year for 15 years, or 10 every two years for 15 years, etc. Each of these fixed patterns can also have a corresponding flexible design, e.g. stop building if conditions are unfavorable, and build more if conditions are favorable. The ensuing sections show two approaches to modeling the chosen flexibilities of the system: decision analysis and lattice analysis. A summary of the two analyses, their flexibilities, and their uncertainties, is shown in the table below:

	Decision Analysis	Lattice Analysis
Uncertainties	Cost of a turbine Full load hours of a turbine	Price of electricity
Uncertainties assumed as fixed	Price of electricity	Cost of a turbine Full load hours of a turbine
Flexibility exercised	Phased construction flexibility	Shutdown flexibility

6 Decision Analysis on Wind Farm Project

This first analysis performed with phased construction flexibility was a 2-stage decision analysis. To fit the analysis into two stages, the wind farm project was simplified into the following decisions:

- First decision: build a 75-turbine wind farm now versus build a 40-turbine wind farm now.
- First chance outcome: the cost of the installation of one turbine including materials, transportation, and labor could be at high, forecasted, or low levels. This outcome resolves itself within the year but after commitment to the project and downpayment is made. As stated earlier, the cost of these levels are \$3.36m, \$2.94m, and \$2.52m, respectively. The probabilities assigned to these outcomes are 0.3, 0.3, 0.4, respectively.
- Second decision: wait 5 years, then build 35 additional turbines (if not at 75 already) if conditions are favorable. Do not build if conditions are not favorable. This exercises the phased construction flexibility.
- Second chance outcome: the number of full load hours per turbine. Due to uncertain wind estimates, the number of full load hours (i.e. the numbers of MWh's each turbine can actually produce in a year due to wind currents) will not be known at initial build time. It will only resolve itself later. The high, forecasted, and low levels of the number of full load hours are 3300, 2900, and 2500 MWh's, respectively. The probabilities assigned to these outcomes are 0.5, 0.25, and 0.25, respectively.

6.1 NPV Model

The model used to compare the different designs was the NPV model discussed earlier.

Turbine construction costs: In the fixed design case, a 75-turbine wind farm is constructed in year 0. A downpayment of 5% of the forecasted total cost of construction, i.e. 5% of \$2.94m x 75 = \$11.025m, is due at the beginning of year 0. After the downpayment is made, the cost of the turbines is resolved and a loan at a rate of 9% is created and amortized over 20 years.

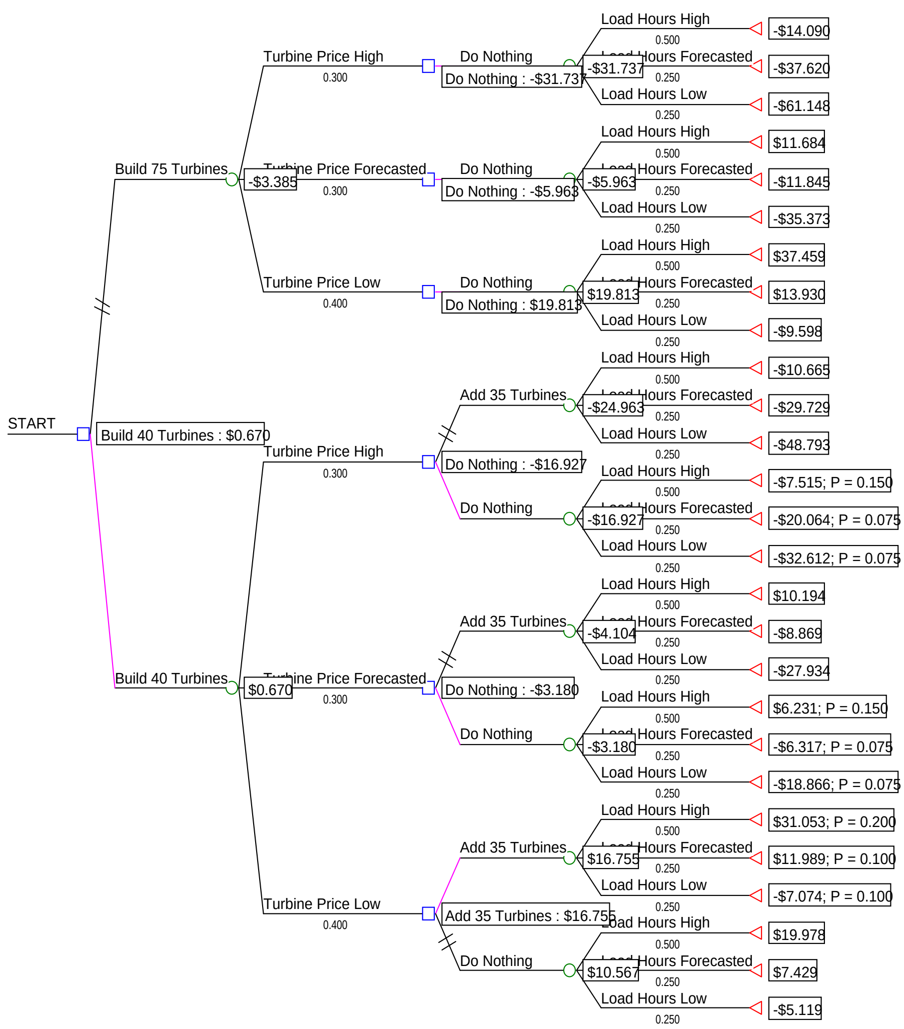
In the flexible design case, a 40-turbine wind farm is constructed in year 1. A downpayment of 5% of the forecasted total cost of construction, i.e. 5% of \$2.94m x 40 = \$5.88m, is due at the beginning of year 0. After the downpayment is made, the cost of the turbines is resolved and a loan at a rate of 9% is created and amortized over 20 years. At year 5, if conditions are favorable, a 35-turbine addition is built. A downpayment of 5% of the actual total cost of construction is due at the beginning of year 5; a loan at a rate of 9% is created and amortized over the remaining 15 years.

Revenue generated: In both the fixed and flexible case, the annual revenue generated is as described earlier: the full load hours of each turbine x number of turbines x price of electricity. It is assumed the full load hours is resolved at a later time than year 5 (i.e. in the first five years wind is generated but a definite estimate of the full load hours is not available until after year 5). To limit the chance events to only two—cost of the turbines and full load hours—it is assumed the price of electricity is the forecasted price of $120 per MWh.

Maintenance costs: A fixed maintenance cost of $15/MWh was assumed for both fixed and flexible designs.

6.2 Decision Tree Structure

A design tree was constructed based on the 2 decisions and 2 chance events. The structure of the decision tree is shown in the following figure, where all values are shown in thousands of dollars.



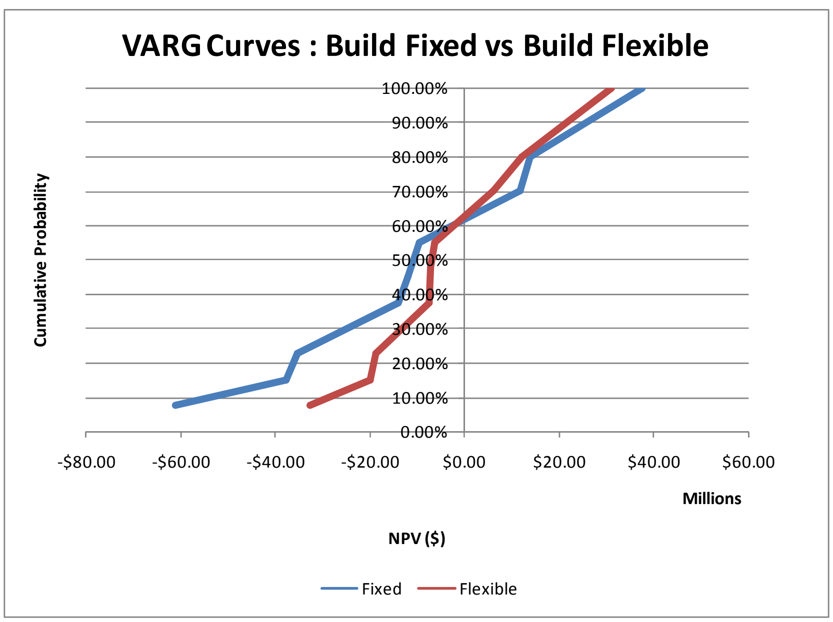
6.3 Decision Analysis

As shown in the tree, in the first decision the "build 40 turbines" option should be chosen. This is the flexible solution and provides an expected value of $0.67m in NPV, versus -$3.39m for the fixed option. Note that in the chance that the turbine price is actually low, it would have been better off to go with the inflexible option of "build 75 turbines." However, the build 40 turbines option provides insurance against high turbine prices.

Looking at the second decision, assuming the first decision to "build 40 turbines" was made, if the turbine price is high then the firm should do nothing (i.e. not add capacity) to maximize expected NPV. If the turbine price is as forecasted, the firm should also do nothing to maximize expected NPV. If the turbine price is lower than forecasted, the firm should add 35 turbines to maximize expected NPV. The second chance event resolves itself later; the higher the load hours the higher the NPV of the project since more electricity revenue is generated. Thus the decision tree shows us how to make informed decisions with the flexible option as time progresses in order to maximize expected NPV.

6.4 Evaluation, Target Curve

A VARG curve was constructed based the decision analysis model and is shown below for the build-fixed and build-flexible design options. As seen on the VARG curve, the flexible solution has a slightly worse upside (i.e. the case where turbine costs are low and full load hours are high), but has much better performance on the downside (i.e. the case where turbines costs are high and full load hours are low).



6.5 Evaluation, Multiple Criteria

Other than the expected net present value, the fixed and flexible designs can be compared based on other criteria. It should be noted that there are relatively few data points from the decision analysis so this should be taken into account when making decisions based on the criteria below. Some of the other criteria are as follows:

Criterion	Fixed Design	Flexible Design	Comparison
Expected NPV	-$3.39m	$0.67m	Flexible design better
Maximum NPV	$37.5m	$31.0m	Fixed design better
Minimum NPV	-$61.1m	-$32.6m	Flexible design better
P10 Value	approx. -$50m	approx. -$30m	Flexible design better
P90 Value	approx. $30m	approx. $25m	Fixed design better
Initial CAPEX	$11.0m	$5.88m	Flexible design better
ENPV/CAPEX	-0.31	0.11	Flexible design better

As can be seen in the table, the flexible design is better in all instances except for the maximum NPV and P90 values. Even in these cases, the fixed design only slightly outperforms the flexible design. These results conclude that building a flexible, phased wind farm is advantageous over a fixed deployment.

7 Lattice Analysis on Wind Farm Project

The second analysis performed was lattice analysis with shutdown flexibility. A lattice analysis for the offshore wind farm was performed over 6 years with the primary uncertainty being the price per MWh of electricity.

7.1 NPV Model

The fixed wind farm under consideration was again a 75-turbine wind farm being constructed in year 0, and the NPV model used was the same as discussed previously. Since only one uncertainty can be considered in lattice analysis, it was assumed that the cost of turbines was at the forecasted value ($2.94m) and the full load hours of the turbine was also at the forecasted value (2900 MWh). It was also assumed a $20m credit is given by the government to offset the cost of construction (this also helps to provide realism since the model only considers 6 out of the 20 years of revenue generation).

Turbine construction costs: Similar to decision analysis, a 75-turbine wind farm is constructed in year 0 with a fixed cost of turbines of $2.94m each. A down payment of 5% of the forecasted total cost of construction, i.e. 5% of $2.94m x 75 = $11.025m, is due at the beginning of year 0. After the down payment is made, a loan at a rate of 9% is created and amortized over 20 years—an annual payment of $22.95m.

Revenue generated: The annual revenue generated is as described earlier: the full load hours of each turbine x number of turbines x price of electricity. The number of full load hours is fixed at 2900 MWh and the price of electricity is the model's uncertainty.

Maintenance costs: A fixed maintenance cost of $15/MWh is assumed; for 75 turbines running at a full load rate of 2900, this totals $3.26m per year. However, a decision to shut down the wind farm can be made from year 1 onward—this is the shutdown flexibility. If the shutdown flexibility is exercised, the maintenance costs do not need to be paid for that year.

7.2 Lattice Setup

The primary uncertainty in the lattice is the price of electricity. To find the values of u, d, and p in the lattice, the three conditions of most likely, maximum, and minimum price per MWh were set to $120, $200, and $25 respectively at year 6, and solved to find the desired variables, assuming a start value at year 0 of $100. Solving for these using Excel, the values of u, d, and p were found to be 1.122, 0.794, and 0.725 respectively. A snippet of the Excel worksheet is shown below.

OUTCOME LATTICE

100.00	112.25	125.99	141.42	158.74	178.18	200.00
	79.37	89.09	100.00	112.25	125.99	141.42
		63.00	70.71	79.37	89.09	100.00
			50.00	56.12	63.00	70.71
				39.69	44.54	50.00
					31.50	35.36
						25.00

Step	(u/d)exp[step]	0utcome/lowest
6	8.00	8.00
5	5.66	5.66
4	4.00	4.00
3	2.83	2.83
2	2.00	2.00
1	1.41	1.41
0	1.00	1.00

AXES

Outcome	**Prob**		
200	0.15		29.04
141	0.33		46.74
100	0.31		31.34
71	0.16		11.21
50	0.05		2.25
35	0.01		0.24
25	0.00		0.01
		Average =	**120.84**

After the values of u, d, and p were found, a binomial lattice model was created. The lattice model consisted of six stages (five of which decisions were made in), each stage representing a year, and was based on the NPV calculations described above. The lattice is shown as follows:

Period	**0**	**1**	**2**	**3**	**4**	**5**
Price	100.00	112.25	125.99	141.42	158.74	178.18
		79.37	89.09	100.00	112.25	125.99
			63.00	70.71	79.37	89.09
				50.00	56.12	63.00
					39.69	44.54
						31.50
Probabilities:	1.00	0.73	0.53	0.381	0.276	0.200
		0.28	0.40	0.434	0.419	0.380
			0.08	0.164	0.239	0.288
				0.021	0.060	0.109
					0.006	0.021
						0.002
Cumulative Prob	1.00	1.00	1.00	1.00	1.00	1.00
Cash Flow	8,975,000	1,796,198	1,193,535	4,549,397	8,316,225	12,544,346
		8,946,761	6,832,701	4,459,748	1,796,198	1,193,535
			12,508,106	10,830,175	8,946,761	6,832,701
				15,334,748	14,002,973	12,508,106
					17,578,255	16,521,224
						19,358,927
PV Cash Flow:	8,975,000	1,603,748	951,479	3,238,171	5,285,111	7,117,999
		7,988,180	5,446,987	3,174,360	1,141,516	677,244
			9,971,386	7,708,705	5,685,829	3,877,058
				10,914,971	8,899,143	7,097,436
					11,171,299	9,374,586
						10,984,775
Probability Weighted Cash Flow	8,975,000	1,302,244	627,352	1,733,676	2,297,620	2,512,685
		2,460,359	2,724,539	1,933,928	752,941	453,409
			945,926	1,781,395	2,133,824	1,969,118
				318,915	844,532	1,367,306
					100,533	342,516
						30,447
	0	**1**	**2**	**3**	**4**	**5**
E [Cash Flow]	8,975,000	3,762,603	3,043,113	2,300,562	1,534,209	743,293
PV(E[Cash Flow])	8,975,000	3,359,467	2,425,951	1,637,494	975,018	421,765
ENPV over 6 years	**192,276**					

7.3 Lattice Analysis

As can be seen, the expected NPV of the inflexible system is $0.192m considering 6 time periods. Next, flexibility was considered in the design. In this case, if the electricity price was low enough the turbines would be shut off (i.e. no electricity would be produced and sold) and the maintenance costs would be zero, though the loan would still need to be paid. Under this analysis, each stage would "look forward" to see if the expected value of that stage would be greater than or less than the loan cost of $22.95m. If it was less than the loan cost (i.e. a greater loss), the turbines would be shut down since it would more expensive to operate than shut down; if not, the turbines continued to operate. The results are shown below.

ENPV (Cash Flow)	**192,276**	125,723	11,304,642	20,127,134	25,151,852	24,853,737	17,290,252
NO FLEXIBILITY		35,438,189	22,999,758	11,882,660	2,865,555	3,043,430	4,549,397
Dynamic programming			47,256,633	34,517,003	22,676,853	12,378,786	4,459,748
approach				50,521,900	36,685,557	23,283,939	10,830,175
(check next year)					46,591,206	30,995,047	15,334,748
						36,447,624	18,519,962
							20,772,248

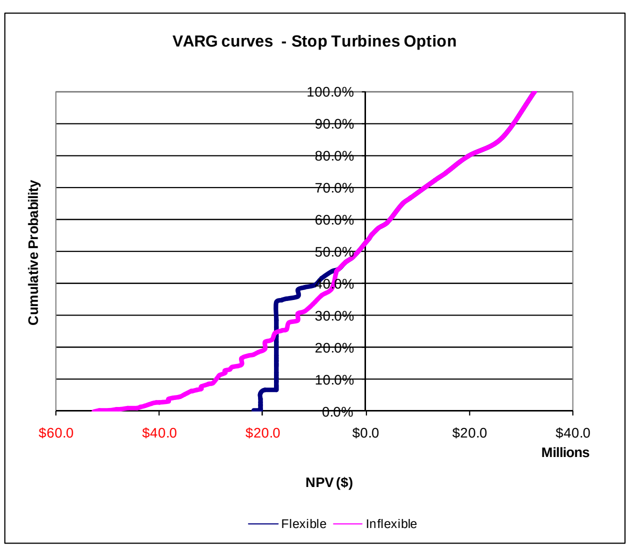
ENPV(Cash Flow)	**1,790,993**	67,090	11,304,642	20,127,134	25,151,852	24,853,737	17,290,252
WITH STOP OPTION		29,435,376	22,214,483	11,882,660	2,865,555	3,043,430	4,549,397
Dynamic programming			32,996,721	31,318,790	22,676,853	12,378,786	4,459,748
approach				35,823,362	34,491,587	23,283,939	10,830,175
(check next year)					38,066,869	30,995,047	15,334,748
						36,447,624	18,519,962
							20,772,248

Stop Turbines?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
WITH STOP OPTION		YES	**NO**	**NO**	**NO**	**NO**
Dynamic programming			YES	YES	**NO**	**NO**
approach				YES	YES	**NO**
(check next year)					YES	**NO**
						NO

The new expected value of the NPV with flexibility is $1.79m whereas the inflexible design had an expected NPV of $0.192m. The turbines should be shut down when the electricity price is too low since the profit of operating the turbines is not as great as the savings incurred by shutting down the turbines.

7.4 Evaluation, Target Curve

The cumulative distribution of the outcomes is shown as follows:



As can be seen, flexibility reduces the downside risk tremendously and in this case has the same upside potential as the inflexible design.

7.5 Evaluation, Multiple Criteria

Other criteria can be used to make decisions on the design. A multi-criteria evaluation table is given below and shows the flexible design is as good or better than the inflexible design in all criteria. The flexible design has the same upside potential as the inflexible design with much less downside risk. Thus in this scenario the flexible design should always be chosen.

Criterion	Inflexible Design	Flexible Design	Comparison
Expected NPV	$0.192m	$1.79m	Flexible design better
Maximum NPV	$32.7m	$32.7m	Same
Minimum NPV	-$52.6m	-$21.8m	Flexible design better
P10 Value	-$29.0m	-$17.3m	Flexible design better
P90 Value	$28.0m	$28.0m	Same
Initial CAPEX	$11.0m	$11.0m	Same
ENPV/CAPEX	0.02	0.15	Flexible design better

8 Conclusions and Lessons Learned

In conclusion, based on the two analyses provided above, adding flexibility to the deployment of an offshore wind farm largely preserves the upside economic potential of the system when environmental uncertainties are favorable and reduces the economic risk of the system when uncertainties are adverse. The decision analysis showed that deploying a phased wind farm (40 turbines immediately, then 35 turbines five years later) rather than a fixed wind farm (75 turbines immediately) can achieve a $4m better ENPV over a 20-year period, based on the given parameter estimates. The lattice analysis showed that the flexibility to shut down turbines when electricity prices are low can achieve an approximately $1.6m better ENPV over a 6-year period, based on the given parameter estimates.

In this particular application portfolio, I felt decision analysis was the most suitable analysis method in studying the offshore wind farm since it provided the ability to make two decisions and have two uncertainties. The lattice model, while also effective, did not provide as much opportunity to have a broad range of decisions, as the same decision had to be made at each stage. However, the lattice model did prove effective when considering only a single, simple decision such as when to shut down the turbines.

The valuation methods that seemed most useful in this project were the expected NPV and the initial CAPEX. The expected NPV is a useful number because it can summarize in one number the comparative benefits of flexible vs. inflexible systems. This allows for a simple, short pitch to management about the benefits of flexibility. The initial CAPEX was also useful in decision analysis as it showed how a phased wind farm deployment requires a smaller initial investment than a fixed deployment but can attain the same (or almost the same) upside potential.

This application portfolio helped my understanding of the course by allowing me to experience firsthand the benefits and the limitations of each analysis method and give me an intuitive understanding when to use each method. I also learned to apply the different evaluation criteria (ENPV, CAPEX, etc.) and was helped understand why a firm may value one metric over the other. Finally, the portfolio helped me to understand how flexibility can be a "win-win" situation—exploiting (or maintaining) upside potential and reducing downside risk.

9 References

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