

Sizing of Offshore Wind Energy Storages

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THESIS

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Preface

Studying at NTNU as part of the Innovative and Sustainable Energy Engineering Programme, I initially started planning this work in August 2013 as I started to investigate the possibility of a collaboration with DNV GL's Arnhem office alongside their energy storage group. They were involved in the early stages of the planning process, helping shape the initial direction of the thesis to focus on mainly an offshore energy storage methodology that could be applied to a variety of different situations. However, I had trouble finding an NTNU professor to supervise the project. Eventually, I approached Erling Næss, who agreed to co-supervise with Lars Sætran. This initial work formed the pre-thesis project, and we slowly developed it into more of an actual sizing model.

Due to the late start of the project, the thesis did not officially start until May 2014. No contract had been signed with DNV GL, and by this time, official cooperation with them faltered due to heavy work loads. However, they had been and continued to be a great asset for providing guidance and information. Lars Nord came on-board to replace Lars Sætran at this point. This thesis had developed further to be a costing optimisation and was described as such in the problem statement.

Trondheim, 15-10-2014

A handwritten signature in black ink, appearing to read 'LaZerte', with a stylized, cursive script.

Franz LaZerte

Acknowledgment

I would like to thank the following persons for their great help during my period working on this thesis:

DNV GL helped shape the original vision of this thesis, with significant contributions by Gerben Dekker, Jillis Raadschelder and Petra de Boer. NTNU has provided many services and resources including the MatLab licence, and of course the contributions, advice and guidance from my supervisors has been invaluable: A special thanks to Earling Næss, Lars Nord, and Lars Sætran (who initially started as one of my co-supervisors).

FL.

Summary and Conclusions

Energy storage has the potential to provide a key benefit for intermittent energy sources such as offshore wind by providing a method to store excess energy to be used when the wind no longer blows. However, to date energy storage has always been a fairly cost prohibitive option, particularly in offshore environments where the technology has not even reached commercial status. To properly assess the potential of energy storage, this thesis proposes a MatLab cost optimisation model which determines the most cost effective sizing of an energy storage system to be used in a given situation. The key feature is flexibility and modularity, allowing a user to customise the scenario accurately but simply to provide a powerful and robust simulation capable of nearly limitless possibilities. As a result, a model is designed that is capable of accepting different modules that will define:

1. the primary power curve, such as the production from a wind farm
2. the demand curve of a selected consumer
3. the backup power production, which is a fuel-driven power production unit of choice
4. the energy storage system, which is chosen from a variety of different technology options

After a literature survey, subsea pumped hydro storage (PHS) and subsea compressed air energy storage (CAES) is thought to be the most interesting and feasible energy storage technologies to investigate, and are implemented into the model. Additionally, a normalised offshore wind farm power curve along with the demand curve of a offshore oil and gas platform are used for primary power and demand respectively, and simple cycle gas turbines are chosen as the backup power production system.

The results from the model suggest that the CAES is actually a competitive option in the current market, while the PHS will need drastic reductions in capital costing before it becomes viable. While the model yields interesting results, it is only as accurate as the cost data used, which is unfortunately bearing quite a large margin of error. Since there have been no actual commercial feasibility studies done on either of these technologies, we are relying on many assumptions and estimates as outlined in detail in the report.

Finally, discrepancies in the results suggest that the model has a major technical flaw and has difficulty on performing its optimisation with 100% certainty. Simulations do not always find the global minimum as required, and sometimes they only find a local minimum. This becomes apparent during sensitivity analyses, and it is suggested that this problem could be alleviated with additional computational resources to run more thorough simulations, as well as using a Global Optimisation Toolbox that MatLab provides.

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Chapter 1

Introduction

1.1 Background and Litterature Review

Renewable energy solutions are becoming increasingly appealing and popular due to their lack of dependency on fossil fuels, allowing nations without access to such natural resources to become more power independent and emit less greenhouse gas (GHG) emissions. More government entities are incentivizing renewable energy [41], while others, such as Norway, are penalizing traditional fossil fuel production with carbon taxation [8]. In particular, offshore wind has seen significant investment in the North Sea in recent years and currently has over 2.3 GW in operation. This is predicted to grow to 25.5 GW by 2020, and 82.9 GW by 2030 [43], making offshore wind one of the fastest growing renewable energy sectors in the region.

The oil and gas platforms and FPSOs in the North Sea and around the world require large amounts of reliable power, some in the magnitude of 100 MW or more [17], and the smallest interruption can cost an operator thousands in loss of production every minute.¹ Offshore platforms are already subject to carbon taxes but in the future they may be restricted even further, obsoleting fossil fuel generators and pushing reliance onto clean power-from-shore (PfS). However, offshore operators are establishing new wells farther out, and providing the necessary reliable power is becoming more difficult and costly as distances surpass a few hundred kilometres. The new, deep-water offshore wind developments that are being produced could be a solution,

¹Based on Galfaks C crude oil production of 165,000 barrels per day [25], and a February 17, 2014 oil price of 100 USD per barrel [1]

but their intermittent nature is a problem for consumers that require 100% reliability and up-time. Studies have shown that wind parks in collaboration with natural gas (NG) generators can reduce fuel consumption, and therefore GHG emissions, up to 42% with 40% wind penetration, while still maintaining an appropriate level of reliability [31]. However, this method does not eliminate the use of fossil fuels entirely.

Large-scale localized energy storage (ES) solutions could perform the same role as a supplementary fossil-fuel generator by providing power during times when the intermittent wind cannot. If sufficiently sized, this could improve a wind park's dependability [37] while replacing fossil fuel generators. In a scenario where fossil fuels become prohibitively expensive, either from increased fuel prices or stricter governmental policies, large-scale ES coupled with offshore wind provides a solution.

1.1.1 Problem Formulation

Using ES systems to supplement any kind of power generation system, let alone a wind-power system, is extremely site-specific. Since there is such a large amount of changing variables based on location, technology used, national policy and so on, it is nearly impossible to determine if an ES system is worth an investment, since previous real-world examples may not be necessarily applicable. Transmission system operators (TSO), investors and renewable energy plant operators could all benefit from an easy-to-use tool that would allow them to roughly predict the lowest possible ES investment costs for a given scenario of their choosing, and whether or not it is competitive to more conventional systems.

Therefore the goal of this Master thesis is to create a generic cost optimisation model that will size energy storage for a specific power production and consumer demand curve for offshore applications in off-grid scenarios. The focus will be on a demonstration of the flexibility and versatility of the model by showing how different scenarios can be adapted and analysed by using case study examples.

1.1.2 Literature Survey

Optimisation

In order for an optimisation of energy storage sizing to provide any realistic conclusions for real-world situations, cost will be the most important issue. Thus, the cost component of this model is determined to be a major priority, and the optimisation shall be built around this focus. Many papers have examined energy storage cost optimisation cases, but they depend on specific ES, generator and wind park sizes and combinations, and focus on optimising operation strategies [31][10][9] of the equipment. While their conclusions provide valuable insight, their optimisations do not appear to be flexible enough for the goals of this thesis. However, their work done in discovering the optimal operation strategies shall be adapted into our model since we can assume that any operator would prefer to use the most efficient practices available. We will focus on optimal sizing of the ES system itself, which will require additional flexibility; the ES size must be capable of dynamically changing as part of the optimisation to assess the most economic setups, and this could be done for multiple scenarios:

- ES versus back-up generators: back-up generator capacity costs would be implemented versus that of ES, and the ratio between the two would be evaluated to determine how much of each would be most cost efficient. Sensitivity analyses of fuel prices and carbon taxes could be performed. This scenario would be predominantly in off-grid situations.
- Distance from Shore: This would take into account the distance-related costs of deep-sea power cables and equipment, and examine how far from shore a consumer would need to be until an ES alternative to PfS becomes affordable. In this case, the ES system would need to fully cover the demand load as it being used as a direct replacement of PfS equipment. The resultant optimisation from the ES versus back-up generators scenario could be used to make a more realistic scenario to compare against.
- PfS Equipment Downsizing: ES could be sized as a supplement to PfS, and the optimisation would compare size of ES with savings of reducing cable and equipment power ratings due to intermittent wind fluctuations. This scenario could become more complex

and specific, but potentially more interesting to key offshore oil and gas technology developers: Currently, certain energy intensive equipment is used

Due to complexity of the problem and time constraints, this thesis focuses on the first item to simplify the problem, meaning only off-grid scenarios will be considered.

Optimisation Algorithms

Matlab's optimisation toolbox provides many different functions and computational algorithms to use. To complete the main objective of the optimisation - that is, to find an ES system that provides adequate power from a combination of stored energy and backup sources to meet demand while minimising the price tag - an optimisation method would be needed.

An optimisation has a general problem: an objective function $F(x)$, which returns a scalar value, is to be minimised by varying design variable x . These general problems are subject to constraints that limit the function, such as equality and inequality arguments. For example, a constraint could be $x^2 - 4 \leq 0$, implying that the solution could not be greater than 2. There are different classifications of optimisation problems depending on their complexity. If the objective functions and constraints are linear, it is known as a Linear Programming (LP) problem, whereas Quadratic Programming (QP) involves a quadratic objective function. These two types are generally easier to solve due to their simplicity, but unfortunately the complexity of the problem in the case of this thesis does not fit into these classifications. It is known as a Non-linear Programming (NP) problem, since it deals with a non-linear objective function. These problems require an iterative process to estimate the correct solution, and breaks the problem down into simpler forms like a LP, QP or unconstrained subproblem. Sequential Quadratic Program (SQP) is such a type, which relies on QP for its subproblem routine.

In MatLab, the *fmincon* SQP algorithm is said to have distinct advantages. It is more robust than other NP algorithms that MatLab has to offer (such as the active-set algorithm), by not allowing return values of complex numbers and non-values to break the optimisation. It is based upon different algebra routines to solve the QP subproblem, which are more efficient in both speed and computational resources.

Like many optimisations, the *fmincon* SQP algorithm is governed by tolerances and stopping criteria which effect the thoroughness and length of the optimisation run. Consider a convex

objective function, as shown in Fig. 1.1:

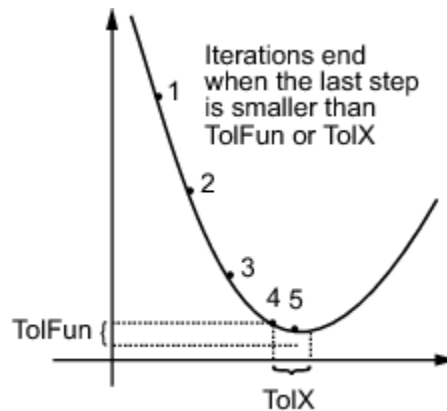


Figure 1.1: Optimisation Tolerances and Stopping Criteria

TolX represents the minimal size of step the iteration is allowed to take in the x direction. Likewise, TolFun represents the same but in the Y direction. If the iteration attempts to take steps that are smaller than either of these tolerances, the iterations end and it is assumed that the solution has been found to adequate accuracy.

For simple convex problems like the one used in Fig. 1.1, finding the global minimum is a simple process of iterating with a stringent enough tolerance to achieve an accurate result. However, more complex objective functions will have many troughs and peaks, and therefore many local minima and maxima. The general accepted method of dealing with this is to rerun the optimisation with different initial values. If each time the optimisation starts in a different place, it finds a different local minimum, the lowest of them can be selected as the overall, or global, minimum, which is of course our objective with this model.

MatLab has a Global Optimisation Toolbox which is specifically designed to solve multiple minima optimisation problems. This system uses a combination of randomized search methods in combination with optimisation solvers to achieve results, as well as implementing further efficiency features like parallel programming. Unfortunately, we did not have access to a licence for this toolbox and had to make do with regular optimisation methods.

Energy Storage Technologies

ES systems have existed both commercially and experimentally for decades and take a vast variety of forms; from battery packs, to mechanical flywheels, to compressed gas and pumped

hydro storage. There are many different sectors in which ES has seen developing interest over the last decades due to a variety of drivers;

- increased intermittent renewable integration - as the penetration of intermittent renewable sources such as wind and solar increase, the reliability of our energy mix begins to see potential problems with guaranteeing power to the population. Large-scale energy storage could be used to store energy during periods of high production for later use.
- the development of smart grids - smart grids use modern communications technology to improve efficiency and sustainability of the grid and involve concepts like peak shaving to lower strain on the energy system. One way of doing this is by storing energy.
- Managing demand peaks - large investments are placed into so-called 'peak plants' which are used to provide extra power during periods of high demand. These plants are generally run at lower efficiencies than base demand plants because they are consistently run at part-load. Using energy storage would lessen the requirement of these plants and improve grid efficiency.
- reliable grid infrastructure investments - AC frequency of the electrical grid must be regulated very strictly, and is normally done by adding and removing generation sources. Once again, these sources run at low efficiencies. Fast-acting energy storage can be used for this purpose to stabilise the grid in a more energy-efficient manner.

According to [40], energy storage can provide a number of different services to end-use consumers all the way to generation-level producers, outlined by Table 1.1:

Each of these services have different operational goals and require different amounts of ES. Each ES technology has different power and capacity costs, making it important to determine what magnitude of ES is required for the particular application examined in this thesis, which is using sizing energy storage for offshore wind parks and other large, fluctuating power producers. The renewable integration service is deemed most appropriate. As shown in Fig. 1.2, renewable integration requires high levels of both power and energy storage capacity.

This application of ES requires a robust system that is capable of providing both high power discharge when required, and for long periods. There are many different kinds of ES technolo-

Table 1.1: Definition of Energy Storage Applications

Value Chain	Application	Description
Generation & System-Level Applications	1 Wholesale Energy Services	Utility-scale storage systems for bidding into energy, capacity and ancillary services markets
	2 Renewables Integration	Utility-scale storage providing renewables time shifting, load and ancillary services for grid integration
	3 Stationary Storage for T&D Support	Systems for T&D system support, improving T&D system utilization factor, and T&D capital deferral
	4 Transportable Storage for T&D Support	Transportable storage systems for T&D system support and T&D deferral at multiple sites as needed
T&D System Applications	5 Distributed Energy Storage Systems	Centrally managed modular systems providing increased customer reliability, grid T&D support and potentially ancillary services
	6 ESCO Aggregated Systems	Residential-customer-sited storage aggregated and centrally managed to provide distribution system benefits
	7 C&I Power Quality and Reliability	Systems to provide power quality and reliability to commercial and industrial customers
End-User Applications	8 C&I Energy Management	Systems to reduce TOU energy charges and demand charges for C&I customers
	9 Home Energy Management	Systems to shift retail load to reduce TOU energy and demand charges
	10 Home Backup	Systems for backup power for home offices with high reliability value

T&D = Transmission and Distribution; C&I = Commercial and Industrial; ESCO = Energy Services Company; TOU = Time of Use

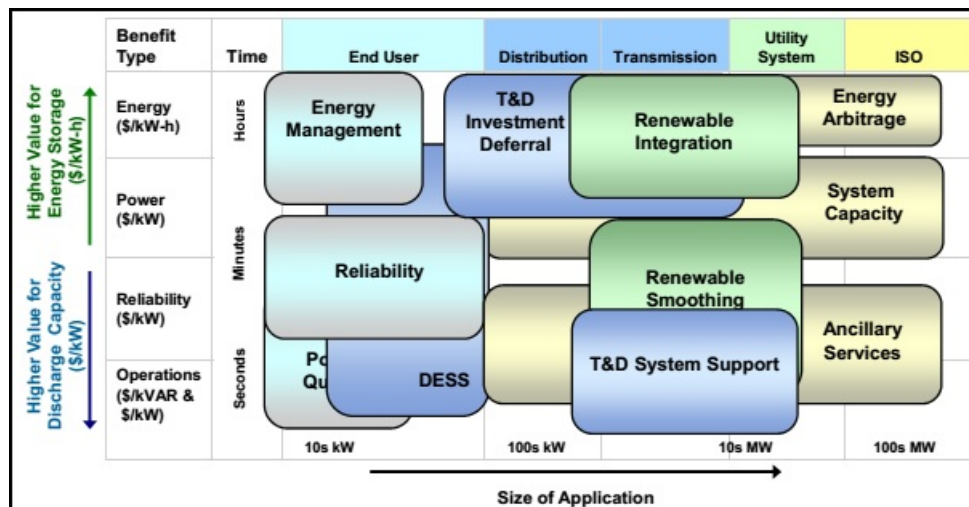


Figure 1.2: Different Services of ES based on Application Size and Monetary Benefit [40]

gies, but not all fulfill this criteria. Using Fig. 1.3, we can eliminate most of the low-power, low-capacity technologies, leaving flow batteries, sodium-sulphur batteries, compressed air energy storage (CAES) and pumped hydro storage (PHS).

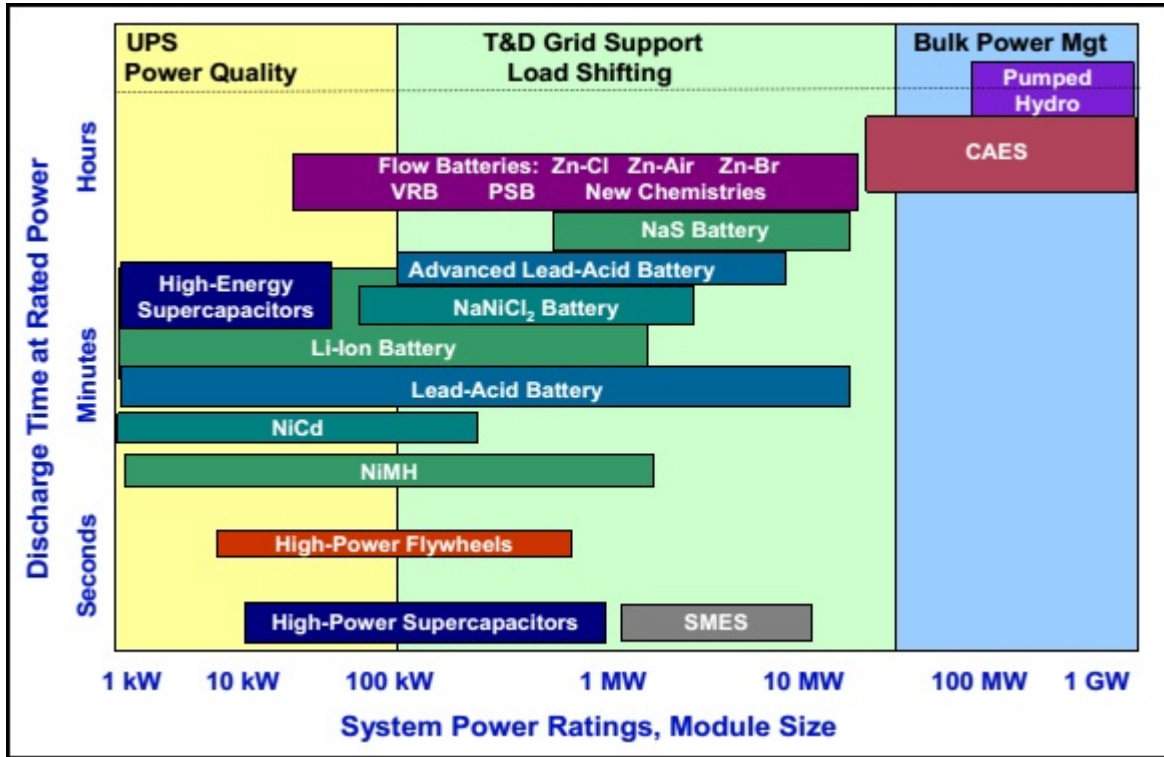


Figure 1.3: Positioning of Different ES Types for Discharge Time and Power Rating [40]

Since the objective of this model is to optimise the size of ES with cost in mind, we have chosen to do a further analysis in the most cost-effective technologies for our chosen service of renewable integration. Fig. 1.4 shows that not only are PHS and CAES the cheapest options per kWh, but are the only two technologies that remotely come close to competing with gas turbine generators - a typical alternative in offshore environments.

Therefore, PHS and CAES will be further investigated to determine if these technologies can be applied in an offshore environment. It should be noted, however, development for offshore solutions has only started in recent years and haven't been proven to be commercially viable for any technology. Regardless, both PHS and CAES are the key technologies currently being investigated by various interested parties for potential commercial offshore applications due to their advantages of:

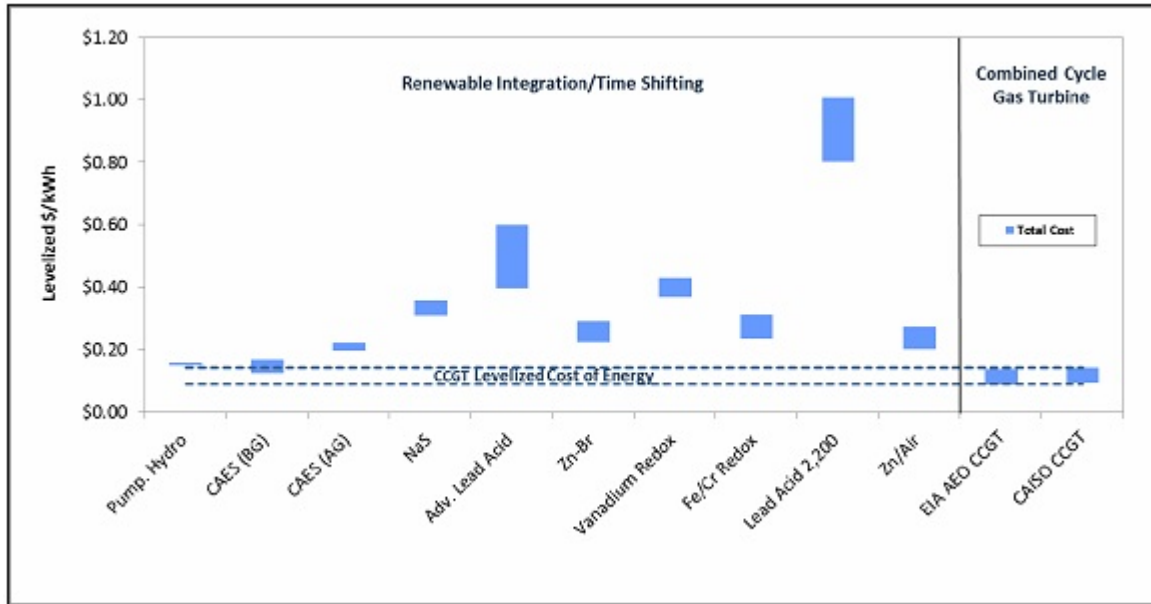


Figure 1.4: ES Costs compared to CCGT [40]

1. being a well-established technology on land
2. fulfilling the criteria of being able to provide high power and large capacity
3. being the most cost-competitive

Compressed Air Energy Storage (CAES) uses pressurised air as a form of energy storage. Excess power is used to drive compressors to store air in containment reservoirs. Since the air is heated adiabatically through compression, multi-stage compressors are often used interchanged with heat-exchangers to release excess heat to the atmosphere. When power is needed, this air is heated and expanded through turbine-generators, working in principal the same way as a gas-turbine. In fact, first-generation plants are basically modifications of gas turbine technology, using gas injection for the heating process. Since the compressor typically consumes over 60% of the produced electricity, having pre-stored compressed air still provides substantial fuel savings [11]. First-generation CAES plants have been in operation since the 1970's, with a 290 MW plant in Germany and later a 110 MW plant in the US [34], demonstrating that this technology has seen commercial success. Early plant designs have saved on storage costs by using massive underground caverns as a natural reservoir, eliminating the need to construct such a large air-tight structure. This, of course, presents other problems, since these ideal cavern

reservoirs are very geologically dependant. Presently, research and development is being put into second-generation CAES plants, which shall operate with little or no fossil fuels. The most popular technology is called Advanced Adiabatic (AA) CAES, which captures the removed heat during the compression process and stores it in thermal tanks to be used to reheat the air prior to expansion. Since compressing air to typical CAES pressures of 70 bar can produce temperatures of 900 C, this stored heat is of high enough quality to replace the use of fossil fuels.

There have been many studies that support our assumption that CAES plants are a mature enough technology to provide renewable integration and time-shifting services. Cavallo et al state that, in conjunction with a wind park, CAES plants are not only technologically feasible at providing stable power, but "are technically equivalent to and economically competitive with that from any nuclear or fossil fuel power plant" [11]. However, this is under the assumption that the CAES plants will use solution-mined salt caverns as reservoirs, lowering capital costs. Adapting this technology to the offshore environment will certainly see additional challenges, including but not limited to finding or constructing sufficiently large and affordable reservoirs for air storage.

Using natural undersea caverns would introduce many safety and technical challenges and hasn't been thoroughly investigated by the scientific community. However, using modular, man-made reservoirs in the form of subsea flexible bags has been investigated by different parties. A Toronto-based company called Hydrostor is currently attempting to commercialise this inflatable bag technology. These bags will be placed subsea and inflated with compressed air during periods of high excess power. With the help of external waterpressure, during times of need the bags are deflated and the pressurized air drives turbines. Opting to keep the inflatable bags cheaper, Hydrostor has not insulated them and instead is using onshore thermal storage in the form of insulated water tanks. Hydrostor has built a business case around this technology focusing on providing cost-effective and green energy storage solutions to islands in the Caribbean which are unable to connect to the mainland grid. Hydrostor is currently installing and running tests on a downsized demonstration facility (1MW/4MWh) in Lake Ontario, and has signed an agreement to install a facility at the Vader Piet wind park near Aruba [29]. Bright Energy Storage, a Denver, Colorado based company, is pursuing a similar venture. [38][39] has shown extensive analysis into an optimum shape and materials for such 'energy bags' to be used to store com-

pressed air below the waves, including examining their mooring and ballasting requirements, using a variety of analytical methods. Pimm et al. has determined optimal costs for these structures at various depths, which can be used in our optimisation model.

Pumped Hydro Storage (PHS) is a large, mature technology and is currently being used in many locations worldwide for commercial-level energy storage. The concept is simple: Functioning in a similar fashion to a regular electric hydro dam, PHS uses potential energy in the form of massive amounts of water to flow from a high elevation down to a lower one, driving electric turbines to produce electricity. During periods of excess, the reversible pump-turbines pump water back up to the higher reservoir, storing potential energy for when it is next needed. PHS is arguable the most affordable large-scale energy storage technology currently in use today. However, due to the massive capital costs, small, local PHS systems aren't a viable option, making this technology traditionally an option only for centralised power systems. Additionally, they are extremely geography-dependant since they rely on natural reservoirs and valleys with sharp changes in elevation. PHS has been shown to lower dependency on peaking plants and lowering the instability risks of renewable penetration [5] [23], and can provide consistent, alternative power to remote communities [2][9].

Traditional PHS systems are not very suited for offshore applications due to their large infrastructure and geography requirements, but the concept and technology is proven. Two different groups - MIT and SubHydro AS, a Norwegian company based in Oslo - are investigating using pump hydro principles to store energy underwater. Air-filled bunkers at atmospheric pressure will be installed subsea, and when energy is required a valve will allow seawater to flow through a turbine into the bunker at high, subsea pressures. When energy needs to be stored, the operation is reversed [27], as outlined in Fig. 1.5. These bunkers, or energy spheres in the MIT concept, would actually function as anchor points for a floating wind turbine. Combining functionality in this way would help further reduce cost. However, it is theoretically possible to install many energy spheres on their own to create a pure subsea energy storage bank that could be connected to shore or to a platform. Although a demonstration facility has yet to be constructed to further validate this technology, MIT has done extensive technical work in an effort to validate all aspects of its energy sphere concept, including manufacturability, transportation and installation [18].

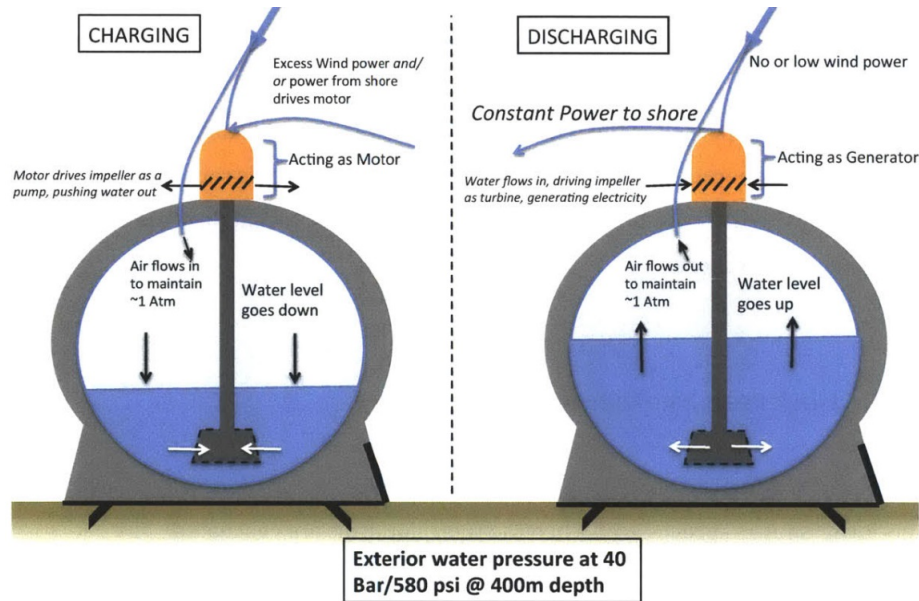


Figure 1.5: MIT Energy Sphere Vent Concept [18].

MIT has developed two main designs:

- Vent or 'snorkle' concept; a connecting tube between the energy sphere and the surface will ensure the interior conditions of the sphere remain at atmospheric pressure. This will increase costs, particularly for deeper depths, and the complexity of installations - particularly for a ES bank only concept without wind farms. In this situation, the vents would be collected together and held at the surface by a spare buoy. However, cost increases are predicted to be only 0.5-1.5% (for wind farm concepts), and 2-9% (for ES bank only concepts) depending on depth.
- Ventless concept; the energy sphere will be made simpler without a vent needed to reach the surface. Instead, when the water is pumped out the sphere will either be filled with a near-vacuum water vapour which could result in cavitation issues for the pump-turbine; or the energy sphere will be prefilled with a small bubble of air and will be at 1/20th atm when pumped out. The advantages of a ventless design are simpler and faster deployment, particularly in a 'ES bank only' situation which would eliminate the need for spare buoys; and eliminating the risk of vent damage. However, according to the study, it is undetermined on how much more complex the system will become due to potential pump cavitation issues and the need of increased pump complexity to ensure consistent per-

formance, whereas installing a vent-line appears to be feasible. There are plans to test a ventless model, but no empirical results have been delivered at the time the report was published.

Transmission Technologies

The location of a scenario plays an important role in establishing the ideal power solution. Isolated scenarios far away from existing grid connections would require additional investment in transmission infrastructure, or require complete grid independence. To assess which option is most economically viable, different transmission technologies should be investigated.

Even though cables are designed out of highly conductive material and have minimal resistance, this resistance is cumulative over its length and can become quite significant over long distances. Since power losses in an electrical system are dependent on resistance and the square of current, $P = I^2 R$, long distance, high power cables are designed to be low current. Due to $P = VI$, to retain the same power, high voltage is required to offset this effect - usually over 10 kV. Transformer stations are used to step-up voltage for transmission, and down again at the consumption location.

There are three established long-distance (over 50km) methods of attaching power consumers and/or producers to the grid:

1. High-Voltage Alternating Current (HVAC)
2. Line Commutated Converter (LCC) High-Voltage Direct Current (HVDC)
3. Voltage Source Converter (VSC) HVDC

Most existing land-based transmission networks are AC, since most consumers and generators use AC. To incorporate HVDC lines into this network, expensive converter stations are required to shift AC to DC and back again.

AC power cables have a high electrical capacitance, meaning that over longer distances they consume great amounts of reactive power; measured in volt-ampere reactive (VAR), this power is used to generate magnetizing flux by that magnetic equipment (such as transformers). Effectively, reactive power represents power that is unusable for actual work. Since this reduces

the power factor and effectively reduces efficiency, at high power transmissions this can result in a significant amount of wasted power. This can be compensated for with the installation of reactive compensation measures such as shunt reactors along the cable. While this is regularly done onshore and above ground, in the submarine or subterranean environment this can become extremely costly as additional platforms are required. AC cables themselves also consume reactive power due to natural capacitance and inductive properties, and increasing their voltage to reduce resistance losses will further increase this, as demonstrated in Fig. 1.6. Therefore, long-distance AC cables are either subject to high resistance (if their voltage remains normal) or high reactive power (if their voltage is increased to reduce the resistance). In both cases, efficiency suffers.

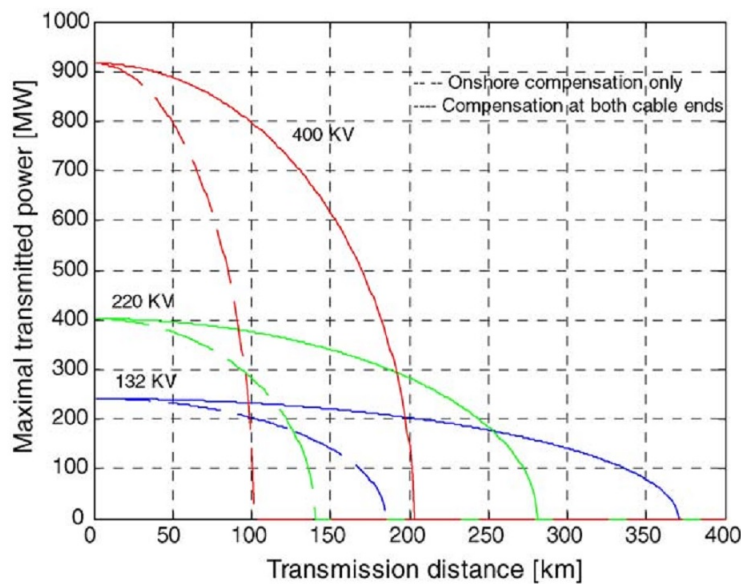


Figure 1.6: Transmission capacity of different HVAC transmission cables [36].

Studies [7][16] have shown that this capacitive charging effect limits the length of AC power lines by being cost-prohibitive at a certain point. Despite the additional cost of converter stations, DC power becomes cheaper at distances of 90+km as shown in Fig. 1.7.

Since there is no capacitive charging effect on DC cables, there is no limit to how long they can be other than physical manufacturing and installing restrictions.

LCC HVDC, also known as HVDC with current source converters, is a mature technology in the onshore environment that has existed since 1954. There are as many as 100 LCC HVDC

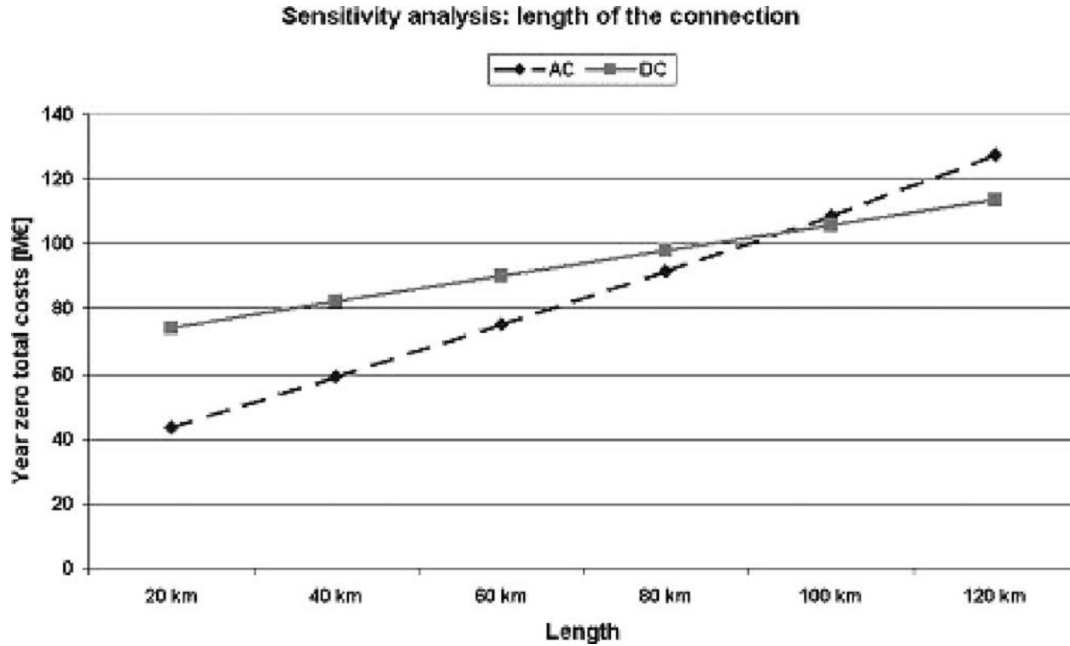


Figure 1.7: Results of sensitivity analysis of transmission distance [7].

installations worldwide, covering a vast range of rated power from 100 MW to 7200 MW, and is generally accepted to be a low-risk and technologically sound alternative to AC. Reactive power compensation might be required to negate its effect on the converters themselves, adding to footprint size. However, the largest shortcoming of the LCC technology is that it requires connection to strong AC networks on both ends; disturbances can cause commutation failures which could result in a temporary shut-down of the entire HVDC system. This limits its effectiveness for connecting isolated grids such as offshore wind parks.

By contrast, VSC HVDC, also known as self-commutated converters (SCC), is a much new technology and has only existed since 1997. VSC is more flexible than LCC systems; they require a 50% smaller footprint for the converter station itself and are suitable for connecting to weaker AC networks, giving VSC systems a distinct advantage for offshore applications. Additionally, they are capable of controlling both active and reactive power flow through the converter and are much more suited for multi-terminal applications, unlike LCC systems. The more-frequent switching that allows for such flexibility has a negative side-effect: higher converter power losses (up to 3% compared to the 0.8% of an LCC system), and generally being more expensive at higher power ratings. More modern modular multilevel converter (MMC) designs have minimised the

power issue to 1% however. Despite being a much newer technology, VSC systems have been developing rapidly over the last decade, with commissioned links ranging from under 100 MW to 800 MW, and industry experts foresee no technical limitations to prevent these from expanding to over 3000 MW in the coming years.

For more thorough grid integration and connectivity, having an HVDC link between only two points is no longer adequate. Multi-terminal HVDC solutions are being considered, capable of connecting the different points of the grid in series, parallel, or both to further strengthen the system. As mentioned previously, LCC systems are not ideal for multi-terminal setups, although a few exist today. It is expected that the VSC technology will dominate this market in the future, as early as 2017 [16] [7] [3] [13].

Standard Simple Cycle Gas Turbines

Standard simple cycle gas turbines (SCGT) have been investigated due to their regular use in offshore environments. As this is a well-established technology, a literature review was deemed unnecessary.

1.1.3 What Remains to be Done?

There has been extensive research into the two key ES technologies we shall investigate in this thesis, as well as how different energy storage systems may be sized. However, every one of these cases is in a very specific scenario, and often does not include cost optimisation. We shall need to create a new model that can combine all the relevant performance and cost data along with optimisation and operation methodology gathered in research.

A model needs to be developed that can provide:

- A comparison between a chosen demand and power production curve
- An assessment of additional power required by a secondary system
- A cost optimisation that will size the most cost-effective energy storage system to match the demand and power production curves

- A built-in thorough comparative and sensitivity analysis of the simulated results which the user could draw conclusions from
- Allow the model to be flexible enough that the user can define their own scenarios

1.2 Objectives

The main objectives of this Master are:

1. A literature survey concerning energy storage technologies shall be performed. The technologies shall be presented, discussed and compared. Available or promising technologies for offshore wind park energy storage shall be identified.
2. Cost data for all relevant subsystems of a stand-alone offshore wind park power supply system (energy production, storage, transport, back-up etc) shall be collected, as shall relevant cost data for gas turbine fuel and CO₂ taxes. The data shall be presented, and uncertainties shall be quantified/estimated.
3. The model developed in the project work shall be further developed and extended to include cost optimisation. The model shall take into account power generation from e.g. gas turbines as an addition or replacement for energy storage. The model shall be presented and discussed.
4. Based on one or more scenarios, optimisation studies using the developed model shall be performed. The scenarios shall be presented, and the results shall be discussed. A sensitivity analysis of the obtained results shall be undertaken.
5. Proposals for further work shall be made.

1.3 Limitations

In terms of the development of the model itself, it is mainly only limited by the programme architecture being used - MatLab, in this case. Luckily, as a mathematical software capable of

advanced programming methods, these limitations are few. In fact, despite having previous experience in programming and additionally learning many new aspects to MatLab programming throughout this thesis, it is my own abilities that would be far more limiting. The only main limitation that we discovered with MatLab is the lack of global optimisation methods pre-installed with the NTNU student package of MatLab. As mentioned before, such a toolbox exists, but unfortunately is less accessible. This, in turn, leads to perhaps the most important limitation - the model has certain issues in finding true global minima, and as a result its robustness has been called into question.

Additionally, there are data-gathering limitations with finding appropriate cost data for the case studies, particularly for the ES technologies. Offshore energy storage is still far away from commercialisation and all cost estimates are based on many assumptions and mathematical studies, but no real cost numbers. It would be helpful to find a corporate partner with more significant data measurements.

Finally, due to time and resource limitations, increasing the complexity of the model to include on-grid simulations including transmission optimisations and factoring in grid codes is simply not achievable at this time, despite much research being performed in these areas.

1.4 Approach

All the literature surveys and cost data analyses is conducted mainly through research of scientific literature. However, both professors from NTNU and other universities, as well as industry experts, will provide much guidance in the form of advice, suggestions and, in some cases, actual data.

The objective for further developing the model is done by creating a comprehensive feature list along with a list of expected timelines and priorities. This is developed both individually and along with my supervisors.

Presenting and discussing results as well as proposing further work is again decided upon with the consultation of my supervisors. Efficient methods of portraying the relevant data are procured with the help of MatLab documentation and advice from the MatLab community as a whole.

1.5 Structure of the Report

The report is split into five chapters:

1. Introduction and Background - This chapter outlines the problem, objectives, and current status of technology.
2. Model Structure - This chapter goes into detail about how the model is structured and fundamentally works. It describes the mathematical relationships between different user-selected information, which is fed through optimisation routines. The different types of analysis that can be performed on the model data are also discussed here.
3. Case Study - this chapter outlines the different case studies that will be investigated to test the functionality and robustness of the model, as well as outlining all assumptions used.
4. Results and Discussion - an analysis of the results from the model using the case studies and assumptions defined in the previous chapters are presented and discussed.
5. Final conclusions and summaries are presented, as well as a recommendation for further work.

Chapter 2

Model Structure

The developed model's main purpose is to determine the optimal sizing of ES that, in conjunction with a backup power system, will yield the lowest costs over the lifetime of a project. This model, when fully developed, would be used as a tool to determine optimal ES solution for a given scenario of a client's choice, allowing them to plug in specific wind and demand data and select from a list of ES options.

To remain consistent with terminology, a list of terms are defined below:

Model:	the entire MatLab project is referred to as the model.
Module:	packages of information that the user can choose to customize the scenario.
Run:	a single iteration of energy storage sizing, back-up power generation sizing, and cost calculation, based on a specific input.
Simulation:	a combination of runs that goes through the optimisation function, outputting the lowest (and optimised) cost along with its associated inputs.
Scenario:	a specific combination of modules that may be used for multiple simulations that is to be analysed in a specific way.
Case Study:	potentially multiple scenarios are compared in a case study. Each case study will have a number of controls, such as the demand profile or base power production.

2.1 Modularity

The variety of different potential scenarios in which energy storage may be applicable is enormous, and the task of developing a tool that is flexible enough to accommodate the vast majority of said scenarios is even more so. Therefore, one of the key goals of this model is provide a flexible platform that can be modified to suite the user's needs and to match a scenario of his or her desire.

To do this, the model is designed from the ground up to be modular, with a core optimisation algorithm that combines four swappable modules. Each of these modules will represent key information about the simulation and will allow easy comparison between different scenarios by allowing the user to simply select different module settings. The individual modules can also be modified for further customisation, but this would require a more in-depth understanding of the model. The different modules are described below:

Demand Profile

This module allows the user to select a specific demand profile plug-in to match their scenario. Generally, a user would select either a specific demand profile (such as historical demand data for the exact community they are trying to model) or a more generic one (generalised data for urban centres in northern climates). For any given run of the model, this is considered to be fixed - that is, although the demand will change over time, the profile will not.

Base Power Production

The base power production is the primary power source and will always be dispatched first in the model. Options could include different historical plant power generation profiles based on what is a typical production. Like the demand profile, the base power production is considered to be fixed for each simulation run.

Backup Power Production

The backup power production will be used to supplement the base power production to meet the demand profile *only* when energy storage is not available. Therefore it is considered to be dispatched third. Backup power modules would include all power generation information (efficiency, carbon emissions, fuel costs etc.) of a particular source, such as simple-cycle gas turbines. The quantity of backup power is variable depending on the demands of the simulation, and is calculated based on the core optimisation algorithm.

Energy Storage Technology

Energy storage technologies will be used to directly supplement the base power production, and will be dispatched second. This module provides all of the relevant technical specifications for the particular technology selected (such as PHS or CAES) for a unit size of energy storage. Similar to the backup, the amount of energy storage is variable depending on the demands of the simulation, and is calculated based on the core optimisation algorithm.

Transmission

This module would include specifications for any transmission network that is used to connect the system to the grid. Specifications would include distance to connection, cable types and prices, and transmission types. The model would be capable of sizing an appropriate transmission system in conjunction with the ES and backup power to provide the cheapest solution. Unfortunately, due to time constraints, this module has not been fully implemented and will not be used in the results.

Grid Codes

Depending on the location, local transmission providers and policies may enforce different grid code requirements, regulating power and service consistency and quality. Again, this module has not been implemented.

2.2 Core Optimisation Algorithm

Table 2.1: Variable List

General Variables	
$P_{BP,t}$	Base power production at time t
$P_{L,t}$	Consumer demand at time t
$P_{Dump,t}$	Dumped power at time t
ϕ	The time size
N	The lifetime of the project
Backup Production Module	
$P_{BU,t}$	Back-up power required at time t
$P_{BU_{max}}$	Maximum back-up power required throughout the simulation t
$P_{BU_{unit}}$	Power per unit of back-up
E_{BU}	Total back-up energy required over time
BU_{unit}	Total number of SCGT units
$BU_{unit,t}$	Total number of SCGT units needed at time t
x	% of part load of the SCGT unit
$\eta_{BU_{unit}}(x)$	Function that calculates unit efficiency based on part-load t
$P_{fuel,t}$	Power of fuel consumed at time t
Energy Storage Module	
$P_{ES,t}$	ES charging/discharging power at time t
P_{ch}	ES rated charging power
P_{dis}	ES rated discharging power
η_{ch}	ES charging efficiency
η_{dis}	ES discharging efficiency
$E_{ES_{min}}$	Lower limit of ES capacity
$E_{ES_{max}}$	Upper limit of ES capacity
$E_{ES,start}$	Initial level of the ES capacity
$E_{ES,t}$	ES level at time t
E_{BU}	Total back-up energy required over time

The core optimization algorithm is the heart of the model that actually performs all the necessary calculations and comparisons based on the inputs gathered from the selected modules. It is built around the principle of minimizing the total costs involved for a complete energy storage solution over the entire simulation timeframe using a combination of energy storage and back-up generation. The optimisation can be broken down into the following five steps:

1. Production-Demand Comparison

2. ES Assessment
3. Backup Sizing
4. Costing
5. Optimisation

Step 1: Production-Demand Comparison

The first step of running the optimisation is directly comparing a base power production profile with a consumer demand curve over time and examining the difference: $P_{BP,t} - P_{L,t}$. The difference between these two values is used to determine how much the ES is required to charge or discharge, for each unit time t . If the difference is positive, there is excess base production power available and charging will occur if possible, implying a positive $P_{ES,t}$. The opposite is true if the relationship is negative. Therefore, the production-demand comparison defines on a timestep-by-timestep basis the charging/discharging potential of an energy storage system.

Step 2: ES Assessment

Now that the charging/discharging potential is determined, it remains to be seen if this falls within the limitations of the ES system. The amount of charging and discharging power the system is capable at any given time of is constrained by its upper and lower limits, P_{ch} and P_{dis} , which is based on data received from the ES module:

$$P_{dis} < P_{ES,t} < P_{ch} \quad (2.1)$$

If the difference surpasses the ES charging or discharging rated power as defined in eq. (2.1), then any further excess is categorised as either dumped power, $P_{Dump,t}$, or required back-up power, $P_{BU,t}$, depending on whether $P_{W,t} - P_{L,t}$ is positive or negative. Therefore the relationship between base power production and demand, if positive, is mathematically defined as:

$$P_{BP,t} - P_{L,t} = \frac{P_{ES,t}}{\eta_{ch}} + P_{Dump,t} \quad (2.2)$$

Meanwhile, if it is negative, it is defined as:

$$P_{BP,t} - P_{L,t} = P_{ES,t} * \eta_{dis} + P_{BU,t} \quad (2.3)$$

It should be noted that all power and energy that is charging or in excess is positive, while that which is discharging or in demand is negative. Therefore, $P_{ES,t}$ and $P_{BU,t}$ in eq. (2.3) will be negative values, and the following are constraints:

$$P_{Dump,t} \geq 0 \quad (2.4)$$

$$P_{BU,t} \leq 0 \quad (2.5)$$

The energy level, or the amount of stored energy that is available at time t , $E_{ES,t}$, will increase or decrease as charging or discharging is required, which delivers or draws energy from the ES:

$$E_{ES,t+1} = E_{ES,t} + P_{ES,t}\phi \quad (2.6)$$

The succeeding energy level, $E_{ES,t+1}$, is always calculated by adding the previous $E_{ES,t}$ with the ES charging or discharging power $P_{ES,t}$ (multiplied by ϕ to convert it into power-hour units), as implied by the $t+1$ nomenclature. The ES energy level is bound by the upper and lower limiting parameters:

$$E_{ES_{min}} < E_{ES,t} < E_{ES_{max}} \quad (2.7)$$

Once $E_{ES,t}$ meets the maximum (or minimum) limit imposed by eq. (2.7), the ES is considered to be full (or empty) and can no longer charge (or discharge). $P_{ES,t}$ will therefore be zero and, according to eqs (2.2) and (2.3), either $P_{Dump,t}$ or $P_{BU,t}$ respectively will equal the entire power difference ($P_{W,t} - P_{L,t}$).

Step 3: Backup Sizing

All power and energy required (as determined by the demand module) which cannot be covered by combined efforts of the base power production and the energy storage will rely on backup power. The backup power system is assumed to be split into equally sized units predetermined by the backup power production module: $P_{BU_{unit}}$. This reflects a common power generation set-up that would use multiple, smaller generators, instead of a single larger one, as it offers greater flexibility.

The number of units required in the simulation is sized by Eq. 2.8:

$$BU_{unit} = \frac{P_{BU,max}}{P_{BU_{unit}}} \quad (2.8)$$

BU_{unit} is rounded up to the nearest whole number. $P_{BU,t}$ determines exactly how much power is needed from the backup system at any given time t . The number of units that are needed to be switched on at any given time t is dependant also on the backup power required at time t as well as the unit size:

$$BU_{unit,t} = \frac{P_{BU,t}}{P_{BU_{unit}}} \quad (2.9)$$

If eq. 2.9 yields a non-whole number, this implies an additional entire unit is in under part-load operation. For example, if $BU_{unit,t} = 3.56$, there are 3 units in operation on full-load ($x = 100\%$) and a 4th under 56% part-load ($x = 56\%$). The reasoning behind choosing this operation strategy where all units are loaded to 100% first (known as 'start-stop' operation strategy) is explained in greater detail in section 3.2.4. The part-load efficiency curve provided by the backup power module is used to determine the efficiency of each module, and the subsequent fuel power $P_{fuel,t}$ is calculated per time-interval (assuming if $BU_{unit,t}$ is rounded down to represent only the full-load units):

$$P_{fuel,t} = \frac{P_{BU_{unit}}x}{\eta_{BU_{unit}}(x)} + \frac{BU_{unit,t}P_{BU_{unit}}}{\eta_{BU_{unit}}(100\%)} \quad (2.10)$$

The sum of eq. 2.10 over the entire simulation lifetime N yields the total fuel consumption of the simulation, which can be used to calculate total greenhouse gas emissions.

Step 4: Costing

Both the backup and ES modules introduce relevant costing information into the model, as summarised in Table 2.2. If modules for transmission and grid codes were to be included, they would also provide additional costing information.

Table 2.2: Cost Parameters

Backup Production Module	
$C_{BU_{unit}}$	Cost per backup production unit
$C_{BU_{OMfix}}$	Cost of operation and maintenance per year per module
$C_{BU_{OMvar}}$	Cost of operation and maintenance per year per MW-h of produced energy
$C_{BU_{fuel}}$	Cost of fuel per MW-h consumed
$C_{BU_{GHG}}$	Cost of CO2 equivalent greenhouse gas emissions
Energy Storage Module	
C_{ES_p}	Cost per MW of energy storage charging/discharging power
$C_{ES_{Cap}}$	Cost per MW-h of energy storage capacity
$C_{ES_{OMfixed}}$	Cost of operation and maintenance per year per MW of discharged power
$C_{ES_{OMvar}}$	Cost of operation and maintenance per year per MW-h of discharged energy

Note that the demand module does not introduce any costing variables because it is simply providing a consumer - all costs relating to the consumer itself (other than energy) are considered to be independent of this model and beyond the scope. Likewise, base power production module also does not impact cost because it is assumed that the base power production facility will already exist, and this model will merely assess what kind of supplemental power system (comprised of backup power and energy storage) that may exist.

Reoccurring costs (O&M, fuel, GHG emissions, etc.) are calculated over the assumed lifetime of the simulation, N , using the standard present value (PV) formula:

$$PV = \sum_{n=0}^N \frac{FV_n}{(1 + DR)^n} \quad (2.11)$$

Eq. (2.11) calculates the total PV of a sum of future values (FV) for each year n over the lifetime of the simulation N at a set discount rate DR .

Using total energy consumption and backup and ES system sizing data previously calculated in sections 2.2, 2.2 and 2.2, it is possible to calculate the cost of the entire system over its lifetime.

$$\begin{aligned}
C_{System} = & \text{Red } C_{BU_{unit}} BU_{unit} + \text{Green } C_{ESp} P_{ES} + C_{ESCap} E_{ES,max} \\
& + \text{Blue } PV_N\{C_{BU_{OMfix}} BU_{unit} P_{BU_{unit}} + C_{BU_{OMvar}} E_{BU,sum}\} \\
& + \text{Cyan } PV_N\{C_{ES_{OMfix}} P_{ES} + C_{BU_{OMvar}} E_{ES,sum}\} \\
& + \text{Magenta } PV_N\{C_{BU_{fuel}} E_{fuel,sum}\} + \text{Yellow } PV_N\{C_{BU_{GHG}} E_{fuel,sum}\}
\end{aligned} \tag{2.12}$$

where:

Red	Total capital cost of backup power production
Green	Total capital cost of energy storage
Blue	Total O&M cost of backup power production
Cyan	Total O&M cost of energy storage
Magenta	Total cost of fuel
Yellow	Total cost of GHG taxes

Note that in eq. (2.12), $PV_N\{\dots\}$ insinuates that the entire term within the brackets has been put through the PV function as shown in eq. (2.11).

Step 5: Optimisation of ES

The core of the problem is to size an appropriate system that can fulfil the power needs of a scenario (provided by the demand module) by using a combination of backup power production and energy storage to supplement the already-existing base power production plant, while being the lowest cost option available. We have ultimately determined the cost of a specific system by using sizing inputs in steps 2-3 and yielding the final cost as an output in step 4. In step 5 we shall optimise this cost by re-running steps 2-4 using different inputs until the global minimum of the output is reached; that is, until we have found the appropriate combination sizing of both backup power production and energy storage that is the lowest cost.

Therefore, the object function of the optimisation is:

$$\min(C_{System}) \tag{2.13}$$

Even though there are many inputs fed into the optimisation from the different modules,

there are only a few that vary between different optimisation runs: P_{ch} , P_{dis} and $E_{ES,max}$. This is simplified further by the assumptions that $P_{ch} = P_{dis}$ since most ES technologies can be designed to have equal charging and discharging powers. Therefore, there are only two variables in this optimisation problem, and all other inputs are considered constants.

The optimisation function used for this model is a built-in MatLab function called *fmincon*, which is a versatile platform capable of non-linear optimisation with constraints should they be required. For the solver, sequential quadratic programming (SQP) algorithm was chosen as it is an iterative method for non-linear optimisation. After running performance tests and following MatLab suggestions for choosing an appropriate solver, SQP was determined to be the fastest and most robust. The *fmincon* function works by calling the pre-programmed costing function (as briefly defined in section 2.2), which in turn calls other functions to run steps 2 and 3. The constraints that are normally defined in the *fmincon* function itself are actually left blank since all constraints have been pre-defined in the functions responsible for steps 2-4. What is defined, however, is the initial input variables - that is, the initial values of P_{ch} and $E_{ES,max}$.

The accuracy of the optimisation was initially tested by comparing it to a far less time-efficient brute-force method of determining the optimised sizing: using endless loops, the steps 2-4 were re-run thousands of times with slowly incrementing inputs. The loops were broken when the simulation results for each optimisation run were determined to be diverging consistently, suggesting that increasing the inputs further would only further yield a more expensive system. Finally, the cost information for all of these runs was analysed, and the absolute minimum (along with its appropriate inputs) was identified. This brute-force method would allow us to roughly determine the global minimum to assess *fmincon*'s accuracy, although it would take significantly longer than using *fmincon*.

Preliminary simulation tests have shown that the *fmincon* was capable of finding local minimums but would not always locate the global one. To combat this issue, *fmincon* is run five times, each with different initial inputs. All five results are gathered, and if they are not equivalent then the lowest output is considered to be the global minimum.

2.3 Analysis Suite

The analysis suite is another key component of this model. This allows the user to select different kinds of analyses to be performed automatically, which is done by running multiple scenarios with different features dependant on the specifications of the user.

Comparative Analysis

This performs a comparison between multiple scenarios, by showing cost-breakdowns and GHG emissions. There will always be a base scenario that is automatically generated, which is a scenario that only uses the same demand and base-power production modules but only uses backup power production as a supplement, and assumes that the energy storage investment will be zero. This analysis will allow the user to compare the effects of using different modules, such as ES technologies, against a basic fossil fuel set-up (the base-case) for a given case study.

There are three different cost comparisons performed:

1. Standard Comparison - This is the most basic, comparing the base scenario with ES scenarios as they are, with no modifications provided other than what the modules have defined.
2. Extreme Comparison - Every cost value has an associated confidence error bands, which can change the results significantly. The extreme cost comparisons compare ES technologies to the base scenario at both ends of the costing confidence spectrum. There is a worst case and a best case option; the former assuming minimised backup costs and maximised ES costs, while the latter assuming the opposite.
3. ES Only Comparison - this option forces the optimisation to avoid the use of backup power, and instead attempts to find the cheapest option for relying entirely on ES. This is done by editing the optimisation function to provide a constraint that the sum of the backup power at any given time must be equal to zero ($\text{sum}(P_{BU,t}) = 0$). The the total costs of base scenario (still being a backup only scenario) is then compared with the different ES only scenarios.

Sensitivity Analysis

Using sensitivity analyses, the user can determine what is the most significant cost driving factor of their system, and can determine how changing factors can effect the results. In particular, there are some key variables that will be used in sensitivity analyses:

1. Fuel Prices - it is expected that fuel prices will fluctuate greatly in the future, and could potentially rise which would make ES more competitive. This sensitivity will suggest how high they must go for this to happen.
2. GHG Taxes - governments are starting to introduce carbon taxes to hold companies accountable for environmental damage. This sensitivity will demonstrate how strict they need to go for ES to be competitive
3. ES Capital Costs - it is assumed that ES technology, which is still new in development, will see reduction in capital costs in the future. This sensitivity will show how this effects the sizing.

Additionally, the power production profile shall be randomized while retaining the same total energy production per year. This will compare how well a particular sized setup adjusts to different variances in power production, which could happen if the power production changes from year to year as is the case with wind power.

Chapter 3

A Validation Case Study

Even though this model is designed to be general and applicable to multiple combinations of different situations, it is difficult to demonstrate its operation without using specific case studies. For this purpose, a case study is chosen to optimise an energy storage system working in conjunction with an offshore wind farm to provide power to a oil and gas platform.

3.1 Different Scenarios

3.1.1 Base Scenario

The base scenario is a power solution using the offshore wind power production and simple-cycle gas turbine generators to provide back-up. No ES is used.

3.1.2 Differing ES Technologies

Two different ES technologies that were deemed to have the most potential of being both technologically feasible and economical are examined; subsea CAES energy bags, similar to Hydrotors concept, and subsea PHS energy spheres, similar to MIT's concept.

3.2 Assumptions

3.2.1 General Assumptions

Unless stated otherwise, all scenarios will include the assumptions within this section.

Model Operation and Strategies

The optimisation model will be a quasi-steady state simulation; that is, the model will simulate the problem on a time-step to time-step basis, meaning it will not be completely dynamic. The time-steps used will be one-hour intervals, and a year-long period will be analysed - the minimum accepted time-frame to take into account seasonal variations [23].

This model functions purely on power and energy balances between production and demand - it will not take into account or calculate currents, voltages and reactive power. Instead, these factors will be addressed from a qualitative point of view.

The power plant dispatch order is as follows:

1. wind park
2. ES
3. back-up energy
4. shut-down of services

The energy storage systems, if applicable, will charge only if there is excess power from the base power production that is not being used to provide direct power to meet the demand. In other words, the back-up power production will not contribute to charging the energy storage. It is assumed that the shut-down of services is not an option.

Financing and Currency

All currency values gathered for this case study have been converted to 2014 Euro currency, based on the following assumptions:

- 1 British Pound Sterling = 1.2288 Euro [33]

- 1 US Dollar = 0.7335 Euro [33]
- 1 NOK = 0.1233 Euro [33]
- 1 SEK = 0.1077 Euro [33]
- accepted inflation rates are used to convert past values into 2014 values, using online inflation calculators [12] [42] [22].

Capital costs are considered to be 'overnight costs', meaning they are paid for immediately and financing options are not considered. Future, or yearly, costs, such as those from O&M, will be converted to present value (PV) using the standard PV formula as outlined in Eq. (2.11). The discount rate (DR) is used to analyse the future value of money by taking factors into account such as inflation and project risk. Generally, riskier projects should incorporate a higher DR. Since offshore energy storage has not been proven economically even at a test plant stage, it can be assumed that the project is fairly risky. MIT judged a DR of 17% would be adequate for their energy sphere technology [18], and this case study will assume the same.

All cost assumptions made will include the following confidence bands in Table 3.1:

Table 3.1: Costing Confidence Bands

Technology Level	Confidence
Proven	±15%
Proven only onshore	±25%
New	±45%

Location

North sea or Norwegian sea, around 500m depth. Since the case study will only take into account off-grid scenarios, distance from shore is irrelevant.

Taxes and Incentives

It is assumed that there are no tax incentives, power purchase agreements or other incentives to take advantage of since these are time bound and not necessarily sustainable. Any incentives

would merely help the economic model of using energy storage, and not including them makes a more conservative estimate.

As the case study location is on the Norwegian continental shelf, GHG taxes are assumed to be at the current Norwegian prices: 410 NOK, or 50.53 Euros / tonne of CO_2 [19]

3.2.2 Demand - Oil & Gas Platform

An offshore oil & gas platform is the prime consumer in this case study. The demand curve is based on published data of an offshore platform located in the North Sea, having a load variation between 91.4% and 100% over the course of a typical 24-hour period [31]. This data was extrapolated over a year to create a typical demand profile to input into the model and split into 15-minute increments to adhere to the case study requirements, and then scaled up to represent a 70 MW peak demand, similar to a typical FPSO [17]. The final curve is shown in Fig. 3.1.

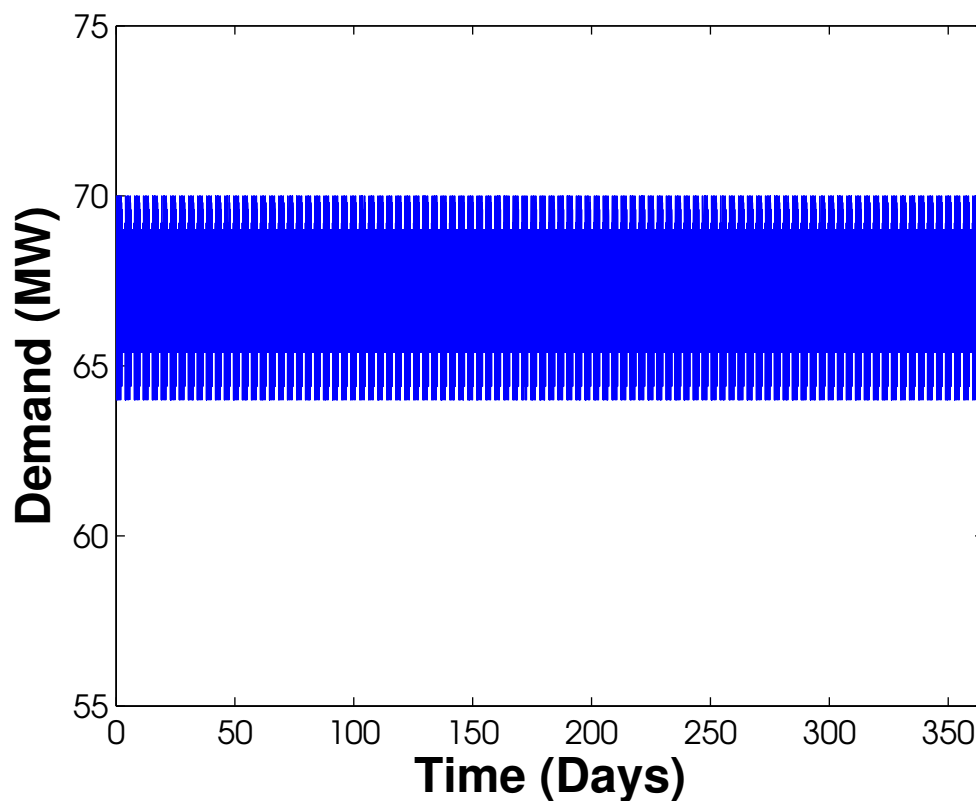


Figure 3.1: Demand Curve of an Offshore Platform over a Year

3.2.3 Base Power Production - Wind Park

In this case study, the main power provider for the platform is a nearby offshore wind park. To simulate the changing wind conditions, actual normalized data from a wind park is used to create a park power profile, which came from a year's worth of performance data from an undisclosed location in the Caribbean Sea [15]. This dataset is split into 15-minute increments over the one-year timeframe.

The wind park capacity will be sized to ensure 115% wind energy penetration within the closed system of the case study, rounded to 1 MW; that is, the total yearly energy production of the park should equal 115% the yearly energy demand of the oil platform. This guarantees that it will not be theoretically impossible for the rig to be powered by wind alone with a perfect ES system. The additional 15% is chosen arbitrarily to account for imperfect ES efficiencies. Alternatively, this will not oversize the wind park which would undermine the usefulness of energy storage and create a prohibitively expensive, and therefore unrealistic, situation. The adjusted wind power curve is shown in Fig. 3.2, with a peak nameplate capacity of 160 MW.

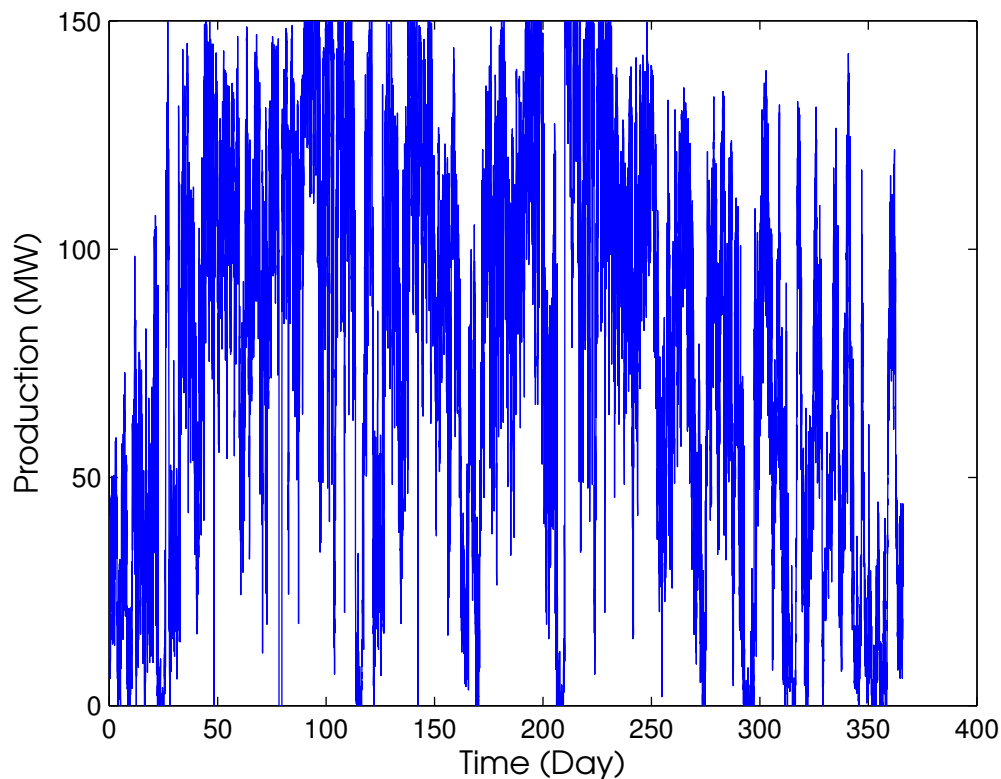


Figure 3.2: Wind Power Curve

The costs of the wind park itself have no effect on the simulations since, like the oil platform, it is considered to be pre-existing and is not relevant in the ES sizing optimisation. Therefore, it is used only for comparison purposes to give an indication as to the expense of having a secondary power system. The costs of offshore wind turbines is calculated based on DOE's Offshore Strategic plan, predicting that they will reach prices of about USD 4000 / kW by 2015 [18]. Additionally, wind turbine downtime due to maintenance is assumed to have already been taken into account with the power curve. With this price scheme, the 160 MW wind park shall cost approximately 526.4 million €.

3.2.4 Back-up Power Production

The back-up generators (which will provide 100% supplemental power to the wind park in the base scenario) will be simple-cycle gas turbines (SCGT), which is a common powerplant for many of today's offshore platforms and FPSOs. SCGTs used in the optimisation model will be split into equal sized modules of 20 MW each. Each of the modules will adopt a standard load-efficiency curve as shown in Fig. 3.3.

This load-efficiency curve is originally used by to measure offshore SCGT performance on an oil rig by Korpås et al [31], and was further validated by observations of SCGTs made by Øystein Flatebø, which followed a very similar curve [21].

As noted, running the GTs at part load is far less efficient. Instead of running all modules at equal part-loads to meet demand, the case study will assume a 'start-stop' operation strategy - that is, only when one module becomes fully loaded will the next one cycle up. This strategy is deemed to be far more fuel efficient, and should be a common practice for the operation of multiple SCGT plants [31]. Each module will be able to cycle up to full power in under 10 minutes - a fully achievable feat for most modern SCGTs. Due to this time-frame being under the one-hour time-step used in this optimisation, the cycle-up time will have little visible impact on the actual results of the optimisation and will therefore be ignored. Each module will remain in operation for at least 60 minutes prior to shutting down again as advised by [31] to reduced the wear and tear due to too many starts and stops over its lifetime.

Standard offshore powerplant contingency procedures will be in effect - in particular, the N+1 sparing philosophy, which dictates that there should always be a spare generator that is

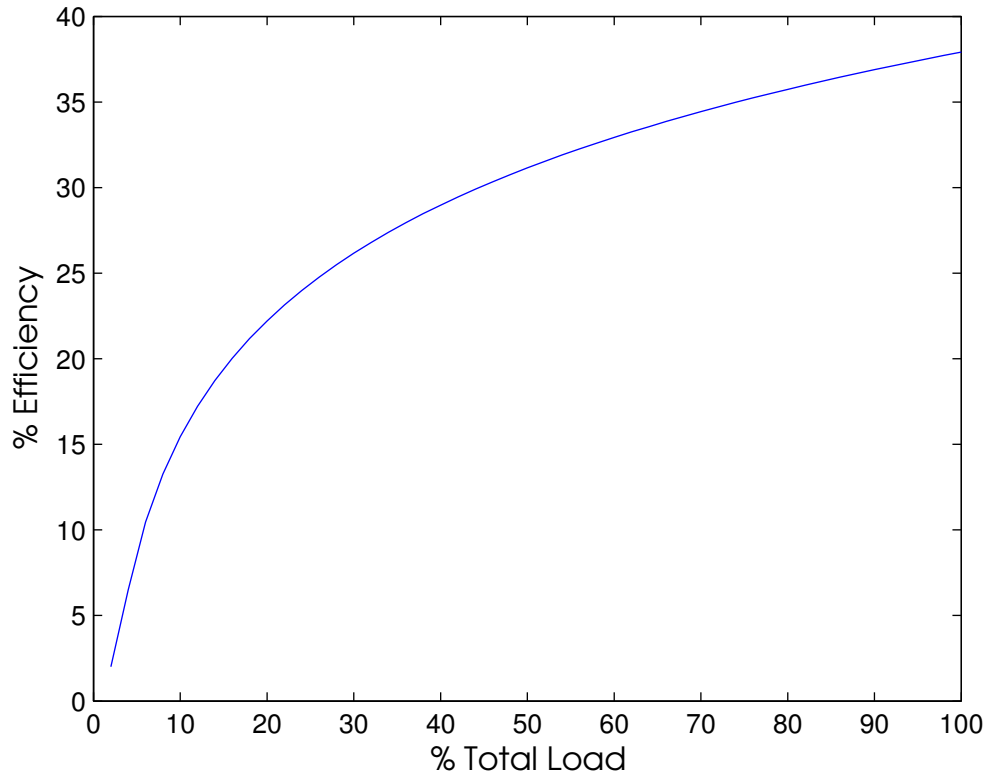


Figure 3.3: Load-Efficiency Curve assumed for SCGTs

not needed in operation. This means that however many GT modules the optimisation model decides is necessary for smooth operation, there will always be an additional one added to the final price.

Cost estimates for SCGT are quite varied. Greenblatt et al assumes they can be costed at \$300/kW [26], whereas General Electric sells 33 MW turbines at 14.325 million USD, implying \$435/kW [24]. It should be noted that the first source assumes onshore applications whereas GE's LM2500 model is specifically designed for seafaring vessels. However, it is based on a single specific model instead of being averaged out among various different types to account for high and low priced types. Lastly, DNV GL investigated optimising FPSO power plants for their OPer project and came up with a base cost of 15-18 MUSD for 25 MW SCGT FPSO power systems [17], equating to about \$600-720/kW USD. Despite it having a higher cost, DNV GL's conservative price estimate of 720 \$/kW was chosen since theirs is actually used for an offshore oil and gas processing facility similar to this case study.

Likewise with the capital costs, the fixed and variable O&M costs for SCGTs also vary from

source to source, ranging from 5.26 to 10.8 USD/kW-yr and 0.0013 to 0.0299 USD/kWh respectively [26] [6]. The more conservative cost estimations shall be used for this study since these figures are based on much larger power plants (+200 MW), and its O&M rates are likely higher per unit power/energy for the smaller scale GTs being used in this case study.

Taking an existing cost figure for a full scale SCGT and simplifying it into \$/kW is not an ideal way of scaling costs, since often larger-scale plants are more cost efficient than smaller ones. However, since we are using the most conservative prediction, we are assuming that this will account for higher costs associated with smaller plant designs.

The SCGT uses natural gas (NG) as a fuel, and standard NG characteristics shall be used as summarized in Table 3.2:

Table 3.2: Fuel Characteristics		
Characteristic	Value	Source
Fuel Costs	12.02 Euros (2014)/MWh	[30]
Total GHG Emissions	237.6 kg _{CO₂equiv} /MWh	[26]
NG content	200.2 kg _{CO₂equiv} /MWh	
Upstream	37.5 kg _{CO₂equiv} /MWh	

The overall costs of the backup SCGT generators are summarised in Table 3.3:

Table 3.3: SCGT Costs				
Cost Type	Original Value	2014 Euros	Unit	Source
Capital	720,000 (2012 USD)	547,031	/MW	[17]
Fixed O&M	10,800 (2004 USD)	9,973	/MW-Yr	[26]
Variable O&M	29.9 (2009 USD)	24.31	/MWh _{el}	[6]
Fuel		12.02	/MWh _{fuel}	[30]
GHG Tax ¹		12	/MWh _{fuel}	[19], [26]

3.2.5 Energy Storage Technologies

PHS Energy Spheres

For this case study, we will use MIT's energy sphere concept due to the sheer amount of investigation that Greg Fennell performed [18]. Despite that there are no test plants in operation to produce empirical data, the in-depth study seems to be suitable. Since there were performance

¹the GHG tax is calculated from the CO₂ emission content of NG and the accepted Norwegian CO₂ tax

concerns discussed regarding the ventless design, we shall use the vented design that will see the vents being installed along with electrical cabling for the windpark.

The pump and turbine efficiency used in the energy spheres is based on common estimates for existing pumped hydro storage, and are assumed to be 90% and 80% respectively, making a roundtrip efficiency of 72%. It is assumed that the energy sphere storage system is capable of reaching 0% capacity with no negative effects, meaning $E_{ES,min} = 0$.

The Black & Veatch corporation amalgamated cost data from nearly 500 hydro power projects and determined that the powerhouse equipment for a 500 MW hydro facility costs 556 USD/kW [6]. However, these turbines are designed for on-land purposes using fresh water, not salt water - therefore a 15% additional factor for marinization of the components shall be applied, which is based upon the marinazation of for similarly complex mechanical and electrical components - wind turbines [20]. Therefore the pump turbine equipment will cost approximate 640,000 USD (2006) per MW.

MIT's Los Angeles and San Francisco case studies which create a 3 GW, 10 hour energy sphere storage system connected with a wind farm at 500m depth use 2400 spheres of 32 m diameters. This equates to each sphere providing 1.25 MW of power and capable of 12.5 MWh of storage. Costs for the entire storage parks are broken down between the energy spheres themselves, including pump turbines (material), the electrical cable to shore (neglected in our case), molds (manufacturing) and barges, towing and installation (installation). Additionally, the vents required to sustain each vented energy sphere will cost \$176.4 USD per metre. As a result, we can assume the individual costs of each sphere as listed in Table 3.4:

It is assumed that the size of the pump turbine has a relatively little impact on the pricing of installation and vent costs. Therefore, the energy storage capacity cost of the energy spheres is summarized as 198,500 USD (2011) per MWh while the power costs are 640,000 USD (2006), or 714,000 USD (2011) per MW (which is based solely upon pump turbine cost predictions detailed above).

These energy spheres are designed with longevity and robustness in mind, with a 40-year lifetime. Only the pump turbines are assumed to require maintenance work, leading to a maintenance cost prediction of 1% of the entire storage system (including manufacturing and deployment) over its 20 year lifetime. Therefore, the fixed O&M costs of the energy spheres is assumed

h

Table 3.4: Energy Sphere Cost Breakdown in thousand USD (2011)

Costs	Entire Plant	Each Sphere	Per 1 MW, 10 MWh unit
Spheres (Incl. Pump Turbines)	6,328,000	2,637	2,109
Spheres (Without Pump Turbines)			1395
Vents		88.2	70.6
Molds	236,000	98	79
Barges	302,000	126	101
Towing	668,000	278	223
Installation	348,000	145	116
Installation Total	1,318,000	549	439
Total	7,882,000	3,372	2,698
Total without Pump Turbines			1,985

to be 1350 USD (2011) per MW-Yr. No variable O&M costs are provided.

Overall pricing of the energy sphere PHS system is represented in Table 3.5:

Table 3.5: Overall Energy Sphere Costs

Component	Original Value	2014 Euros	Unit	Source
Power (Pump Turbines)	640,000 (2006 USD)	553,100	/MW	[6],[20]
Capacity (Energy Sphere)	198,500 (2011 USD)	151,420	/MWh	[18]
Fixed O&M	1350 (2011 USD)	1,046	/MW-Yr	[18]

CAES Energy Bags

We assume that the CAES subsea technology being used will be of a similar setup to Hydrostor's solution and will use excess energy to compress air from the surface into inflatable energy bags anchored to the sea floor. The air will be compressed topside on the platform, and as the air heats due to this process heat exchangers will draw it out and store it within hot water thermal tanks. Once the energy is needed, the compressed air will be reheated with the thermal tanks and drive turbines to produce electricity. Therefore the entire process is adiabatic, and there will be losses from heat exchangers, the thermal storage system, and pressure losses throughout the system.

Hydrostor claims to achieve a roundtrip efficiency of 60-70%. This is far more conservative than some predictions of onshore facilities which range from 77-89% [26], but considering the uncertainty of offshore storage, the most conservative seems appropriate. Therefore for this

case study we will use a round trip efficiency of 60%.

The energy bags themselves will be of A. Pimm et al's optimal subpressure balloon with hanging ballast design [38]. Based on a mathematical optimisation using equilibrium equations to minimise the bag cost function and associate material cost assumptions, at a depth of 500 metres this energy bag design costs £907/MWh in 2009 of potential stored energy if expanded isothermally. This cost includes the mooring system (anchor and cables) and ballast for the energy bag, and is assuming each one is capable of storing 2249 m³ of air at 50.96 bar of absolute pressure, or 12.52 MWh of energy. However, since we are modelling this system off of Hydrotor's adiabatic solution, this needs to be recalculated. Using initial, atmospheric conditions (1 bar pressure, 20°C) and compressing adiabatically, 7.73 MWh of energy is stored, which translates to £ 1,469/MWh, or € 2,107/MWh. It should be noted that this includes only material costs, and manufacture, transport and installation will raise the price. Since this information is not available, we shall assume a similar installation cost to that of the PHS energy spheres: 43,900 USD (2011) per MWh, or € 34.3 per kWh. It is assumed that these bags are designed not to be maintained, and will simply be replaced if there are defects. Due to their simplicity and rugged material, it is assumed that they would withstand a lifetime at least as long as most windparks; approximately 20 years.

The remaining equipment - heat exchangers, compressors, turbines and thermal storage tanks - will be located on the platform, and is based on existing technology. According to Greenblatt et al [26], the total cost ground-based CAES systems (discluding storage) is roughly equivalent to 1.63 times the combined compressor and expander costs. Since they are examining older plants without thermal energy storage capabilities, we can assume that this cost estimate does not include such features. However, heat exchangers are required for the older designs to expel the heat from compressed air into the atmosphere, so we can assume these costs are already included.

The amount of heat produced by compressing enough air to fill these energy bags is approximately 25.4 kWh (calculated using Ideal Gas Law and heat energy equations), meaning that for each MWh of energy bags, it is required to have 3.3 kWh of thermal storage. Based on research by Herrmann et al on molten salt storage for solar power plants [28], thermal storage costs conservatively reach US\$ 40 / kWh_{th}, or € 39.27 / kWh_{th} in 2014 Euros. This translates to € 129 / MWh

of energy bag storage.

Assuming standard expander technology that is commonly used for gas turbines, the ratio of heat-input to electrical-output is usually 3:1. Therefore, it is assumed that for each MW-h of stored energy within the energy bags, the thermal tanks must be capable of storing 3 MW-h of heat. Therefore, the tanks cost € 117.8 / kWh_{el}. Costs of the subsea AA CAES system are summarized in Table 3.6.

Table 3.6: CAES Component Prices

Component	Original Value	2014 Euros	Unit	Source
Compressor	170 (2003 USD)	161	/kW	[26]
Expander	185 (2003 USD)	175	/kW	[26]
Heat exchangers	included	included	n/a	
CAES Plant Balance Modifier	63	63	%	[26]
Total		547.7	/kW	
Energy Bags	1.469 (2009 £)	2.107	/kWh	[38]
Thermal Storage	0.132 (2004 USD)	0.129	/kWh	[28]
Total		2.236	/kWh	
Fixed O&M	4 (2003 USD)	3.78	/kW yr	[26]
Variable O&M	0.003 (2003 USD)	0.00285	/kWh	[26]

3.2.6 Transmission

Local Power Transmission

The collection system for the offshore wind park - that is, the system of cabling and transformers that gathers the power production of the entire wind park and sends it to a central collection point - is assumed to part of the wind park costs and is therefore not included in this study. The most proven and cost-effective collection voltage is approximately 30-36 kV according to [7], and will be used for these cases.

Power-from-Shore Equipment

Studies have been done evaluating using combinations of HVDC and HVAC, but the results have shown that these compromises never provide fewer losses than a single system [36]. Therefore, combinations will not be considered. The most economic system is highly dependant on the distance, with HVAC being the more affordable choice in scenarios under 90 km [7].

For offshore wind park applications, it is the general consensus of the industry that HVDC VSC systems are superior to that of LCC despite having higher power losses due to their enhanced versatility for multi-terminal situations and not being dependant on strong AC networks on either end [16] [7] [3] citeDeAlegria2009 [36]. Many experts do not even consider LCC in their analyses due to this shortcoming. Additionally, modern advancements in multilevel VSC technology reduce losses from 3% to 1% [3]. Therefore, it is assumed that a modern, high-efficiency (1% losses) multilevel VSC HVDC transmission system is the most ideal for an offshore wind application and will be used as the HVDC option for these cases.

Simplified power loss calculations will be based on the derived calculations developed by Stefan Lundberg [35]:

Subsea HVAC cables are assumed to be XLPE-insulated with three copper cores, and the power loss (including both resistance and reactive power losses) is calculated with Eq. (3.1)

$$P_{loss} = P_0 l + C_0 l^3 + P_k l \frac{S_{in}^2}{S_n^2} \quad (3.1)$$

Where:

P_{loss}	Losses [W]
P_0 and C_0	No-load parameters
P_k	Load parameters
S_{in}	Input power [VA]
S_n	Rated power of the cable = $3V_{rated}I_{rated}$ [VA]
l	Length of the cable [km]

The P_0 , C_0 and P_k parameters are based on pre-calculated values done in Lundberg's work, showing in Table 3.7.

Table 3.7: HVAC Cable Power Loss Coefficients

Voltage (kV)	Po	Co	Pk
11	5.01	0.0212	57656
22	13.08	0.0354	57656
33	21.48	0.0421	57656
45	38.4	0.0694	57656
66	70.71	0.1069	57656
132	200.87	0.1726	49470
220	530.3	0.2982	51211

P_{loss}	Losses [W]
P_k	Load parameter=58742
P_{in}	Input power [W]
P_n	Rated power of the cable = $V_{rated}I_{rated}$ [W]
l	Length of the cable [km]

By interpolating these parameters, the power losses at any voltage HVAC cable can be calculated.

It is assumed the HVDC cable will be constructed with similar materials, and therefore the power losses will be calculated based on Eq. (3.2).

$$P_{loss} = P_k l \frac{P_{in}^2}{P_n^2} \quad (3.2)$$

Cables are costed using Eq.(3.3) and Eq.(3.4) for HVAC and HVDC respectively.

$$Cost_{AC} = (A_p + B_p \exp \frac{C_p S_n}{10^8}) 0.123855 \quad (3.3)$$

$$Cost_{AC} = (A_p + B_p P_n) 0.123855 \quad (3.4)$$

Where:

$Cost_{AC}$	Cost of the AC Cable [€]
$Cost_{DC}$	Cost of the DC Cable [€]
A_p, B_p, C_p	Cost constants, listed in Table 3.8 and Table 3.9
S_n	$\sqrt{3}U_{rated}I_{rated}$
P_n	$U_{rated}I_{rated}$

Table 3.8: AC Cable Cost Coefficients			
Rated voltage [kV]	$A_p [10^6]$	$B_p [10^6]$	C_p
22	0.284	0.583	6.15
33	0.411	0.596	4.1
45	0.516	0.612	3
66	0.688	0.625	2.05
132	1.971	0.209	1.66
220	3.181	0.11	1.16

Transformers are costed using Eq.(3.5).

Table 3.9: DC Cable Cost Coefficients

Rated voltage [kV]	$A_p[10^6]$	$B_p[10^6]$
5	-0.346	0.408
40	-0.314	0.0618
160	-0.1	0.0164
230	0.079	0.012
300	0.286	0.00969

$$Cost_{TR} = (A_p + B_p P_{rated}^\beta) 0.123855 \quad (3.5)$$

Where:

$Cost_{TR}$	Cost of the transformer [€]
A_p	Offset constant = -1.208×10^6
B_p	Slope Constant = 2143
β	Exponent = 0.4473

HVDC voltage source converters are based on the assumption that they cost approximately 0.123855 €/VA, according to [35]. This rough model seems to match up with actual VSC cost data gathered from [16], supporting Lundberg's predictions.

Unfortunately, despite all of the cost estimates gathered, due to time constraints the transmission module is not programmed into the model.

3.2.7 Grid Codes

Since this case study is assuming to be offgrid, grid codes are not taken into account.

3.2.8 Summary

The following Table 3.10 summarizes all quantitative assumptions that shall be used in the case study and analysed in the results. All costs are in 2014 Euros.

²Base Fuel and GHG Tax costs combined

Table 3.10: Assumptions Summary

Parameter	Value	Unit	Confidence	Source
General				
Discount Rate	17	%		[18]
Project Lifetime	20	Years		
Demand Curve				
Demand Curve	See Fig. 3.1	MW		[31]
Peak Demand	70	MW		[17]
Wind Power Profile				
Wind Curve	See Fig. ??	MW		[15]
Wind Nameplate Capacity	150	MW		
Wind Cost	3,290,000	€/MW		[18]
Energy Storage - PHS				
Charging Efficiency	90	%		[18]
Discharging Efficiency	80	%		[18]
Capital Costs (Power)	553,100	€/MW	±25%	[6], [20]
Capital Costs (Capacity)	151,420	€/MWh	±25%	[18]
Fixed O&M Cost	1,046	€/MW-Yr	±25%	[18]
Energy Storage - CAES				
Charging Efficiency	78	%		[18]
Discharging Efficiency	78	%		[18]
Capital Costs (Power)	547,700	€/MW	±15%	[26]
Capital Costs (Capacity)	2,236	€/MWh	±45%	[28]
Fixed O&M Cost	3,780	€/MW-Yr	±15%	[26]
Variable O&M Cost	2.85	€/MWh-Yr	±15%	[26]
Back-up SCGT Generators				
Efficiency Curve	See Fig. 3.3			[31]
Cycle-up Time	10	Minutes		[31]
Min. Running Time	60	Minutes		[31]
Module Size	20	MW		
Capital Cost	547,031	€/MW	±15%	[17]
Fixed O&M Cost	9,973	€/MW-Yr	±15%	[26]
Variable O&M Cost	24.31	€/MWh _{el.}	±15%	[6]
Fuel Cost ²		€/MWh _{fuel}	±15%	[30], [19], [26]

Chapter 4

Presentation of Results and Discussion

4.1 Cost Comparisons

Cost comparisons will directly compare the different scenarios final costs in a variety of different situations.

4.1.1 Standard Case

Using all of the assumptions outlined in Chapter 3, the model is used to assess the optimal sizing of the system in three different simulations: the base scenario, using only the SCGT back-up as a supplementary powersource to the main; the PHS scenario, using PHS as the ES technology; and the CAES scenario, using subsea CAES as the ES technology. The cost outcomes of all three simulations are directly compared in Fig. 4.1, each broken down into six relevant costing categories. Additionally, each technology's costing confidence band is implemented into the simulation, and is shown by the error bars on the graph:

The base scenario, which uses no ES technology options, naturally has zero expenses for ES technology. The initial costs of the investment are entirely in the Backup (BU) capital costs, while the yearly costs over the 20-year lifetime of the project are split into three: O&M of the SCGT equipment, fuel costs, and GHG taxations. As is shown in Fig. 4.1, the yearly costs over 20 years account for more than the entirety of the initial investment. By comparison to the cost of the wind power plant itself (526.4 million €), this system adds 25% to the initial investment.

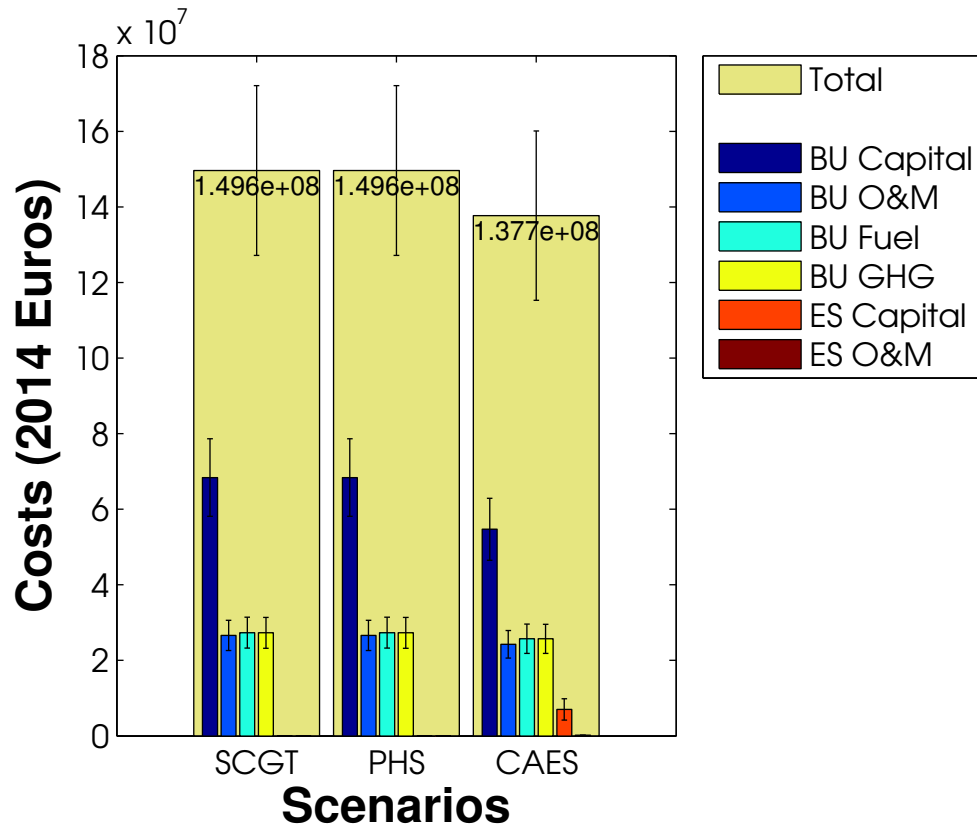


Figure 4.1: Basic Optimised Cost Comparison between Base, PHS and CAES

The next two simulations use PHS and CAES technologies. The PHS simulation has yielded identical results to the base scenario. This implies that the cost optimised solution is to use only backup power and forego the PHS tech entirely because, in its current state, is simply too expensive. However, the CAES option has successfully determined a setup that will yield a cheaper net result than the base scenario, as shown in the graph. It has determined that utilising 2.12 MW CAES system with a storage capacity of 2,622 MWh will be cheaper - namely because this setup requires one less SCGT unit. In these simulations it is assumed that each SCGT unit is 25 MW, while the maximum demand is 70 MW + 10% (to account for the potential of wind curve variation). In order to cover max demand in a no-wind situation, 4+1 units (due to the N+1 sparing ideology) are necessary to cover the final 2 MW. Therefore, at a relatively low cost, those 2 MW can be instead covered by an ES system, as is the case in the CAES simulation.

4.1.2 Extreme Case

However the cost data used for running these simulations is subject to large costing confidence errors as demonstrated by the error bars in Fig. 4.1 and the assigned confidence bands shown in Table 3.10. Therefore, a worst and best costing case scenario is devised. The terminology of 'worst' and 'best' is from the viewpoint of promoting the use of ES - that is to say, the worst case scenario assumes that the backup generation system (capital, O&M, fuel and GHG costs) is actually lower than expected, while the ES technology costs matches the maximum prediction. The best case scenario assumes the opposite. Once again, three simulations are run for both of these scenarios and compared in Fig. 4.2 and 4.3:

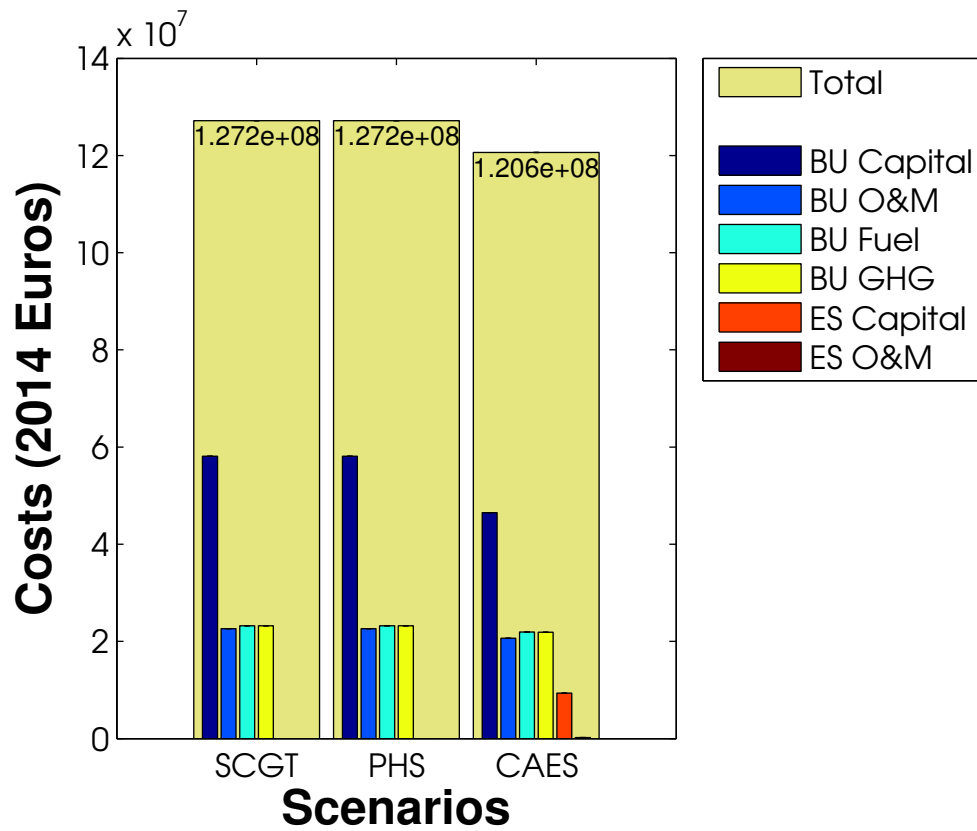


Figure 4.2: Worst Case Scenario Cost Comparison

As can be expected, running a scenario such as this worst case scenario where the costing conditions for the ES technologies are even less favourable yields the same conclusion for the PHS simulation - the ES technology is simply too expensive, and the optimisation model chooses to forgo ES entirely. However, even with the cost increases of the ES technology, the

CAES simulation is still considered to be cheapest when using just over 2 MW of ES, likely for similar reasons stated previously. It can be noted that overall costs on all simulations have decreased, however, since the backup system has become cheaper and it is still the most prominent contributor to cost.

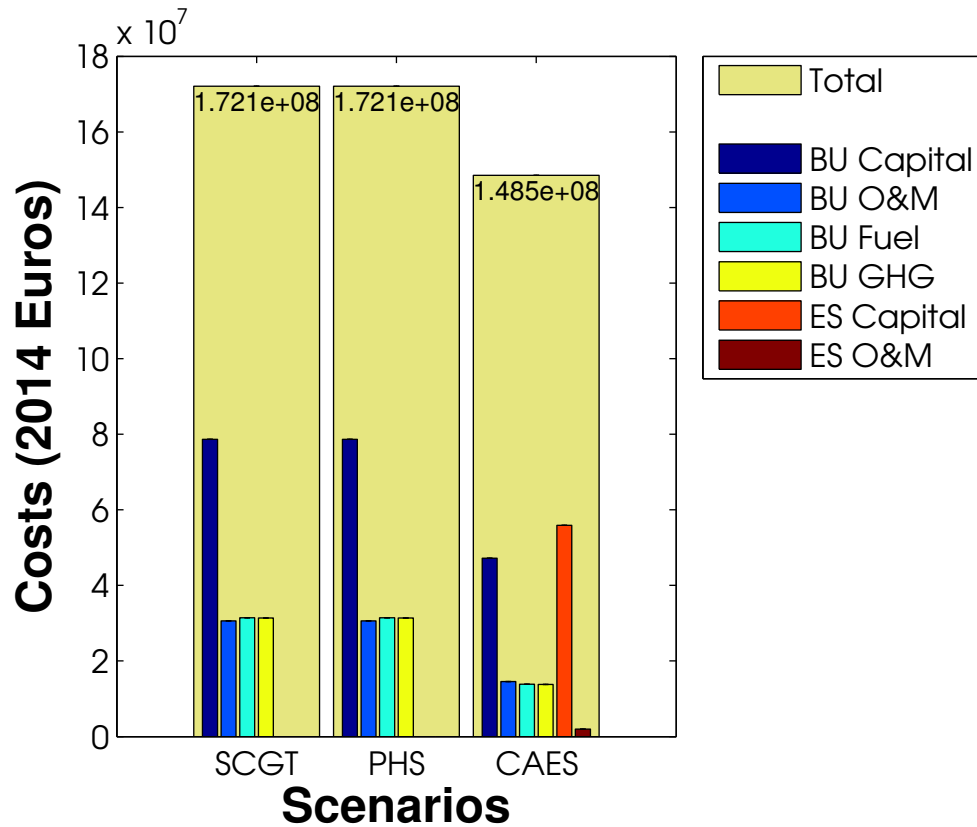


Figure 4.3: Best Case Scenario Cost Comparison

Minimising ES technology costs still has had little effect on the outcome of the PHS technology simulation, meaning that even within its large costing confidence error limits it is still considered to be too expensive to even consider. However, the CAES technology has become sufficiently affordable (in comparison to the increasing prices of the backup system) that an even larger system is used; approximately 28.7 MW and 34,601 MWh of storage. This allows the backup system to be reduced to 2+1 SCGT units, reducing capital and fuel-related costs. In this simulation, the CAES system capital costs actually surpass that of the SCGTs, while by contrast the yearly costs (O&M) are almost negligible.

4.1.3 ES Only Case

We already know that both ES technologies are expensive in their current form and cannot compete with a SCGT backup power system to replace it entirely. However, we could imagine a scenario where it is absolutely paramount that reliance on fossil fuels be eliminated, and the entirety of any additional power being supplied to the consumer be from green power. There are many reasons why this may occur, but the most likely ones would be to meet aggressive emission targets that could be required in the future, or developing strong proof-of-concept plants. Without considering the option of increasing the size of the primary power system (the wind power plant), the only other option is to design a suitably sized ES system that can compensate for the lack of back-up power. Since, as stated in the assumptions, the wind power plant has been sized to produce 115% wind energy penetration, it should be possible to fulfil all of the consumer's needs from this source with an adequate amount of ES.

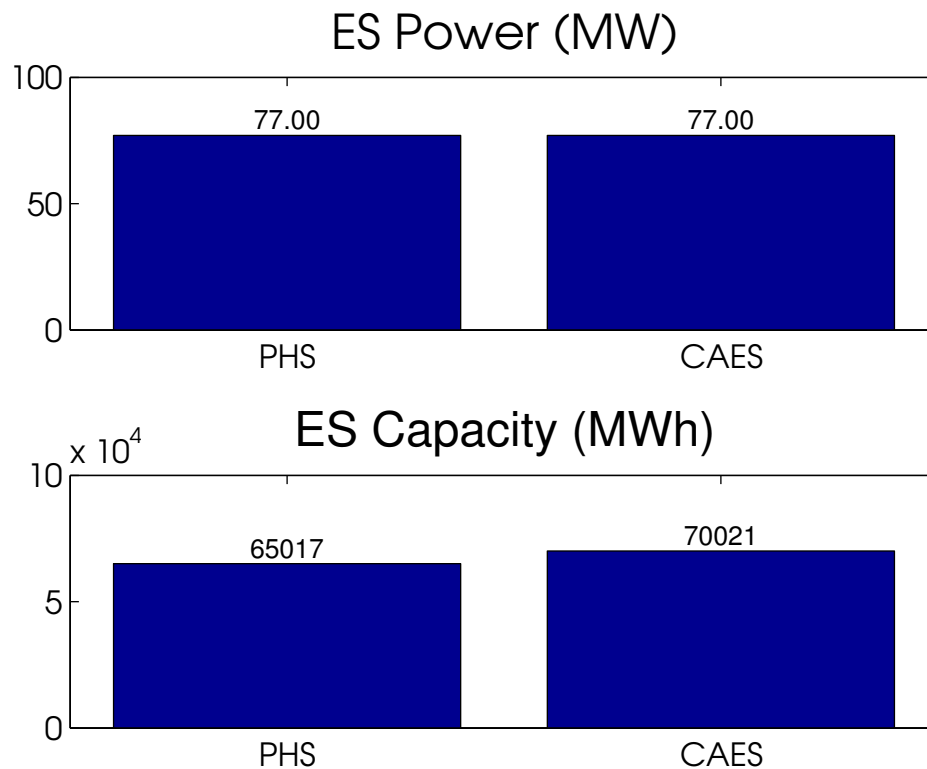


Figure 4.4: Costs of a PHS-only System

Therefore the next set of simulations are designed to not factor in a backup power source at all; in fact, the only costs related to the SCGTs that remain is the cost and O&M of a single SCGT

unit to provide emergency backup, as well as the fuel costs related to initially powering up the ES to allow it to start at full capacity. This was done by putting a constraint on the optimisation algorithm forcing the ES system to be capable of matching the demand curve at all times.

The resultant ES simulations for both PHS and CAES were sized very similarly, as shown in Fig. 4.4, with CAES requiring a slightly larger system. This possibly accounts for its lower efficiency of transforming excess electricity to and from stored energy. Considering peak demand is 70 MW + 10% and there are periods of time when the wind does not blow (meaning the primary power production will be zero), it is reasonable that the ES be sized to 77 MW to account for this. However, it is interesting to note that both systems require an extremely large amount of ES capacity in order to become completely fossil fuel independent - approximate 35 days for PHS and 38 days for CAES, which has a slightly larger required capacity due to it being a less efficient system. However, since PHS is far more expensive than CAES per MWh of storage, its final price tag is much higher. PHS is extremely expensive and would likely never be used in an ES only situation at the current prices.

By contrast, CAES is actually approaching a reasonable pricetag. It is certainly far higher than a SCGT backup system, but by comparison it is only half the price of the wind power plant itself (526.4 million €).

4.2 Sensitivity Analyses

Running sensitivity analyses will determine the level of impact changing certain variables will have on the system allowing us to predict which variables have the potential to bring about the most change to the results of these simulations. This could help give some indication on what changes need to occur for different ES technologies to become more competitive, or how resilient a technology is to unpredictable variables, such as weather effects and fuel prices.

4.2.1 Fuel Price and GHG Emission Tax

Both of these variables have a similar impact on the system - as their cost increases, so does the yearly use of fossil-fuel backup power. Increasing these variables should, in theory, encourage the simulations to adopt a more ES-heavy set-up as the most economic option.

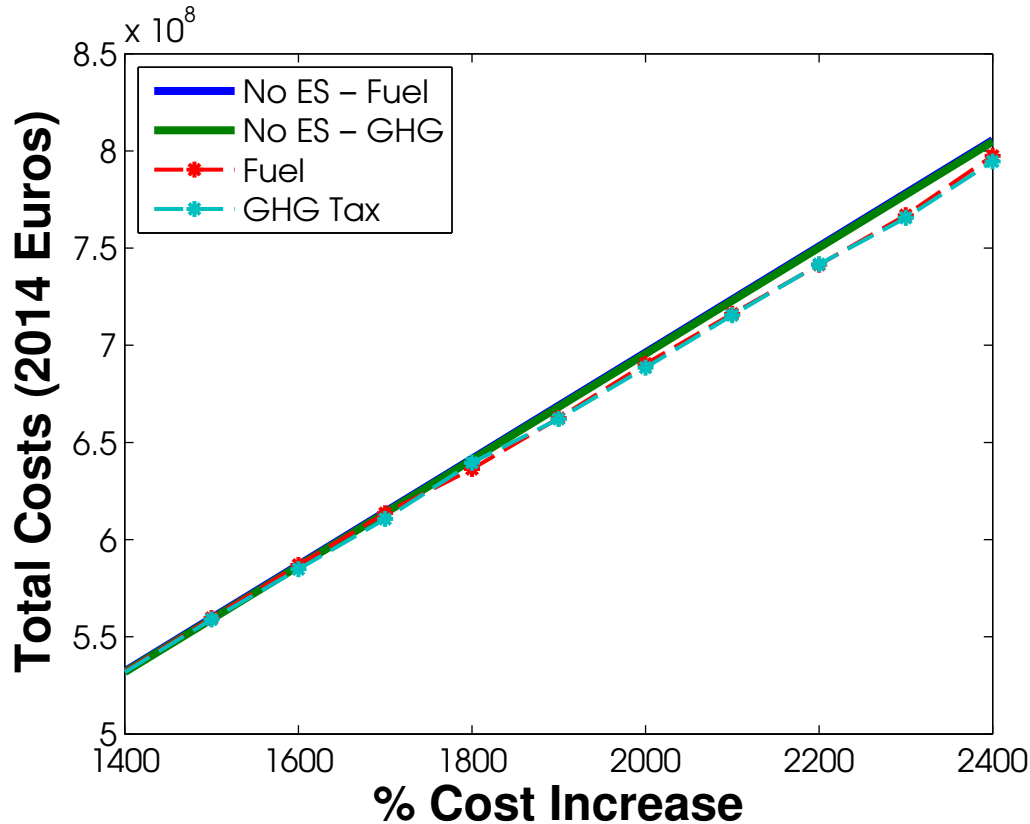


Figure 4.5: PHS: Effects of Increasing Fuel and GHG Costs

As noted in Fig. 4.5, increasing fuel price and GHG taxes eventually will make a PHS system competitive that the simulation will decide to, in part, use ES to keep costs down. However, this only happens in a very extreme situation. As is shown in Fig. 4.6 and Fig. 4.7, PHS is not considered an economic option until prices increase for 1600% and 1400% respectively. While fuel prices and GHG taxes are generally expected to only go up in the future, it may be unlikely that they will reach levels that are this high.

After these so-called break-even points, as costs increase the savings earned from implementing PHS ES further increase, as can be expected. Naturally, even with its use the secondary power system is still predominantly backup generation, meaning increasing costs of fossil fuels will still have significant effect. The rate at which the ES charging power and capacity increase, however, is not as consistent. The general trends shown in Fig. 4.6 and Fig. 4.7 are to gradually increase, but they are full of peculiar spikes. There is no logical explanation as to why these drastic changes should occur as fuel and GHG tax prices increase slightly - if anything, they may

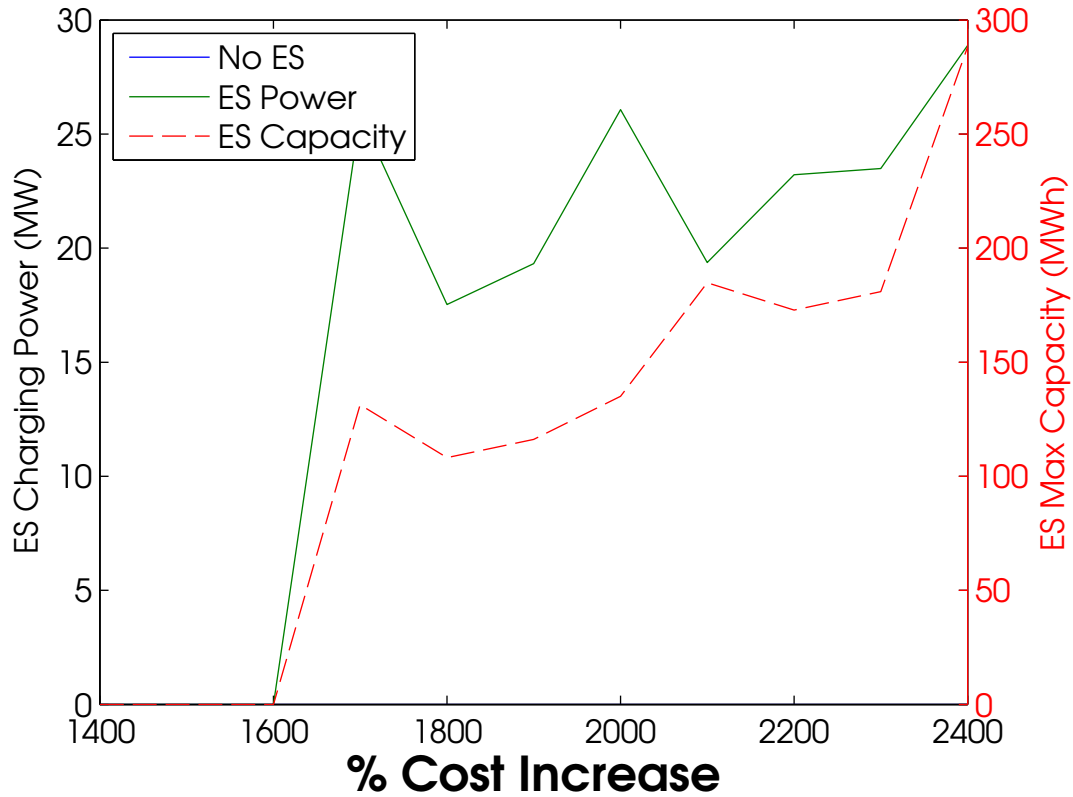


Figure 4.6: PHS: ES Sizing as Fuel Costs Increase

spike suddenly if it becomes cheaper to remove one of the SCGT units entirely and replace it with ES, but there is no evidence of this being the case and the spikes should not suddenly drop again. These may show evidence of issues with the optimisation algorithm itself, which shall be discussed in greater detail later.

The results for CAES yielded similar observations, as can be seen in the appendix section [A](#).

4.2.2 Energy Storage Capital Costs

The next sensitivity analyses performed was the reduction ES capital costs in three different ways:

1. Power costs - Reducing price per MW
2. Capacity Costs - Reducing price per MWh
3. Both reductions combined

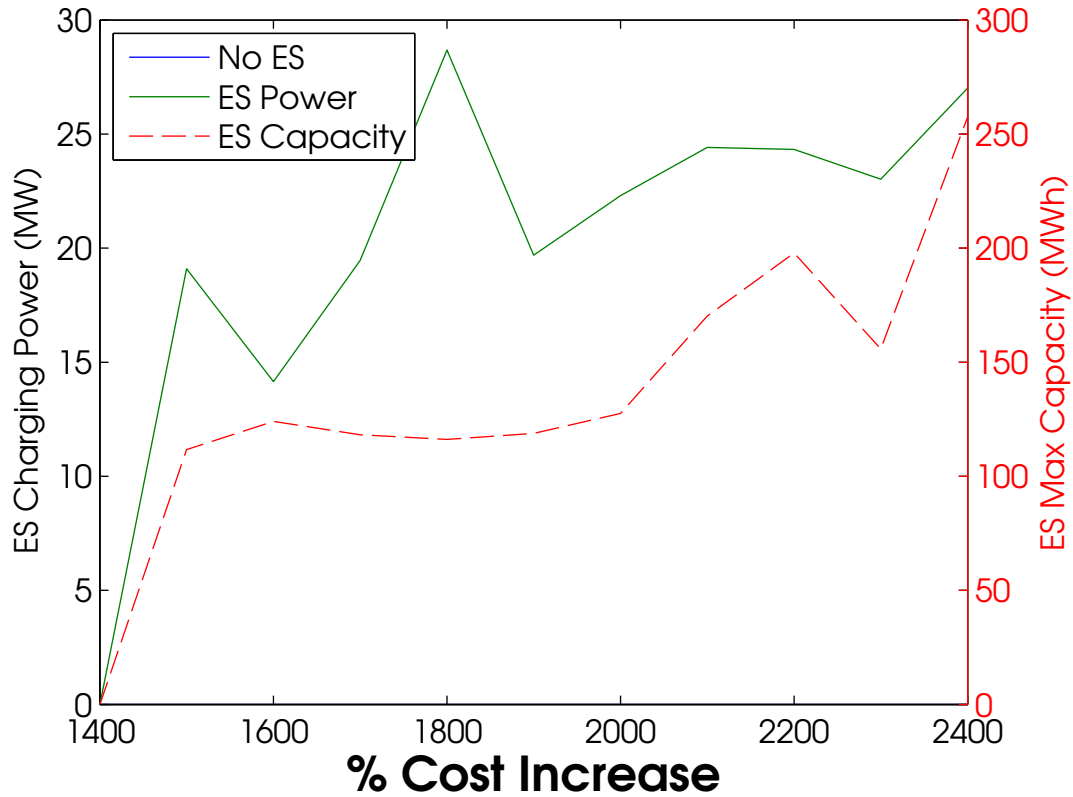


Figure 4.7: PHS: ES Sizing as GHG Costs Increase

As noted in Fig. 4.8, what is particularly noteworthy is that the cost of the capacity of the ES (price per MWh) seems to have a greater effect on the total cost of the system. In fact, even removing the power cost entirely from the PHS simulation yielded no change - the model still decided that having no ES is the cheapest option. However, reducing capacity costs begins to have a far more significant effect. Since we have seen in previous simulations that the ES system usually tends to be sized with a large capacity (100+ hours) in relation to its power, it is logical that reducing the price of capacity would have the greatest impact.

Again, we are seeing some unusual results, mainly from the CAES simulations. Instead of consistently deviating in cost from the No ES simulation as would be expected, they tend to fluctuate up and down between the 0%-60% region. This makes little logical sense - as ES capital costs decrease, an ES system should not become more expensive. This provides further evidence that there may be something wrong with the optimisation, and will be further investigated.

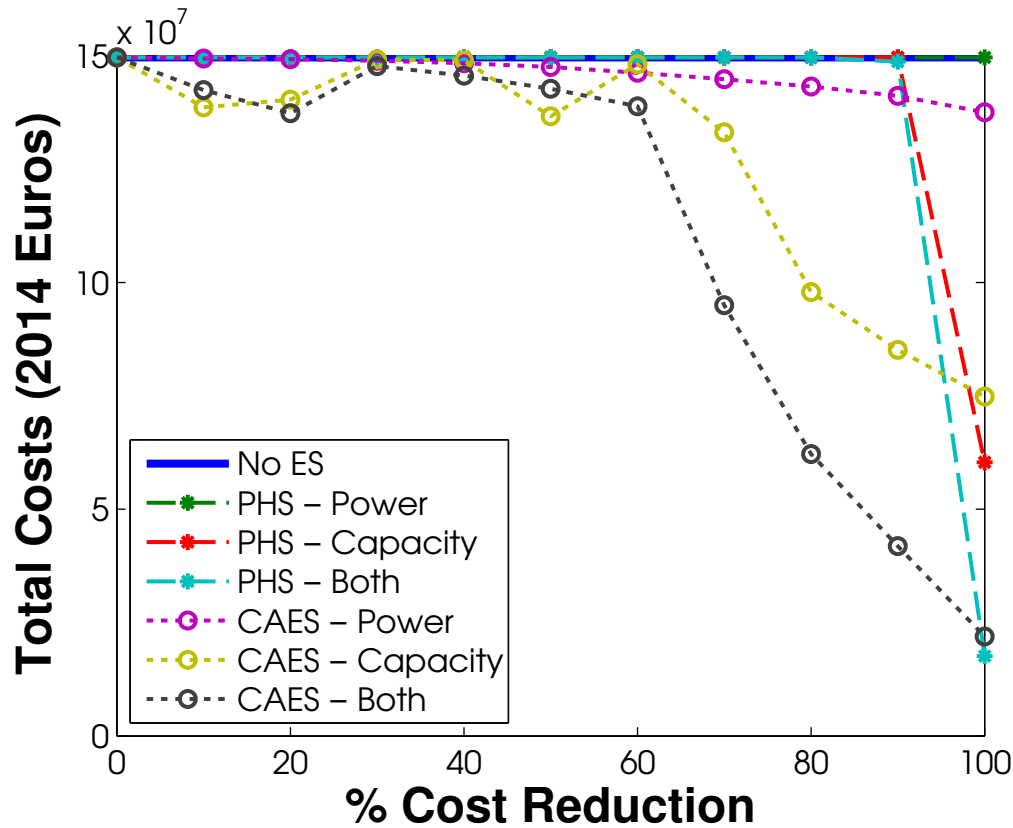


Figure 4.8: Cost Comparison of ES Only Systems

4.2.3 Change in Base Production Power Curve

To evaluate the sensitivity of the model to changes in power production, we run an additional case study using a different base power production curve. While using an intermittent base power source such as wind, it is quite likely that the actual conditions will not exactly follow those defined in the model. Even though we accounted for this by using an averaged wind power curve and adding a 10% sizing to account for fluctuations, it may be interesting to see how the results of the model are affected when the curve is completely changed.

The overall energy production for the entire year remains the same, but a noise generator is introduced to randomise the time-period by time-period power production. The result is a wind power profile that is far more random than before with increased rates of variation and reduced periods of consistent power. Using this new wind curve, we ran the standard cost comparison again, as seen in Fig. 4.9.

When comparing to the results using the original power curve in Fig. 4.1, the new costs are

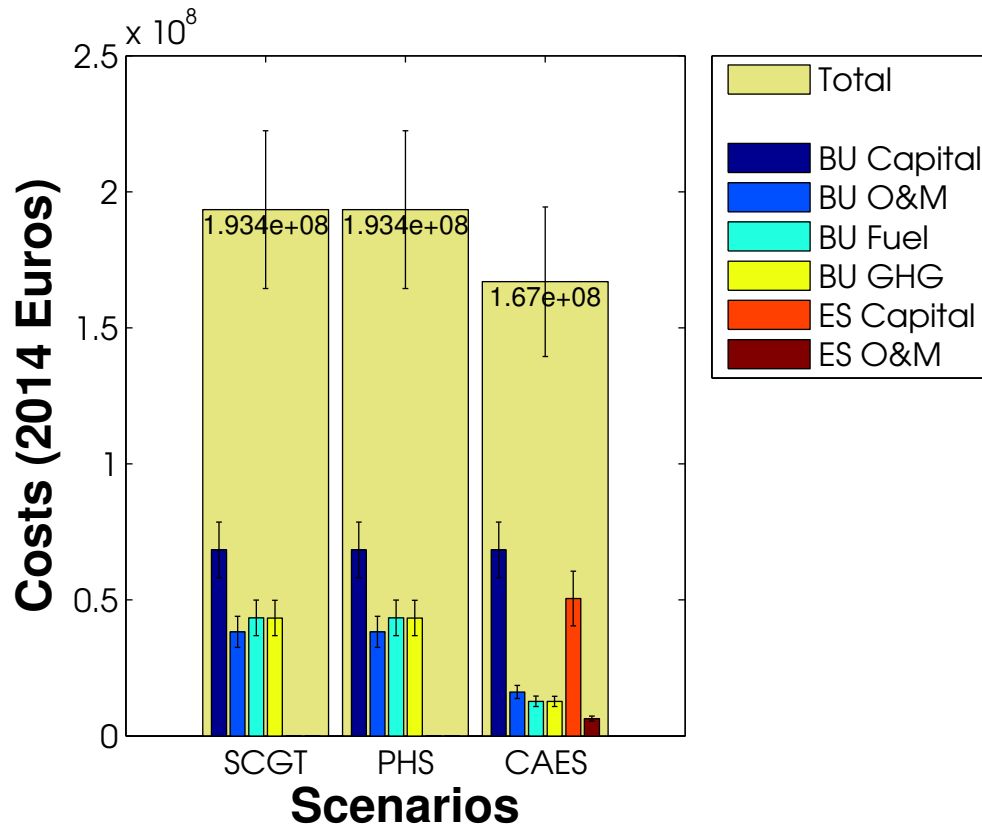


Figure 4.9: Cost Comparison of with Alternate Power Curve

higher for all three simulations (SCGT only, PHS and CAES). Upon closer examination, it appears that additional costs mainly come from the operational expenses in the SCGT only scenario, implying that there is a greater amount of total energy required to supplement the base power source, even if the amount of power provided remains the same. This is because since the base power supply is so erratic, even though the net energy production is the same, the total energy surplus and deficiency when compared to the demand profile is much larger on both accounts. Sure enough upon further investigation it was discovered that this new wind profile would result in approximately 40% more excess energy in periods of high wind while having 60% more required energy in periods of low wind. In a SCGT only scenario, all of the excess energy is simply wasted while the additional required energy naturally increases operational costs, as shown. Meanwhile, as demonstrated by the CAES costs, an ES system will require additional capacity to take advantage of the increased excess energy to meet the increased requirement for a secondary source of energy when the winds are low. As a result, the CAES scenario has a much

larger capital cost, but manages to keep the backup operational costs low.

This erratic wind behaviour, although increasing overall costs, will make ES systems more attractive in relation to the SCGT only base scenario. The opposite can be assumed for more constant wind conditions. This information could be quite valuable for a operator when deciding which wind parks should be investigated to have ES installed.

4.3 Optimisation Algorithm Errors

As mentioned previously, inexplicable and unexpected anomalies in the simulation results have placed the accuracy of the optimisation algorithm itself under suspect. Upon much investigation, testing and scrutiny, the calculations themselves appear to be functioning properly - however, the problem more lies in whether or not the algorithm has decided that the calculated value is, in fact, the correct one. It was theorised that the algorithm is not doing a robust enough job at finding the true global minimum, and occasionally will find a local minimum and assume its the global.

This is a common issue with optimisation problems, particularly ones that have rather complex functions that are not very predictable (such as is the case here). If the problem has many local minima and maxima, the optimisation algorithm can mistake such a minimum as the global one. According to experiences from many other MatLab users, the optimisation function used in this model, *fmincon*, can also run into this issue. A common practice to avoid this is to run the optimisation many times with different initial conditions, as is done in this model. However, it appears this particular function is so complex that we were not thorough enough.

We determined that even though the code was re-run up to seven times with different initial conditions (a practice in itself which could last over three hours), occasionally the global minimum was not found. This was done by manually manipulating the inputs and code and using a 'brute-force' method of checking every single ES combination instead of an optimisation; a method which discovered that lower minimums existed. Unfortunately, this method is extremely resource-intensive from a computational standpoint, and can only realistically be done for small data sets. Performing lengthy sensitivity analyses would likely take days instead of hours.

Chapter 5

Summary and Recommendations for Further Work

5.1 Summary and Conclusions

After much testing, we created a generic cost optimisation model that will size energy storage for a specific power production and consumer demand curve for offshore applications in off-grid scenarios, as was the original goal. One of the key components was to be flexibility, allowing a user to plug in different data sets as they saw fit, and this was achieved using the modular system that was implemented into the model. A demonstration of the flexibility and versatility of the model by showing how different scenarios was done by using case study examples. However, it is still somewhat problematic in that any modules that are to be used must be in a fairly specific format, which hinders versatility. There were plans to improve upon this by having the model automatically be able to detect a wide array of data and compensate for different formats, but this was not included due to lack of time and priority.

Unfortunately, the accuracy of the model has been called into question due to its tendency to locate local minima instead of the true global in certain simulation setups. This hampers the usefulness of the model as it has the potential to provide unreliable results, and should take top priority for future improvements.

The main objectives of the Master have been fulfilled:

1. A literature survey concerning energy storage technologies was performed. Two key technologies, subsea PHS and CAES, were identified as being the most promising for the near future, and were therefore used in our case studies.
2. Cost data for all relevant subsystems of a stand-alone offshore wind park power supply system (energy production, storage, transport, back-up etc) was collected, as well as relevant cost data for gas turbine fuel and CO₂ taxes. All this data was used during the case studies to demonstrate the functionality of the model, and is summarised in Table 3.10.
3. The model developed in the project work was further developed and extended to include cost optimisation. The model now takes into account power generation from a backup source, such as gas turbines, as an addition or replacement for energy storage.
4. Based on several scenarios, optimisation studies using the developed model were performed and presented, in addition to sensitivity analyses.
5. Proposals for further work is made in the following section.

5.2 Recommendations for Further Work

The ultimate goal of this model is to size ES systems for real-world situations that could be relevant for the industry. Unfortunately, it is currently not yet at this stage.

The first priority is to fix the fundamental issue with the model finding the correct global minimum. As suggested, there could be multiple methods to increase chances which may require additional computational resources, such as using the MatLab Global Minimum package. Implementing and testing this would likely have a much higher success rate and could clean up some of the discrepancies that has been seen in the tests. Additionally, gaining access to NTNU's mainframe computers could alleviate the computational resource issue and allow these tests to be run in a timely manner.

At present, the model has utilised an offshore case study with wind power and an oil platform as a consumer, but the model should be flexible enough to use a host of different primary power producers and consumers. The same goes for backup power and ES technologies - if sufficient

research is performed, other technologies of interest could be applied within this model, which would help test its robustness beyond what has been done in this thesis.

It is important to note, however, that the model in its present state is only capable of handling off-grid case studies. Despite that much research has gone into investigating power-from-shore (PFS) scenarios, including technology assessments and cost assumptions, there was not enough time to fully implement this feature into the model itself. Future work would finalize the implementation of PFS scenarios, predominantly in two ways:

- Distance from Shore: This would take into account the distance-related costs of deep-sea power cables and equipment, and examine how far from shore a consumer would need to be until an ES alternative to PFS becomes affordable. In this case, the ES system would need to fully cover the demand load as it being used as a direct replacement of PFS equipment. The resultant optimisation from the ES versus back-up generators scenario could be used to make a more realistic scenario to compare against.
- PFS Equipment Downsizing: ES could be sized as a supplement to PFS, and the optimisation would compare size of ES with savings of reducing cable and equipment power ratings due to intermittent wind fluctuations. This scenario could become more complex and specific, but potentially more interesting to offshore oil and gas technology developers that would like to determine if ES would benefit their system.

Both PFS scenarios will have consumers that are no longer grid-independent. Being attached to the grid drastically increases the complexity of optimisation problem as many new factors are introduced. Studies examining using ES combined with wind parks to take advantage of fluctuating market prices [32][4] have already been done, but there are many other complex features that are quite location dependent, such as grid codes. There may even be additional services that could be provided that could be sold such as black-start capability, further complicating the analysis. A thorough investigation on different types of grid codes would be a worthwhile pursuit, and cataloguing common grid code factors that may influence the simulation would be needed in order to implement these features into the model. Additionally, this would need to be thoroughly tested through case studies and examples from different regions, again to ensure the robustness of the model.

Therefore, a future version of the model would have two additional modules: Transmission, and Grid Codes. This would allow the user to even further specify their scenario down to distance from the grid, type of cabling (onshore, subsea etc), and what kind of grid codes are in effect. All these features would impact the results of the simulation, and create more complex but realistic results.

An interesting facet to consider and implement into the cost model of either of these scenarios would be the cost of a blackout: Originally, we assume that the consumer must have 100% uptime. However, this isn't necessarily true. Guaranteeing that power dependability comes with a price, and blackouts will cost the consumer money. A simple example would be an oil rig where a blackout would disrupt the extraction process, directly translating into lost income. Taking this into the cost consideration may yield interesting results, such that it is actually cheaper to accept a lower power reliability in favour of smaller ES or PfS systems.

Another major barrier to achieving a thorough and useful cost optimisation has always been finding realistic cost data – particularly of offshore ES technologies, of which are still in the technology development phase. Up until the present, focus has been on developing the model itself instead of finding historical cost data (since, in the case of the ES technology, little historical data exists), and many assumptions were made. In the future, more accurate assumptions would be made with the help of more accurate data - perhaps actual industry numbers delivered by an interested party. Numbers for many ES technologies are still unavailable, but perhaps in the coming years that will change as start-up ES companies are beginning to break ground on economic assessments of their technologies. If reasonably accurate cost data can not be achieved, this model will only be able to be used as a vague guide as opposed to a useful simulation.

As noted, there are many improvement points for this model and although the main objectives for this thesis are accomplished, there are many additional goals that were originally considered. Unfortunately the scope of these goals do not line up with the timeframe of this thesis, but hopefully this work can continue and these future work ideas can be one day implemented.

Another feature that would make the model more interesting to the industry would be to include physical size of ES (and possibly the wind farm itself, should this also be designed for optimisation). Offshore operations are much more expensive than on land, and space becomes an important issue [14]. Being able to input an energy density for the ES would allow a com-

parison of physical size of the ES system after the optimisation is complete. Additionally, if a cost metric could be related to physical size, this could help drive the cost optimisation. This functionality has been initially implemented into the model itself, but is not being used due to lack of data and it being low on the list of priorities.

The current infrastructure of the model is entirely in MATLAB, and requires the user to tweak variables in the code to change ES parameters and adjust wind and load data. The learning curve is very high, and in its current state would be very confusing to the average user. Ideally, the model would be shifted over to a more user-friendly interface, like Simulink, that will prompt the user to input specific parameters to customize their simulation run. Ideally, the user would be prompted to select specific modules and assessment packages to run the simulation, allowing the user to operate an entirely graphic user interface. Of course, programming would always be an option for power users desiring more flexibility at the expense of user-friendliness.

Appendix A

Additional Graphs

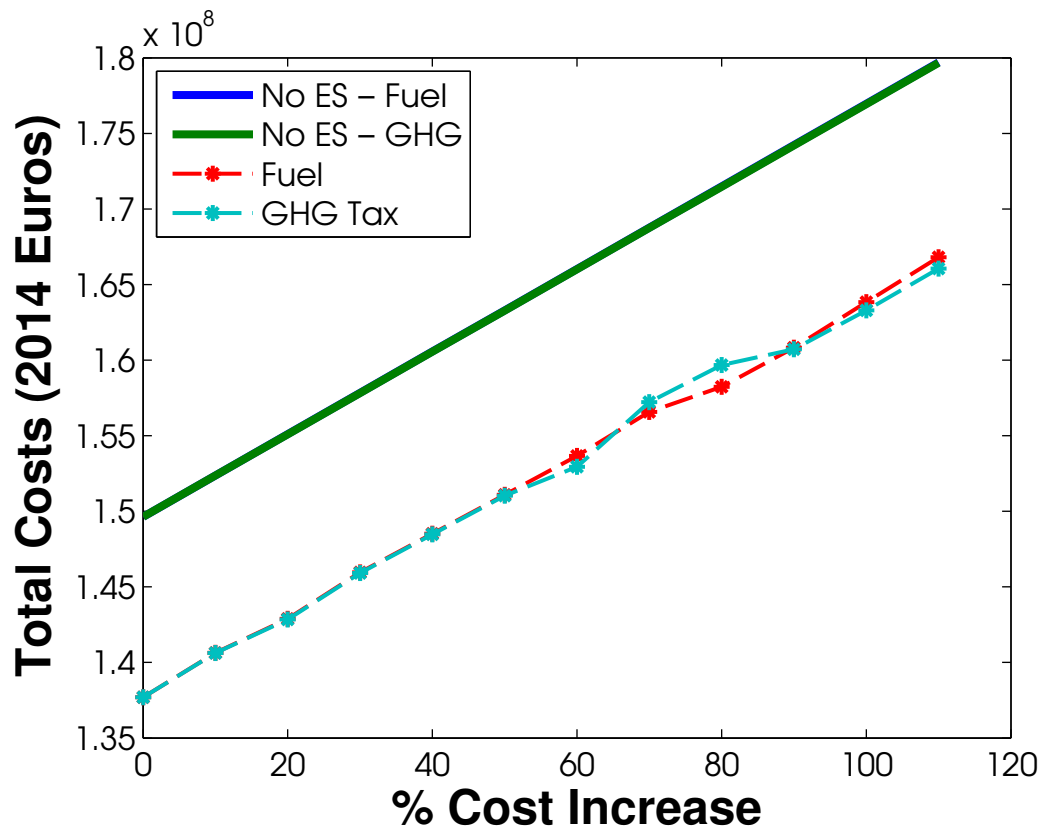


Figure A.1: CAES: Effects of Increasing Fuel and GHG Costs

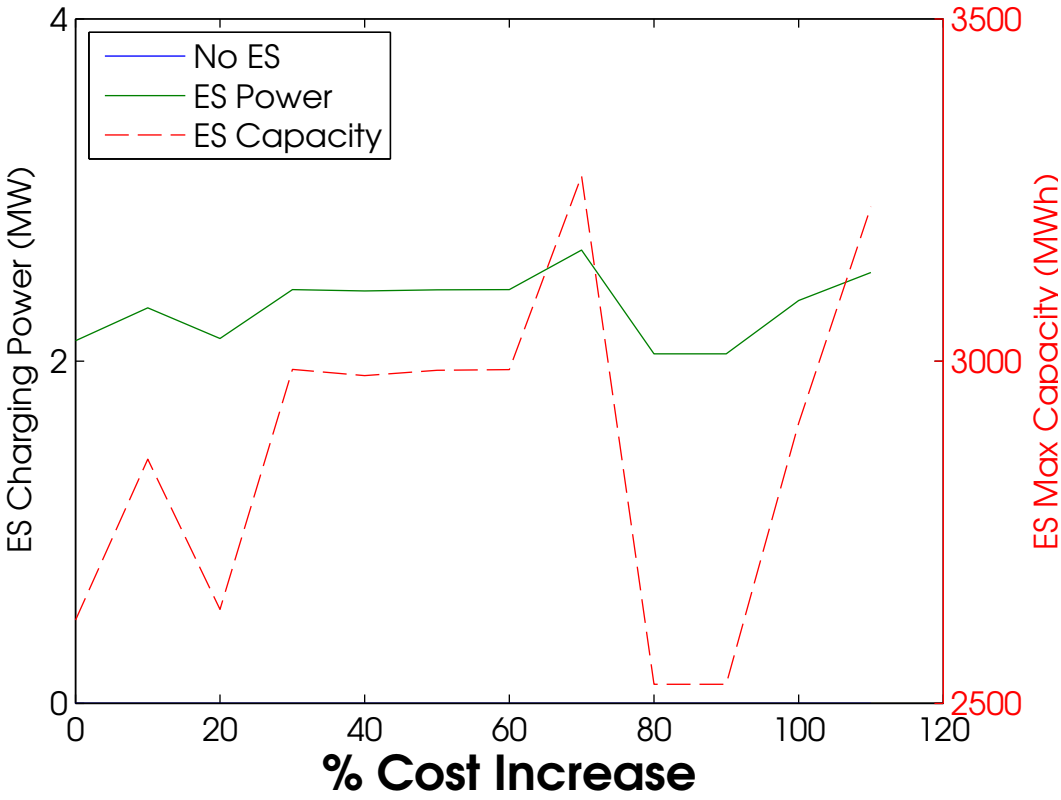


Figure A.2: CAES: ES Sizing as Fuel Costs Increase

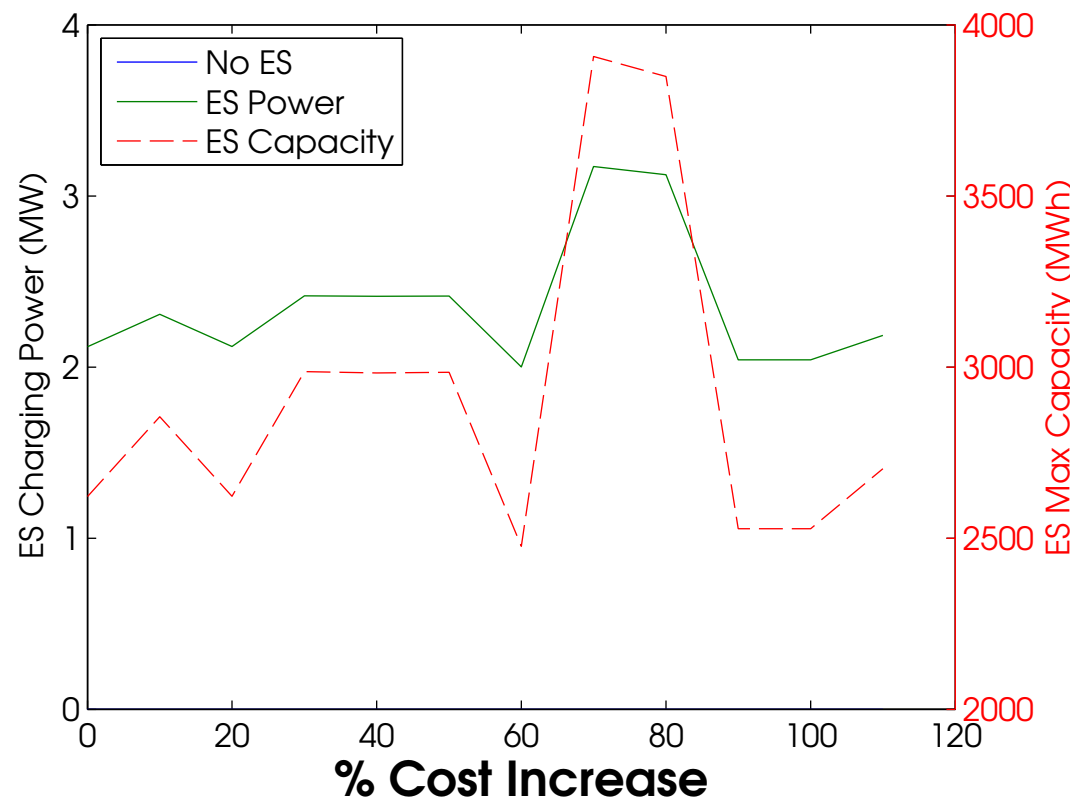


Figure A.3: CAES: ES Sizing as GHG Costs Increase

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