ABSTRACT

Title of Thesis	A LEVELIZED COST OF ENERGY MODEL FOR WIND FARMS THAT INCLUDES POWER PURCHASE AGREEMENTS (PPAs)
	Maira Bruck, Master of Science, 2018
Thesis directed by:	Professor Peter A. Sandborn, Department of Mechanical Engineering

Many government entities throughout the world are developing mechanisms to help renewable energy become better integrated and more competitive with nonrenewable energy. Typically, renewable energy is more expensive and riskier than conventional energy generation, thus creating an emphasis on the need for cost reduction of renewable energy, as well as understanding how contractual agreements affect buyers and sellers of energy. In the United States, government mandates have been developed in the form of State-specific Renewable Portfolio Standards (RPS) that require specific percentages of renewable energy consumption to be met, along with the procurement methods to be used that ensure the renewable energy percentages will be met. The usage of RPS and renewable energy requirements have increased the need for long-term energy agreements.

The two most common forms for managing the purchase of renewable energy are Power Purchase Agreements (PPAs) and bundled Renewable Energy Credits

(RECs). Both RECs and PPAs typically use a Levelized Cost of Energy (LCOE) calculation to determine the price of energy and they may contain limitations on how much energy can be purchased. Conventional LCOE calculations are limited, as most analyses assume constant cash flows, and do not account for variable annual energy generation from renewable energy or contractual terms that limit the purchase of energy. This can lead to significant errors, because the conventional LCOE calculation may be lower than the actual LCOE, since it does not consider the energy purchase limitations created by PPAs and RECs that lead to additional costs when energy generation falls above and below the energy purchase limitations. The conventional LCOE calculation also does not consider the effect on financing a project when penalties associated with the under or over production of energy are not symmetric. It is critical to have an LCOE that accurately reflects the actual situation for an energy project or the project may be in danger of failing as the costs to run the project are not being covered from the revenue received from selling energy. It is also important for utilities to obtain accurate LCOEs because utilities may be reluctant to use renewable energy if the calculated LCOE is higher than the actual LCOE.

This thesis develops a new model for LCOE that accounts for the energy purchase limitations used in PPAs for wind farms. The thesis also provides a real case study from the Maryland Offshore Renewable Energy Credits (ORECs). The case study demonstrates that the LCOE is higher when including the production loss from years where energy is higher than the awarded OREC quantity. The case study also demonstrates the potential to award more ORECs at a lower cost, because the Total Life Cycle Cost (*TLCC*) is able to be distributed amongst more energy produced.

A LEVELIZED COST OF ENERGY MODEL FOR WIND FARMS THAT INCLUDES POWER PURCHASE AGREEMENTS (PPAs)

by

Maira Bruck

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Advisory Committee:

Professor Peter A. Sandborn, Chair

Professor Allison Reilly, Chair

Professor Greg Baecher

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List of Abbreviations and Nomenclature

AALE	Annual applicable load
ARC	Avoided renewable energy credit cost
BOEM	Bureau of ocean energy management
CAPEX	Capital expenditures
CF	Capacity factor
COE	Cost of energy
CPE	Cost to produce energy
CRF	Capital recovery factor
cy	Last year ORECs are received
D	Depreciation
E	Energy produced
F	Fuel cost
I	Investment cost
INFL	Inflation rate
LCOE	Levelized cost of energy
Max_{lim}	Maximum energy purchase limit
Min_{lim}	Minimum energy purchase limit
MPE	Market price effect
MO	Months of operation
NRC	Net ratepayer cost
NRDB	Nominal discount rate of benefits
NRDP	Nominal discount rate of OREC price

NREL	National renewable energy laboratory
OM	Operations and maintenance cost
OPEX	Operational expenditures
OREC	Offshore renewable energy credit
P_{exp}	Expected average energy to be produced
PBR	Performance Based Rate
PSC	Public service commission
Pen	Total penalty cost
PL	Production loss
PN	Penalty cost
POP	Price of ORECs
PPA	Power purchase agreement
PPA_{term}	Fraction of the COE for energy purchase and produced above the Max_{lim}
PTC	Production tax credit
PVOM	Present value of operations and maintenance
REC	Renewable energy credit
r	Weighted average cost of capital (WACC)
R	Royalties
RP	Rated power
RPS	Renewable Portfolio Standards
RRI	Residential ratepayer impact
SAM	System advisory model
sd	Start date

T	Tax levy
TC	Tax credit
TLCC	Total life-cycle cost

Chapter 1: Introduction

1.1 Motivation

The Cost of Energy (*COE*) becomes a major concern for the public and utilities as the demand for power from renewable energy sources, such as wind, increases. Utilities may become reluctant to purchase more renewable energy than they are required to purchase if the *COE* is too high. *COE* or the contractual price for energy is usually calculated from the Levelized Cost of Energy (LCOE). The *COE* is the actual cost to buy energy while the LCOE is the break-even cost to generate the energy. A level of profit or buffer against unpredicted costs may be included into the *COE* on top of the LCOE.

LCOE is a commonly accepted calculation of the Total Life-Cycle Cost (*TLCC*) for each unit of energy produced in the lifetime of a project [1]. Many people have worked to improve the computation of the *TLCC* to ensure that every potential cost is accounted for so that an energy system can be protected against financial failure [2] - [7]. However, conventional calculations of LCOE do not account for contractual obligations from Outcome-Based Contracts such as Power Purchase Agreements (PPAs) and certain types of Renewable Energy Credits (RECs) that allocate risk to the generator through the usage of energy purchase limits, where the costs from the energy purchase limits are referred to as penalties. It is critical to ensure that all potential costs, such as those that arise from energy purchase limits, are accounted for in the LCOE in order to promote the financial success of renewable energy projects and the future of

renewable energy as interested parties are looking to see if there is success in existing projects.

1.2 Background

1.2.1 The Levelized Cost of Energy (LCOE)

The levelized cost of energy, also known the levelized cost of electricity, or the levelized energy cost, is an economic assessment of the average total cost to build and operate a power-generating system over its lifetime divided by the total power generated of the system over that lifetime [1].

The definition of LCOE is the cost that, if assigned to every unit of energy produced by the system over the analysis period, will equal the Total Life-Cycle Cost (*TLCC*) when discounted back to the base year [1],

$$\sum_{i=1}^{n} \frac{(E_i)LCOE}{(1+r)^i} = TLCC \tag{1}$$

where discrete compounding is assumed, E_i is the amount of energy produced in year i, r is the WACC (or discount rate), and n is the number of years over which the LCOE is calculated.

The *TLCC* is the sum of the initial investment (*I*), and the present value of the total O&M costs (*PVOM*) given by [1],

$$PVOM = \sum_{i=1}^{n} \frac{OM_i}{(1+r)^i} \tag{2}$$

where *OM* is the Operations and Maintenance (O&M) cost in year *i*. The LCOE assigns a value for every unit of energy produced during the given lifetime of a project. Traditionally, PPAs treat the contract length as the whole lifetime of the project, making short-term PPAs more expensive than long-term PPAs [8] - [11].

Since LCOE is, by definition, a constant, it can be factored out of the summation in Equation (1) and is given as,

$$LCOE = \frac{TLCC}{\sum_{i=1}^{n} \frac{E_i}{(1+r)^i}} \tag{3}$$

Although the denominator of Equation (4) appears to be discounting the energy (and is sometimes refer to as the "discounted energy", e.g., [12]), the discounting is actually a result of the algebra carried through from Equation (1), in which revenues were discounted (energy is not discounted, only cost can be discounted).

Based on the derivation of LCOE, the LCOE model must incorporate all financial parameters that contribute to the *TLCC*. This thesis presents a model that includes PPA penalties in the *TLCC*.

1.2.2 Power Purchase Agreements (PPAs)

In 1978, the Public Utility Regulatory Policies Act (PURPA) was passed to promote "alternative" generation sources and reduce reliance on fossil fuels. During this period, most utilities were both the generators and sellers of energy [13]. PURPA served to create the market for PPAs as utilities were required to purchase energy from non-utility facilities and those facilities were outside of the transmission and distribution network that had already existed for utilities [11]. PPAs became the

primary mechanism for integrating generator-only facilities into the electricity market as utilities were required to enter long-term energy contracts. Initially, the PPA price was based on the avoided cost of the utility [11]. The Federal Energy Regulatory Commission (FERC) was concerned that the contractual price was based on a future estimate of avoided costs and the actual avoided cost at a specific moment in time could fall above or below the contract price. In the end, FERC decided that a single contractual price still managed to balance the risk of varying avoided costs for both the energy generator and the utility. The avoided cost model looks at the avoided costs at a specific time during the project, but the FERC determined that it would be impractical to measure the costs in short intervals to determine prices throughout the contract and the contract price should be determined based on the duration of the PPA [11].

PPAs are Performance-Based Contracts (PBCs) that aim to create a "fair" and risk-controlled agreement for the purchase and sale of energy between a utility (the Buyer) and a generator (the Seller). They do so by allocating risks in energy generation and delivery through mechanisms such as energy purchase limits, defining the point in transmission when energy officially transfers ownership, and prescribing the frequency of O&M [14]. Energy purchase limits serve to reduce risk to the Buyer. A maximum energy purchase limit is used by the Buyer that may not want to buy as much of renewable energy than what may be required by the State because it may be more expensive than conventional energy sources. A minimum energy purchase limit may be used by the Buyer to ensure that enough energy is being sold to them to ensure that consumer demand is being met and to keep the Buyer out of the spot-market, which can be highly volatile. Figure 1 shows how volatile the spot-market can be while PPAs

allow for more stability in prices between utilities and energy generators. PPAs also ensure that the Seller is selling energy at value that can recuperate the cost of producing energy when the spot-market may be selling energy at lower prices than the cost to generate.

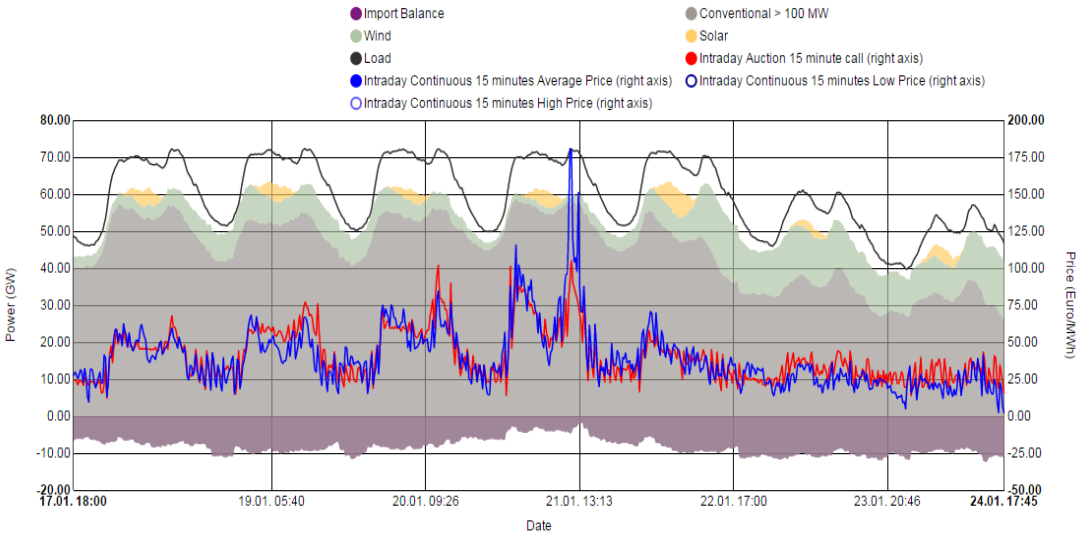

Figure 1: Spot-market prices for 3rd week of 2016 in Germany [15]

The use of PPAs has been increasing around the world and are common in Europe, the U.S., and in Latin America. In Germany alone, wind projects with PPAs totaled over 1.2 GW in capacity in 2013 [16]. In a data published by Lawrence Berkeley National Laboratory with a total of 34,558 MW of capacity in 387 signed or planned PPAs for 2016-2017 [17]. Between 2008 and 2016, 650 MW of new capacity was signed in the U.S. and in 2015 the use of PPAs in the U.S. grew to 1.6 GW [18]. In Latin America, governments typically award PPAs instead of private corporations or utilities. In 2014, the government of Peru awarded PPAs to projects with a total of 232 MW of capacity [19].

Within the U.S., PPAs have gained more prominence as State governments set Renewable Portfolio Standards (RPS). RPS laws mandate the level of renewable energy that a State is expected to consume. Utilities must then purchase renewable energy at the levels required by the RPS [20]. Because renewable energy is currently more expensive than gas or coal (in the U.S.), utilities utilize a maximum energy purchase limit so they do not have to purchase more of the expensive renewable energy than required. In other parts of the world, minimum energy purchase limits may be preferred over maximums due to a government's energy policies, as is the case in some Latin American countries. Government policies shape the preferences for using a minimum, maximum, minimum and maximum, or no energy purchase limitation in PPAs. Even within a region of the world, such as Europe or Latin America, differences in energy or environmental policies amongst countries mean energy purchase limitation preferences vary.

In the electricity market, another type of Outcome-Based Contract is utilized between utilities and consumers called Performance Based Rates (PBRs). A PBR is designed to reward utilities for good performance and penalize for poor performance [21]. The penalty in PBRs is based on the under-delivery of electricity to the customer based on number of interruptions and the duration of those interruptions. Similar to the penalty, the utility may receive a bonus from consistently providing uninterrupted electricity to the consumer. There is a maximum level allowed for both the penalty and the bonus. In between the beginning of the bonus level and the beginning of the penalty level is a "dead zone" where performance is not measured and the penalty and bonus are not applied. Figure 2 gives an example of what the PBR structure may look at where

the x-axis represents theoretical levels of performance. This contract is similar to a PPA, but in this case the utility is the Seller and not the Buyer.

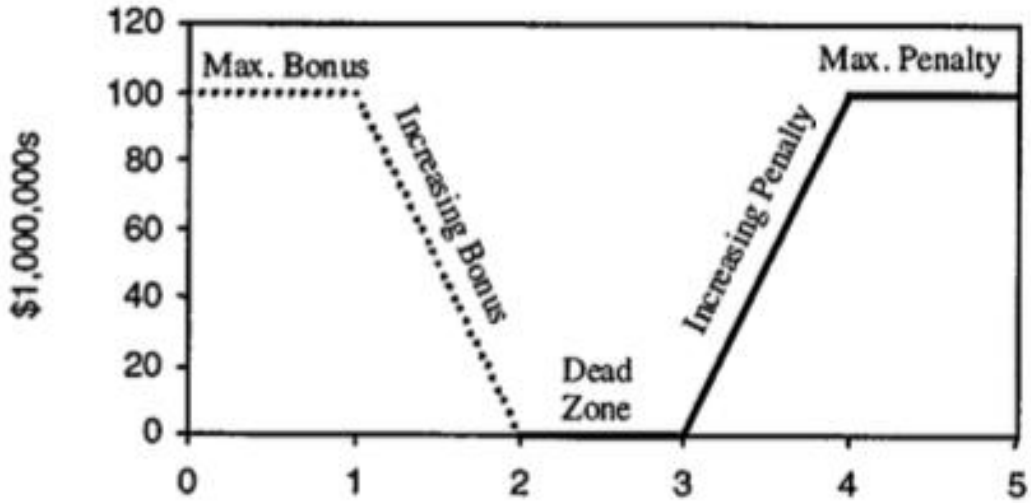

Figure 2: PBR penalty and bonus structure [21]

1.3 Existing Work

1.3.1 LCOE Modeling

Several LCOE models currently exist and are used to determine prices for wind [2] - [7]. NREL uses SAM (System Advisor Model) to compute the LCOE using wind farm data for PPAs as shown in Equation (4) [5],

$$LCOE = \frac{\sum_{i=0}^{n} \frac{CPE_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{E_i}{(1+r)^i}} \tag{4}$$

where CPE_i is the cost to produce energy in year i and each parameter is given in the ith year. In the SAM model, the LCOE is calculated based on expected cash flows for O&M and capital expenditures. Although cash flow is important for determining the

actual money spent and costs involved in a wind farm project, SAM does not recognize the implementation of penalties in its wind LCOE model [5]. The SAM model calculates a PPA price within its financial model that includes tax credits, but the PPA price is only a discounted value from the calculated LCOE and does not capture the impact of penalties.

Similar to SAM, the most commonly used LCOE models do not include tax credits, production losses, or penalties. Some LCOE models, such as the one shown developed in [7],

$$LCOE = \frac{\sum_{i=0}^{n} \frac{I_i + OM_i + F_i - PTC_i - D_i - T_i + R_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{E_i}{(1+r)^i}} \tag{5}$$

which explicitly include the following costs: fuel cost (*F*), production tax credit (*PTC*), depreciation (*D*), tax levy (*T*), and royalties (*R*)[1]. Equation (5) includes fuel cost and royalties that are not relevant (equal to zero) for wind, however, we include them here for generality. Equation (5) recognizes that the tax credits reduce the total cost, but it does not recognize PPA penalties as a cost. Other models have also been used, such as [2],

$$LCOE = \frac{CRF}{E}(I + OM) \tag{6}$$

[1] Note, the sum in the numerator of Equation (5) starts at 0 (versus the sums in Equations (1)-(3) and the denominators of Equations (4) and (5), which start at 1). This difference is a result of the treatment and interpretation of the investment cost. Equation (7) assumes that the investment cost is all charged at the end of year 0 (beginning of year 1), while Equations (1)-(3) assume that the initial investment is allocated using a depreciation factor over the entire time period of the project. However, some projects will depreciate investment costs over the length of their first energy contract and some over the recovery period of the investment. In the model developed in this thesis, investment is depreciated over the entire lifetime of the project.

where *CRF* is the capital recovery factor. The model in Equation (6) considers the LCOE as a direct project cost and not the sum of the TLCC of wind farms, which should include tax credits and PPA penalty costs in the TLCC.

LCOE has also been used to compare systems and optimize system design strategies. In a photovoltaic (PV) system, LCOE is used to compare the efficiencies of different units [22]. PV modules that produce at higher efficiencies will have lower LCOEs than similar modules producing at lower efficiencies [22]. LCOE allows for the systems to compare the life-time cost for PV modules and whether the cost is worthwhile based on the expected efficiency of the module. In another case, LCOE can be used an objective function when optimizing the design of a system. In aiming to minimize the LCOE of a wind turbine, costs per part of the turbine have been evaluated compared to the industry's average on a 5 MW turbine to produce an LCOE lower than the LCOE produced using the industry's average 5 MW turbine [23]. Although some of the parts of the turbine are optimally a higher price than the industry's average, the performance is more optimal on the system at a higher cost and may reduce the LCOE of the system. LCOE has even been used to compare the cost of entire grid systems with various options on different levels energy sources that could be used to meet consumer demand [24].

Besides LCOE, the Levelized Avoided Cost of Energy (LACE) is another commonly used metric to calculate the *COE*. LACE is the difference between the cost of electricity on the grid and the cost of electricity generated by the project [25]. Compared to LACE, the LCOE looks at the direct and indirect costs on the system

without concern on the effect of the local market (assuming that the energy generator is not engaging in the spot-market).

1.3.2 PPA Analysis

While PPAs are not a new concept, there has been relatively little modeling and analysis published on PPAs. The various components that should be included in a PPA, including descriptions of PPA pricing and PPAs price escalations have appeared, e.g., [26]. There are also descriptions of how RECs can be incorporated into PPAs and the usage of PPAs to meet State RPS mandates [26]. In [26] a description of what is used in a PPA and development of the link between RECs and PPAs is provided. In addition, many papers view PPAs as simple agreements for the purchase of energy based on a specific price and include discussions on the purchase and sale of energy, length of the agreement, commissioning process, curtailment agreements, transmission, milestones and defaults, credit, insurance, and environmental attributes and/or credits [14] [26] [27]. These are useful for understanding how PPAs work, but do not address how the PPAs should be priced.

Linking PPA elements to LCOE has also been addressed in the literature. Miller et al. [28], looks at the increase in LCOE and PPA price as *OM* increases and as losses to the system increase. This work includes a review on how an increase in the *CF* can decrease the LCOE [28]. The effects described in [28], are only qualitatively addressed and do not account for contractual conditions that produce additional costs. The work in [28] demonstrates the link between using LCOE and PPA and then demonstrates how the two can be affected by different cost variables. The work in [28], is similar to

the SAM model in the way it connects LCOE to the PPA price, but it demonstrates more of the sensitivity to cost variables whereas SAM will just produce a PPA price that is discounted from the LCOE [5].

Beyond considering just PPAs, a study has looked at the optimal bidding of wind power into the day-ahead market [14]. In this study, it is assumed that not all wind farms want to sell into their PPAs and would like to consider entering the spot-market. The purpose of the study is to determine the optimal quantity and price based on a penalty between the spot-market price and the price that was bid into the day-ahead market by the wind energy producer [14]. The results of the study are based on maximized profit where the optimal amount of energy to bid into the market depends on the expected day-ahead price, but the profit is not reflected in the price of energy in a PPA or meeting and energy purchase limit [14]. The decision to divert energy from the PPA into the market is purely based on the expected day-ahead prices and the actual PPA price.

Most papers that include the terms “PPAs” and “LCOE” are creating a simple link where LCOE is used to calculate the PPA price (e.g., [28] [29] [30]). There are the basic connections to LCOE such as reductions to capital expenditures (*CAPEX*) and operational and maintenance expenditures (*OPEX*) reducing the LCOE and PPA price (e.g., [28] [31] [30]). Some authors make the distinction between PPA price and LCOE. LCOE is an estimated cost or it may be a cost that reflects the actual break-even cost at a point in time while the PPA price reflects the actual agreed-upon price [32] [33]. Although a lot of research has been done on how *CAPEX*, *OPEX*¸ discount rates, and energy production can affect the LCOE, there has not been any quantitative

analysis done connecting contractual conditions, such as energy purchase limits, to the LCOE.

1.3.3 Renewable Energy Credits (RECs)

RECs are mechanisms used by utilities to meet RPS requirements and are used by governments to ensure that RPS requirements are being met. The purposes of RECs, which is to help renewable energy become integrated into the energy market in accordance with RPS requirements, are reviewed in [34]. RECs also allow for a lower cost method for utilities to meet RPS requirements by allowing the utilities to choose between directly purchasing renewable energy or to obtain the REC associated with the output of renewable energy. There are also reduced costs in transmission as renewable energy does not have to be transmitted long distances, i.e., it can be claimed as used in a location from ownership of the credit [34]. The study in [34] takes an economist approach to determining REC prices by looking at the supply of renewable energy versus the demand for it based on RPS requirements. The model considers the cost of energy to be linear to generation, which this thesis later shows is not the case. The model makes the simple assumption that renewable energy can be produced at a constant rate and if more energy is produced the cost will increase at the same constant rate [34].

RECs also provide flexibility for the energy market by allowing entities to claim the renewable energy without worrying about locational and physical bottlenecks [35]. Beyond locational and physical benefits for meeting RPS requirements, RECs also provide an additional revenue source for utilities who can sell their additional RECs

after they have met RPS requirements. The market for RECs has even further benefits in providing an easier method for tracking renewable energy. Without RECs, it would be difficult to distinguish renewable energy from nonrenewable energy. Without RECs, a separate transmission would have to be built just to track renewable energy, which is not practical. In [35], an outline is provided to demonstrate the difference between unbundled and bundled RECs, where unbundled RECs represent the environmental attributes of renewable energy and bundled allow for the unbundled to be traded while also holding the REC to account for the renewable energy that actually flowed through the utility. Overall, the benefits from RECs are extensive and they allow for technical, market, and political flexibility [35].

1.3.4 Non-PPA Outcome-Based Analysis with Contract Penalties

Outcome-Based Contracts have also been referred to as: Performance Contracting, Availability Contracting, Contract for Availability, Performance-Based Service Acquisition, Performance-Based Contracts, and Value-Based Contracts [36]. Pharmaceuticals are an example of an industry that is leaning towards outcome-based contracts. In these contracts, like PPAs, payments are contingent upon achievement of goals, objectives, or performance benchmarks [37]. Unlike PPAs, in the pharmaceutical industry value-based contracts have performance benchmarks based on how well the drugs provided will achieve their intended use [37]. The penalty in this case is that there will be no payment for drugs that did not work as intended, essentially this penalty will function like a maximum purchase limit where the limit is modified to reflect a performance goal of quality, not quantity. These types of contracts use cost models that

allow for higher prices to account for the drugs that may not work and for drugs of higher quality [37]. These contracts have become popular in the health industry as new laws have been passed to manage patients' health through the cost and quality of the care provided to them [38]. It is suggested that the penalties for not meeting performance outcomes outlines in the contract incentivize better market outcomes through improving output [39].

In Europe, countries such as Sweden and Denmark have opted to use Performance-Based Contacts on public transportation systems [40]. In these contracts, there is a penalty for delivery under the minimum service level (minimum delivery limit), but there are also incentives within the contract to perform above the minimum service level. These incentives include subsidizing some of the cost per person per trip above the minimum service level and to pay for the vehicle hours above the minimum service level [40]. Although the pricing of the contract may not reflect the incentives to perform above the minimum service level, the contract recognizes the commercial benefit of running public transportation more often.

Another example in Outcome-Based Contracting is Roll Royce's Power-by-the-Hour Performance Based Contract. In this type of contract, the contract price is based on provided availability in hours [41]. This is a similar contract model to PPAs as the contract is attempting to guarantee a specific minimum quantitative level of performance that functions like a minim purchase limit, but it is not the same since it aims to meet hours of performance while PPAs aim to provide a quantity of the product. More details on the difference between Availability and Performance contracts to PPAs can be found in Lei., which focuses on optimizing predictive maintenance scheduling

for wind farms under Outcome-Based Contracts [42]. In the context of PBCs, a lot of research has been done on optimizing the O&M side of servicing the contract to ensure that the specified level of availability can be achieved [42] - [44]. The works mentioned have the goal to meet a level of availability to deliver to the customer already defined in the contract by the customer while this thesis focuses on the cost impact and penalty of not meeting the specified level of delivery.

1.3.5 Gaps in the Current Cost Models

LCOE is a simplified model used to reflect a system that is running in steady state. The terms within LCOE models allow for each cost contribution to vary annually, but typically the calculation is used with constant annual costs and constant energy production. The most significant problem with LCOE models is that they implicitly assume that years of overproduction of energy cancel out the years of underproduction of energy, which allows for the usage of an average energy generation in LCOE. This is an assumption that cash flows and the penalties are symmetric with respect to energy production. Discounting on cash flow and variability in energy generation, which makes energy flow unevenly around energy purchase limits, creates asymmetry in cash flows that invalidate the treatment of LCOE with a steady-state, i.e., infinite horizon, model.[2] This problem makes conventional LCOE models invalid for use in defining PPA-based pricing and ratepayer impacts.

[2] Infinite horizon models assume that over an infinite time period, stochastic processes will become stationary and there will be a convergence to a steady state. This process assumes that initial conditions and variability will lose influence over the infinite time horizon [74].

Under very specific conditions, LCOE could be used as an infinite horizon model. One of these conditions is a discount rate that is very small or zero. To be treated as an infinite horizon model PPAs must also allow for very specifically structured conditions for the roll-over or roll-under of energy generation to meet or not exceed energy purchase limits, i.e., the provision to push under or over production into future years. This would not be an issue if energy production did not fall significantly over or under the PPA imposed energy limits, meaning that there is little variability in energy production.

It is important to note that for real applications, LCOE is an asymmetric problem, because the penalty for exceeding the energy purchase limit is not equivalent to the penalty for producing under the energy purchase limit (i.e., the two do not cancel each other out). In general, the LCOE model does not account for the actual cost of these penalties. The model needs to be improved to account for certain conditions that arise from energy purchase limitations in State RPS, RECs, and PPAs.

1.4 Thesis Objective

An accurate LCOE is critical to ensuring the financial success of an energy project as it is used to calculate the price of energy and determine what the future revenue will look like to offset the costs of the project. However, the contractual conditions used to regulate risk in energy projects may create unforeseen costs not accounted for in conventional LCOE models. Energy purchase limitations, a mechanism used to reduce the risk in uncertain energy production to the Buyer, is a prime example of a cost that is not accounted for in conventional LCOE models. The

energy purchase limits produce penalties, which with uncertain cash flows, create asymmetric cash flows. An argument can be made that the penalties imposed by the PPAs for over production and underproduction should average out over the lifetime of the project, discounting (especially with high discount rates for wind farm projects) does not allow for this to happen[3]. This is not a problem unique to the private sector, the public sector also engages in PPAs and distributes RECs that function like PPAs with energy purchase limitations, specifically the Maryland ORECs (see Chapter 3).

The objective of this thesis is to develop a modified LCOE model that accounts for variation in energy production. The model must be applicable to real wind farms and show that the LCOE can vary significantly based on energy generation variation. Two verification tests are provided in this thesis that demonstrate how different wind farms are affected by energy purchase limits and variable energy generation. This thesis also applies the modified LCOE to a case study on the Maryland ORECs, which have already been awarded to two wind farms, but the price does not reflect the LCOE with a maximum energy purchase limit. As there are three possibilities to what can happen with the Maryland ORECs, the modified LCOE model is applied for each wind farm and a combined price for both wind farms for each of the three possibilities. Policy implications and suggestions are provided at the end from the results of the study.

[3] In PPAs, energy is purchased as it is delivered and the account for the purchase of energy is rectified at the end of the year. If energy is under-delivered, money will be taken out of the account to pay the penalty to the Buyer. If energy is over-delivered, then money will be taken out for the energy that should not have been purchased or purchased at a lower price. This develops part of the need for a cost model that considers the penalties because the project is assumed to be correctly financing energy as it is bought, but then additional costs to the Seller are incurred at the end of the year.

1.5 Research Tasks

- *Task 1*: Modify the LCOE model to account for energy purchase limits. The model must account for the production loss and various options for overproduction of energy for a PPA with a maximum energy purchase limit, as well as the penalty cost that arises from a PPA with a minimum energy purchase limit.
- *Task 2*: Very the modified LCOE model.
    - Task 2.1: Test the LCOE model using a controlled wind farm case study where capacity factor (*CF*) is varied along with energy purchase limits for three different PPAs: (1) one with a minimum energy purchase limit, (2) one with a maximum energy purchase limit and no sell option for excess energy, and (3) one with an option to sell excess energy into the spot market.
    - Task 2.2: Apply the modified LCOE model to real wind farms with real *CF* data.
- *Task 3*: Apply the modified LCOE model to a case study of the Maryland Offshore Renewable Energy Credits (ORECs).
    - Task 3.1: Reverse engineer the calculations for the OREC price and ratepayer impact from LAI models[4]

[4] Levitan Associates Inc., (LAI) is a consultant that was hired by the Maryland Public Service Commission (PSC) that was tasked with reviewing and financially modeling the applications submitted for the Maryland ORECs. The two applicants for the Maryland ORECs were Skipjack, an offshore wind developer with a lease off the coast of Delaware, and US Wind, an offshore wind developer with a lease off the coast of Maryland.

- Task 3.2: Use LAI's assumed cost variables along with the modified LCOE to calculate new OREC prices.
- Task 3.3: Perform sensitivity analysis on the cost variables in the modified LCOE model.
- Task 3.4: Determine ratepayer impact.
- Task 3.5: Determine policy implications.

Chapter 2: Modified LCOE Model

2.1 Formulation of the New LCOE Model

Existing LCOE models do not consider all the cost parameters in a wind farm managed via a PPA. There are limits to the delivery and purchase of energy within PPAs that may be referred to as energy purchase limits or energy delivery limits. PPAs may define a maximum annual energy delivery quantity, a minimum annual energy delivery quantity, both of these limits, or neither. The energy delivery limits are cost parameters that are typically not considered, but should be considered, in a conventional LCOE model. The terms generally follow the rule that after the maximum energy delivery is reached, energy will no longer be purchased by the Buyer, the energy will be sold at a reduced price, or it will be sold on the spot-market [45]. This is generally considered a cost/penalty for the Seller, since they lose some or all of the value of the energy that is produced after the maximum delivery quantity is reached. Similarly, there is a direct cost/penalty in the minimum energy delivery defined in the PPA, as every unit of under-produced energy must be paid back at the agreed upon COE. The PacifiCorp draft PPA is an example PPA with a minimum energy delivery penalty, which is referred to as the liquidated damages from output shortfall in the PPA [46].

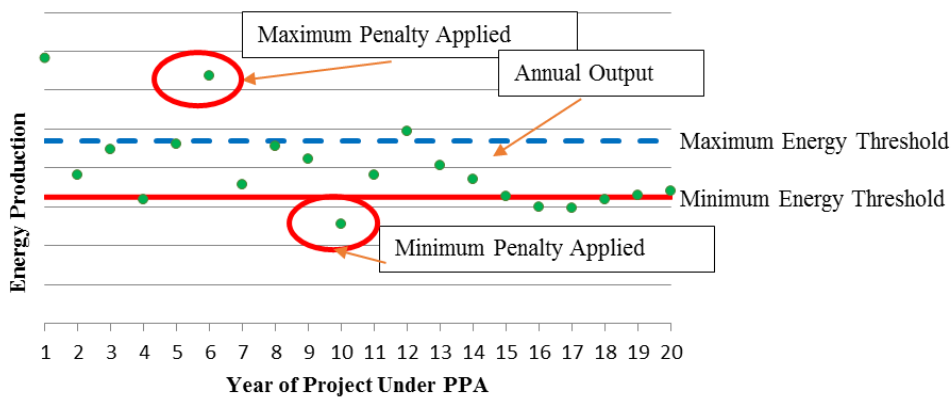

Figure 3: Application of Penalties for a Wind Farm Under a PPA

In Figure 3, the maximum and minimum energy limits demonstrate how the penalties are applied. As shown in the figure, each year that the energy production is above or below the limits, a penalty is applied. The new LCOE model reflects the costs of energy production that is above the maximum and/or below the minimum energy delivery limits. The model begins with an existing LCOE model, Equation (5), and alters it to include the delivery penalties and all applicable tax credits (*TC*s). The cost for under-delivering energy (*PN*), is the difference between the energy that was generated and delivered (*E*) and the threshold for the minimum penalty (Min_{lim}) based on average expected energy production (P_{exp}). *E* is calculated using,

$$E_i = \sum_{j=1}^{N} (CF_{i,j})(RP_j) \tag{7}$$

where E_i is the sum of all the energy produced in the wind farm from *N* turbines in year *i*, $CF_{i,j}$ is the average capacity factor in year *i* for turbine *j*, and RP_j is the rated power of turbine *j*. Using this calculation for energy, the production loss and the penalty from the minimum energy delivery limit can be calculated. *PN* is then calculated using,

$$PN_i = \begin{cases} (Min_{lim}P_{exp} - E_i)COE_i & \text{when } E_i < Min_{lim}P_{exp} \\ 0 & \text{when } E_i \geq Min_{lim}P_{exp} \end{cases} \quad (8)$$

In Equation (8), Min_{lim} is smallest fraction of expected energy production (P_{exp}) that the Buyer requires. The purpose of the minimum limit is for the benefit of the Buyer. The Buyer expects a minimum amount of energy to meet the demands of its consumers. If the energy does not meet the requirement, then the Buyer has to go to an outside source (e.g., the spot-market) and may have to purchase energy at a higher price, which the Buyer will require the Seller to compensate them for. Similarly, the production loss (PL) is the difference between the energy that was generated (E) in that year and the threshold for the maximum penalty (Max_{lim}) based on the P_{exp},

$$PL_i = \begin{cases} (E_i - Max_{lim}P_{exp})COE(1 - PPA_{term}) & \text{when } E_i > Max_{lim}P_{exp} \\ 0 & \text{when } E_i \leq Max_{lim}P_{exp} \end{cases} \quad (9)$$

In Equation (9), Max_{lim} is the largest fraction of expected energy production that the Buyer is willing to purchase. PPA_{term} is a fraction that represents the type of penalty placed on the Seller after the maximum energy limit has been reached. In a PPA with no outside sell option the PPA_{term} has a value of 0. When all the energy is purchased by the Buyer regardless of the limit the PPA_{term} is 1 and therefore PL is never applied.[5] PN is only applied during the years that actual energy production is less than the quantity of energy determined by $Min_{lim}P_{exp}$, i.e., when $E_i < Min_{lim}P_{exp}$. PL is only applied when

[5] Maximum limits are used for various purposes and do not apply to every PPA case. Certain states in the United States, e.g., Maryland, New Mexico, and Pennsylvania have renewable energy standards [20]. These standards force utilities to obtain a specific fraction of their energy from renewable energy. At the present time in the United States, renewable energy is more expensive than energy from non-renewable sources. Therefore, utilities will only buy up to the required fraction and will create maximum limits so they do not have to purchase more than the required amount.

the energy produced exceeds the amount of energy determined by $Max_{lim}P_{exp}$, i.e., when $E_i > Max_{lim}P_{exp}$.

The LCOE model including the unaccounted-for cost variables that exist in PPAs is given by[6],

$$LCOE = \frac{\sum_{i=0}^{n} \frac{(I_i + OM_i + F_i - TC_i + Pen_i)}{(1+r)^i}}{\sum_{i=0}^{n} \frac{E_i}{(1+r)^i}} \tag{10}$$

where *PL* and *PN* are only included in the total penalty cost (*Pen*) when their calculated cost in a year is greater than $0. Generally, the variable *I* can be fall within the term *CAPEX* and *OM*, *F*, and *TC* can all be categorized as variables that fall within the term *OPEX*. In Equation (10) the sums in the numerator and denominator start at $i = 0$ under the assumption that the investment cost (I_i) comes from a depreciation schedule (see footnote 1). In the case where the PPA allows for the Buyer to sell into the spot-market, the *PL* may have a negative value. The Pen_i in year *i* is the sum of the production loss and the penalty cost,

$$Pen_i = PN_i + PL_i \tag{11}$$

and the tax credit in year *i* (TC_i) is given by,

$$TC_i = IBI_i + PBI_i + CBI_i + ITC_i + PTC_i + D_i \tag{12}$$

where all types of tax credits that can be applied to a wind farm are included (see nomenclature for specific tax credit contributions). Both *Pen* and *TC* depend on the conditions imposed by the PPA.

[6] This thesis does not focus on modeling the myriad of individual cost contributions to the LCOE. More complex models with more parameters that attempt to account for all the costs in an energy project exist, e.g., [3] [4]. In contrast, this thesis uses a simple LCOE model and focuses on the effect of penalties from PPAs (other more detailed cost contributions could be added to the model in this thesis without a loss of generality).

Figure 4 demonstrates the recursive process of calculating LCOE. It considers all costs that go into *CAPEX* and *OPEX*. It also takes the actual annual energy production, the total value of *TCs*, and the P_{exp} used to determine the energy purchase limits. With all these variables, the *COE* of the project can be determined, and the *COE* can then be used to calculate the total penalty cost depending on the particular energy purchase limit the PPA has. The *Pen* is then included in the LCOE equation and if LCOE is equivalent to the *COE*, the process stops, and the energy purchase price is determined. If not, the *COE* must be adjusted accordingly, and a new *Pen* is determined until *COE* is the same as LCOE.

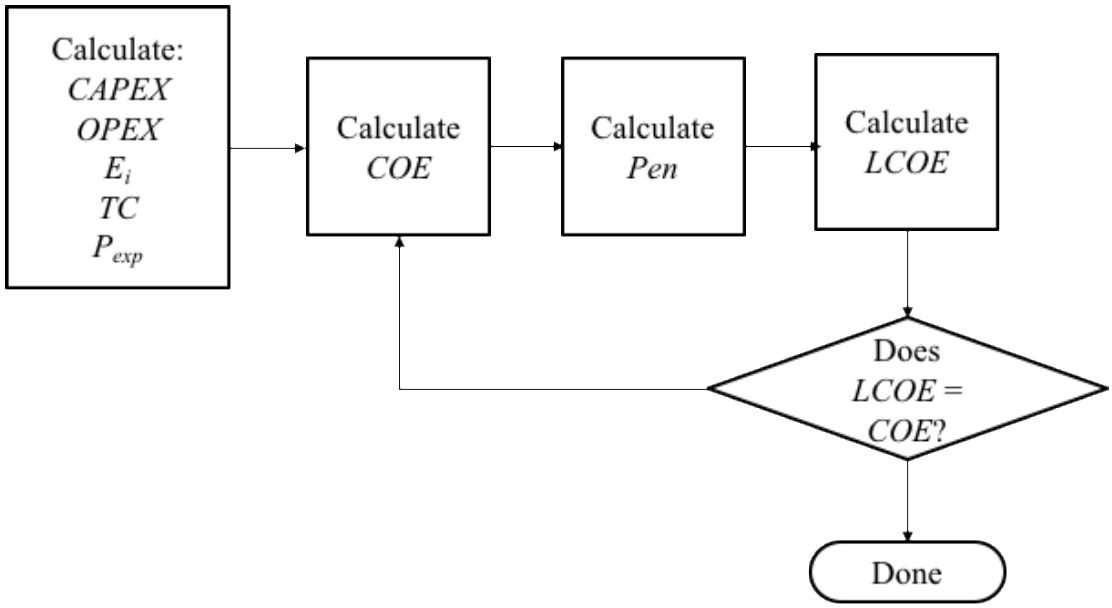

Figure 4: LCOE Model Flow Chart

2.2 Model Verification

A controlled study of wind farms was conducted to explore the effects of *CF* variation and energy delivery requirements on the LCOE[7]. LCOEs were calculated based on three types of PPAs for wind farms with an annual *CF* that varies around an average *CF* of 0.4, as shown in Figure 5. This study uses a *CF* of 0.4 as a best-case scenario based on projections as most wind farms operate on a capacity factor of 0.25 to 0.4 [47]. Wind speed varies significantly from location to location. Although wind turbine technology has been working to improve the capacity factor, some locations may still have a poor wind source and the capacity factor can fall significantly below 0.4. The LCOE and *CF* are both strongly dependent on wind source and the location of the wind farm. Under favorable wind conditions, the LCOE of an onshore wind farm can vary from 0.05 USD/kWh to 0.06 USD/kWh and under unfavorable wind conditions it can vary from 0.07 USD/kWh to 0.12 USD kWh [48]. The change in *CF* considered in this model verification exercise was determined by increasing and decreasing the average *CF* by the same fraction per year in the same wind farm. In Figure 6, Figure 7, and Figure 8 the fractions in *CF* change ranged from 0 to 0.4, where at the *CF* of 0 is the best-case for a wind farm and 0.4 is the worst-case [47] [49] [50].

[7] This thesis does not explicitly consider pre-construction risks and how they impact the LCOE. This study focuses on the impact of the variation in energy production due to uncertainty in wind speed. However, pre-construction could be incorporated into the model if relevant.

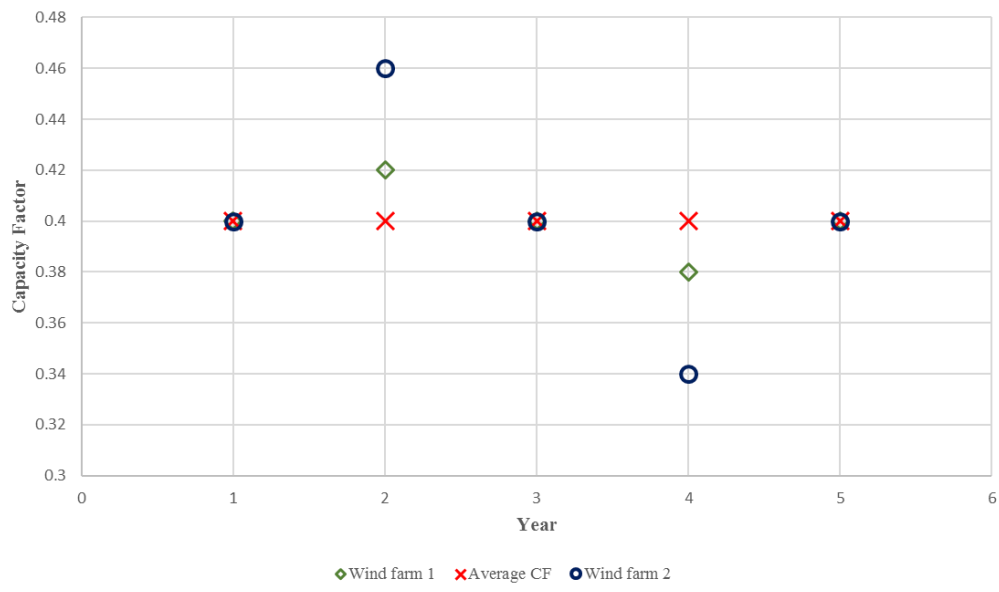

Figure 5: CF variation used in model verification tests with an average CF of 0.4

The three types of PPAs considered in the model verification are: (1) one with just a minimum penalty, (2) one with just a maximum penalty where no energy can be bought above the limit, and (3) one with just a maximum penalty where the energy above the maximum energy delivery limit has to be sold into the spot-market at spot-market prices or can be bought at a fraction of the *COE*. The penalty from the maximum energy delivery limit, either reflected by selling energy at a fraction of the value or selling energy onto the spot market, determines the value for the PPA_{term} as a fraction of the *COE* (which is demonstrated in the design for the maximum penalty in a Pakistan PPA [51]). Although the average $CF = 0.4$ is the same in all the cases considered in this section, the *COE* for each wind farm is different since the LCOE differs for each wind farm due to the variations in the *CF*. The costs and energy produced in each year varies, thus creating differences in the discounted total costs for each farm in the years

that the *CF* varies. Each LCOE in this section was calculated for a duration of 5 years. The following data was used to calculate the LCOE,

I = \$1500 per installed kW [52]

OM = \$0.01 per kWh produced [52]

F = \$0

TC = \$0.05 per kWh sold [53]

r = 0.089 per year [54]

RP = 3000 kW

COE = LCOE from Equation (12) with $Pen_i = 0$ and using Equation (7) for E_i

The investment (I), although shown as a single value, is a value that is depreciated over the lifetime, or in many cases the length of the PPA, of the wind farm and changes for every year i. The *COE* in a PPA is generally calculated from an LCOE that does not consider delivery penalties as a cost. For this reason, the cost calculated from penalties in the new model uses the calculated LCOE (for an individual wind farm) under a PPA without penalties as the *COE*. P_{exp} is calculated as the average annual expected energy production from a specific farm[8]. In these cases, the expected energy production is calculated using a *CF* of 0.4 for every year (Danish wind farms averaged 0.41 in 2012 [55] and it has been predicted that between 2005 and 2030, wind farms will be operating at capacity factors between 0.36 and 0.43 [50]). E_i is calculated using a *CF* that is based

[8] However, the *COE* should be adjusted as shown in Section 2.1 and Figure 4. For the sake of simplicity, the model verification calculates the *COE* before penalties are included and uses that first calculation without adjustment to find the LCOE.

on the variability around the average *CF*. The values of Min_{lim}, $Max_{lim,}$ and E_i, are then used to calculated penalties.

CF variation in the following series of tests was generated as the fraction of energy that is produced in year *i* that falls above or below the average *CF* of a project. Figure 5 demonstrates this with two farms that have an average *CF* of 0.4 over 5 years. Wind farm 1 in this case has a *CF* variation of 0.05, this means that 0.05 more energy is produced in one year and 0.05 less is produced in another. Wind farm 2 in Figure 5 is similar as it assumes a *CF* variation of 0.15. The algorithm used in this study valued year 2 as the higher than "expected" *CF* year and year 4 as the lower than "expected" *CF* year. A different pattern of uncertainty than Figure 5 would yield different results. We only use the pattern in Figure 5 as a simple example for model verification purposes (in the case study in the next section of this thesis we have used actual *CF*s for actual wind farms).

Figure 6 shows the results for a PPA with only a minimum energy delivery limit. In this case, as the variation in the *CF* increases, more energy is likely to fall below the annual minimum requirement, thus increasing the LCOE. The greater the variation, the more likely the LCOE will be affected by the minimum energy delivery limits. The domain for Min_{lim} is [0,1], because the required minimum annual delivery quantity could range from no required quantity, $Min_{lim} = 0$, to a requirement for the entire expected output of the wind farm, $Min_{lim} = 1$. The increase in values for the different variations in Figure 6 are ramps where the LCOE increases between values of Min_{lim} and then increases at a slower rate thereafter. Before the value of Min_{lim} where the LCOE starts to increase, the LCOE has no dependence on Min_{lim}, i.e., in these cases

there is no energy produced below Min_{lim}. When there is no variation in the *CF* (the "None" case in Figure 6), the LCOE is independent of Min_{lim}.

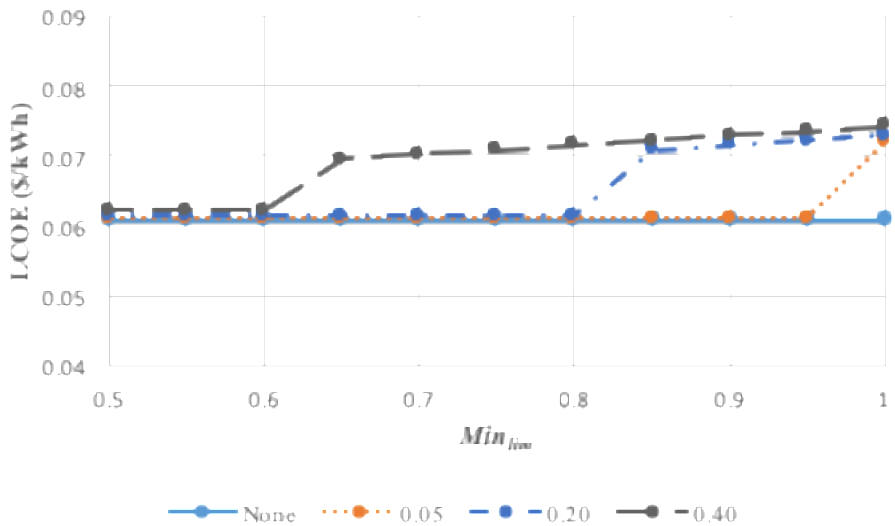

Figure 6: Offshore PPA with just a minimum energy delivery limit with different variation in energy around the average CF = 0.4

The value of Max_{lim} can range from 0 to greater than 1. $Max_{lim} = 0$ implies that every unit of energy produced is penalized, and $Max_{lim} = 1$ implies that every unit of energy over P_{exp} (the annual expected energy production) is penalized and every unit of energy below P_{exp} is not penalized. However, a PPA will generally not create a Max_{lim} much lower than 0.5. The Max_{lim} may also exceed 1 because of variation in energy generation. If a wind farm generates above the expected energy production every few years, a Max_{lim} greater than 1 gives the wind farm room to avoid being penalized for producing more than P_{exp}.

Figure 7 shows a PPA where once the energy goes above the maximum energy delivery limit, that excess energy can be sold into the spot-market. A normal distribution of spot-market prices was sampled for this PPA type with a mean of $52.32

per MWh and a standard deviation of $38.75 per MWh [56]. Those values were then used to determine an expected value for the PPA_{term} fraction used in the production loss calculation. In Figure 7 the PPA_{term} = 1.1, which means that (from the point of view of the Seller) it was cheaper to sell into the spot-market then to sell to the Buyer under the PPA contract (i.e., "cheaper to sell" means more money for the Seller).[9] The results from Figure 7 show that the LCOE remains almost flat or very slowly decreasing, as the Max_{lim} increases, followed by two sudden drops. When Max_{lim} increases in Figure 7, there is more loss to the Seller because it is more profitable to sell on the spot-market. When Max_{lim}= 1, a majority of years are producing energy at or below the expected *CF*, and all of that energy in those years is bought by the Buyer, quickly dropping the LCOE. However, some energy is still purchased in the spot-market in the few years (or single year in these cases) when the capacity factor is higher than expected. When Max_{lim} reaches the same fraction as the variation around the *CF*, there will be no change in the LCOE. This is seen in the cases where Max_{lim} = 1 for a farm with no variation ("None"), Max_{lim} = 1.05 for a wind farm with 5% variation, and Max_{lim} = 1.2 for a wind farm with 20% variation.

[9] This is not the always the case. Energy prices can vary from below $0 to $300 per MWh on the spot market as shown in Figure 1.

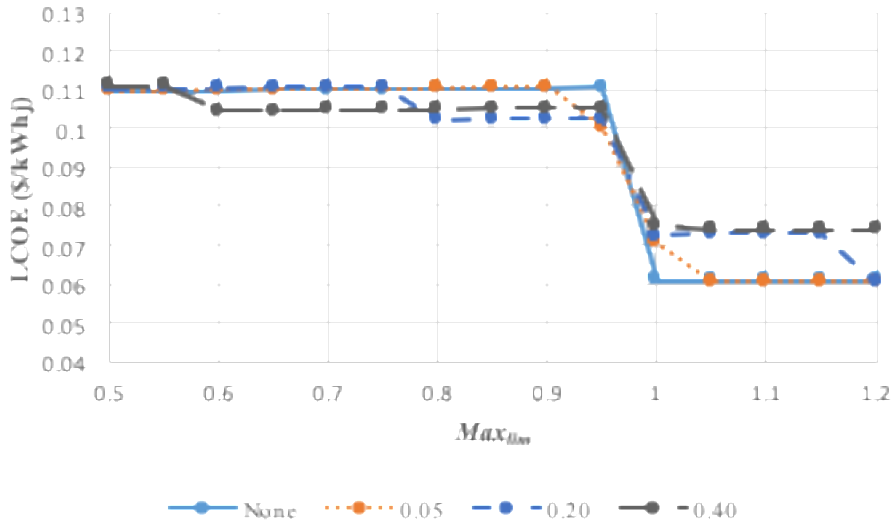

Figure 7: Offshore PPA with just a maximum energy delivery requirement with spot-market sell option with different variations in energy around the average CF = 0.4, PPA_{term} = 1.1

Results can be seen in Figure 8 for the case where all of the production is lost loss (PPA_{term} = 0) above the maximum energy delivery requirement. In this case, the PPA states that energy produced above the maximum limit cannot be sold. This figure shows that as the Max_{lim} is increased, which means the maximum energy delivery requirement is increasing, less energy is being produced outside of the limit. Higher variations in the *CF* are more effected by the Max_{lim} than those with less variation. Figure 7 is different from Figure 8 because Figure 8 does not have an outside sell option, and is therefore always experiencing a production loss at the value of the *COE* during the years that there is over production.

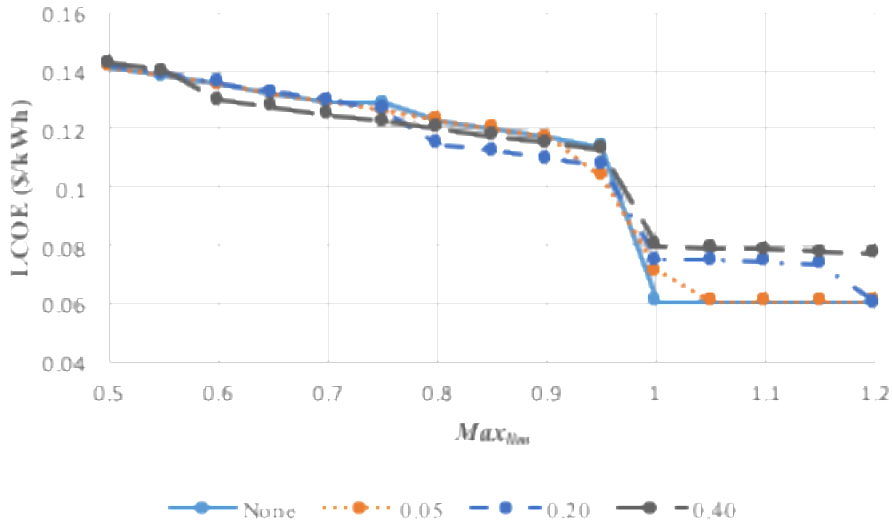

Figure 8: Offshore PPA with just a maximum energy delivery requirement with no outside energy sell option (defined by PPA_{term} = 0) with different variations in energy around the average CF = 0.4

Both Figure 7 and Figure 8 appear to have a sudden drop in LCOE from a Max_{lim} of 0.95 to 1. This sudden decrease can be attributed to the number of years that have energy production above the Max_{lim}. According to the model used in this section (Figure 5), only one year is producing below the expected *CF* value. This means that for 4 years, and all 5 years for the wind farm which has no variation in *CF*, energy is being produced above the maximum annual energy delivery limit, and energy is always being produced at a loss in those years. Therefore, only when Max_{lim} = 1 are the majority of years are not producing above the limit. Even at Max_{lim} = 1, one year for every wind farm, except for the wind farm without variation, there is a higher than expected *CF*. Due to this one year, the LCOE for the wind farm without variation is lower than the LCOEs for the wind farms with variation at Max_{lim} = 1.

There is another type of PPA that was not presented in this section, which is a PPA that contains both a Max_{lim} and a Min_{lim}. This PPA follows almost the same

conditions and requirements for both limits. The only difference is that the Max_{lim} can never be lower than the Min_{lim}. Generally, in a PPA containing both limits, there is enough of a gap between the limits for energy to fall between them, but Min_{lim} can never be larger than Max_{lim} or all energy produced will always be penalized. The case of a PPA with both limits is considered in the wind farm cast study in the next section.

2.2.1 Real Wind Farms Application

This section explores the actual LCOEs produced for a set of real wind farms (real *CF* histories). All the cases in this section use identical contract variables, requirements on energy delivery, and *COE*. The purpose of this wind farm case study is to evaluate the effects of using the same PPA on farms that vary in location and energy production. Four PPA options are considered. First a PPA with no energy delivery limits, where the energy is bought and sold as it is produced. The first type of PPA reflects a conventional LCOE where the PPA energy delivery limits are not applied. The second PPA has only a minimum delivery limit where energy is not allowed to be purchased or sold in the spot market after that limit has been reached. The third PPA has just a maximum delivery limit, and the fourth PPA has both delivery limits. Real data was collected from 7 different wind farms (Table 1 [57]) that have different numbers of turbines, manufacturers, years built, rated power and country (Germany or Denmark). The data from Germany and Denmark was readily available from established wind farms with long enough history of data collection to be viable for consideration in the study. All the costs used in the model verification tests were used in this case study except a fixed *COE* for each farm of $0.25 per kWh, based on

NREL's highest expected *COE* in wind farms from 2025-2050 [58] is used in this case study.

Table 1 - Wind farm dataset details [57]

Wind Farm Dataset/Manufacturer/Rated Power	Year Built	Location (Number of Turbines)
1 - Vestas (2 MW)	2002	Germany (17)
2 - Enercon (2 MW)	2005	Germany (24)
3 - Siemens (2.3 MW)	2010	Denmark (11)
4 - Enercon (2 MW)	2010	Germany (10)
5 - Vestas (3 MW)	2010	Denmark (18)
6 - Vestas (3 MW)	2007	Germany (5)
7 - Siemens (3.6 MW)	2006	Germany (7)

The four different PPA types assume $Max_{lim} = 0.75$ and a $Min_{lim} = 0.52$.[10] Figure 9 and Figure 10 portray two different wind farms actual *CF* compared to the Max_{lim} and Min_{lim} used in the PPAs. The figures show that using the same annual energy delivery quantities on two different farms potentially produce different results due to the different actual annual *CF* variation. The wind farm in Figure 9 has more variation in *CF* than the wind farm in Figure 10, where the *CF* of the wind farm is nearly constant from year to year. The LCOE of each turbine was calculated from the sum of LCOE costs at the end of 5 years. Figure 11 shows the LCOEs based on the different annual energy delivery requirements and the selection of applied penalties.

[10] The values of $Max_{lim} = 0.75$ and $Min_{lim} = 0.52$ are based on limits previously used in Zhu [76] and Delmarva Power and Light Company and Bluewater Wind Delaware LLC Power Purchase Agreement [75].

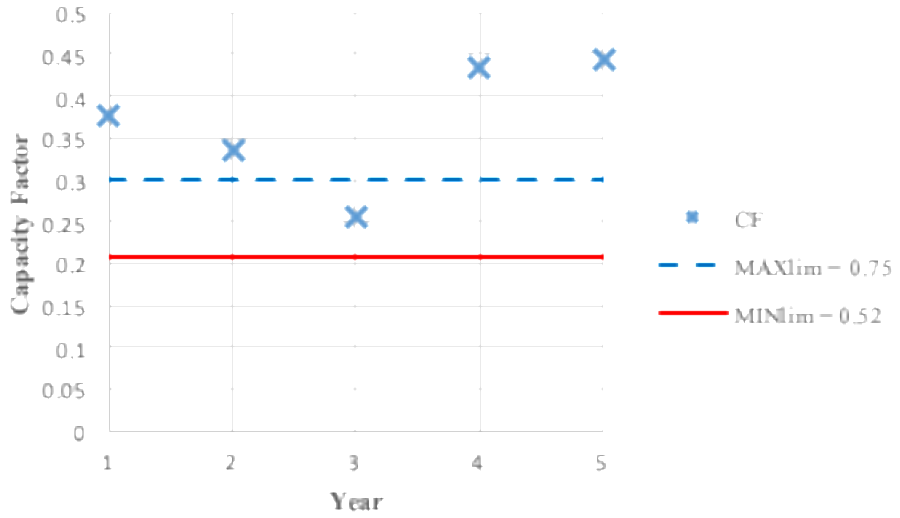

Figure 9: Wind Farm 3 actual CF to Max_{lim} = 0.75 and Min_{lim} = 0.52 for a P_{exp} = 0.4

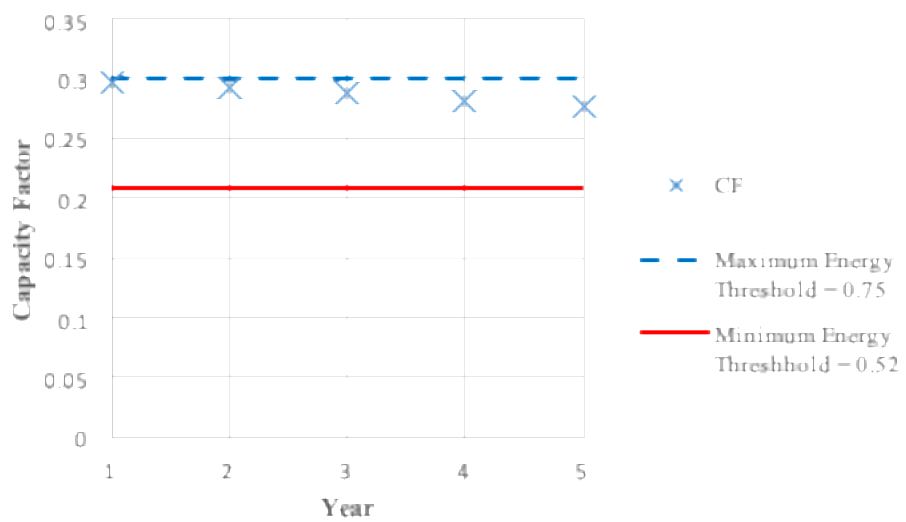

Figure 10: Wind Farm 5 actual CF to Max_{lim} = 0.75 and Min_{lim} = 0.52 for a P_{exp} = 0.4

The results in Figure 11 show that in most of the wind farms, while using the same Max_{lim} and/or Min_{lim} parameters, just having a maximum penalty resulted in LCOEs that are closest to the LCOEs with no penalties. The results show that LCOEs

with both penalties or those with just minimum penalties resulted in higher LCOEs. Based on the results from the model verification tests, for wind farms with the same turbine types and year manufactured, it can be assumed that the different clusters of LCOEs are caused by the differences in *CF*. Lower *CF*s cause larger differences between a PPA with just a maximum penalty and a PPA with just a minimum penalty as produced by wind farm datasets 1 and 2. While datasets 4 and 7 have tighter clusters of LCOE due to less variation in *CF*s. Wind farm data set 3 has a higher LCOE for PPAs with a maximum energy delivery limit that is caused by annual *CF*s that do not frequently fall below the threshold for the minimum annual energy delivery limit, but more frequently have production loss due to producing energy above the maximum annual energy delivery limit. There is significant value in setting appropriate limits in the PPAs for different farms due to the different wind characteristics and design of each project, which can create no difference in the conventional to the actual LCOE up to an actual LCOE that is approximately 1.5 times the conventional LCOE.

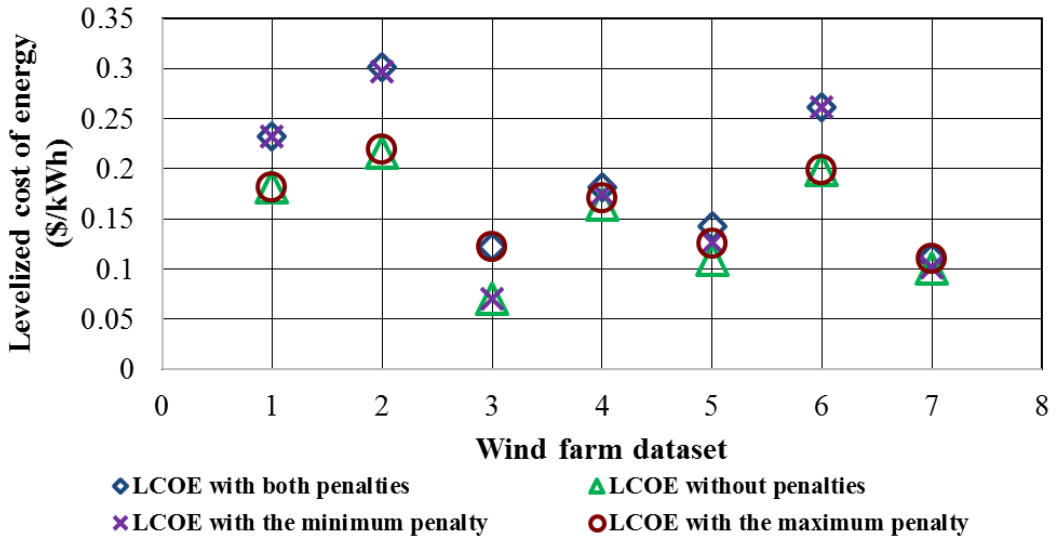

Figure 11: LCOE for PPA comparison

Table 2 shows the actual LCOEs for three of the wind farms from the dataset. Offenheim, Germany is wind farm 7, Galmsbüll-Marien-kogg, Germany is wind farm 6, and Svoldrup by. Vognsild, Denmark is wind farm 3. Again, it is demonstrated that wind farm 7 would not lose from entering into a PPA with a minimum energy purchase limit or a PPA with a maximum energy purchase limit. On the other hand, wind farms 3 and 6 need to be careful, and would have to request a different PPA price depending on which energy purchase limit the PPA has.

Table 2 - Specific Wind Farms Names and LCOEs from Model Verification

Wind Farm Name and Country	**Conventionally Calculated LCOE**	**LCOE with a Max. Energy Purchase Limit**	**LCOE with a Min. Energy Purchase Limit**
Svoldrup by. Vognsild, Denmark (wind farm 3)	0.07 $/kWh	0.12 $/kWh	0.07 $/kWh
Offenheim, Germany (wind arm 7)	0.10 $/kWh	0.11 $/kWh	0.10 $/kWh
Galmsbüll-Marien-kogg, Germany (wind farm 6)	0.20 $/kWh	0.20 $/kWh	0.26 $/kWh

Chapter 3: Case Study: Maryland Offshore Renewable Energy Credits (ORECs)

3.1 Background

3.1.1 Renewable Portfolio Standards (RPS)

Renewable Portfolio Standards are laws passed by States requiring that certain renewable energy consumption levels be met. At the moment, 29 States have an RPS and 7 States have a voluntary renewable energy standard or target [59]. Typically, a State RPS will break down renewable energy into Tier 1 and Tier 2 renewable sources. Tier 1 will include solar, onshore wind, biomass, methane, geothermal, ocean, fuel cell that produces electricity from a Tier 1 source, hydroelectric, poultry litter-to-energy, waste-to-ender, refuse-derived fuel, and thermal energy from a thermal biomass system [60]. Tier 2 includes hydroelectric power other than pump storage generation, but some Tier 1 RECs may be used to satisfy Tier 2 requirements [60]. Offshore wind does not fall under either of these tiers and is considered its own category. For the State of Maryland, the RPS requirements by Tier are shown in Figure 12 [60].

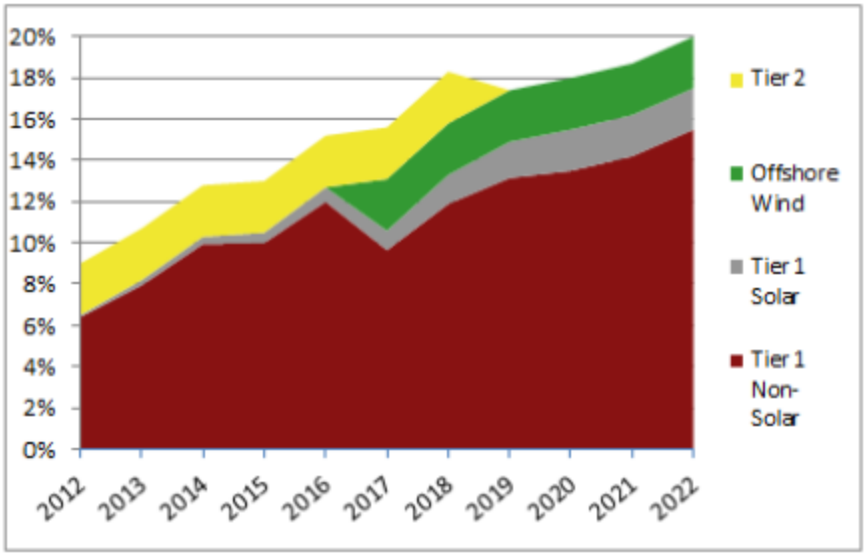

Figure 12: Annual RPS Requirements by Tier [60]

3.1.2 Renewable Energy Credits (RECs)

Renewable Energy Credits (RECs) in the U.S. are a State developed solution for increasing the competitiveness of renewable energy in the market. These credits are important to PPAs as they decrease the LCOE by subsidizing part of the cost. There are two types of RECs, RECs that fully cover the cost of renewable energy at their LCOE value and RECs that partially cover the cost of renewable energy. This thesis focuses on RECs that fully cover the LCOE value of energy, specifically the Maryland Offshore Renewable Energy Credits (ORECs). The Maryland ORECs function like a PPA as they set a price schedule and the maximum amount of offshore wind energy that will be purchased within the state of Maryland [61].

3.1.3 Maryland Offshore Renewable Energy Credits (ORECs)

In 2013, the governor of Maryland, Martin O'Malley, in conjunction with the Maryland Energy Administration (MEA), wrote and passed a bill that developed a secure financial mechanism to meet the offshore wind carve-out mandated in the State's Renewable Portfolio Standards (RPS). The Bill was based on a similar law passed in New Jersey. According to the bill, Maryland utilities are required to meet 2.5% of all energy sales from offshore wind [61]. This mandate can be tracked by the number of ORECs utilities have in which they can claim they have purchased 1 MWh of offshore wind energy. ORECs are tax credits (*TCs*) that fully fund offshore wind farms to ensure that they are sold into the Maryland energy market while bundling in other partial *TC*s.

The ORECs function like PPAs by limiting the amount of energy that can be purchased within the State, and they used a calculated LCOE to determine the levelized OREC price and price schedule. While the law requires utilities to reach the offshore wind carve-out, it also limits the amount of energy that can come from offshore wind into the State by that same carve-out. In this sense, the carve-out functions like a minimum and maximum energy limit, but the law only requires utilities to meet the carve-out and therefore the minimum energy purchase limit does not apply in the LCOE for the offshore wind farms. Instead, the offshore wind farms only need to consider the cost that arises from the maximum amount of energy they can sell into the State. In addition to limiting the amount of allowed offshore wind energy, the ORECs place financial limitations on applicants. The limitations included that the OREC price could

not exceed a levelized value of $190/MWh in 2012 dollars and the applicants' energy generation into the State cannot increase the average residential ratepayer's monthly bill by more than $1.50/month in 2012 dollars [61].

Table 3 - Offshore Wind Farm Specifications for US Wind and Skipjack

	US Wind	**Skipjack**
Number of turbines	62	15
Total capacity (MW)	248	120
Cost to build ($ million)	1,375	720
Expected start of operation date	January 2020	November 2022
Number of requested and awarded ORECs per year	913,845	455,482
LCOE ($/MWh)	137.06	131.93
Average Monthly Ratepayer Impact ($ per month)	0.974	0.433

In late 2016 and early 2017, the Maryland Public Service Commission (PSC), which was assigned the task of reviewing the OREC applications and ensuring that they met the standards articulated in the House Bill, received two applications for ORECs from US Wind and Skipjack. US Wind is the current lease holder for the offshore lease off the coast of Maryland and Skipjack is the current leaseholder of the offshore lease off the coast of Delaware [62]. The lease area of Skipjack is shown in Figure 13, and the lease area for US Wind is shown in Figure 14. A third party, Levitan Associates Inc. (LAI), was hired as a consultant to perform financial modeling and calculate the average monthly ratepayer impact and price for the ORECs. LAI worked with both US

Wind and Skipjack to calculate their LCOEs, and determined the final values shown in Table 3 [62]. Determining the LCOE and Gross OREC price during the application process for each wind farm was an iterative process as the proposed farms contested several of the cost variables used by LAI in the calculations and the LCOEs. LAI utilized a conventional LCOE model that did not include production loss, but does consider that each wind farm might have increased some of the expected costs to add some buffer against costs than expected. The LCOEs also include a level of profit, which is only known by each applicant. U.S. Wind was finally determined to have an LCOE of $137.06/MWh and Skipjack was determined to have an LCOE of $131.93/MWh [63]. Both offshore applicants requested a number of ORECs based on the average annual output of energy.

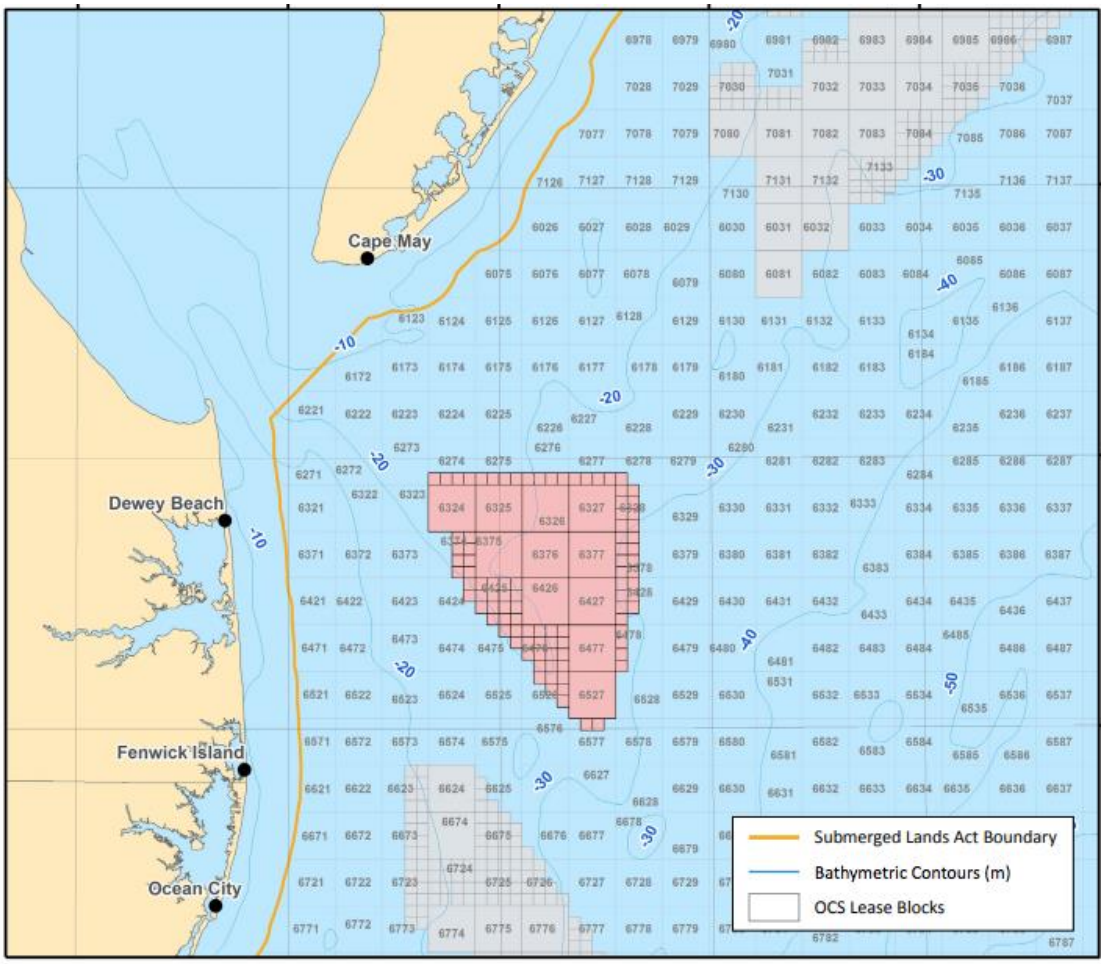

Figure 13: Skipjack offshore wind farm lease area [64]

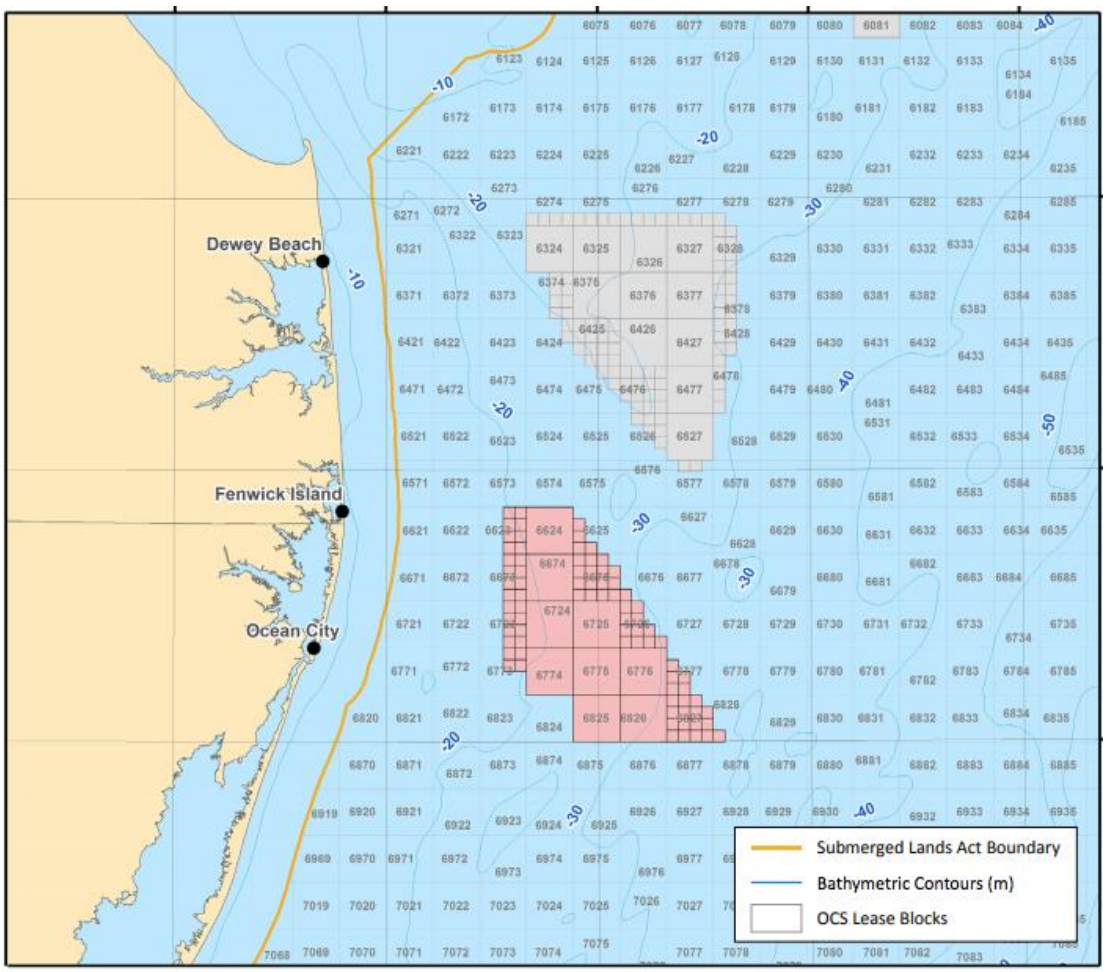

Figure 14: US Wind offshore wind farm lease area [64]

After the LCOEs and quantity of ORECs were agreed upon by the applicants, the PSC was then given the task of determining which wind farm would receive the ORECs. In May 2017, the PSC decided to award both applicants their requested ORECs at a levelized 2012-dollar price of $131.93/MWh. The decision to award both applicants ORECs was a political decision based on the assumption that together, the offshore wind farms will be under the requirements outlined in the House Bill. One of those requirements was that offshore wind could not exceed 2.5% of all energy sales. During the application process, the total number of ORECs for each wind farm was

added up and the PSC noted that the sum of awarded OREC to both applicants fell below the offshore wind carve-out stated in the law as seen in Table 4 [12].

LAI was also tasked with calculating the average residential ratepayer impact. The expected average monthly ratepayer impact was calculated at $0.975/month for U.S. Wind and $0.433/month for Skipjack [62]. The Maryland PSC summed up the two impacts ($1.408 per month) and determined that both wind farms could be awarded ORECs because $1.408 per month is less than the OREC limited ratepayer impact of $1.50 per month. Finally, the OREC price of $131.93/MWh was awarded to both offshore wind farms at the LCOE of Skipjack, disregarding the higher LCOE of U.S. Wind [62].

The PSC did not account for various conditions such as a combined OREC price that addresses the separate financing of the two wind farms and the PSC did not account the ratepayer effect of having both wind farms utilizing the ORECs and offloading their energy onto the grid during the same period. The PSC assumed that the effect of both wind farms was a simple summation of the two. This is not how ratepayer impact is calculated and a method to calculating the ratepayer impact is shown in Section 3.2.2 where it is notable from the model that a simple summation of the expected impacts is not correct. The ratepayer impact also needs to consider that more energy is in the grid than what was calculated initially. The calculation for both also considers the ratepayer impact if US Wind was receiving ORECs at $137.06/MWh and not at $131.93/MWh.

Table 4 - Percentage of Energy Sales in Maryland Met from Current Awarded ORECs for Skipjack and US Wind [12]

Year	Offshore Wind Carve-Out Met by Awarded OREC Quantity (%)
2021	1.37
2022	1.36
2023	2.03
2024	2.01
2025	2.01
2026	1.99
2027	1.98
2028	1.96
2029	1.96
2030	1.94
2031	1.93
2032	1.91
2033	1.91
2034	1.89
2035	1.88
2036	1.87
2037	1.86
2038	1.85
2039	1.83
2040	1.82

2041	0.60
2042	0.60

3.2 LAI's Analysis

Before applying the modified LCOE calculation formed in this thesis, it is necessary to reproduce (reverse engineer) the analysis performed for the PSC by LAI. Most of the inputs to reproduce the OREC price for each offshore wind farm are provided in the various LAI and Maryland PSC reports. Additional inputs necessary for the analysis (obtained from LAI and other sources) are provided herein.

3.2.1 OREC Price Calculation

The LAI reports provided most of the information necessary to reproduce the LCOE calculation [12] [65] [66]. These reports provide the expected energy generation and *CAPEX* value from the cost to build as were given in Table 3 [62]. In another report, the assumed discount rate was also provided by LAI at 0.03/year [65]. The calculated LCOEs of $131.93 per MWh for Skipjack and $137.06 per MWh for US Wind were provided. However, the *OPEX* values were missing from the reports and had to be derived from the given information.

A simple LCOE calculation (Equation (13)) was used to determine the cost variables to be included in the case study on the Maryland ORECs.

$$LCOE = \frac{\sum_{i=2012}^{n} CAPEX_i + OPEX_i}{\sum_{i=2012}^{n} \frac{E_i}{(1+r)^i}} \tag{13}$$

Where *OPEX* is the cost for every unit of produced energy. In this calculation *E* is evaluated by MWh as the ORECs are awarded per MWh. Using the values provided by LAI and the following LCOE calculations were derived.

$$LCOE = \frac{\sum_{i=0}^{n} \$1{,}375{,}000{,}000 + \$61.83E_i}{\sum_{i=2012}^{n} \frac{E_i}{(1+0.03)^i}} = \$137.06 \tag{14}$$

$$LCOE = \frac{\sum_{i=0}^{n} \$720{,}000{,}000 + \$52.893E_i}{\sum_{i=2012}^{n} \frac{E_i}{(1+0.03)^i}} = \$131.93 \tag{15}$$

Equation (14) shows the LCOE calculation for US Wind where E_i is 913,845 MWh and Equation (15) shows the LCOE calculation for Skipjack where E_i is 455,482 MWh. E_i appears in this these equations for the case study as it depends on the assumed wind speed distribution and will affect the LCOE equation when *PL* is included. For now, Equation (14) and Equation (15) primarily show the fixed cost variables. A total list of the cost variables in the LCOE equation are provided in Table 5.

Table 5 - LCOE cost variables for each offshore wind farm

	US Wind	**Skipjack**
CAPEX ($/kW installed)	5,544.35	6,000
OPEX ($/MWh)	61.83	52,89
E_i (MWh)	913,845	455,482
r	0.03	0.03
n (year)	2041	2042

After the OREC price was calculated, the price schedule for ORECs had to be calculated. The Maryland PSC provided a bid price form where the levelized OREC price was adjusted based on the annual deflator and real discount rate to determine the annual price and price schedule of the ORECs (see Table 6). While awarding of the ORECs was determined by the levelized OREC price, the annual bid price is important in calculating the Ratepayer Impact which is addressed in the next section.

Table 6 - Deflator Rates and Real Discount Rates as Provided by Maryland PSC [67]

Year	Deflator	Real discount rate
2021	0.856	0.937
2022	0.840	0.931
2023	0.825	0.924
2024	0.810	0.917
2025	0.795	0.911
2026	0.780	0.904
2027	0.766	0.898
2028	0.752	0.891
2029	0.738	0.885
2030	0.724	0.879
2031	0.711	0.872
2032	0.698	0.866
2033	0.685	0.860
2034	0.672	0.854
2035	0.660	0.848

2036	0.648	0.842
2037	0.636	0.836
2038	0.624	0.830
2039	0.613	0.824
2040	0.602	0.818
2041	0.590	0.812

3.2.2 Ratepayer Impact Calculation

Ratepayer impact was calculated using the LCOE calculation in Equations (8)-(11) and the following analysis. First, a 20-year OREC bid price form was provided by the Maryland Public Service Commission (PSC) to set an escalating yearly price per MWh based on a levelized 2012-dollar value (see previous section). This calculation utilizes the LCOE and a built-in discount and inflation rate to determine the annual OREC price [67]. Once the annual price for ORECs (*POP*) has been calculated, the next step in finding the average monthly ratepayer impact (*RRI*) is to determine the net ratepayer cost (*NRC*) [65]. *NRC* is calculated as,

$$NRC = \frac{\sum_{i=sd}^{cy} \frac{POP_i EOA_i}{(1+NDRP)^{(i-2012)}}}{\sum_{i=sd}^{cy} \frac{\frac{MO_i}{(1+INF)^{(i-2012)}}}{(1+NDRP)^{(i-2012)}}} - \frac{\sum_{i=sd}^{cy} \frac{MRC_i + ARC_i + MPE_i}{(1+NDRB)^{(i-2012)}}}{\sum_{i=sd}^{cy} \frac{\frac{MO_i}{(1+INF)^{(i-2012)}}}{(1+NDRB)^{(i-2012)}}} \quad (16)$$

Where *cy* is the last year ORECs will be received, this is expected to be 20 years for each wind farm from the first year of the offshore wind farm operation (*sd*) and the

expected end dates are provided in Table 5. *POP* is the price of ORECs for calendar year *i* according to the schedule provided by the Maryland PSC. *EOA* is the expected OREC amount obtained in the State for year *i*. *NDRP* is the nominal discount rate for OREC payments. *MO* is the proposed months of operations in calendar year *i*. *INF* is the inflation rate. *MRC* is the market revenue credits, *ARC* is the avoided REC cost, *MPE* is the market price effect, and *NDRB* is the nominal discount rate for OREC benefits.

The *NRC* is divided by the number of years that the ORECs are awarded to account for the average annual *NRC*. In the case study, each wind farm is expected to run 20 years individually and 21 for the combined wind farms because they are expected to have different operational start dates. The residential ratepayer impact (*RRI*) can then be calculated by [65],

$$RRI = \frac{NRC}{AALE} \tag{17}$$

where *AALE* is the annual applicable load, also known as the annual load of energy entering the Maryland grid. It should be noted that from these equations that *AALE* was derived from the number of awarded ORECs and the offshore wind carve-out percentage provided by LAI in Table 4. There were most terms used by LAI to convert the *RRI* from an annual impact to a monthly impact which in the end through the division and multiplication of the terms equaled 1 [65]. The variables used by LAI for Equation (12) can be found in Table 7.

Table 7 - Ratepayer Impact Calculation Variable Values

Terms	US Wind	Skipjack
NDRP (per year)[11]	0.03	0.03
NDRB (per year)	0.033	0.033
INFL (per year)	0.02	0.02
MO (months/year)	12	12
MRC ($)	$45.89EOA_i$	$47.91EOA_i$
ARC ($)	$12.40EOA_i$	$11.86EOA_i$
MPE ($)	$1.57EOA_i$	$1.97EOA_i$

3.3 New LCOE Model Application

3.3.1 Model Application to 3 Different Cases

PPAs are designed to guarantee the purchase and sale of energy between two parties, whereas ORECs are designed to incentivize the purchase and sale of offshore wind energy between utilities in the State and offshore wind farms. Both PPAs and the Maryland ORECs calculate LCOE to negotiate an agreed upon purchase price for each unit of energy. Like PPAs, the ORECs utilize an energy purchase limitation,

[11] This value represents the nominal rate of return on a 30-year Treasury Bond. LAI used this rate while calculating the OREC price and *RRI*, although LAI recognizes that this is not a normal discount rate for utilities or wind farms, which typically run at 0.06-0.08 per year for onshore wind.

specifically there is a clause in the law that limits the amount of energy that can be sold and purchased in the State of Maryland.

For the Maryland ORECs, only the *PL* is used because there is no penalty on the wind farms when they produce under the expected energy output. During the awarding of the ORECs, no *PL* was included in the LCOE because energy generation was assumed to be constant (the average energy generation) and the combined quantity of ORECs were assumed to never go above the 2.5% offshore wind carve-out [12][12]. The ratepayer impact was also assumed to be only affected by the OREC price after the *TC*s and price effects were removed. LAI used load forecasting to determine the annual applicable load (see Equation (14)). During the awarding of the ORECs the combined effect of the two offshore wind farms was not considered. It was assumed that the residential ratepayer impact could just be summed up, which is not the case because each ratepayer impact only considered the separate load and effect of energy from one offshore wind farm entering the grid at a time. Additionally, the lower LCOE of the two wind farms was chosen to be the OREC price.

In this case study, an hourly analysis (8760 hours per year) was used to generate energy production based on the wind speed distributions and the planned turbine models for each wind farm. In this analysis, the wind speed distributions were gathered by NOAA from onshore data both of the offshore wind lease areas. The locations of the wind speed data stations are shown in Figure 15, and are circled in red and scaled to hub height [68] [69]. Wind speed was sampled from a Weibull distribution, and was

[12] The offshore wind developers may have accounted for some uncertainties in potential *CAPEX* and *OPEX* costs to the wind farms, but they did not account for the loss from continuing to produce energy above the maximum energy deliver limit.

scaled to hub height for each turbine type where the shape parameter was 2.57 m/s and scale of 7.94 m/s for US Wind and the shape for Skipjack was 2.57 m/s and the scale was 8.28 m/s. The actual sampled wind speed distribution for Skipjack is shown in Figure 16 [69] and the wind speed distribution for US Wind is shown in Figure 17 [68]. Power curves for Skipjack (Figure 18) and US Wind (Figure 19) were then used with the wind speeds to calculate the energy generated.

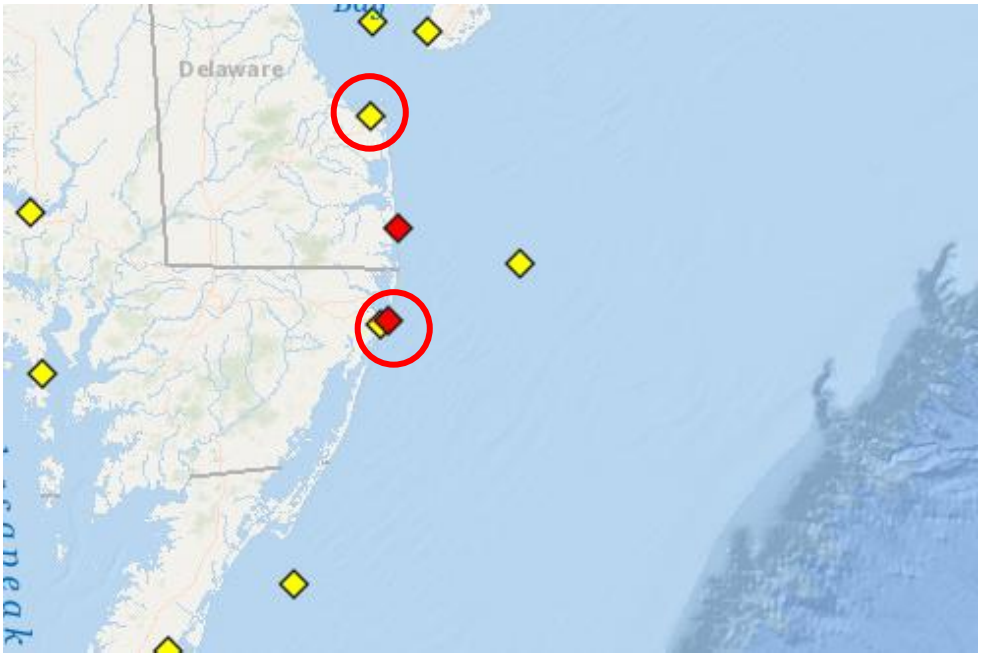

Figure 15:Wind speed data collection stations [70]

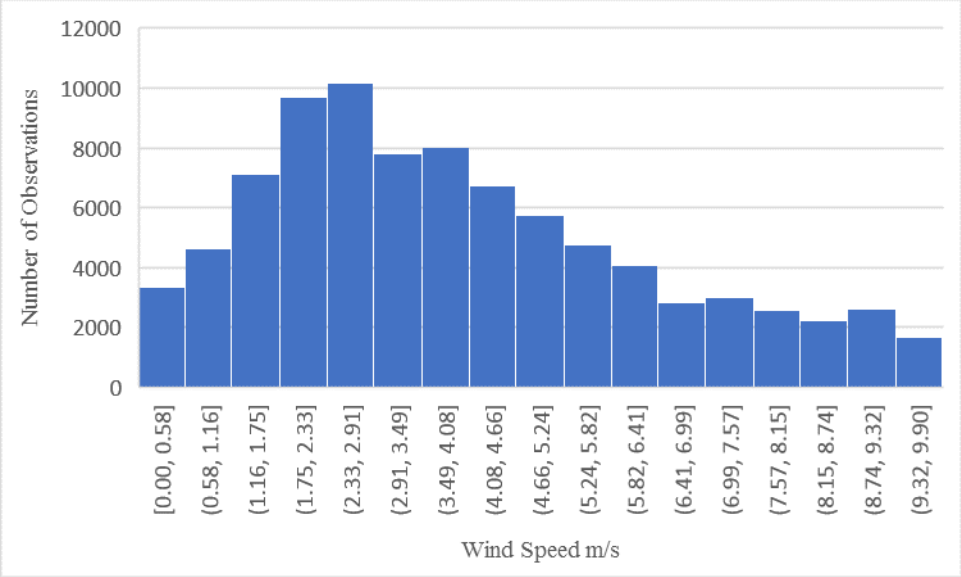

Figure 16 - Wind speed distribution for Skipjack site [69]

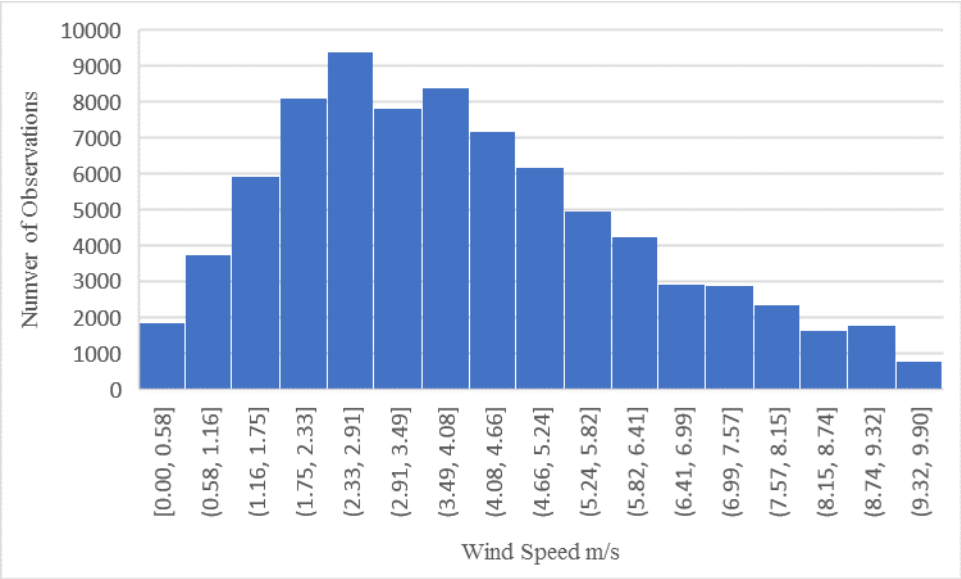

Figure 17 - Wind speed distribution for US Wind site [68]

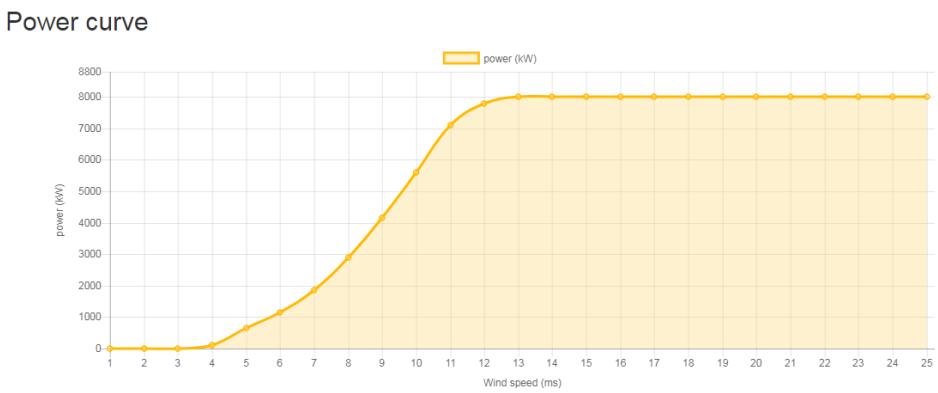

Figure 18: SWT-8.0-154 turbine to be built be Skipjack [71]

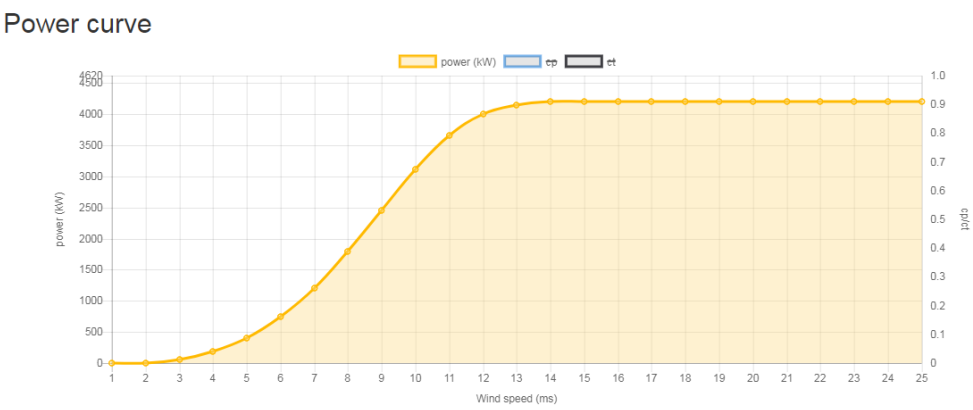

Figure 19: SWT-4.0-130 to be built by US Wind [72]

Maryland's grid is part of a larger network known as the Pennsylvania-Jersey-Maryland (PJM) network. This means that the offshore wind energy may enter the grid in Maryland, but it may not necessarily be consumed within the State. This creates part of the complexity in modeling offshore wind consumption in the state after offshore wind energy has been produced up to the awarded OREC quantity, but still falls below the offshore wind carve-out. Due to a lack of clarity associated with how the energy generated can or cannot be sold during the years that the offshore wind farms are generating more than the awarded OREC quantities, three cases have been developed

to analyze the actual LCOE for the wind farms. Figure 20 provides a graphical description of the three cases considered in this thesis, and Figure 21 shows how Equation (9) is modified to account for each case.

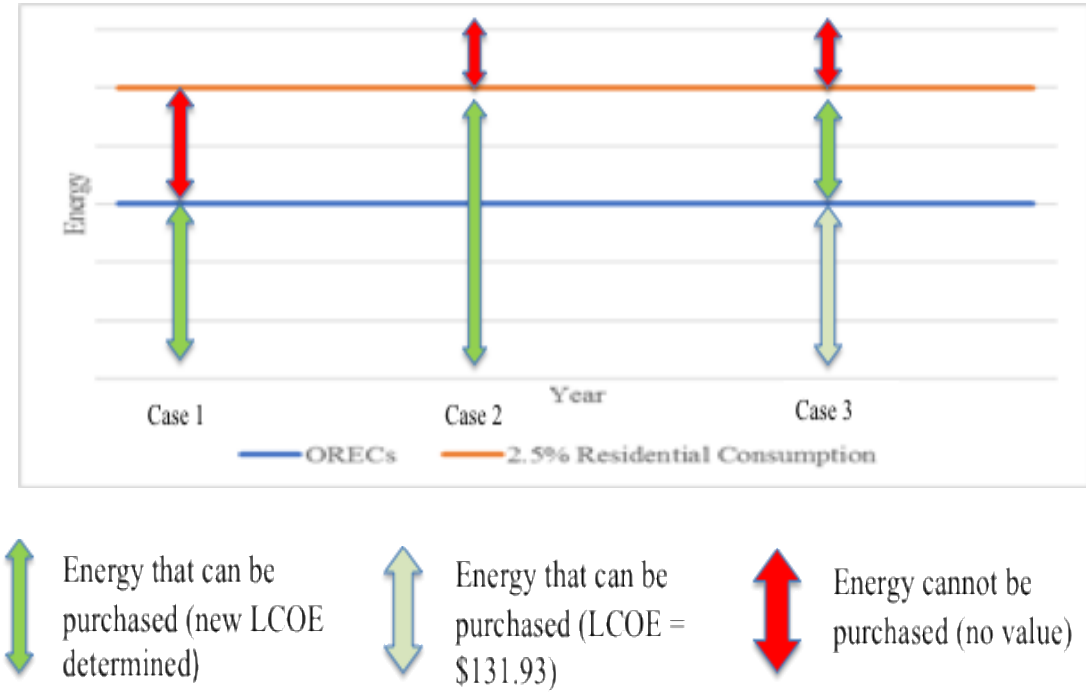

Figure 20: Three possible cases for maximum energy purchase limit for ORECs

$$PL_i = \begin{cases} (E_i - Max_{lim}P_{exp})COE(1 - PPA_{term}) & \text{when } E_i > Max_{lim}P_{exp} \\ 0 & \text{when } E_i \leq Max_{lim}P_{exp} \end{cases}$$

Changing variable based on limit imposed by RPS Law. Either:

- 2.5% of total energy consumption
- Awarded OREC quantity because $Max_{lim} = 1$

COE = $131.93

Remains 0 for case 1 and 2, but is changed to reflect selling into the spot market for case 3. The spot market prices were randomly sampled from a hand collected data set for random hours throughout the day from 3/12/17-6/5/18

Figure 21: PL modified for ORECs

In Case 1, the quantity of awarded ORECs to each offshore wind farm is the absolute maximum energy purchase limit. Above this limit, energy has no value (i.e., excess energy production has to be "dumped"). Max_{lim} in this case is 1, and P_{exp} is the number of awarded ORECs for each farm. PPA_{term} in this case is 0.

In Case 2, it is assumed that more ORECs can be awarded to both wind farms. The maximum energy purchase limit is the offshore wind carve-out of 2.5% of all energy sales in the State and above that carve-out the offshore wind energy would be "dumped". This also assumes that each wind farm would be receiving ORECs for the maximum expected energy production so that all potential energy production can be financed through the ORECs. Max_{lim} in this case is 1, and P_{exp} varies annually to

represent energy sales in the State of Maryland as calculated by LAI. PPA_{term} in this case is 0.

Case 3 assumes that no additional ORECs can be awarded to the two future offshore wind farms. The quantity is fixed, but excess energy generation can be sold into the market at spot-market prices where the spot-market price was determined using a distribution of sampled prices (see Figure 22). The energy price is no longer guaranteed and energy could be purchased above or below the LCOE. This case assumes that *TC*s are still available for the excess energy. Energy sold into the market is still regulated by the offshore wind carve-out, which functions as the maximum energy purchase limit. Max_{lim} in this case is 1 and because this case looks at the value of offshore wind energy sold beyond the ORECs amount, P_{exp} is the same as case 2. However, in this case the PPA_{term} is calculated for every MWh of energy between the awarded ORECs quantity and the P_{exp} by randomly sampling a spot-market price per MWh from a sample of hourly MWh prices collected between 3/12/18 and 6/5/18 and then calculating the fraction by dividing the COE by the spot-market price, the sampled distribution is seen in Figure 22.

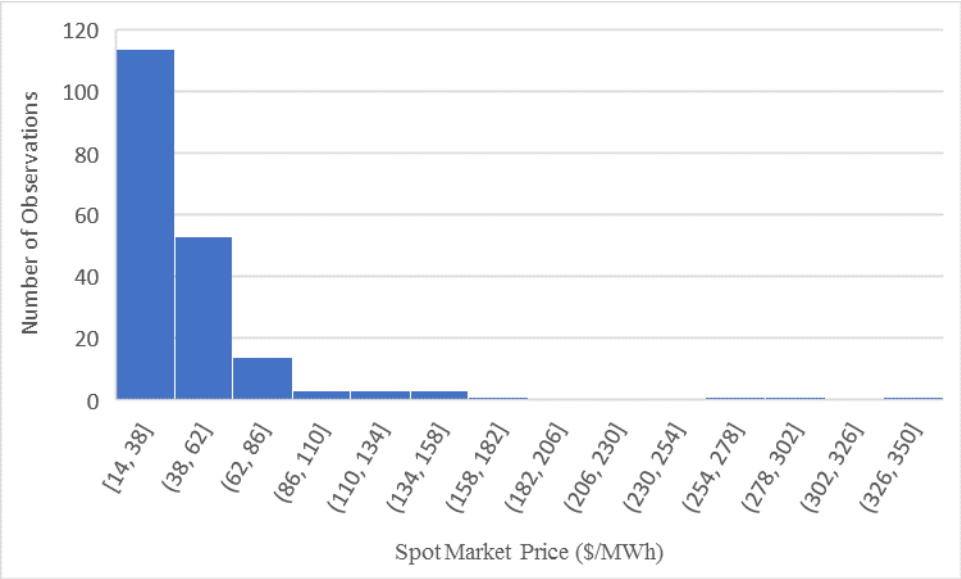

Figure 22: Spot-Market Prices Sampled from 3/12/18 - 6/5/18

Table 8 contains the values used for triangle distributions assumed for each cost variable in the sensitivity analysis [73]. It is suggested by NREL in their report that these distributions are triangular as they represent the highs, the lows, and the average of the industry [73]. The report also suggests that LCOE is more sensitive to *CAPEX* and *CF* than operating life and discount rate. These values were collected from fixed offshore wind farms in Europe, there is not enough data in the U.S. on offshore wind farms, and the most reliable values at this time come from European data.

Table 8 - Distributions for Variables Used in Sensitivity Analysis (triangular distributions assumed)

Variable	Minimum Value	Peak Value (Mode)	Maximum Value
CAPEX ($/kW installed)	2,000	4,579	7,500
OPEX ($/MWh)	79	158	237
r	6.8	9.1	11.4

3.4 Results

In all of the results to follow, the distributions of each variables' sensitivity for US Wind, Skipjack, and the combined wind farm price are presented in the same figure. Figure 23 contains a legend for the results on the sensitivity analysis that are uniform across all cases and wind farms. The distributions in blue are the sensitivities for LCOE to the discount rate. The distributions in pink are the sensitivities for LCOE to *CAPEX*. The distributions in green are the sensitivities for LCOE to *OPEX*. The distributions in purple are the fixed cost variable results where only E_i is sampled based on the wind speed distributions. Finally, the distributions in yellow are the sensitivities to all the variables on LCOE.

Each case also has a table with the average LCOE and variance in LCOE that results from the sensitivities. The results are compared in each table to LAI's calculated LCOEs to demonstrate the differences under the assumption that the fixed cost variables are correct and the LCOE calculation was only missing the penalty cost.

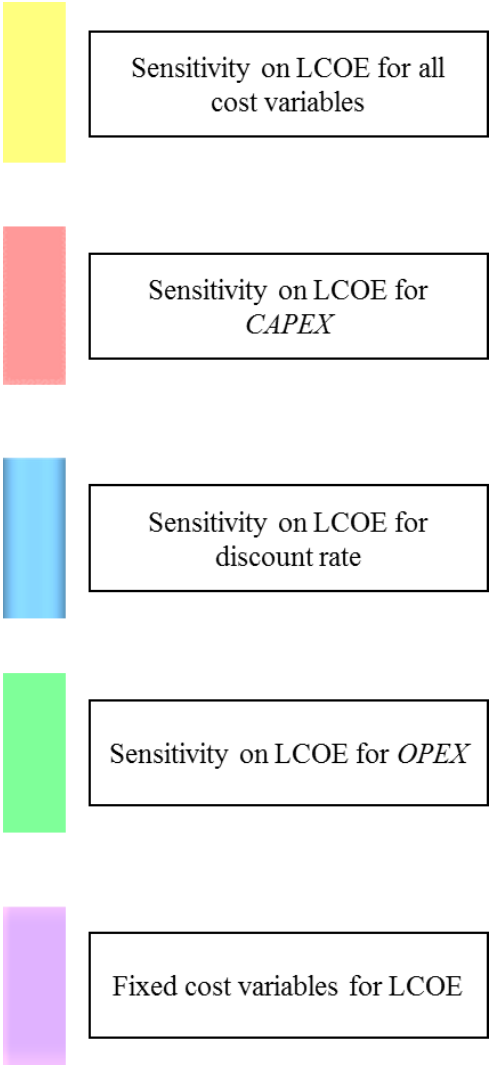

Figure 23: Legend for LCOE Sensitivity Analysis

3.4.1 Case 1

Table 9 provides the results from the fixed cost variable LCOE analysis where only *PL* is varied with energy production. The LCOEs presented are the average LCOE in the analysis and the variance of those results. Compared to the calculated OREC price for each wind farm, the Case 1 results using the fixed cost variable provided from the LAI analysis shows that the LCOEs for both wind farms and the combined wind

farm price are higher what was awarded. In Figure 24, Figure 25, and Figure 26 the distributions corresponding to the discount rate and the fixed variables analysis are not included because there is very little variance for both (see Table 9). This demonstrates that while the maximum energy purchase limit is the number of awarded ORECs, there is more certainty that expected LCOE is correct given that the *CAPEX* and *OPEX* values are correct. Figure 23, Figure 24, and Figure 25.

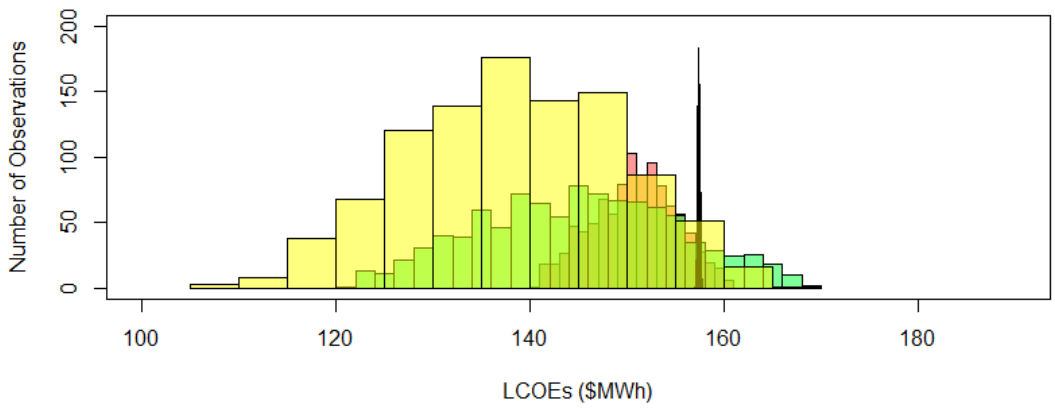

Figure 24: Sensitivities on cost variables for US Wind LCOE for Case 1

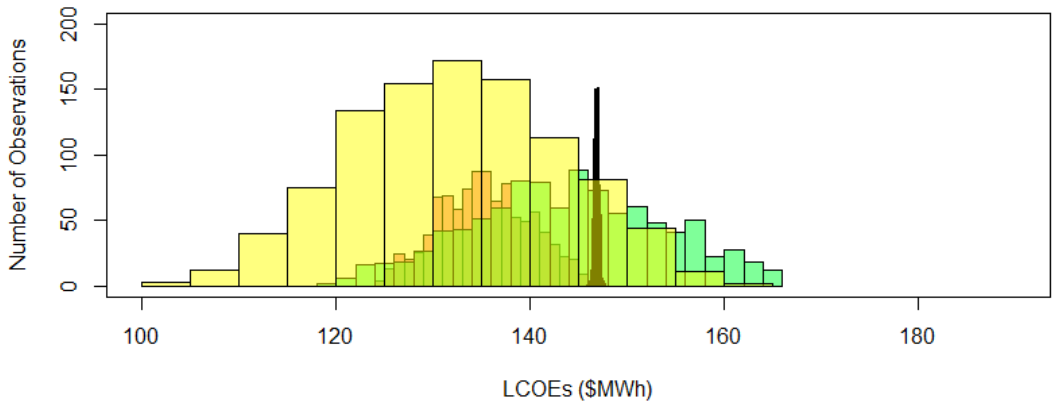

Figure 25: Sensitivities on cost variables for Skipjack LCOE for Case 1

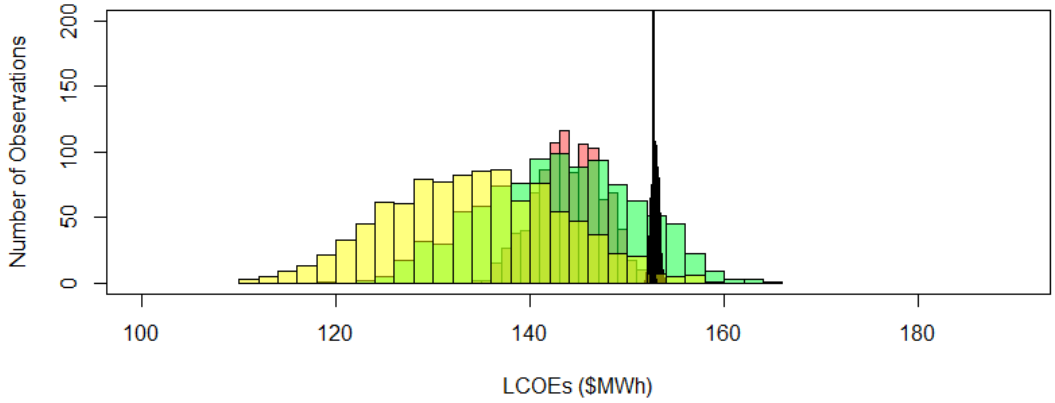

Figure 26: Sensitivities on cost variables for combined wind farm LCOE for Case 1

Table 9 provides a closer look at the variance and average values of all the sensitivity results. For all three wind farms, the lowest average LCOE occurs when all cost variables are varied. However, with the sensitivity on all cost variables there is also the highest level of variance across all results. The distributions allow for lower costs to be sampled compared to the fixed costs assumptions that LAI made, which produces the lower average LCOE results, but the distributions also allow for more variations, which produce the highest variance results. This same assumption can be derived as the highest average LCOE results arise from the sensitivity analysis using fixed costs and these results also produce the least variance. The results also show that the sensitivities on *OPEX* produce the highest variance of all cost variables, which implies that *OPEX* can have the greatest impact on the level of accuracy while calculating LCOE. This agrees with the sensitivity analysis conducted by NREL [73].

Table 9 - Average and standard deviation in LCOE results for Case 1

	US Wind ($/MWh)	Skipjack ($/MWh)	Combined ($/MWh)
LAI Calculated OREC Price	137.06	131.93	N/A
Average LCOE with fixed costs	157.37	146.83	152.65
Variance in LCOE with fixed costs	0.01	0.05	0.01
Average LCOE with variation in CAPEX	150.75	135.30	144.05
Variance in LCOE with variation in CAPEX	17.94	21.61	11.72
Average LCOE with variation in OPEX	144.96	143.82	142.97
Variance in LCOE with variation in OPEX	104.30	98.56	60.99
Average LCOE with variation in discount rate	157.36	146.86	152.88
Variance in LCOE with variation in discount rate	0.01	0.06	0.14
Average LCOE with variation in all variables	138.33	132.47	134.25
Variance in LCOE with variation in all variables	120.27	117.64	78.58

Figure 24, Figure 25, and Figure 26 show that there is little effect on the LCOE from discount rates. However, the means of the distributions are higher for each wind farm and the combined case compared to the distributions from the sensitivities on the other cost variables. This suggest that using a discount rate of 0.03 has reduced the overall LCOE of the wind farms and allowed for a lower OREC price to be awarded, but there is little effect on the LCOE as the discount rate varies in real time.

3.4.2 Case 2

Figure 28 demonstrates the same principal that there is little difference between the average and variance in results between the sensitivty on discount rate and the

controled sensitivity on the fixed costs. However, Figure 27 and Figure 29 show that there is a difference in the average LCOE between the fixed costs results and the results from the sensitivity analysis on the discount rate. Table 10 shows that the average LCOE for sensitvity on discount rate for US Wind is lower than the average LCOE is using fixed cost variables. In comparison, the average LCOE with sensivity on discount rate is higher for the combined wind farm than the average LCOE using fixed costs. This can imply that uncertainty in the discount rate for both wind farms that are generating more energy than expected into the market can result in a higher LCOE. Although we know from the results in Case 1 that *PL* has the largest impact on making LCOE higher than calculated, the results in Figure 29 imply that a higher than expected discount rate can also have a sever impact on the LCOE for Case 2 because the only time *PL* is incurred in this analysis is during the combined wind farm consideration and the impact is minimal because the maximum energy purchase limit is much higher than Case 1. If the discount rate is higher than expected, than the impact of the *TLCC* is higher for each unit of produced energy.

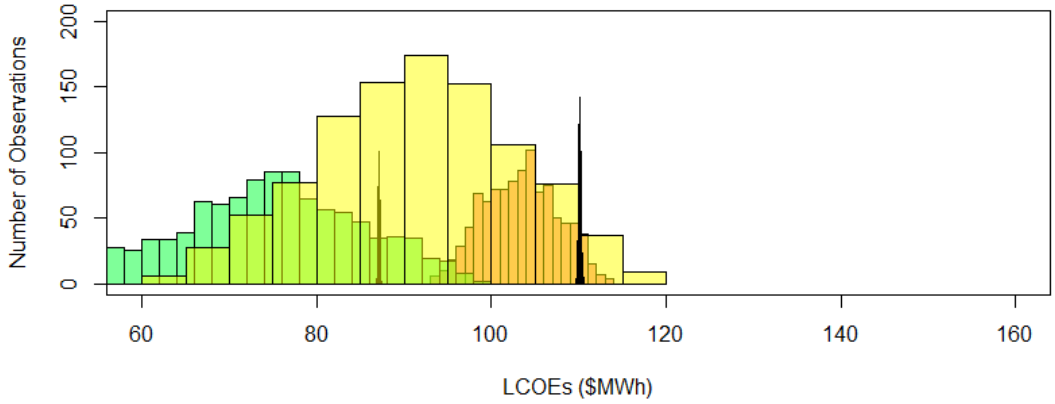

Figure 27 - Sensitivities on cost variables for US Wind LCOE for Case 2

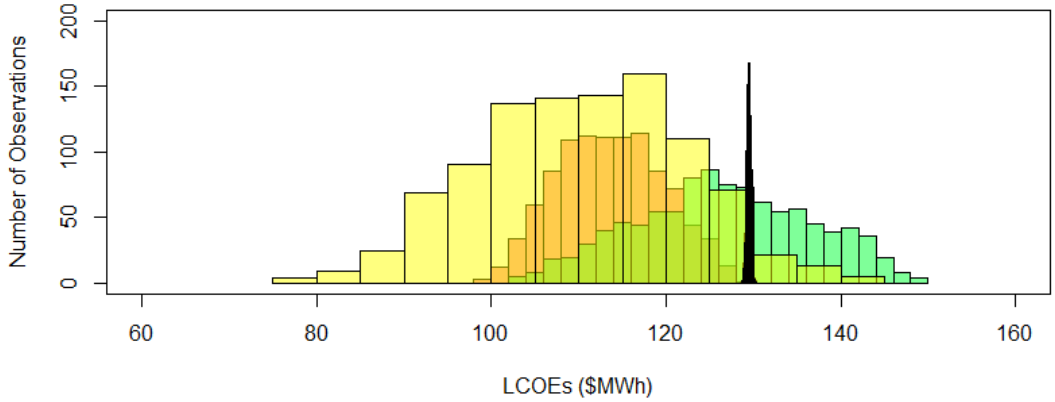

Figure 28: Sensitivities on cost variables for Skipjack LCOE for Case 2

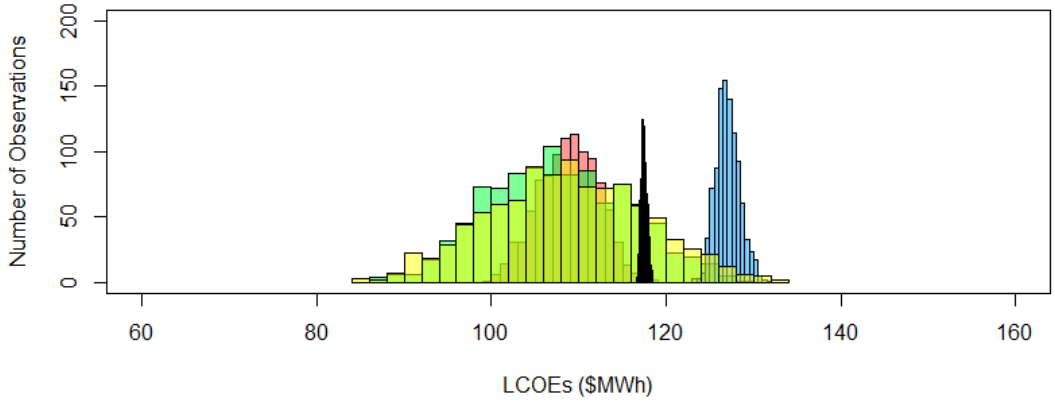

Figure 29: Sensitivities on cost variables for combined wind farm LCOE for Case 2

Table 10 provides all the averages and variance in LCOEs from the sensitivity analysis. The results are similar to Case 1 (see Table 9) as the higher average LCOEs from the results are in the fixed costs, which also have the lowest variance, and the highest variance in the results with almost all the lowest average LCOEs are in the sensitivity on all cost variables. From each individual cost variable sensitivity, *OPEX* shows to have the highest variance implying the importance on accurate predictions on *OPEX* while the discount rate has the least variance.

Table 10 - Average and standard deviation in LCOE results for Case 2

	US Wind ($/MWh)	Skipjack ($/MWh)	Combined ($/MWh)
LAI Calculated OREC Price	137.06	131.93	N/A
Average LCOE with fixed costs	110.12	129.49	117.35
Variance in LCOE with fixed costs	0.02	0.06	0.12
Average LCOE with variation in CAPEX	103.37	113.62	108.84
Variance in LCOE with variation in CAPEX	17.67	35.92	11.40
Average LCOE with variation in OPEX	75.06	126.54	107.69
Variance in LCOE with variation in OPEX	100.16	99.19	63.89
Average LCOE with variation in discount rate	87.12	129.49	127.07
Variance in LCOE with variation in discount rate	0.01	0.06	1.77
Average LCOE with variation in all variables	91.36	110.59	108.64
Variance in LCOE with variation in all variables	126.21	140.37	79.86

Case 2 results using fixed cost variables from LAI demonstrate that the LCOE could be lower if more offshore wind energy was being purchased. This is because the more energy being produced and sold by the system, the more costs that can be distributed across the system's output. In Case 2, the only time *PL* is incurred is during the combined wind farm LCOEs, but the results are still lower than the current awarded price of ORECs and the offshore wind carve-out can actually be achieved.

3.4.3 Case 3

Table 11 provides all the averages and variance in LCOEs from the sensitivity analysis. The variance and average LCOE results for discount rate, fixed costs, all cost variables, and *OPEX* are similar to Case 2 and Case 3 results. However, the highest

average LCOE in Case 3 is from the combined wind farm that has variation in all cost variables at $162.83/MWh and the highest variance at 173.08. Not only is it notably the highest average LCOE and variance in Case 3, it has the highest average LCOE and variance amongst all three cases. The combined wind farm also contains produces a high variance during the sensitivity on discount rate, which is likely causing the high variance and high average LCOE in the results for the sensitivity analysis on all cost variables. It is possible that the higher variance and average LCOE in the results on variation discount rate and variation on all cost variables due to the spot-market price effect having more impact on both wind farms as the two are selling more energy combined into the spot-market compared to the individual results. The discount rate would reflect the how much more uncertainty in the spot-market could impact the LCOE of wind farms as they choose to distribute more energy in it compared to distributing energy towards a Buyer at an established cost. At the same time, the results do show that if the wind farms are working separately and entering the spot-market where a majority of the generation has already been purchased through a PPA or REC, there is significantly less risk.

Table 11 - Average and standard deviation in LCOE results for Case 3

	US Wind ($/MWh)	**Skipjack ($/MWh)**	**Combined ($/MWh)**
LAI Calculated OREC Price	137.06	131.93	N/A
Average LCOE with fixed costs	110.11	109.53	133.75
Variance in LCOE with fixed costs	0.02	0.12	3.10
Average LCOE with variation in CAPEX	103.47	98.15	126.96
Variance in LCOE with variation in CAPEX	17.80	20.69	20.40
Average LCOE with variation in OPEX	98.16	106.11	121.45

Variance in LCOE with variation in OPEX	100.50	101.19	105.57
Average LCOE with variation in discount rate	110.11	109.53	181.19
Variance in LCOE with variation in discount rate	0.02	0.16	51.36
Average LCOE with variation in all variables	91.23	95.49	162.83
Variance in with variation in all variables	110.25	119.37	173.08

It is possible that the LCOEs from Case 3 are lower than the OREC price because the Seller receives the benefit of the *TCs* for energy sold into the spot market. As seen in Equation (10), *TCs* reduce the LCOE of a project if the project directly receives them. In the case of ORECs, they are bundled with other partial RECs and therefore the utility indirectly receives the benefit of the partial RECs. The spot market sample distribution from Figure 22 indicates that there would be a loss. since energy in the spot-market is more frequently sold at a lower price than the COE ($131.93/MWh).

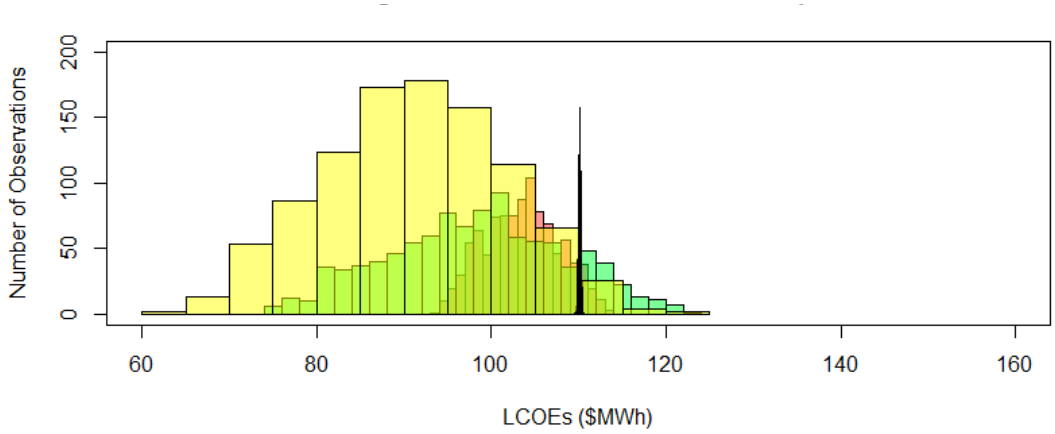

Figure 30: Sensitivities on cost variables for US Wind LCOE for Case 3

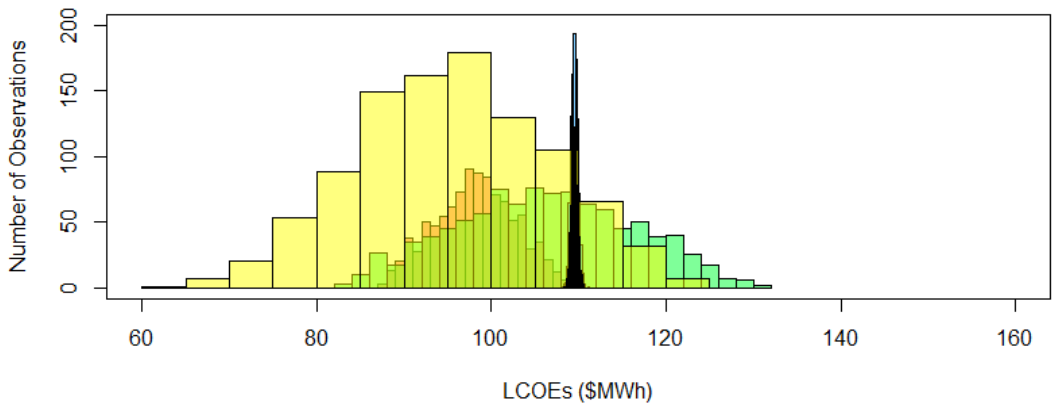

Figure 31: Sensitivities for cost variables for Skipjack LCOE for Case 3

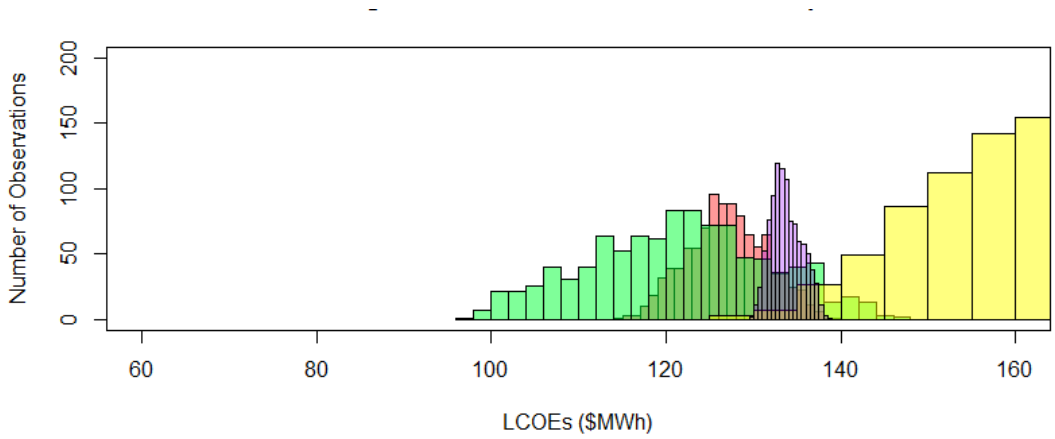

Figure 32: Sensitivities for cost variables for combined wind farm LCOE for Case 3

Table 12 provides a comparison of all the average LCOEs for the fixed cost variables for each case and wind farm to the calculated LCOEs by LAI. The fixed cost variables results were provided for the final comparison under the assumption that the predictions were correct and the awarding of more ORECs or a change in OREC price would be dependent solely on an LCOE that included the *PL* and not the probabilities that the other cost variables are off.

Table 12 - Summary of all cases for OREC Price using LAI cost variables with modified LCOE

	US Wind OREC price	**Skipjack OREC price**	**Combined**
LAI's calculation	$137.06	$131.93	N/A
Case 1 calculation	$157.36	$146.83	$152.66
Case 2 calculation	$110.12	$129.49	$117.35
Case 3 calculation	$110.11	$109.53	$133.75

Based on the results shown in Table 12, the ideal case for both wind farms receiving ORECs is Case 2 where each would receive the maximum amount possible as long as it is under the 2.5% offshore wind carve-out. This results in a lower price of $117.35/MWh compared to the $131.93/MWh that was awarded and the offshore wind carve-out would be achieved compared to the current situation. The other ideal case for each offshore wind developer is to sell their excess energy into the spot-market (Case 3). This is a higher risk, but it can be sold at a lower value than the OREC price and it is better than not selling excess energy. The combined wind LCOE in Case 3 is not probable as both wind farms would have to work together, but they are competitors once they reach the spot-market.

3.4.4 Ratepayer Impact

Table 13 provides the monthly residential ratepayer impact from the average LCOEs for each wind farm for each case given under fixed costs provided by LAI. The results show that under the current situation, if the wind farms are limited to sell their energy at their awarded OREC quantity at the price of $131/93/MWh, the monthly residential ratepayer impact is lower than expected at $1.267/month. However, if the OREC quantity were to remain the same, but the LCOEs were adjusted to account for the production loss incurred from the maximum energy purchase limit, then the monthly residential ratepayer impact of both farms selling their energy into Maryland would be higher than the $1.50/month limit at $1.633/month.

Table 13 – Residential Ratepayer Impact Results ($/month)

Impacts	US Wind	Skipjack	Combined
LAI's calculation	$0.974	$0.433	$1.407 (PSC)
Current Situation	$0.974	$0.433	$1.267
Case 1	$1.158	$0.578	$1.633
Case 2	$0.767	$0.526	$1.209
Case 3	$0.842	$0.849	$1.057

Case 3's combined results reflect the residential ratepayer impact for the energy sold in the spot market. It does not consider the impact from the ORECs in addition to energy sold in the spot-market. However, it should be noted that in conjunction with

the awarded ORECs, offshore wind energy entering the spot-market will likely have a higher overall ratepayer impact than that demonstrated in Table 13. Additionally, the combined wind farm in Case 3 is not likely as both wind farms would have to be working together beyond the ORECs when they will be competitors in the market at that point.

The ideal situation out of the 3 cases is Case 2 combined. The average monthly ratepayer impact would be lower than the current situation although more offshore wind energy would be entering the grid. Not only would Maryland be closer to meeting the 2.5% offshore wind carve-out set by the State's RPS, they could do so at a lower cost to consumers. This is likely do to the lower LCOE of $117.35/MWh that could be awarded to both offshore developers compared to $131.93/MWh as currently awarded.

3.5 Conclusions

For the current state of the ORECs the average monthly ratepayer impact still falls below the $1.50/month limit set by Maryland law. However, the price of the ORECs is not consistent with the actual LCOEs. The actual LCOEs are higher than expected as seen in the results from Case 1, and if the ORECs were awarded at the current quantity at the actual LCOE for both wind farms, the average monthly ratepayer impact would be $1.633 per month, which is above the $1.50 per month limit set by the law. Case 2 demonstrates that not only can more ORECs be awarded at a lower price, the expected ratepayer impact is still lower than that "calculated" by LAI for the PSC. This does not mean that more ORECs can be awarded at the current offshore wind carve-out. During the Case 2 results there were various years that the combined wind

farms produce energy over the offshore wind carve-out and incurred a cost from the production loss. However, the results do suggest that if the offshore wind carve-out was increased more ORECs could be awarded at a lower than expected price. This may allow for US Wind to build more turbines in the second half of their lease area[13].

All of the results from sensitivity on discount rate, excluding the results in Figure 32, indicate that LCOE is least sensitive to discount rate. This is surprising as many people focus on choosing an appropriate discount rates when calculating LCOE [31]. The results also indicate that LCOE is most sensitive to *OPEX* although the resulting average LCOE is typically lower than the LCOE using fixed costs. This is likely due to the distribution of *OPEX* values that can fall lower than those expected for each wind farm. High variance in *OPEX* results also suggest that it is critical to calculate with as much accuracy as possible an expected *OPEX* value or the LCOE may be much higher or lower than expected.

Choosing which maximum energy purchase limit to use for the ORECs can significantly change the actual LCOE of the wind farm. At a limit that is too low (i.e., the current awarded OREC quantity), the LCOE can be higher than the OREC price and LCOE determined by LAI. At a limit that is higher (i.e., 2.5% of all energy sales in the State), the wind farms can still incur a penalty from overproduction of energy when both are selling the maximum amount of energy into the State, but the actual LCOEs can be lower than the awarded OREC price.

[13] Originally, US Wind submitted their application to build 750 MW with the ORECs only covering 248 MW. US Wind stated in the application that with 248 MW they will safely be covered under the ORECs and in the future they could build the rest under other PPAs [77].

Chapter 4: Conclusions, Contributions, and Future Work

4.1 Summary

PPA and REC energy purchase limits can increase the actual LCOE of wind farms as the penalty from overproduction and underproduction of energy is applied. This can create significant losses to the wind farm as the actual LCOE could be higher from the conventionally calculated LCOE by a factor of 1.5. In the case of the Maryland ORECs, the actual LCOE given the maximum energy purchase limit at the number of awarded OREC quantity are higher by a factor of 1.16 from the awarded OREC price. This can cost the wind farm millions in lost revenue.

The threshold of the energy purchase limit can also significantly affect the LCOE. The penalty may be more significant depending on where the threshold is compared to what energy may actually be produced by the system. A maximum energy purchase limit that is close to the maximum expected amount of energy that will be generated could lower the LCOE compared to the conventionally calculated LCOE that assumes average energy generation. This is demonstrated in the ORECs as Case 2 how a lower LCOE by a factor of 0.89 from the awarded OREC price.

4.2 Scientific and Technical Contributions

The contributions of this work include the following:

1. The first LCOE model that includes PPA penalties was developed.
2. It was demonstrated that there are significant discrepancies created by asymmetric cash flows and penalties when using the LCOE model as an infinite horizon model when energy production is uncertain.
3. It was demonstrated that the Maryland ORECs have been awarded at a lower price than the LCOE considering the penalty from only selling the average expected energy generation.
4. It was determined that the State of Maryland could award additional ORECs at a lower price while still producing energy under the offshore wind carve-out.

4.3 Future Work

Another case has been suggested to the Maryland PSC, where the offshore renewable energy credits could roll over and under each year. This is a more complicated case, since one would have to account for the value of energy that was sold or not sold the year before as it is sold into the next year. The LCOE model becomes a significantly more complex as the time value of energy is considered in the analysis, but it is uncertain if that energy is actually sold in the next year as the cash flows and value of energy in year i becomes dependent on year $i+1$.

This work could also be extended towards increasing the offshore wind carve-out and allowing for a third party to be awarded ORECs. The issue then is, can the ORECs be awarded at a different price? US Wind could ask for more ORECs for the rest of their wind farm development, but this would be complicated as to how to model

the LCOE where half the wind farm is already receiving ORECs. It is unknown if US Wind would have to consider the "other half" that is receiving ORECs as if it is a third party or if the State would not care as long as offshore wind energy is entering the State below the offshore wind carve-out.

Wind blows more during certain periods of the year compared to others, and PPAs and RECs currently adjust their accounts at the end of the year. This means that one party may be paying back the other for energy that should have been purchased or energy that was not supposed to be purchased. This brings into question of when is the optimal time to do financing on the project: quarterly, monthly, or remain annually?

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Publications Associate with this Thesis

[1] Bruck, M., Goudarzi, N., Sandborn, P., "A Levelized Cost of Energy (LCOE) Model for Wind Farms with Power Purchase Agreements (PPAs)," *Renewable Energy*, vol. 122, pp. 131-139, 2018.

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